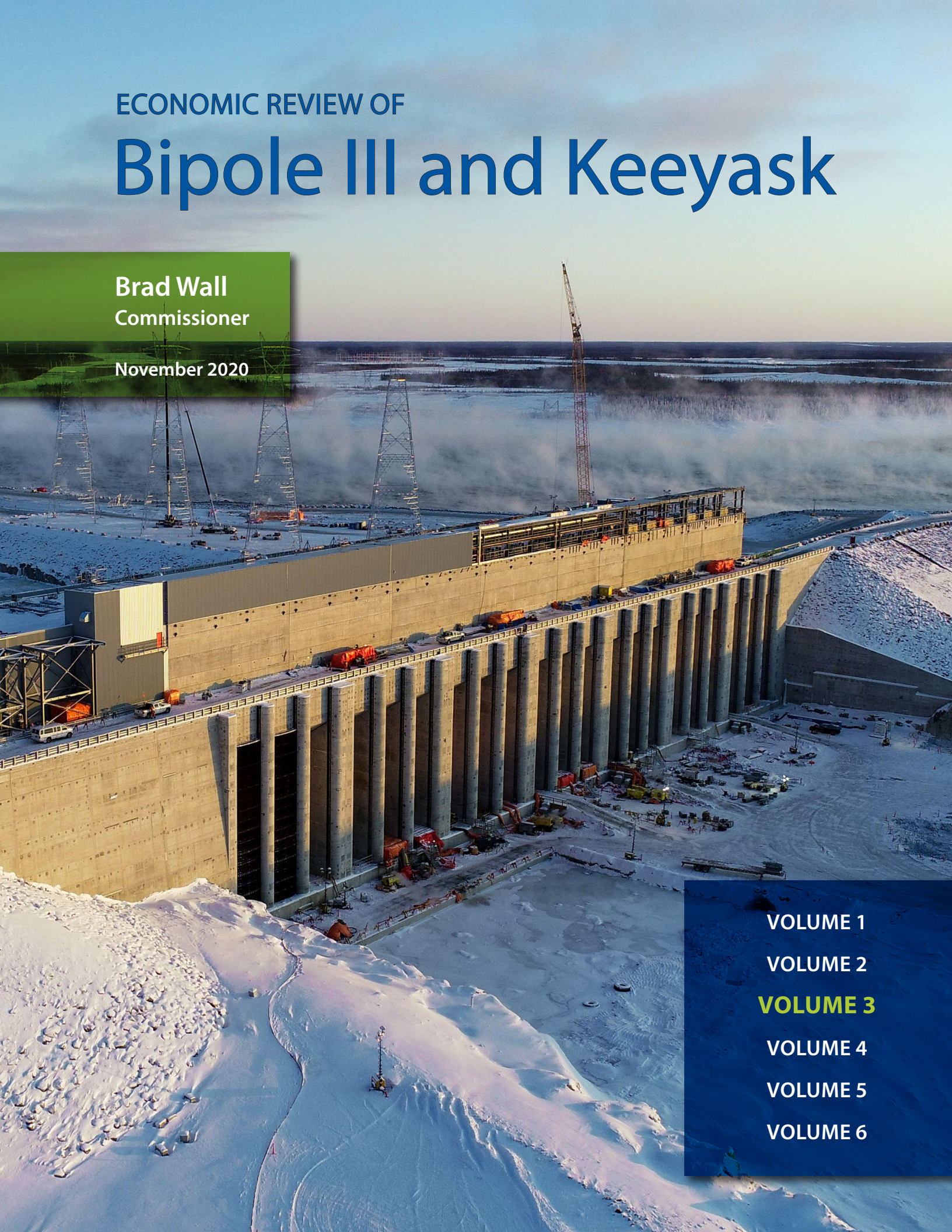
ECONOMIC REVIEW OF

Bipole III and Keeyask

Brad Wall
Commissioner

November 2020



VOLUME 1

VOLUME 2

VOLUME 3

VOLUME 4

VOLUME 5

VOLUME 6

APPENDIX A: NON-CONFIDENTIAL DOCUMENTS CITED

Index of Non-Confidential Documents Cited

Tab	Description	Page
	VOLUME 2	
1	The Western Producer, "Dam-nation: Why Man. plan is too costly," June 28, 2013	1
2	ChrisD, "Selinger: 'Hydro Power is Manitoba's Oil'," September 29, 2011	4
3	Reuters, "Analysis: Obama's climate agenda may face setbacks in federal court," March 24, 2013	7
4	New York Times, "Supreme Court Deals Blow to Obama's Efforts to Regulate Coal Emissions," February 9, 2016	14
5	Manitoba, Legislative Assembly, *Hansard*, 38th Leg., 4th Sess., Vol. 57, No. 55 (April 25, 2006)	18
6	Manitoba, Legislative Assembly, *Hansard*, 39th Leg., 1st Sess., Vol. 59, No. 10 (September 26, 2007)	50
7	Manitoba, Legislative Assembly, *Hansard*, 40th Leg., 2nd Sess., Vol. 65, No. 10 (December 3, 2012)	161
8	World Commission on Dams, "Dams and Development: A New Framework for Decision Making," December 2001	209
9	Order in Council 304/2011	230
10	Bent Flyvbjerg, "What You Should Know About Mega Projects and Why: An Overview" (2014) 45:2 Project Management	232
11	John Hollman, "Estimate Accuracy: Dealing with Reality," 2012	263
12	Order in Council 301/2018	283
13	2017/18 GRA, Exhibit DEA-1	288
14	PUB Order No. 99/11	383
15	NFAT Report	495
16	NFAT, Exhibit ERA-5	802
17	2017/18 GRA, Exhibit MH-64	823
18	NFAT, Exhibit MH-204, Manitoba Hydro Final Argument	903
19	Manitoba Hydro, Capital Expenditure Forecast (CEF09), November 2009	1210
20	Manitoba Hydro, Bipole III Transmission Line Project Environmental Impact Statement, Final Argument	1301
21	NFAT, Exhibit MPA-3-1	1362
22	BCG, "Review of Bipole III, Keeyask and Tie-Line Project," September 19, 2016	1407
23	NFAT, Information Request (IR) KP/MH II-26a	1416
24	2017/18 GRA, Transcript, January 22, 2018	1418
25	Winnipeg Sun, "Tories open to private-sector Hydro deals," November 13, 2006	1740
26	Manitoba Hydro, Environmental Impact Statement (Bipole III), December 2011, Chapter 2: Need and Alternatives	1742
27	Decision of the CEC on the Motion of the Bipole III Coalition, August 29, 2012	1767
28	BCG, "Bipole III, Keeyask and Tie-Line Review," September 19, 2016	1779
29	2012/13 GRA, Information Request (IR) CAC/MH II-47	1820

Tab	Description	Page
30	2017/18 GRA, PUB Minimum Filing Requirement (MFR) 155	1825
31	PUB Order No. 7/03	1920
32	2017/18 GRA, PUB Minimum Filing Requirement (MFR) 154	2068
33	PUB Order No. 116/08	2070
34	PUB Order No. 59/18	2436
35	PUB Order No. 5/12	2753
36	Manitoba Hydro, System Planning Division, "Bipole III: Past, Present and Future," Presentation at the 2019 Minnesota Power Systems Conference, November 13, 2019	2986
	VOLUME 3	
37	2015/16 GRA Tab 4	3039
38	Manitoba Hydro, Capital Forecast (CEF 99-1), October 1999	3067
39	Letter from Greg Selinger, then Minister Responsible for Manitoba Hydro, to Vic Schroeder, then Chair of the MHEB, September 20, 2007	4366
40	CMC Consultants Inc., "Bipole III Transmission Routing Study," September 2007	4371
41	Phil Fontaine & Ed Wood, *Promises to Keep: Towards a Broad Area Plan for the East Side of Lake Winnipeg*, November 2004, Appendix 8.10 and Appendix 8.11	4417
42	Phil Fontaine & Ed Wood, *Promises to Keep: Towards a Broad Area Plan for the East Side of Lake Winnipeg*, November 2004, Executive Summary	4506
43	Manitoba Hydro, Capital Expenditure Forecast (CEF14), December 2014	4580
44	Manitoba Hydro, NFAT Submission, Executive Summary	4624
45	Canada Energy Regulator, "Provincial and Territorial Energy Profiles – Manitoba"	4667
46	Manitoba Hydro, NFAT Submission, Chapter 4: The Need for New Resources	4677
47	Manitoba Hydro, 2013 Electric Load Forecast	4730
48	NFAT, Exhibit MH-95	4812
49	2017/18 GRA, Information Request (IR) PUB/MH II-50a	4961
50	NFAT, Transcript, March 6, 2014	4965
51	NFAT, Transcript, March 4, 2014	5306
52	NFAT, Information Request (IR) MIPUG/MH I-043b	5708
53	PUB Order No. 73/15	5717
54	NFAT, Exhibit LCA-6	5826
55	2017/18 GRA, PUB-42-4 (excerpt)	5864
56	2017/18 GRA, Transcript, December 11, 2017	5866
57	Manitoba Hydro, 2018 Electric Load Forecast	6160
58	NFAT, Exhibit ERA-6	6249
59	Dr. Garland Laliberte, "A Review of Manitoba Hydro's Electric Load Forecasting," Presentation to the PUB, January 5, 2018	6294
60	2017/18 GRA, Exhibit MH-137, Manitoba Hydro Written Argument	6319
61	PUB Order No. 43/13	6609
62	2017/18 GRA, Exhibit AY-1	6672

Tab	Description	Page
63	2017/18 GRA, Exhibit DEA-2-1	6761
64	Manitoba Hydro, 2016 Electric Load Forecast	6847
65	Manitoba Hydro, Finance & Regulatory, "Board Recommendation – 2015 Corporate Risk Management Report," February 2016	6930
66	Manitoba's Clean Energy Strategy, 2012	7370
67	Winnipeg Free Press, "Exporting 'Manitoba's oil' down south," May 26, 2011	7419
68	Winnipeg Free Press, "Market forces weighing on hydro exports," April 5, 2016	7422
69	NFAT Terms of Reference	7425
70	Manitoba Building Trades, "Allied Hydro Council"	7434
71	Manitoba Hydro, "The Burntwood/Nelson River Agreement"	7437
72	John DiNardo & David S. Lee, "Do Unions Cause Business Failures?", March 2003, Unpublished Working Paper, U.C.-Berkeley Department of Economics	8053
73	Progressive Contractors Association, "Manitoba's Outdated Labour Laws," August 2, 2016	8109
74	Karen Ellis & Rohit Singh, "The Economic Impact of Competition," Overseas Development Institute Project Briefings No. 42, July 2010	8112
75	PPP Canada, "The Benefits of P3s"	8117
76	Saskatoon StarPhoenix, "Two months after opening, Saskatchewan Hospital North Battleford needs entire roof replacement," May 22, 2019	8125
	VOLUME 4	
77	Government of Alberta, "P3 Value for Money Assessment and Project Report – Alberta Schools Alternative Procurement (ASAP) Project Phase 1," June 2010	8129
78	Government of Alberta," P3 Value for Money Assessment and Project Report – Alberta Schools Alternative Procurement (ASAP) Project Phase II," September 2010	8153
79	Government of Alberta, "P3 Value for Money Assessment and Project Report – Alberta Schools Alternative Procurement (ASAP) Project Phase III," March 2013	8179
80	Government of Alberta, "P3 Value for Money Assessment and Project Report – Southeast Stoney Trail (SEST) Ring Road Project," September 2010	8208
81	Government of Alberta, "P3 Value for Money Assessment and Project Report – Northeast Anthony Henday Drive (NEAHD) Ring Road Project," November 2012	8237
82	PUB Order No. 69/19	8272
83	Winnipeg Free Press, "Shocking exclusion," May 25, 2013	8323
84	Keeyask Hydropower Limited Partnership, "Keeyask Infrastructure Project"	8328
85	NFAT, Transcript, March 3, 2014	8337
86	Government of Manitoba, News Release, "$4 billion in power sales to U.S. for Manitoba Hydro: Selinger," May 25, 2011	8746
87	Wuskatim Power Limited Partnership, "About The Wuskwatim Generating Station"	8749
88	Manitoba Hydro, NFAT Submission, Chapter 7: Screening of Manitoba Resource Options	8752
89	Manitoba Hydro, NFAT Submission, Chapter 8: Determination and Description of Development Plans	8793
90	Manitoba Hydro, NFAT Submission, Chapter 9: Economic Evaluations – Reference Scenario	8818
91	NFAT, Exhibit MH-104-8	8848

Tab	Description	Page
92	Manitoba Hydro, NFAT Submission, Chapter 10: Economic Uncertainty Analysis	8857
93	Order in Council 128/2013	8922
94	Manitoba Hydro, NFAT Submission, Appendix 2.3: Economic Impact Assessment	8925
95	NFAT, Exhibit MH-159	8934
96	NFAT, Exhibit CAC-85-1	8958
97	Manitoba Hydro NFAT Submission, Chapter 13: Integrated Comparisons of Development Plans	8983
98	NFAT, Exhibit MMF-31	8988
99	NFAT, Transcript, May 13, 2014	9114
100	NFAT, Exhibit MPA-3	9413
101	NFAT, Exhibit LCA-12	9508
102	NFAT, Exhibit, LCA-3-3	9699
103	NFAT, Exhibit MH-202	9712
104	NFAT, Transcript, May 1, 2014	9714
105	NFAT, Exhibit CAC-62	10211
106	NFAT, Exhibit TyP-1	10274
107	NFAT, Exhibit MMF-26	10380
108	2014/15 GRA, Exhibit MH-57	10432
109	2017/18 GRA, Exhibit MH-125	10446
110	NFAT, Exhibit MMF-14	10461
111	Manitoba Hydro, NFAT Submission, Appendix 9.3: Economic Evaluation Documentation	10507
112	NFAT, Exhibit POT-2	11044
113	PUB Order No. 32/09	11096
114	2017/18 GRA Tab 3	11147
	VOLUME 5	
115	William R Montalvo, "Cracks on the Wall: Why States Should Be Allowed to Lead on Climate Change" (2010) 21:2 Fordham EnvtI LJ 383	11171
116	Michael P Vandenbergh & Jim Rossi, "Good for You, Bad for Us: The Financial Disincentive for Net Demand Reduction" (2012) 65:6 Vand L Rev 1527	11203
117	2014/15 GRA, Appendix 11.7	11243
118	2017/18 GRA, PUB Minimum Filing Requirement (MFR) 9	11270
119	Manitoba Hydro, NFAT Submission, Chapter 15: Implementation and Risk Management Plan for Preferred Development Plan	11369
120	2017/18 GRA, Exhibit MH-130	11423
121	2017/18 GRA, Information Request (IR) PUB/MH II-64a-b	11500
122	NFAT, Exhibit KP-3-2	11504
123	2017/18 GRA, Appendix 5.1	11546
124	NFAT, Exhibit KP-4	11595

Tab	Description	Page
125	NFAT, Transcript, April 14, 2014	11654
126	2017/18 GRA, Exhibit MGF-2	11994
127	2014/15 GRA, Information Request (IR) PUB/MH I-20a	12253
128	2017/18 GRA, Appendix 5.4, p. 12	12257
129	2017/18 GRA, Transcript, January 30, 2018	12259
130	2017/18 GRA, Exhibit MH-117	12572
131	2017/18 GRA, PUB Minimum Filing Requirement (MFR) 136	12648
132	Natural Resources Canada, "Canadian LNG Projects"	12763
133	2017/18 GRA, MH-120	12770
134	Manitoba, Legislative Assembly, Standing Committee on Crown Corporations, *Debates*, 39th Leg., 2nd Sess., Vol. 60, No. 4 (December 19, 2007)	12896
135	Brandon Sun, "Why the west side is the best side," April 9, 2008	12930
136	Brandon Sun, "West side is wrong, but you don't have to take my word for it," April 12, 2008	12932
137	Manitoba, Legislative Assembly, *Hansard*, 39th Leg., 3rd Sess., Vol. 61, No. 38B (May 7, 2009)	12934
138	Manitoba, Legislative Assembly, *Hansard*, 39th Leg., 4th Sess., Vol. 62, No. 12 (December 15, 2009)	13004
139	Brandon Sun, "Bipole III route best for Hydro's future," August 13, 2010	13047
140	Brandon Sun, "Project must proceed," February 1, 2010	13049
141	Brandon Sun, "McFadyen misses mark with Hydro comments" September 23, 2010	13051
142	Winnipeg Free Press, "Hydro, gas hikes get go-ahead," April 27, 2013	13053
143	Brandon Sun, "Halting hydro projects puts long-term prosperity at risk," February 12, 2013	13058
144	Manitoba Hydro, Integrated Financial Forecast (IFF08-1), November 2008	13060
145	2010/11 GRA, Appendix 16	13107
146	Winnipeg Free Press, "Hydro board slams handling of Bipole III, Keeyask dam projects – but says it's too late," September 21, 2016	13124
147	NFAT, Exhibit MH-111	13132
148	2017/18 GRA, Exhibit MH-93	13217
149	2019/20 Electric Rate Application	13232
150	2017/18 GRA, Exhibit CC-17	13277
151	2017/18 GRA, Appendix 4.5	13439
152	2017/18 GRA, Information Request (IR) PUB/MH I-21	13530
153	2017/18 GRA, Exhibit MIPUG-30	13534
154	*The Environment Act* Licence No. 3055, August 14, 2013	13552
155	*The Environment Act* Licence No. 3106, July 10, 2014	13564
156	Leonard Bateman, "A History of Electric Power Development in Manitoba," IEEE Canadian Review, Winter 2005	13577
157	Macleans, "The Shaping of Limestone," August 11, 1986	13582
158	2017/18 GRA, Transcript, December 18, 2017	13593
159	2017/18 GRA, PUB Minimum Filing Requirement (MFR) 122	13802

Tab 37

Tab 4
Index
January 23, 2015

MANITOBA HYDRO

2015/16 & 2016/17 GENERAL RATE APPLICATION

CAPITAL EXPENDITURE FORECAST

INDEX

4.0 Overview 1
4.1 Capital Expenditure Forecast 2
4.2 Electric Operations Capital Expenditure Forecast (CEF14) 3
4.3 Major New Generation & Transmission Capital Expenditures 5
4.3.1 Bipole III Reliability Project 7
4.3.2 Keeyask Generating Station 8
4.3.3 Conawapa Generating Station 9
4.3.4 Demand Side Management 10
4.4 Sustaining Capital Expenditures (Major & Base Capital) 10
4.5 Capital In-Service 13
4.6 Investing to Maintain Reliable Service 15
4.6.1 Impacts of Aging Infrastructure on Reliability 15
4.6.2 Capacity Constraints Impacting System Performance & Customer Growth 23

Appendices

4.1 Capital Expenditure Forecast (CEF14)
4.2 Asset Condition Assessment Report

MANITOBA HYDRO
2015/16 & 2016/17 GENERAL RATE APPLICATION

CAPITAL EXPENDITURE FORECAST

4.0 OVERVIEW

Tab 4 summarizes the Capital Expenditure Forecast (CEF14) and the capital investments required to meet the growing energy needs of Manitoba and to replace aging utility assets.

Sections 4.1 and 4.2 discuss Manitoba Hydro's Capital Expenditure forecast for Electric Operations (CEF14). Section 4.3 provides an overview of major new generation and transmission capital expenditures. Section 4.4 provides an overview of sustaining capital expenditure requirements. Section 4.5 summarizes the assets that are projected to enter into service. Section 4.6 provides more detailed information with respect to the condition of Manitoba Hydro's assets and future sustaining capital requirements.

The key conclusions with respect to Tab 4 are:

1. Historically, the reliability performance of Manitoba Hydro's electric system has been excellent, but has recently begun to degrade with the condition of the Corporation's assets more and more contributing to the decline in reliability.

2. Manitoba Hydro is entering a period of extensive capital investment to meet the growing energy requirements of Manitoba, to replace aging utility assets and address increased capacity needs on the system.

3. Manitoba Hydro's projected costs and revenue requirements are significantly increasing due to the investment in assets and are the key factors driving the need for rate increases.

4. The proposed 3.95% rate increases are the minimum required to continue to deliver a reliable energy supply to Manitobans, to which they are accustomed, and fund Power Smart Programs to assist customers in meeting their energy needs.

5. The key reliability risks associated with inadequate funding as a result of rate increases lower than 3.95% include:
    i. Reliability would degrade further; outages would be longer and more frequent;
    ii. Increased safety risks to public and staff; and
    iii. Increased maintenance and emergency costs.

4.1 CAPITAL EXPENDITURE FORECAST

The Capital Expenditure Forecast is a projection of Manitoba Hydro's capital expenditures for new and replacement facilities to meet the electricity requirements in the Province of Manitoba as well as expenditures required to meet firm sale commitments outside the Province. Expenditures included in the CEF provide for an ongoing safe and reliable supply of energy in the most efficient and environmentally sensitive manner. A copy of CEF14 is included as Appendix 4.1.

The CEF for the current year and subsequent nineteen year period is submitted annually to the MHEB for approval. Since capital construction projects typically span several years, each year's CEF is presented to the MHEB as a revision to the previous year's approved CEF. In addition to the identification of new projects, changes to previously approved projects are also identified.

Business Units' initiate capital expenditure proposals to meet energy load growth demands within the Province, to respond to specific customer service extension requirements, to improve the efficiency and reliability of the energy delivery system or to take advantage of revenue generating opportunities in the export market. Once the need for a capital project is identified, a Capital Project Justification (CPJ) is prepared by the initiating department. The CPJ contains detailed information relative to each project such as system load growth statistics, business case analysis, risk assessment, and other pertinent details. The requirement and justification for the project is reviewed at the department, division and business unit level before the CPJ is forwarded to either the responsible Vice-President or the Executive Committee of Manitoba Hydro for approval. Projects greater than $50 million require approval of the Executive Committee, items below $50 million are approved at the Business Unit level. Depending on the nature and

complexity of the project, the CPJ may also be advanced to Manitoba Hydro's Planning Review Committee.

CPJs are scrutinized to confirm the need for the project based on the following criteria: system reliability, safety, efficiency, customer service, environmental impacts and corporate profitability. Further consideration is given to the priority of proposed projects and whether projects of lesser priority can be displaced so overall funding levels remain within the MHEB approved CEF limits. Risks of not proceeding with the project are also assessed based on information provided within the CPJ. All projects are assessed for environmental impacts.

During the year, actual expenditures on projects are reported monthly to Business Unit Management and the Executive Committee. Variance explanations are provided for any significant variances from the approved CEF. This information is also reported to the MHEB at their regularly scheduled meetings.

Each Vice-President oversees the portfolio of capital projects within their approved target. Advancement and deferral of capital projects occurs throughout the year to manage within annual approved funding levels. Available capital is allocated to asset categories in a prioritized manner to mitigate overall operational and financial risk.

4.2 ELECTRIC OPERATIONS CAPITAL EXPENDITURE FORECAST (CEF14)

The CEF includes Major New Generation & Transmission projects which increase capacity and energy or provide increased reliability and a number of specifically identified large projects or "major items" as well as numerous unspecified smaller projects referred to as "base items." Major and base items together comprise sustaining capital.

Figure 4.1 below provides a breakdown of Major New Generation and Transmission and sustaining capital by Business Unit over the 2014/15 to 2016/17 timeframe and the 10 year forecast period.

Figure 4.1 Summary of Electric Capital Expenditure Forecast CEF14

(in millions of $)	2014/15	2015/16	2016/17	Cumulative to 2023/24*
Major New Generation & Transmission	**1 452**	**1 914**	**2 463**	**11 671**
Sustaining Capital (Major & Base)	**571**	**577**	**610**	**5 661**
Generation Operations	132	132	132	1 336
Transmission	125	125	125	1 350
Customer Service & Distribution	236	241	268	2 212
Customer Care & Marketing	3	4	4	39
Human Resources & Corporate Services	75	75	55	597
Finance & Regulatory	0	0	0	2
Target Adjustment	-	-	25	125
Total Electric	**2 023**	**2 491**	**3 073**	**17 332**

Figure 4.2 below illustrates projected capital expenditures by major category to 2023/24.

Figure 4.2 Capital Expenditure Forecast- Electric Operations

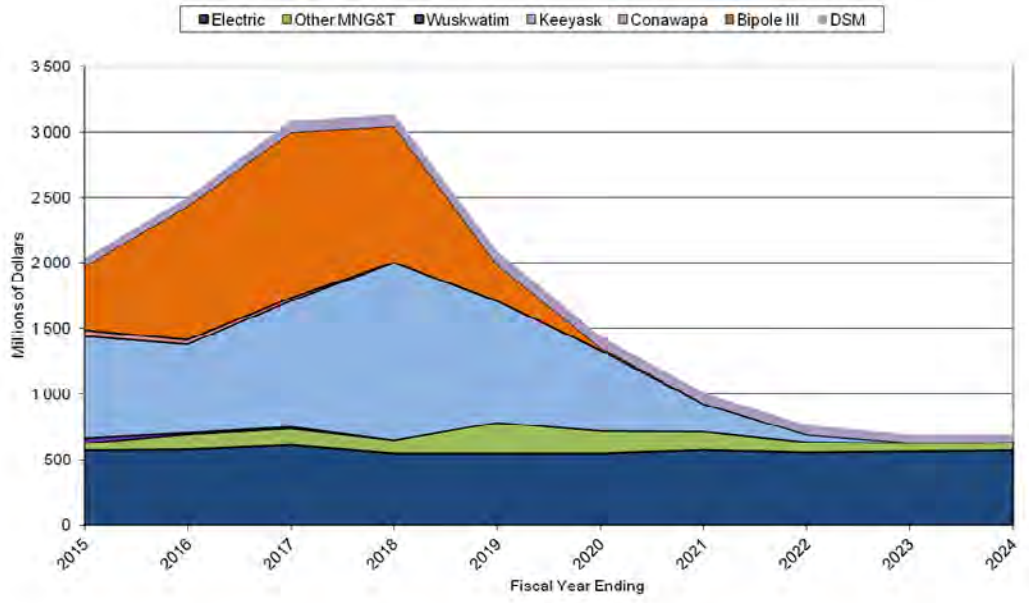


Figure 4.3 provides a summary of CEF14, related to Electric operations, and shows a reduction of $3.5 billion for the 10 year period to 2023/24 as compared to CEF13.

Figure 4.3 Change in Cost Flow from CEF13 to CEF14 ($ millions)

Electric Only	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	10 Year Total
CEF13	**2 013**	**2 422**	**2 496**	**2 326**	**2 030**	**1 845**	**1 337**	**1 719**	**2 281**	**2 322**	**20 792**
Incr (Decr)	9	69	577	799	48	(414)	(339)	(968)	(1 601)	(1 641)	(3 460)
CEF14	**2 023**	**2 491**	**3 073**	**3 125**	**2 078**	**1 432**	**999**	**751**	**679**	**681**	**17 332**

The decrease of $3,460 million in capital expenditures over the ten year forecast period is comprised of the following:

Figure 4.4 Breakdown of CEF14 10 Year Cost Flow Change

	Total Projected Cost	**10 Year Increase (Decrease)**
		($ Millions
Conawapa - Generation	397	(6 052)
Bipole III - Transmission Line	1 655	407
Bipole III - Converter Stations	2 675	881
Bipole III - Collector Lines	260	71
Keeyask - Generation	6 496	349
Demand Side Management	NA	463
Base Capital Target	NA	422
Additional North South Trasmission	-	(90)
Gillam Redevelopment and Expansion Program	266	(77)
Dorsey 230KV Zone Building	-	(63)
Slave Falls Major Overhauls	126	(63)
Pointe du Bois Powerhouse Rebuild	1 852	(19)
New Adelaide Station - 66/12kV	62	62
Other System Upgrades		249
		(3 460)

4.3 MAJOR NEW GENERATION & TRANSMISSION CAPITAL EXPENDITURES

The CEF14 includes Major New Generation & Transmission projects which significantly increase capacity and energy or provide increased reliability for the transmission system.

As noted in Figure 4.5, Major New Generation & Transmission expenditures continue to increase primarily due to the commencement of construction of the Bipole III Reliability project and the Keeyask Generating Station.

Figure 4.5 New Major Generation & Transmission 2013-2017

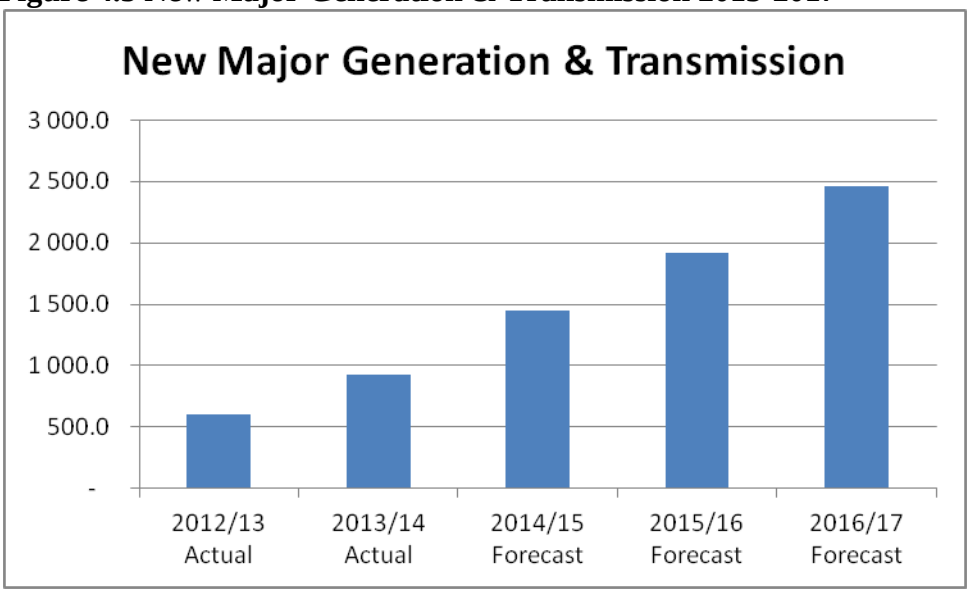


Figure 4.6 below summarizes the significant Major New Generation and Transmission capital projects.

Figure 4.6 Major New Generation & Transmission Capital Expenditure Forecast CEF14

(in millions of $)	2014/15	2015/16	2016/17	Cumulative to 2023/24*
Wuskwatim - Generation	41	13	15	68
Keeyask - Generation	776	676	962	5 579
Grand Rapids Hatchery Upgrade & Expansion	2	5	9	23
Conawapa - Generation	43	31	21	96
Kelsey Improvements & Upgrades	14	9	13	37
Kettle Improvements & Upgrades	7	24	25	138
Pointe du Bois Spillway Replacement	114	52	4	170
Pointe du Bois - Transmission	16	17	14	51
Gillam Redevelopment and Expansion Program (GREP)	20	22	23	212
Bipole III - Transmission Line	203	360	381	1 514
Bipole III - Converter Stations	221	581	829	2 356
Bipole III - Collector Lines	58	76	52	227
Bipole III - Community Development Initiative	2	2	2	8
Riel 230/ 500 kV Station	36	6	-	42
Manitoba-Minnesota Transmission Project	7	33	100	348
Demand Side Management	52	59	77	676
Target Adjustment	(161)	(51)	(61)	(12)
Other	-	-	-	139
Total	**1 452**	**1 914**	**2 463**	**11 671**

* Excludes capital expenditures prior to 2013/14

The following sections provide a summary of cost updates with respect to the significant Major New Generation & Transmission projects and Electric Demand Side Management.

4.3.1 Bipole III Reliability Project

In August 2013, the Province of Manitoba issued an Environmental Act licence for the Bipole III Reliability project and construction has commenced with a planned in-service date of 2018/19, which represents a deferral of nine months from October 2017.

CEF14 incorporates a more detailed scope based on an issued Environmental Act licence, approved finalized route and right-of-way width and up-to-date market information. In addition, the revised estimate incorporates the awarding of major contracts and the selection of LCC technology, which has resulted in synchronous condensers being included in the updated estimate. The rating for the Bipole III Reliability project was increased from 2000MW to 2300MW to ensure adequate spare HVDC transmission on

the northern collector system. Figure 4.7 provides an explanation of the major changes in the cost estimates.

Figure 4.7 Bipole III Reliability Total Project Cost Update

Cost Breakdown (in millions of dollars)	CEF 14	CEF 13	Increase	Explanation for change
HVdc Converter Stations (Riel & Keewatinohk)	1 878.3	1 208.8	669.5	- Increased for awarded contracts: HVdc Equipment, AC Switchyard, Site Development, Camp, Camp Operations, etc. - Addition of Synchronous Condensers to project scope as result of LCC converter technology selection - Increase to 2300 MW converters
500kV T-Line	1 191.0	889.0	302.0	- Increase for extended Licencing process - Increase for revised property acquisition costs - Increased clearing costs - Increase due to additional towers required
AC Collectors	198.2	115.0	83.2	- Addition of station upgrade and breaker replacement scope of work - Estimated increase to construction costs
Riel 230kV Expansion	228.7	133.4	95.3	- Increase from attribution of Riel Sectionalization costs (realized costs) - Estimated increase to construction costs
Contingency & Reserves	347.6	203.0	144.6	- Contingency & reserves included based on analysis and recommendation of 3rd party risk and contingency expert
Interest & Escalation	747.8	730.8	17.0	
Community Development Initiative	62.0	60.8	1.2	
TOTAL	**4 653.6**	**3 340.8**	**1 312.8**	

Total project change will not tie to 10 year cost flow change shown earlier due to rollover of under expenditures in 2013/14 compared to CEF13 forecasted flow.

4.3.2 Keeyask Generating Station

In July 2014 the Province of Manitoba issued an Environmental Act licence for the Keeyask Generating Station and construction has commenced with a planned in-service date of 2019/20.

The Keeyask Project budget was updated in March 2014 as part of the Needs For and Alternatives To review. The last detailed project estimate was completed in 2009. The budget includes bid prices from the major contractors including the General Civil Contract. Figure 4.8 provides an explanation of the major changes in the cost estimates.

Figure 4.8 Keeyask Generating Station Total Project Cost Update

Cost Breakdown (in millions of dollars)	CEF 14	CEF 13	Variance	Comments
Generating Station (Including GCC and KIP)	3 681.1	3 060.6	620.5	Increase related to: - updated base expenditures from 2013$ to 2014$ on generating station and KIP - post-construction adverse effects and operational employment which were previously excluded from the estimates. Accretion is also added. - commitments made in EIS and CEC hearings related to the environment and social mitigation. - direct negotiated service contracts, interface management, forebay clearing, and community monitoring. - stage 5 engineering and construction management staff augmentation. - Increase for awarded contracts. - unforeseen conditions related to the north access road construction, and work areas site development.
Construction Power	30.4	30.4	0.0	No Change
Licensing & Planning	393.0	397.3	(4.3)	Decrease related to transfer of budget for adverse effects.
Transmission (excluding contingency)	142.1	138.3	3.8	Increase related to updated base expenditures from 2013$ to 2014$.
Contingency & Management Reserves	685.2	1 063.7	(378.5)	Decrease related to: - Contingency and labour reserve revised based on updated risk model. - Escalation reserve revised based on updated escalation reserve model.
Interest & Escalation	1 564.2	1 530.3	33.9	Increase due to Interest on higher base costs and an advanced general civil contract cash flow; partially offset by decreased Escalation indexing from the increase to 2014$.
TOTAL	**6 496.0**	**6 219.6**	**276.4**	

Note: Sunk Costs are included in each project component

Total project change will not tie to 10 year cost flow change shown earlier due to rollover of under expenditures in 2013/14 compared to CEF13 forecasted flow.

4.3.3 Conawapa Generating Station

For CEF14 forecast purposes, it is assumed that the Conawapa Generating Station has been suspended and replaced with a gas turbine required in 2037/38 to meet firm capacity requirements. While the majority of the planning and licensing activities on Conawapa have been suspended, Manitoba Hydro continues to pursue dependable firm export sales based on the earliest possible in-service date of Conawapa in 2029/30 and will re-evaluate the business case (currently anticipated by Fall of 2016). Remaining expenditures in the forecast include capitalized interest on construction in process through to August 2016, the wrap up of preliminary engineering studies and limited environmental and aboriginal studies.

Figure 4.9 Conawapa Total Project Cost Update

(in millions of dollars)	CEF 14	CEF 13	Decrease	Explanation
Conawapa GS	397	10 492	(10 095)	Majority of expenditures have been suspended pending re-evaluation of the business case. Remaining expenditures are for the wrap up of preliminary engineering studies and limited environmental and aboriginal studies including capitalized interest on construction in progress through August 2016.

Total project change will not tie to 10 year cost flow change shown earlier due to rollover of under expenditures in 2013/14 compared to CEF13 forecasted flow and expenditures previously forecast outside the 10 year timeframe.

4.3.4 Demand Side Management

Manitoba Hydro's DSM plan targets the achievement of 1,136 MW and 3,978 GWh of savings over the next 15 years and involves an investment of more than a billion dollars and will be relied upon to meet 66% of projected load growth during this period. Figure 4.10 provides an explanation of the major changes over the 10 year forecast period associated with the updated DSM plan.

Figure 4.10 DSM 10 Year Cost Flow Update

Cost breakdown (in millions) 10 Year	CEF 14	CEF 13	Increase / (Decrease)	Explanation
Residential Energy Efficiency Programs	$68.7	$4.9	$63.8	Extended and enhanced program offerings and added new programs including but not limited to introducing Residential LED Lighting program and increased insulation incentives and introduced free energy assessments for electrically heated homes.
Commercial Energy Efficiency Programs	$210.4	$69.7	$140.7	Extended and enhanced program offerings and added new programs including but not limited to adding direct installation of high efficiency pre-rinse spray valves to the Commercial Kitchen program, higher performance levels beyond the new energy code for buildings, and increased incentives and technical assistance to support energy modeling under the Commercial New Buildings program, and increased incentives under the Refrigerator Retirement, Commercial Lighting, Commercial Building Envelope, Commercial CO2 Sensors, and Commercial Refrigeration programs.
Industrial Energy Efficiency Program	$102.0	$27.7	$74.4	Enhanced program offering by expanding financial and technical support for embedded energy managers in large commercial and industrial facilities under the Industrial Performance Optimization Program.
Load Management Program	$65.8	$57.7	$8.0	Enhanced program offering by increasing incentives in the Curtailable Rates Program.
Load Displacement & Alternative Energy Programs	$97.8	$8.8	$89.0	Added customer sited load displacement program.
Conservation Rates	$26.3	-	$26.3	Added conservation rates for residential and commercial customers.
Fuel Choice Program	$55.1	-	$55.1	Added fuel choice program.
Support & Contingency	$50.1	$44.7	$5.4	Increased activities to support the enhanced DSM portfolio such as increased program evaluation activities including external evaluation consulting services.
Demand Side Management	**$676.2**	**$213.4**	**$462.8**	

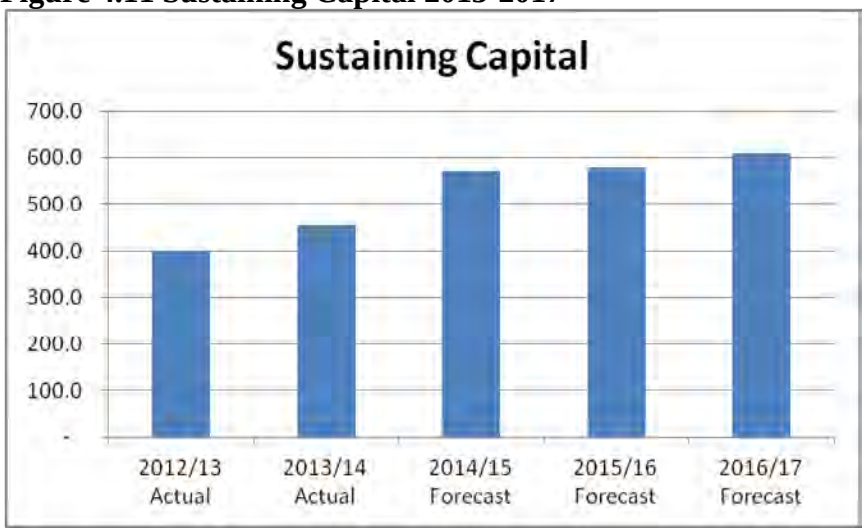
4.4 SUSTAINING CAPITAL EXPENDITURES (MAJOR & BASE CAPITAL)

Sustaining capital includes items identified in CEF14 as either Major or Base capital expenditures and consists of additions, improvements and replacements of existing infrastructure.

Capital targets established for fiscal years 2014/15 through 2020/21 in CEF14 considered increased requirements for aging infrastructure based upon asset condition assessments as well as expansion requirements to support customer growth. The target adjustment of $25 million annually beginning in 2016/17 through 2020/21 provides funding to address

future priorities. Investment in sustaining capital has increased $428 million over the ten year forecast period in order to maintain reliability and address anticipated load and customer growth as further discussed in Section 4.6.

Figure 4.11 Sustaining Capital 2013-2017



The following figure provides a further breakdown of sustaining capital for the first three forecast years of CEF14. Capital expenditures have been broken down by asset type, identifying the investment required to maintain reliable service.

Figure 4.12 CEF14 Sustaining Capital by Asset Type

(in millions of dollars)	2015	2016	2017
Generation Operation			
Turbines	19.7	13.4	15.8
Generators	14.4	17.8	20.1
Auxiliary Systems (Sewer, Water, Fire, etc)	12.4	10.3	12.5
Transformers	12.4	7.4	7.9
Licensing	10.4	10.8	8.3
Instrumentation & Controls	9.0	15.1	11.8
Townsite Infrastructure	8.9	10.4	5.0
Breakers	8.9	4.3	1.3
Spillway & Water Controls	7.4	13.5	24.1
Powerhouse, Dams, Dykes	6.7	7.6	8.1
Physical Security & Public Safety	5.4	3.2	2.0
AC Supporting Electrical Systems	5.2	7.6	6.4
Governors	4.6	3.9	1.6
Exciters	2.9	3.5	3.7
Tools & Equipment	2.4	2.2	1.4
Communication Systems & Equipment	1.4	1.2	1.9
	132.0	**132.0**	**132.0**
Transmission			
Station Equipment	16.3	15.2	13.9
Station Civil Infrastructure	15.9	9.1	2.8
Transformers	15.2	12.5	12.6
Communication Systems & Equipment	14.5	7.2	8.6
Protection Relays & Control, Metering & SCADA	13.8	7.2	3.2
HVDC Synchronous Condensers	9.0	8.8	2.9
Steel Structures	7.3	12.4	34.0
Wood Poles	6.7	33.2	14.1
Breakers	6.7	5.3	3.7
Battery Banks	4.0	2.5	1.9
Conductor Attachments	3.6	4.4	5.1
HVDC Valve Group	2.8	0.7	0.1
Tools & Equipment	2.4	1.6	1.4
Land & Easements	2.3	1.1	10.2
Overhead Conductors	1.8	2.4	9.5
System Control Centre	0.4	0.3	0.3
Diesel Generation	0.4	-	-
HVDC Smoothing Reactors	0.1	0.4	0.5
Other	1.8	0.9	0.1
	125.0	**125.0**	**125.0**
Customer Services & Distribution			
Poles	43.3	38.5	48.3
Overhead Conductors	39.1	33.3	33.8
Underground Cables	31.3	37.3	45.5
Station Breakers and Other Station Equipment	23.8	29.6	28.7
Overhead Transformers	22.5	18.2	22.2
Station Transformers	21.0	23.1	24.7
Padmount Transformers	17.9	12.2	15.7
Street Lights	11.0	10.8	12.8
Ductlines & Manholes	7.9	16.0	13.2
Station Site Prep	6.0	9.2	9.3
Land & Easement	3.7	0.4	0.0
Buildings	4.4	10.1	12.7
Equipment	1.4	1.2	1.4
Steel Structures	0.8	0.7	-
Other	1.3	-	-
	235.5	**240.9**	**268.3**
Customer Care & Energy Conservation			
Meters & Meter Transformers	3.2	4.0	4.1
	3.2	**4.0**	**4.1**
Human Resources & Corporate Services			
Computers & IT Systems	29.0	29.1	29.6
Buildings	22.4	24.3	9.3
Fleet	21.0	18.9	13.3
Land & Easements	1.7	1.8	1.8
Tools & Equipment	0.9	0.9	0.9
	75.0	**75.0**	**55.0**
Finance Regulatory			
Tools & Equipment	0.2	0.2	0.2
	0.2	**0.2**	**0.2**
Target Adjustment	-	-	25.0
Sustaining Capital Total	**570.9**	**577.0**	**609.6**

4.5 CAPITAL IN-SERVICE

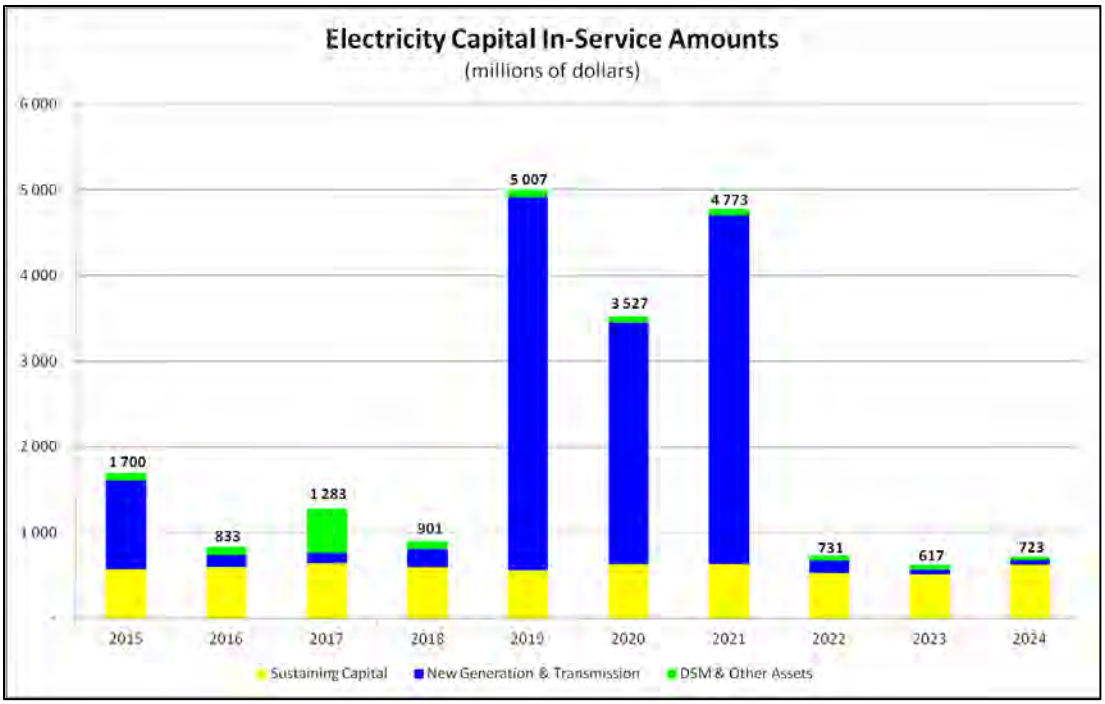
While assets are under construction, the capital expenditures and associated financing costs are held in construction work in progress. Once these assets are placed into service, the associated carrying costs (depreciation and finance expense) form part of the Corporation's revenue requirements.

Figures 4.13 and 4.14 provide a summary of the amount of capital that is forecast to go in service, as well as deferred assets that will commence amortization for the first three forecast years as well as the 10 year forecast period. Figure 4.13 indicates that $1.7 billion, $0.8 billion and $1.3 billion of assets are projected to be placed in-service in 2014/15, 2015/16 and 2016/17 respectively. The most significant assets being placed in-service during this period include the Pointe du Bois spillway replacement, and the Riel 230/500kV Station in 2014/15. In this three year period, there is also approximately $1.8 billion of sustaining capital expenditures that will be placed into service, and $0.2 billion of DSM expenditures that will commence amortization.

Figure 4.13 Electricity Capital In-Service Amounts

(millions of dollars)	2015	2016	2017	Cumulative 10 Year Total
Wuskwatim - Generation	40	4	26	70
Keeyask - Generation	-	-	-	6 496
Grand Rapids Hatchery Upgrade & Expansion	-	-	-	24
Kelsey Improvements & Upgrades	17	8	15	41
Kettle Improvements & Upgrades	6	24	24	141
Pointe du Bois Spillway Replacement	477	91	4	572
Pointe du Bois - Transmission	21	0	10	59
Gillam Redevelopment and Expansion Program (GREP	18	24	24	210
Bipole III - Transmission Line	0	0	-	1 593
Bipole III - Converter Stations	123	-	-	2 657
Bipole III - Collector Lines	4	-	13	260
Bipole III - Community Development Initiative	-	-	-	62
Riel 230/500kV Station	329	0	-	330
Manitoba-Minnesota Transmission Project	-	-	-	349
Generating Station Improvements & Upgrades	-	-	-	139
New Generation & Transmission Sub Total	**1 036**	**152**	**116**	**13 003**
				-
Demand Side Management	52	59	77	676
Conawapa - Generation	-	-	397	397
Other	36	29	53	138
DSM & Other Assets Sub Total	**88**	**89**	**526**	**1 211**
				-
Generation Operations	154	188	85	1 466
Transmission	88	94	168	1 346
Customer Service & Distribution	259	234	296	2 303
Customer Care & Energy Conservation	3	4	4	39
Human Resources & Corporate Services	72	73	64	600
Finance & Regulatory	0	0	0	2
Target Adjustment	-	-	25	125
Sustaining Capital Sub Total	**576**	**593**	**642**	**5 882**
				-
TOTAL	**1 700**	**833**	**1 283**	**20 096**

Figure 4.14 Electricity Capital In-Service Amounts 2014/15-2023/24



4.6 INVESTING TO MAINTAIN RELIABLE SERVICE

Manitoba Hydro's asset management has enabled the Corporation to defer hundreds of millions of dollars of capital investment to date. However, increased investments are required for generation, transmission and distribution system renewal and capacity expansion in order to support the growth requirements of Manitoba Hydro's customers. These capital investments are needed to sustain the Corporation's current electric infrastructure considering the increasing pressures associated with aging infrastructure and the need to provide more capacity to accommodate increased demand resulting from increased population and business growth. CEF14 forecasts capital expenditures of $493 million, $498 million and $525 million in 2014/15, 2015/16, and 2016/17, respectively for investment in generation, transmission and distribution assets (does not include expenditures associated with corporate infrastructure).

4.6.1 Impacts of Aging Infrastructure on Reliability

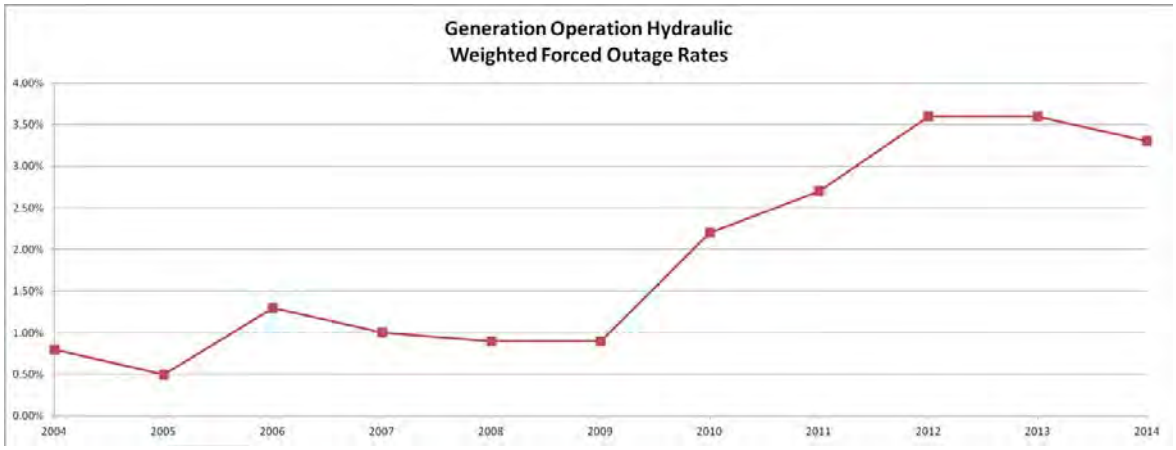
Manitoba Hydro has prudently invested in the electrical system which has provided reliable service to customers for decades. Where system reliability risk dictates, Manitoba

Hydro has installed redundant capacity to ensure that it can supply load in the event of an outage in an acceptable timeframe. Contingency plans, such as the transfer of load to available stations, the use of mobile stations, and allowing temporary overloads on equipment where it can be determined that such overloads are not expected to appreciably reduce equipment life, allow the Corporation to supply load at acceptable voltage levels after a system outage occurs.

In the past, Manitoba Hydro has been able to effectively deal with capacity challenges on its system by taking advantage of redundant capacity and contingency plans which has allowed the Corporation to defer capacity upgrades while maintaining reliability levels. However, the number of areas of the electric system with capacity challenges is growing, and this is the result of an aging system and strong load growth in some parts of the Province. Consequently, Manitoba Hydro's ability to respond to these challenges without negatively impacting reliability is diminishing.

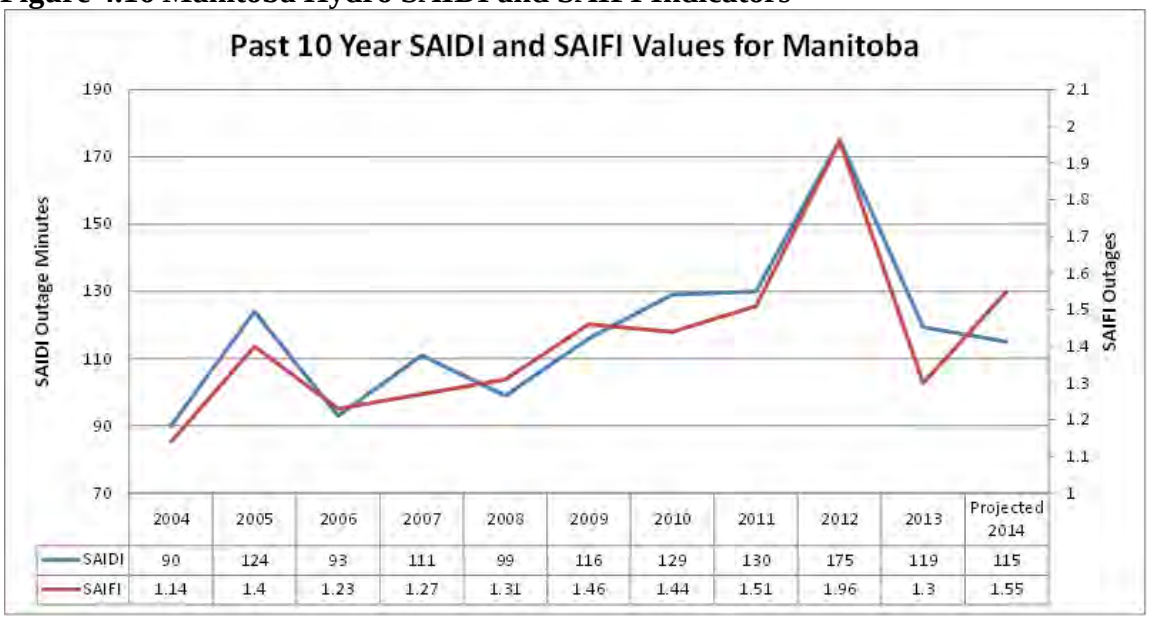
Reliability is critical for Manitoba Hydro and its customers. Historically, the reliability performance of Manitoba Hydro's electric system has been excellent, but has recently begun to degrade. While reliability is impacted by factors such as adverse weather, tree contacts, and the lengthening of restoration time due to changes in work procedures to conform to safety, legal and environmental requirements, the condition of Manitoba Hydro's assets is contributing more and more to the decline in reliability. This is evident in Manitoba Hydro's performance in key reliability indicators. As illustrated in Figure 4.15 below, generation forced outage rates have significantly increased in the past four years.

Figure 4.15 Hydraulic Generation Forced Outage Rates



Likewise, Manitoba Hydro's recent performance on the System Average Interruption Duration Index (SAIFI) and the System Average Interruption Frequency Index (SAIDI) indicators (with the exception of 2013 which reflects lower than normal storm activity) shows a trend of increased outage frequency and duration.

Figure 4.16 Manitoba Hydro SAIDI and SAIFI Indicators



	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Projected 2014
SAIDI	90	124	93	111	99	116	129	130	175	119	115
SAIFI	1.14	1.4	1.23	1.27	1.31	1.46	1.44	1.51	1.96	1.3	1.55

Manitoba Hydro has been taking actions for many years to mitigate the impacts of aging infrastructure on reliability performance, such as implementing an integrated pole maintenance program that has allowed the Corporation to extend the pole asset

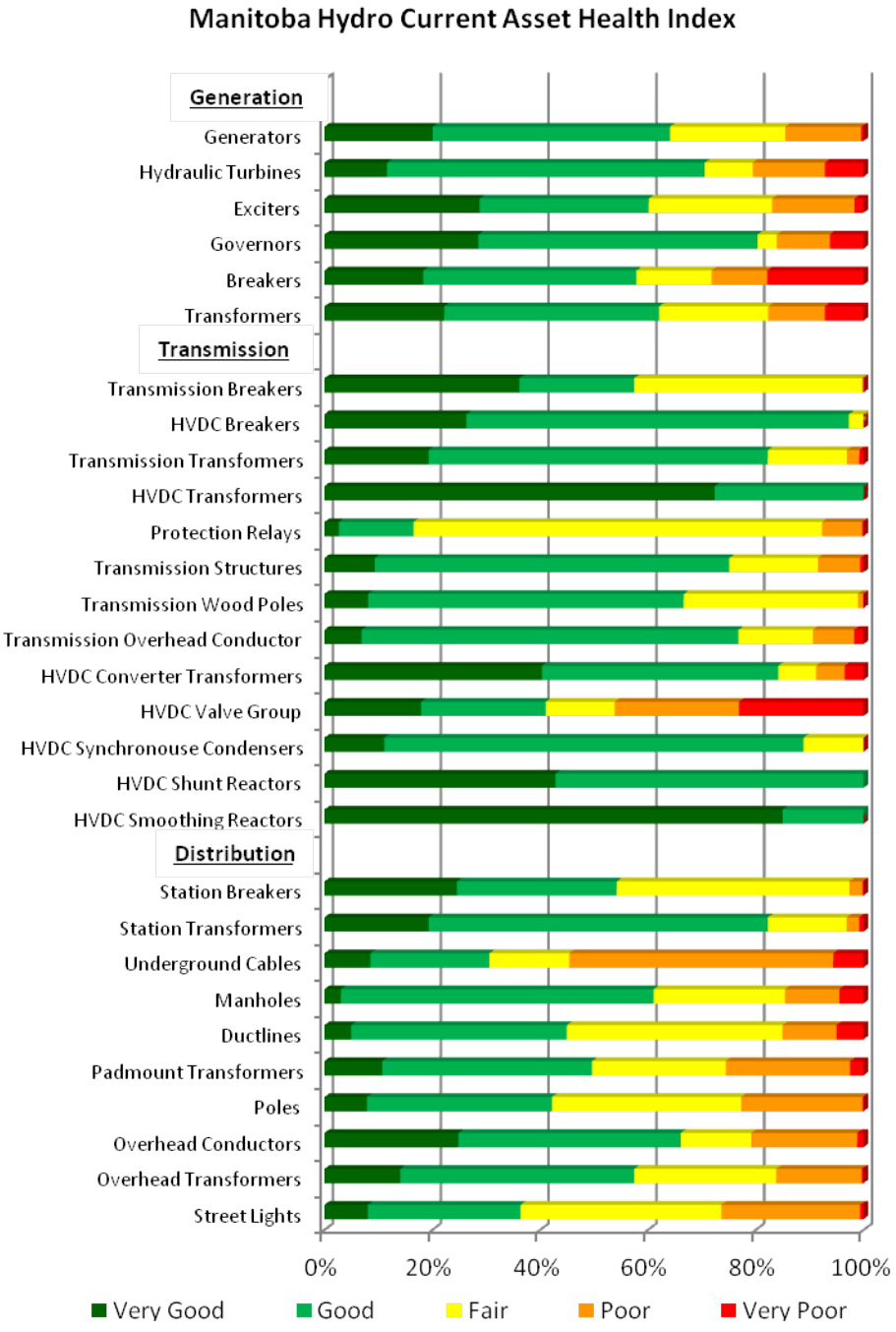
serviceable life well-beyond industry standards, and more recently, leveraging cable silicone injection technology to extend the serviceable life of underground cables. However, significant capital investments are required to address aging infrastructure and increased capacity needs on the system.

A considerable amount of Manitoba Hydro's assets were installed prior to 1960 when many of the first generating stations and transmissions systems were built (1911-1950) and a large portion of the province was electrified (1940-1960). Many of these assets have been well maintained or overhauled and are still in operation, providing decades of valuable service to the Corporation and its ratepayers. A large number of assets were subsequently installed from 1960 through to 1990 when generating stations were developed on northern Manitoba river systems along with the supporting HVDC system to transport the electricity to customers in the south.

Many components of this generation, transmission and distribution system are coming due for replacement, with some components requiring investments in the short term. Some of Manitoba Hydro's assets are in poor condition with ages well beyond industry standards and present a significant risk of failure which can result in customer outages and/or load shedding. Some of these assets types, such as breakers, generators, wood poles and valve groups, also require significant resources, lead time and capital investment to address their present condition. Though assets are being continually maintained, current levels of system reliability will not be sustained with current asset replacement rates.

As Appendix 4.2 to this Tab, Manitoba Hydro has included its Electric Infrastructure Condition Assessment Report. The report provides an overview of the condition of major electrical assets and their demographics, as well as an overview of critical assets' life expectancy versus the current replacement rates and the quantities of assets in critical condition. Manitoba Hydro used an Asset Health Index (AHI) to quantify equipment condition based on numerous parameters, as described in section 3 of Appendix 4.2. A condition index was calculated for each asset indicating whether the asset type is in very poor, poor, fair, good or very good condition. Figure 4.17 below provides a summary of current AHI results for Manitoba Hydro's generation, transmission and distribution asset types.

Figure 4.17 Current Asset Health Index by Asset Type



Manitoba Hydro can effectively manage its assets through the use of maintenance, spares and contingency strategies when the majority of assets in a particular asset class are in

fair to very good condition. However, as larger percentages of these assets fall into the poor and very poor categories, system failures regretfully will occur more frequently.

It is notable that the majority of critical assets are being replaced at levels substantially less than their anticipated lifespan. Today, a majority of the asset types have equipment which remains in service well beyond industry expectations, without causing significant impact to reliability. Going forward, as a larger percentage of assets age beyond life expectancy, significant changes to current replacement rates[1] will be required to mitigate the negative impacts of aging infrastructure on the electrical system. Figure 4.18 illustrates turnover at current replacement rates[2], indicating that replacement rates in the majority of Manitoba Hydro's asset types need to be increased to better align with life expectancy.

Figure 4.18 Asset Type Life Expectancy and Turnover at Current Replacement Rates

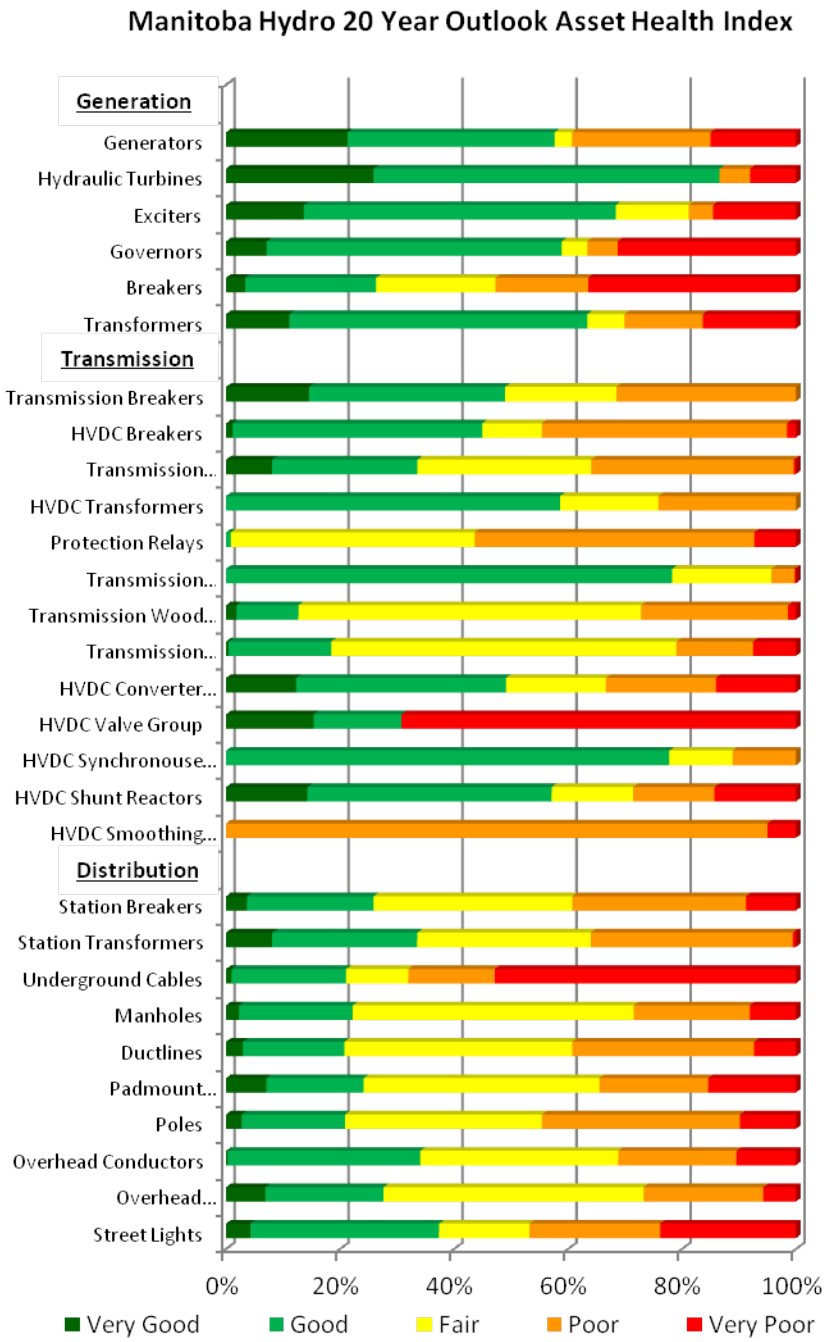
Business Unit	Asset	Life Expectancy (years)	Turnover at Current Replacement Rates (years)
Generation	Generators	60	117
	Hydraulic Turbines	90-100	84
	Exciters	50-90	117
	Governors	20-125	50
	Breakers	60-65	129
	Transformers	40-70	150
Transmission	Transmission Breakers	60-65	149
	HVDC Breakers	60-65	58
	Transmission Transformers	40-70	152
	HVDC Transformers	40-70	70
	Transmission Structures	85	285
	Transmission Wood Poles	75	255
	Transmission Overhead Conductor	85	410
	HVDC Converter Transformers	40-50	73
	HVDC Valve Group	25	48
	HVDC Synchronouse Condensers	65	65
	HVDC Shunt Reactors	35	55
	HVDC Smoothing Reactors	25	30

[1] The replacement rate is the average number of assets replaced each year divided by the total number of in service assets.
[2] Turnover at Current Replacement Rate is the number of years it would take to replace all our existing in service assets at current replacement rates.

Business Unit	Asset	Life Expectancy (years)	Turnover at Current Replacement Rates (years)
Distribution	Station Breakers	60-65	180
	Station Transformers	40-70	370
	Underground Cables	30-70	328
	Manholes	80	500
	Ductlines	100	378
	Padmount Transformers	50	70
	Wood Poles	70	200
	Overhead Conductors	100	200
	Overhead Transformers	75	70
	Street Lights	50-70	100

The original cost of Manitoba Hydro's electric assets is approximately $16 billion with an estimated replacement value many multiples higher due to inflation, increases in commodity prices and other factors. An asset portfolio of this size requires significant reinvestment to ensure that performance and safety standards are achieved. As a result, it is essential that investments on asset renewal be undertaken. Manitoba Hydro will continue to extend the life of its assets to the extent feasible based on economic and risk assessments, however, current replacement rates do not allow for a sustainable electrical system in the near future. Figure 4.19 demonstrates the impact to asset health if current replacement rates are maintained, indicating a trend toward less asset reliability as more slip into the poor and very poor condition.

Figure 4.19- 20 Year Outlook Asset Health Index by Asset Type



As discussed in Appendix 4.2, it is expected that over the next 20 years more assets will slip into poor and very poor condition, which will result in lower reliability than experienced historically, reduced revenues, increased safety risks to public and

employees, increased maintenance costs, increased emergency restoration costs and consequential damages. In addition, internal resource levels to address both maintenance and asset replacement requirements would be strained and the ability to secure external resources may be limited.

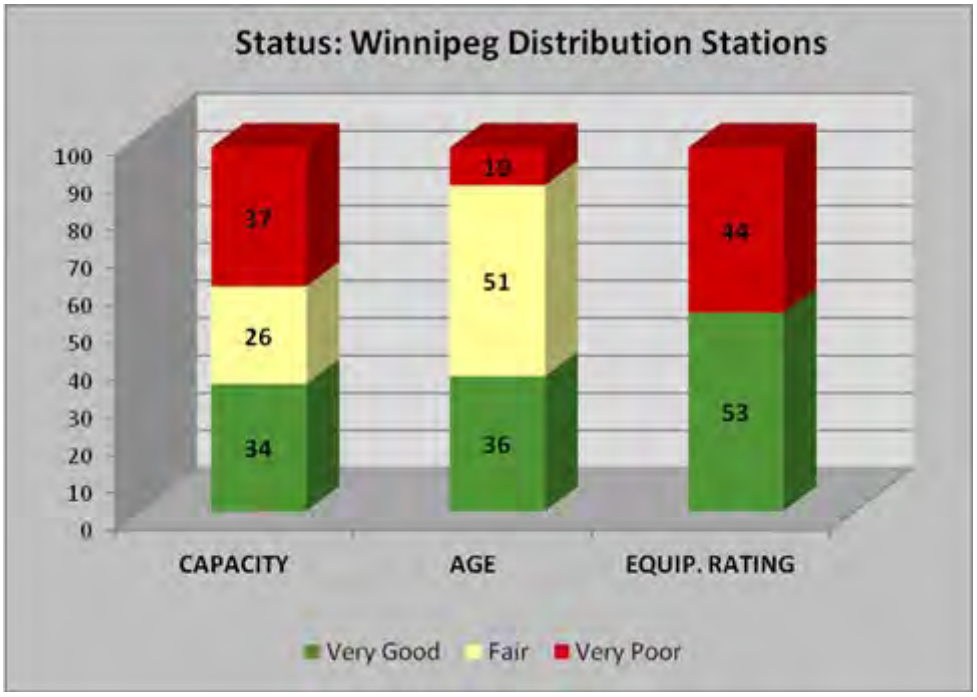
4.6.2 Capacity Constraints Impacting System Performance & Customer Growth

In conjunction with the impacts of aging infrastructure, Manitoba Hydro is facing significant capacity issues. Electric load in an increasing number of service areas has grown to the point where Manitoba Hydro may not be able to adequately supply load in the event of an outage despite contingency plans. Capacity challenges also make it more difficult to respond to customer connection requests. The Corporation has identified a number of capital investment priorities for its distribution and transmission systems related to capacity and investments are being undertaken and will be required in the near future to address these capacity issues.

For example, significant capital investment in distribution stations in Winnipeg and rural Manitoba is required as a large number of the stations are currently overloaded. There are 276 distribution stations in rural Manitoba; 19 of these are loaded above their maximum capacity, while 27 stations are at or above 80% of their loading limit. There are areas of the Province experiencing load growth much higher than the system average. In addition, there are areas of the province where the distribution system is near its end of life. In areas where these issues intersect, investment requirements become more important, such as in the Steinbach area, the Morden/Winkler area, Western oil fields, Brandon South and the Eastern Lake Winnipeg Area. As is noted below, the transmission system that supports the distribution in these areas is also facing capacity challenges.

Likewise, current Winnipeg distribution system capacity is not sufficient to meet current or future loads, which results in a high likelihood of extended outages to customers. Figure 4.20 provides an overview of the current status of the distribution system in the City of Winnipeg.

Figure 4.20 Status of Distribution Stations in Winnipeg



There are 97 distribution stations supplying the City of Winnipeg; 37 stations are currently loaded beyond their maximum capacity, and 26 stations are at or above 80% of their loading limit. The in-service dates of substation capacity projects can be deferred by transferring load to other, less loaded stations; however, the use of this strategy has been exhausted and is no longer practical. Contingency plans have become ineffective to restore full load in the event of an outage. Furthermore, ten of the distribution stations are 61 years or older, exceeding the design life of the equipment, and 44 stations have fault levels that exceed equipment ratings under certain operating conditions, such as during extreme low temperatures where electrical demand is typically highest.

Based on current capital plans, Manitoba Hydro is working towards reducing the percentage of overloaded distribution stations in Winnipeg to 20% by 2020 and in rural Manitoba by 5% in 2015 with a long term objective of ensuring that no stations exceed their maximum rating. Achieving this objective requires significant investments today and in the coming years. This issue is of significant concern, not only as it limits Manitoba Hydro's ability to supply electricity reliably to existing customers, but also in light of the expected load additions in many areas of the Province, including downtown Winnipeg where load additions are much larger than anticipated. It is estimated that

service extensions are required for approximately 5,300 new electric customers each year across the Province.

Similarly, Manitoba Hydro's transmission system is facing significant capacity issues. There are a number of areas in the transmission system where significant investments are required in order to address higher than average load growth, deteriorating voltage levels, and/or impacts of increasing transmission system capacity on some existing system equipment. Manitoba Hydro has also identified a number of high-priority transmission capital investments to address capacity requirements that will need to be undertaken.

As noted above, Manitoba Hydro has experienced higher than average load growth in areas such as the eastern Lake Winnipeg area, the Winkler/Morden area, and the Steinbach area which exceed the firm capacity of its stations, and/or result in low voltage issues. In the Eastern Lake Winnipeg, load has grown beyond the maximum capacity of Pine Falls Station, a key station that supplies the area, and over the next several years, the load is expected to grow to the point that overloads could not be reduced to acceptable levels by transferring load to other stations, potentially resulting in transformer damage or rotating load shed in a difficult to serve region of the Province.

With respect to the Morden/Winkler area, the 115 kV transmission system supplying the area can experience low voltage issues, particularly during peak load conditions and outages on the system. In such cases, rotating load shed during peak winter loading conditions may be required to restore system voltages to acceptable levels.

Likewise, the Winnipeg area has become heavily loaded due to load growth and upgrades to the transmission system are required, including the construction of a new transmission line, in order to protect against blackouts, and improve the system performance and reliability during normal operations as the load grows in southern Manitoba. In addition, as the capacity of the Winnipeg area transmission system continues to increase, the ratings of some system protection/interrupting equipment in the area are expected to be exceeded. This necessitates the replacement of breakers in order to avoid potential harm to employees, the public and infrastructure.

As well, steady load growth in Western Manitoba has resulted in deteriorating voltages on the transmission system in the Portage South area, which is impacting local load and Saskatchewan export capabilities and the ability to supply new oil pipeline related load.

If the capacity-related projects are not undertaken, customers in the impacted areas would be at a higher risk of extended outages and there is a risk that Manitoba Hydro could potentially be subject to significant financial penalties if having to report North American Electric Reliability Corporation violations.

Addressing the above matters will require investments in new transmission lines, investments to address station overloading, capacity upgrades and new construction to accommodate future load growth.

The continued provision of safe and reliable service requires Manitoba Hydro to undertake investments today and in the near future. The proposed rate increases will ensure that there is adequate funding available to make the necessary investments.

Tab 38

Manitoba Hydro

Capital Forecast

CEF 99-1

1999/00 – 2018/19

October 1999

FALL 1999 FORECAST

SECTIONS

SUMMARY

POWER SUPPLY

FUTURE ENERGY SUPPLY

HVDC FACILITIES

HYDRAULIC REHABILITATION

THERMAL REHABILITATION

OTHER

DOMESTIC ITEM - POWER SUPPLY

TRANSMISSION & DISTRIBUTION

TRANSMISSION FOR GENERATION

INTERCONNECTIONS - T & D

TRANSMISSION

SUBTRANSMISSION

DISTRIBUTION

COMMUNICATIONS, CONTROLS AND INFO TECHNOLOGY

OTHER

DOMESTIC ITEM - T & D

CUSTOMER SERVICE

MAJOR ITEMS

DOMESTIC ITEM - CUSTOMER SERVICE

CORPORATE GROUP

MAJOR ITEMS

DOMESTIC ITEM - CORPORATE GROUP

POWER SUPPLY

	FUTURE ENERGY SUPPLY	
24	WUSKWATIM GENERATING STATION	1
264	CONAWAPA GENERATING STATION	2
	HVDC FACILITIES	
223	HVDC BIPOLE RELIABILITY ENHANCEMENTS	3
88	BIPOLE 1 CONVERTER TRANSFORMERS	4
11	BIPOLE 1 MERCURY ARC VALVES STAGE 3	5
5	HVDC BIPOLE 2 THYRISTOR POLY PIPE REPLACEMENTS	6
54	CONVERTER TRANSFORMER BUSHING REPLACEMENT	7
203	DORSEY BIPOLE 1 SYNCH CONDENSER BREAKER REPLACEMENT	8
216	BIPOLE 1 & 2 DC FILTER CAPACITOR REPLACEMENT	9
213	S.E.R. REPLACEMENT	10
214	BIPOLE 1 VALVE HALL WALL BUSHING REPLACEMENT	11
249	DORSEY BRINE EFFLUENT DISPOSAL STUDY AND IMPROVEMENT	12
258	BIPOLE 1 & 2 ELECTRODE LINE MONITORING	13
259	HVDC SWITCHGEAR ARCPROOF/SAFETY UPGRADES	14
260	HVDC AUXILIARY POWER SUPPLY UPGRADES	15
272	DORSEY SYNCHRONOUS CONDENSER REFURBISHMENT	16
	HYDRAULIC REHABILITATION	
3	GREAT FALLS G.S. REHABILITATION	17
52	SEVEN SISTERS G.S. REHABILITATION	18
32	PINE FALLS G.S. REHABILITATION	19
33	McARTHUR G.S. REHABILITATION	20
1	LAURIE RIVER PLANT 1 AND 2 REHABILITATION	21
48	GRAND RAPIDS G.S. REHABILITATION	22
25	JENPEG G.S. UNIT OVERHAULS	23
22	KETTLE & LONG SPRUCE G.S. STATOR REWEDGING	24
82	DAM SAFETY UPGRADES	25
26	WINNIPEG RIVER CONTROL SYSTEM	26
234	LIMESTONE OUTSTANDING WORK	27
243	WPG RIVER RIVERBANK PROTECTION PROGRAM	28

COMPLEX	BUDGET REFERENCE DESCRIPTION	PAGE
246	KETTLE G.S. STATOR REWIND	29
252	KELSEY GS GATE REHABILITATION	30
256	KETTLE CAS SYSTEM UPGRADES	31
	THERMAL REHABILITATION	
38	THERMAL G.S. ASSURANCE	32
226	BRANDON G.S. LICENCE RENEWAL	33
220	BRANDON G.S. SWITCHYARD JETAIRE BREAKER REPLACEMENT	34
	OTHER	
224	200MW ONTARIO HYDRO SALE - SYNC COND CONVERSION	35
227	SITE REMEDIATION OF CONTAMINATED CORPORATE FACILITIES	36
225	OIL CONTAINMENT	37
228	FIRE PROTECTION PROJECTS	38
13	POWER SUPPLY BUILDINGS	39
990	PLANNING STUDY COSTS	40
121-129	**DOMESTIC ITEM - POWER SUPPLY**	41
	TRANSMISSION & DISTRIBUTION	
	TRANSMISSION FOR GENERATION	
58	WUSKWATIM TRANSMISSION	42
262	CONAWAPA TRAMSMISSION	43
263	HVDC CONVERSION BIPOLE 3	44
265	RIEL > WINNIPEG AC TRANSMISSION	45
266	DORSEY > RIEL 500KV AC T/L	46
	INTERCONNECTIONS - T & D	
95	200MW ONTARIO HYDRO SALE - T/L UPGRADE	47
268	GLENBORO > HARVEY 230KV LINE	48
	TRANSMISSION	
87	KETTLE AC TRANSMISSION IMPROVEMENTS	49
30	THOMPSON > HERBLET LAKE 230kV TRANSMISSION	50
16	NORTH CENTRAL MANITOBA PROJECT	51
40	FLIN FLON - CLIFF LAKE TRANSFORMER REPLACEMENT	52
47	HERBLET LAKE > THE PAS 230kV TRANSMISSION	53
57	DORSEY > NEEPAWA > CORNWALLIS 230kV LINE	54

COMPLEX	BUDGET REFERENCE DESCRIPTION	PAGE
60	WINNIPEG > BRANDON 230kV TRANSMISSION	55
45	FT GARRY - PERIMETER SOUTH BANK REPLACEMENT	56
84	RIDGEWAY 230kV TRANSFORMER ADDITION	57
78	RIDGEWAY > ST. VITAL 230kV TRANSMISSION	58
64	ST. VITAL 230kV TRANSFORMER ADDITION	59
42	DORSEY > ROSSER 230kV TRANSMISSION IMPROVEMENTS	60
27	DORSEY > ST. VITAL 230kV TRANSMISSION	61
96	DORSEY > LAVERENDRYE > ST. VITAL 230kV TRANSMISSION	62
21	ROSSER > SILVER 230kV TRANSMISSION	63
39	RAVEN LAKE STATION 230-66kV TRANSFORMATION	64
18	NEEPAWA 230 - 66kV STN	65
201	ASSINIBIONE WILKES AVE 115-24 KV BANK 1 ADDITION	66
202	ROSSER > MCPHILLIPS 115kV TRANSMISSION IMPROVEMENTS	67
204	RICHER - SOUTH 230-66kV TRANSFORMER ADDITION	68
205	PINE FALLS > BLOODVEIN 115kV LINE TRANSMISSION	69
207	ST. VITAL > STEINBACH 230kV TRANSMISSION	70
208	RIDGEWAY > SELKIRK 230kV TRANSMISSION	71
210	SOURIS > PEMBINA VALLEY 230kV TRANSMISSION	72
4	WINNIPEG AREA TRANSMISSION REFURBISHMENT	73
28	DORSEY STATION 230kV BREAKER REPLACEMENT	74
43	DORSEY > US BORDER D602F 500KV AC T/L INSULATOR REPLACEMENT	75
7	BIPOLE 1 & 2 LINE SPACER DAMPERS REPLACEMENT	76
247	DORSEY 230KV BUS ENHANCEMENTS	77
251	FLIN FLON AREA TRANSMISSION IMPROVEMENTS	78
257	PINE FALLS > GREAT FALLS 115-66KV SUPPLY	79
	SUBTRANSMISSION	
55	JENPEG > NORWAY HOUSE 66 kV SUB TRANSMISSION LINE	80
53	RUTTAN > SOUTH INDIAN LAKE 66 kV LINE	81
17	CENTRAL SUPPLY > PIKWITONEI & THICKET PORTAGE	82
206	PINEY > SPRAGUE 66kV LINE	83
209	BIRTLE > ROSSBURN 66kV LINE	84
237	ST BONIFACE - PLESSIS RD 115-25kV STATION	85
238	ROSSER - OAK POINT 115-24kV STN	86

COMPLEX	BUDGET REFERENCE DESCRIPTION	PAGE
239	ROSSER - OAK POINT BANK 2 ADDITION	87
240	ST BONIFACE - PLESSIS RD BANK 2 ADDITION	88
241	NEEPAWA 66kV SYSTEM	89
242	RESTON / GLENBORO CAPACITY INCREASE	90
80	ST LEON 230-66KV TRANSFORMER ADD'N AND IPL EXPANSION	91
253	BRANDON EAST 115KV IMPROVEMENTS	92
250	BRANDON CROCUS PLAINS 115-25KV BANK ADDITION	93
	DISTRIBUTION	
86	DIESEL UPGRADING ENHANCEMENT	94
221	VIRDEN AREA DISTRIBUTION CHANGES	95
217	DEFECTIVE RINJ CABLE REPLACEMENT	96
261	BRERETON LAKE STATION AREA	97
267	PAINT LAKE NEW FEEDER	98
	COMMUNICATIONS, CONTROLS AND INFO TECHNOLOGY	
10	EMS SCADA	99
12	MICROWAVE RADIO REPLACEMENTS	100
219	MAPINFO IMPLEMENTATION PART II	101
	OTHER	
2	SITE REMEDIATION	102
81	OIL CONTAINMENT	103
131-139	**DOMESTIC ITEM - T & D**	104
	CUSTOMER SERVICE	
	MAJOR ITEMS	
991	DEMAND SIDE MANAGEMENT CAPITAL COSTS	105
97	AUTOMATIC METER READING IMPLEMENTATION	106
141-149	**DOMESTIC ITEM - CUSTOMER SERVICE**	107
	CORPORATE GROUP	
	MAJOR ITEMS	
230	FIRE PROTECTION PROJECTS	108
231	CORPORATE BUILDING PROGRAM	109
244	YEAR 2000 CONVERSION	110
245	NEW CUSTOMER SERVICE SYSTEM	111
111-119	**DOMESTIC ITEM - CORPORATE GROUP**	112

CAPITAL EXPENDITURE FORECAST (CEF99-1)
(IN MILLIONS OF DOLLARS)
FOR THE YEARS 1999/00 TO 2018/19

		Total	Prev	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	20 year Forecast
POWER SUPPLY																								
	FUTURE ENERGY SUPPLY																							
24	WUSKWATIM GENERATING STATION	632.5												45.1	-49.9	24.1 131.1	11.7 151.7	76.0 246.4	158.3 346.2	182.5 393.8	179.9 390.1	436.4	359.5	632.5 2,550.3
264	CONAWAPA GENERATING STATION	2,695.6																						
	HVDC FACILITIES																							15.9
223	HVDC BIPOLE RELIABILITY ENHANCEMENTS	32.3	16.4	10.9	5.0																			151.0
88	BIPOLE I CONVERTER TRANSFORMERS	4.9	4.9																					2.2
11	BIPOLE I MERCURY ARC VALVES STAGE 3	151.0				1.0	3.8	43.5	60.5	41.6	0.7													2.4
5	HVDC BIPOLE 2 THYRISTOR POLY PIPE REPLACEMENTS	5.5	3.4	1.4	0.8																			6.4
54	CONVERTER TRANSFORMER BUSHING REPLACEMENT	6.4	4.0	0.4	1.3	0.6	0.1																	4.7
203	DORSEY BIPOLE 1 SYNCH CONDENSER BREAKER REPLACEMENT	7.0	0.6	1.5	0.4	2.3	2.2																	0.7
216	BIPOLE 1 DC FILTER CAPACITOR REPLACEMENT	5.0	0.2	0.8	1.7	2.0	0.3																	7.1
213	S.E.R. REPLACEMENT	2.0	1.3	0.7																				
214	BIPOLE 1 VALVE HALL WALL BUSHING REPLACEMENT	9.1	2.0	4.9	2.0	0.2																		1.4
249	DORSEY BRINE EFFLUENT DISPOSAL STUDY AND IMPROVEMENT	0.8	0.8																					1.1
258	BIPOLE 1 &2 ELECTRODE LINE MONITORING	1.4				0.2	1.2																	1.8
259	HVDC SWITCHGEAR ARCPROOF/SAFETY UPGRADES (PHASE 1)	1.1			0.4	0.5	0.1																	7.3
260	HVDC AUXILIARY POWER SUPPLY UPGRADES	1.8			0.5	0.5	0.4	0.4																
272	DORSEY SYNCHRONOUS CONDENSER REFURBISHMENT	7.3			1.1	1.3	1.3	1.3	1.2	1.2														
	HYDRAULIC REHABILITATION																							23.5
3	GREAT FALLS G.S. REHABILITATION	23.6	0.1	0.3	2.7	10.6	7.4	2.5																1.5
52	SEVEN SISTERS G.S. REHABILITATION	19.5	18.0	1.5																				15.3
32	PINE FALLS G.S. REHABILITATION	18.1	2.8	0.8	0.8	1.5	7.1	5.0	0.1															0.8
33	McARTHUR G.S. REHABILITATION	11.9	11.1	0.8											1.2	0.9	0.9							6.9
1	LAURIE RIVER PLANT 1 AND 2 REHABILITATION	16.1	9.3	0.5	2.2		0.1	0.5	0.5															25.0
48	GRAND RAPIDS G.S. REHABILITATION	100.7	75.7	5.4	13.8	5.8																		22.3
25	JENPEG G.S. UNIT OVERHAULS (UNITS 1 - 6)	29.0	6.7	2.2	0.7	3.7	3.7	3.6	0.3	3.8	0.3	3.9												1.3
22	KETTLE & LONG SPRUCE G.S. STATOR REWEDGING	7.1	5.8	1.0	0.3																			11.6
82	PRODUCTION NORTH DAM SAFETY UPGRADES	14.8	3.3	2.1	1.7	2.2	2.2	2.3	1.1															11.1
26	WINNIPEG RIVER CONTROL SYSTEM	13.5	2.4	2.6	2.0	5.6	0.9																	6.4
234	LIMESTONE OUTSTANDING WORK	17.9	11.5	1.7	2.8	0.6	0.6	0.6																6.2
243	WINNIPEG RIVER RIVERBANK PROTECTION PROGRAM	8.3	2.0	0.8	0.7	0.7	0.8	0.8	0.8	0.8	0.8													33.8
246	KETTLE GS - STATOR REWIND	33.8			0.2	0.9	2.5	2.5	2.6	2.6	2.6	2.7	2.7	2.8	2.8	2.9	2.9	3.0						3.5
252	KELSEY G.S. GATE REHABILITATION	3.5				0.6		0.7		0.7		0.7		0.8										1.5
256	KETTLE ANNUNCIATION SYSTEM RENEWAL	1.5			1.0	0.5																		
	THERMAL REHABILITATION																							4.9
38	THERMAL G.S. ASSURANCE	134.1	129.2	4.0	0.9			2.1	0.9	5.8	0.9	1.7	1.0	2.7	1.5	0.9	2.1	0.5	1.2	0.5	0.5	0.5	0.7	23.3
226	BRANDON G.S. UNIT 5 LCENSE RENEWAL	23.3																						1.4
220	BRANDON G.S. SWITCHYARD JETAIRE BREAKER REPLACEMENT	3.6	2.2	1.4																				
	OTHER																							3.5
224	200MW ONTARIO HYDRO SALE - SYNC COND CONVERSION	7.7	4.2	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.5													12.0
227	SITE REMEDIATION OF CONTAMINATED CORPORATE FACILITIES	12.9	0.9	0.8	0.8	0.8	0.8	0.9	0.9	0.9	0.9	0.9	1.0	1.0	1.0	1.0	0.3							7.4
225	OIL CONTAINMENT	15.6	8.2	0.3	0.6	2.3	1.0	1.6	1.6															4.1
228	FIRE PROTECTION PROJECTS	6.7	2.6	0.5	3.1	0.6																		16.2
13	POWER SUPPLY BUILDINGS	35.4	19.1	5.7	2.3	2.8	3.6	1.8																
990	PLANNING STUDY COSTS			16.1	16.5	3.1	2.7	0.9	2.8	2.8	9.7	9.1	18.9	(14.4)	2.8	(15.0)	2.6	2.6	2.8	2.8	2.9	3.0	3.0	75.7
	DOMESTIC ITEMS - POWER SUPPLY			10.0	10.2	10.5	10.7	11.0	11.2	11.5	11.7	12.0	12.2	12.5	12.8	13.1	13.4	13.7	14.0	14.3	14.6	14.9	15.3	249.5
	SUB-TOTAL POWER SUPPLY			79.4	77.1	61.8	54.0	82.3	84.9	72.1	28.1	30.9	35.8	50.4	72.0	159.0	185.6	342.2	522.5	593.9	588.1	454.8	378.5	3,953.2

CAPITAL EXPENDITURE FORECAST (CEF99-1)
(IN MILLIONS OF DOLLARS)
FOR THE YEARS 1999/00 TO 2018/19

		Total	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	20 year Forecast
TRANSMISSION AND DISTRIBUTION																							
	TRANSMISSION FOR GENERATION																						
58	WUSKWATIM TRANSMISSION	66.5												1.1	1.2	2.7	2.6	8.2	25.8	25.1			66.5
263	HVDC CONVERSION BIPOLE 3/CONAWAPA TRANSMISSION	1,896.2										2.6	9.2	15.3	15.8	41.5	55.3	215.8	412.4	509.3	372.7	186.7	1,836.6
	INTERCONNECTIONS																						
79	MANITOBA > MINNESOTA 500kV TRANSMISSION UPGRADE (MMTU)	0.8	0.8																				0.8
95	200MW ONTARIO HYDRO SALE - T/L UPGRADE	16.0		1.6	6.4	8.0																	16.0
268	HARVEY-GLENBORO 230KV LINE																						
	TRANSMISSION																						10.6
87	KETTLE AC TRANSMISSION IMPROVEMENTS	10.6	0.1	0.0	0.2	1.0	4.3	5.0															0.8
16	NORTH CENTRAL MANITOBA PROJECT	0.8	0.0	0.3	0.4																		57.1
30	THOMPSON>HERBLET LAKE 230kV TRANSMISSION	57.1			0.2	0.2	0.8	5.4	21.5	14.1	14.9												1.5
40	FLIN FLON - CLIFF LAKE TRANSFORMER REPLACEMENT	1.5	0.6	0.9																			48.5
47	HERBLET LAKE > THE PAS 230kV TRANSMISSION	55.3				0.2	0.5	1.0	0.3	1.1	3.4	16.4	19.0	6.7									18.5
57	DORSEY > NEEPAWA > CORNWALLIS 230kV LINE	18.5	16.8	1.7																			73.0
60	WINNIPEG > BRANDON 230kV TRANSMISSION	73.0			0.1	3.0	4.8	7.4	13.7	18.7	15.1	10.3											4.4
45	FT GARRY - PERIMETER SOUTH BANK REPLACEMENT	4.4			0.4	2.5	1.5																9.2
84	RIDGEWAY TRANSFORMER ADDITION	9.2					0.3	0.6	0.8	4.1	3.4												1.7
78	RIDGEWAY > ST. VITAL 230kV TRANSMISSION	1.7	1.7																				9.0
64	ST. VITAL TRANSFORMER ADDITION	9.0	0.3	3.6	4.0	1.0																	1.8
42	DORSEY-ROSSER 230kV TRANSMISSION IMPROVEMENTS	1.8	0.0	1.4	0.4																		7.7
27	DORSEY > ST. VITAL 230kV AC TRANSMISSION	7.7	0.0	1.3	5.3	1.1	0.0									1.7	3.5	10.7	10.0				25.9
96	DORSEY > LAVERENDRYE > ST. VITAL 230kV TRANSMISSION	25.9																					27.6
21	ROSSER > SILVER 230kV TRANSMISSION	27.6	3.6	0.4	0.5	3.3	9.9	10.0															
9	RAVEN LAKE > BIRTLE 230kV TRANSMISSION																						
94	BRANDON 115kV LOOP	8.3																0.6	1.5	3.0	3.3		8.3
39	RAVEN LAKE STATION 230-66kV TRANSFORMATION																						
98	VERMILION STATION STATIC VAR GENERATOR	17.5					0.1	1.0	7.4	9.1													17.5
18	NEEPAWA 230-115kV STN	7.2	7.1	0.1																			7.2
201	ASSINIBOINE - WILKES AVE 115-24 KV BANK 1 ADDITION	2.4	0.0	0.1	0.4	1.8																	2.4
202	ROSSER > MCPHILLIPS 115kV TRANSMISSION IMPROVEMENTS	4.9				0.4	0.4	2.3	1.8														4.9
204	RICHER SOUTH 230-66kV TRANSFORMER ADDITION	29.1								0.2	0.2	1.0	1.7	7.0	15.6	3.4							29.1
205	PINE FALLS > BLOODVEIN 115kV TRANSMISSION LINE	22.3						0.3	0.3	0.6	3.3	4.2	13.6										22.3
207	ST. VITAL > STEINBACH 230kV TRANSMISSION	25.1				0.6	2.0	3.3	4.5	7.0	7.6												25.1
208	RIDGEWAY > SELKIRK 230kV TRANSMISSION	32.6								0.6	0.9	1.4	1.6	12.0	16.1								32.6
210	SOURIS > PEMBINA VALLEY 230kV TRANSMISSION	4.0	1.1	0.6	0.4	0.8	1.1	0.0															4.0
4	WINNIPEG AREA TRANSMISSION REFURBISHMENT	1.6	1.6																				1.6
28	DORSEY STATION 230kV BREAKER REPLACEMENT	2.7	1.2	0.5	0.4	0.6																	2.7
43	DORSEY > US BORDER D602F 500KV AC T/L INSULATOR REPL.	5.1	0.7	2.5	1.9	0.0																	5.1
7	BIPOLE 1 & 2 LINE SPACER DAMPERS REPLACEMENT	16.0	0.4	0.9	3.2	7.0	4.6																16.0
247	DORSEY 230kV BUS ENHANCEMENTS	17.3	0.3	2.0	5.2	1.6	5.2	2.9															17.3
251	FLIN FLON AREA TRANSMISSION IMPROVEMENTS	9.4		0.9	2.7	3.4	1.2	1.1															9.4
257	PINE FALLS-GREAT FALLS 115-66kV SUPPLY																						
	SUBTRANSMISSION																						12.5
55	JENPEG > NORWAY HOUSE 66 kV SUB TRANSMISSION LINE	12.5	0.0	0.0	0.3	0.9	4.9	6.3															5.5
53	RUTTAN > SOUTH INDIAN LAKE 66 kV LINE	5.5	0.3	0.3	0.3	1.6	3.0																0.7
17	CENTRAL SUPPLY > PIKWITONEI & THICKET PORTAGE	0.7	0.0	0.7																			1.7
206	PINEY > SPRAGUE 66kV LINE	1.7	1.7	0.0																			5.4
209	BIRTLE SOUTH > ROSSBURN 66kV LINE	5.4				0.1	0.2	3.6	1.5														16.4
237	ST. BONIFACE-PLESSIS ROAD 115-25KV STATION	16.4	7.8	8.3	0.3																		18.5
238	ROSSER - OAK POINT 115-24KV STATION	18.5			0.0	0.7	2.0	10.1	5.7														9.8
239	ROSSER - OAK POINT BANK 2 ADDITION	9.8										0.8	6.2	2.7									4.9
240	ST. BONIFACE - PLESSIS ROAD BANK 2 ADDITION	4.9	0.1	1.6	3.2																		3.4
241	NEEPAWA 66KV SYSTEM	3.4			0.2	3.3																	4.9
242	RESTON/GLENBORO CAPACITY INCREASE	4.9	0.5	2.8	1.6																		8.9
80	ST. LEON 230-66KV TRANSF. ADD'N AND IPL EXPANSION	8.9	0.2	0.9	1.6	5.0	0.7	0.5															1.0
253	BRANDON EAST 115kV IMPROVEMENTS	1.0	1.0																				7.2
250	BRANDON CROCUS PLAINS 115-24kV BANK ADDITION	7.2		0.1	0.6	3.9	2.3	0.4															
	DISTRIBUTION																						10.3
86	DIESEL UPGRADING ENHANCEMENT	10.3	2.1	1.7	4.4	2.0																	10.0
221	VIRDEN AREA DISTRIBUTION CHANGES	10.0	4.2	1.3	1.6	0.9	1.0	1.0															7.8
217	DEFECTIVE RINJ CABLE REPLACEMENT	7.8	0.8	1.2	1.8	1.9	2.1																6.6
261	BRERETON LAKE STATION AREA	6.6		2.6	2.2	0.7	0.5	0.5	0.1														1.6
267	PAINT LAKE NEW FEEDER	1.6			1.8	(0.2)																	
	COMMUNICATIONS, CONTROLS AND INFO TECHNOLOGY																						2.1
10	EMS SCADA	2.1	2.1																				48.1
12	MICROWAVE RADIO REPLACEMENTS	48.1	9.0	3.3	9.6	8.1		1.6	16.5														10.7
218	LAN NETWORK EXPANSION	10.7	4.4	4.3	2.0																		
219	MAPINFO IMPLEMENTATION																						
	OTHER																						5.5
2	SITE REMEDIATION	5.5	1.3	2.2	0.9	1.1																	3.4
81	OIL CONTAINMENT	3.4	0.1	0.8	1.2	1.0	0.3																
92	FIRE PROTECTION PROJECTS																						

CAPITAL EXPENDITURE FORECAST (CEF99-1)
(IN MILLIONS OF DOLLARS)
FOR THE YEARS 1999/00 TO 2018/19

	Total	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	20 year Forecast
DOMESTIC ITEMS - TRANMISSION AND DISTRIBUTION		77.6	75.8	78.6	80.6	86.0	88.3	90.6	92.9	95.2	97.6	100.1	102.7	105.4	108.1	110.8	113.6	116.5	119.6	122.7	125.8	1,988.3
SUB-TOTAL TRANSMISSION AND DISTRIBUTION		**149.5**	**126.6**	**144.5**	**148.0**	**139.7**	**152.6**	**164.7**	**148.3**	**143.8**	**134.2**	**151.4**	**147.5**	**154.1**	**157.4**	**172.1**	**348.8**	**566.1**	**657.0**	**498.7**	**312.5**	**4,617.7**

CAPITAL EXPENDITURE FORECAST (CEF99-1)
(IN MILLIONS OF DOLLARS)
FOR THE YEARS 1999/00 TO 2018/19

		Total	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	20 year Forecast
CUSTOMER SERVICE																							
991	DEMAND SIDE MANAGEMENT CAPITAL COSTS		8.2	10.1	10.4	9.2	9.3	7.2	7.3	7.2	7.4	7.5	5.3	5.4	5.5	5.6	5.7	5.8	5.7	5.8	5.9	6.0	140.7
97	AUTOMATIC METER READING IMPLEMENTATION	30.5		0.1	2.1	3.2	3.3	3.1	3.4	3.5	3.5	6.2	2.3										30.5
	DOMESTIC ITEMS - CUSTOMER SERVICE		33.7	30.3	31.3	32.5	35.0	36.1	37.1	38.1	39.1	40.2	41.3	42.5	43.7	44.9	46.1	47.4	48.8	50.2	51.6	52.9	823.0
	SUB-TOTAL CUSTOMER SERVICE		**41.9**	**40.5**	**43.8**	**44.9**	**47.6**	**46.3**	**47.8**	**48.8**	**50.1**	**54.0**	**49.0**	**47.9**	**49.2**	**50.5**	**51.8**	**53.2**	**54.4**	**56.0**	**57.5**	**58.9**	**994.2**

CAPITAL EXPENDITURE FORECAST (CEF99-1)
(IN MILLIONS OF DOLLARS)
FOR THE YEARS 1999/00 TO 2018/19

		Total	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	20 year Forecast
CORPORATE GROUP																							
230	FIRE PROTECTION PROJECTS	1.0	0.7	0.3																			1.0
231	CORPORATE BUILDING PROGRAM	17.2	0.0				15.1	2.1															17.2
244	YEAR 2000 CONVERSION	8.8	6.8	2.0																			8.8
245	NEW CUSTOMER SERVICE SYSTEM	8.0			0.3	2.6	5.1																7.9
	DOMESTIC ITEMS - CORPORATE GROUP		23.0	23.6	22.2	24.8	25.7	26.2	26.8	27.3	27.9	28.4	29.0	29.6	30.2	30.8	31.5	32.1	32.8	33.4	34.1	35.0	574.4
	SUB-TOTAL CORPORATE GROUP		**30.5**	**25.9**	**22.6**	**27.3**	**45.9**	**28.3**	**26.8**	**27.3**	**27.9**	**28.4**	**29.0**	**29.6**	**30.2**	**30.8**	**31.5**	**32.1**	**32.8**	**33.4**	**34.1**	**35.0**	**609.3**
	TOTAL CAPITAL EXPENDITURES		**301.3**	**270.0**	**272.7**	**274.3**	**315.4**	**312.0**	**311.3**	**252.6**	**252.7**	**252.5**	**279.8**	**297.1**	**392.6**	**424.3**	**597.5**	**956.7**	**1,247.2**	**1,334.4**	**1,045.1**	**784.9**	**10,174.4**

CAPITAL EXPENDITURE FORECAST REVISIONS (CEF99-1)
(IN MILLIONS OF DOLLARS)
FOR THE YEARS 1999/00 TO 2018/19

		2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	20 year Forecast
POWER SUPPLY																						
	FUTURE ENERGY SUPPLY																					
24	WUSKWATIM GENERATING STATION											(31.0)	(24.8)	(30.4)	(159.9)	(118.2)	(30.2)	182.5	179.9			(32.1)
264	CONAWAPA GENERATING STATION											45.1	49.9	131.1	151.7	246.4	346.2	393.8	390.1	436.4	359.5	2,550.3
	HVDC FACILITIES																					
223	HVDC BIPOLE RELIABILITY ENHANCEMENTS	(4.2)	(4.1)	(2.1)																		(10.4)
88	BIPOLE 1 CONVERTER TRANSFORMERS	(1.6)																				(1.6)
11	BIPOLE 1 MERCURY ARC VALVES STAGE 3			0.0	0.1	0.7	1.0	0.7	0.0													2.5
5	HVDC BIPOLE 2 THYRISTOR POLY PIPE REPLACEMENTS	(0.8)	0.1																			(0.7)
54	CONVERTER TRANSFORMER BUSHING REPLACEMENT	(0.9)	0.7	0.4	0.1																	0.3
203	DORSEY BIPOLE 1 SYNCH CONDENSER BREAKER REPLACEMENT	0.2	(1.0)	(0.2)	(0.4)																	(1.3)
216	BIPOLE 1 DC FILTER CAPACITOR REPLACEMENT	0.1	0.7	1.0	0.3																	2.1
213	S.E.R. REPLACEMENT	0.7																				0.7
214	BIPOLE 1 VALVE HALL WALL BUSHING REPLACEMENT	1.8	(2.0)	0.2																		0.1
249	DORSEY BRINE EFFLUENT DISPOSAL STUDY AND IMPROVEMENT																					
258	BIPOLE 1 &2 ELECTRODE LINE MONITORING			0.2	1.2																	1.4
259	HVDC SWITCHGEAR ARCPROOF/SAFETY UPGRADES (PHASE 1 & 2)		0.4	0.5	0.1																	1.1
260	HVDC AUXILIARY POWER SUPPLY UPGRADES		0.5	0.5	0.4	0.4																1.8
272	DORSEY SYNCHRONOUS CONDENSER REFURBISHMENT		1.1	1.3	1.3	1.3	1.2	1.2														7.3
	HYDRAULIC REHABILITATION																					
3	GREAT FALLS G.S. REHABILITATION	(0.6)	(6.7)	(0.5)	5.1	2.5																(0.1)
52	SEVEN SISTERS G.S. REHABILITATION	0.8																				0.8
32	PINE FALLS G.S. REHABILITATION	(2.3)	(6.2)	(3.5)	6.9	5.0	0.1															0.1
33	McARTHUR G.S. REHABILITATION	0.1																				0.1
1	LAURIE RIVER PLANT 1 AND 2 REHABILITATION	(0.0)	0.1		(0.0)	(0.0)	(0.0)						(0.0)	(0.0)	(0.0)							0.0
48	GRAND RAPIDS G.S. REHABILITATION	(10.9)	8.8	1.3	(4.6)	(3.6)	(2.4)															(11.5)
25	JENPEG G.S. UNIT OVERHAULS (UNITS 1 - 6)	(1.7)	(3.2)	0.6	3.7	0.3	0.3	0.3	0.3	0.3												0.9
22	KETTLE & LONG SPRUCE G.S. STATOR REWEDGING	0.1	0.0																			0.1
82	PRODUCTION NORTH DAM SAFETY UPGRADES	0.8	1.6	2.2	2.2	2.3	1.1															10.2
26	WINNIPEG RIVER CONTROL SYSTEM	0.7	(4.7)	4.0	0.5																	0.6
234	LIMESTONE OUTSTANDING WORK	(2.2)	2.4	0.0	0.0	0.0																0.2
243	WINNIPEG RIVER RIVERBANK PROTECTION PROGRAM	0.4	0.1	0.1	0.2	0.2	0.2	0.2	0.2													1.5
246	KETTLE GS - STATOR REWIND	(0.9)	(1.2)	(1.3)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.3)	(0.3)	(0.3)	1.0	3.0						(1.6)
252	KELSEY G.S. GATE REHABILITATION		(0.6)	0.6	(0.7)	0.7	(0.7)	0.7	(0.7)	0.7	(0.7)	0.8										0.1
256	KETTLE ANNUNCIATION SYSTEM RENEWAL		1.0	0.5																		1.5
	THERMAL REHABILITATION																					
38	THERMAL G.S. ASSURANCE	3.2	0.9																			4.2
226	BRANDON G.S. UNIT 5 LICENSE RENEWAL		(1.1)	(3.6)	(2.5)	0.9	(0.4)	(1.7)	(1.3)	(0.3)	(0.8)	2.7	1.5	0.9	2.1	0.5	1.2	0.5	0.5	0.5	0.7	0.1
220	BRANDON G.S. SWITCHYARD JETAIRE BREAKER REPLACEMENT	(0.6)																				(0.6)
	OTHER																					
224	200MW ONTARIO HYDRO SALE - SYNC COND CONVERSION	(0.7)	(0.3)	(0.1)	(0.1)	0.1	0.4	0.4	0.5													0.6
227	SITE REMEDIATION OF CONTAMINATED CORPORATE FACILITIES	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0							0.4
225	OIL CONTAINMENT	(0.3)	(1.6)	(2.6)	0.1	1.6	1.6															(1.1)
228	FIRE PROTECTION PROJECTS	0.1	0.7	0.6																		1.3
13	POWER SUPPLY BUILDINGS	(0.2)	(1.6)	(1.1)	1.4	1.8																0.3
990	PLANNING STUDY COSTS	0.0	14.5	0.8	0.4	(1.4)	0.5	(0.2)	3.7	3.0	10.7	0.5	0.5	(17.4)	0.1	(0.2)	(0.1)	2.5	0.5	0.3	0.3	19.0
	DOMESTIC ITEMS - POWER SUPPLY	(0.0)	0.0	0.0																		(0.0)
	SUB-TOTAL POWER SUPPLY	(19.0)	(0.1)	0.0	15.6	12.6	2.7	1.4	2.5	3.5	8.9	17.8	26.8	84.0	(5.0)	131.6	317.1	579.2	571.1	437.2	360.5	2,548.4

CAPITAL EXPENDITURE FORECAST REVISIONS (CEF99-1)
(IN MILLIONS OF DOLLARS)
FOR THE YEARS 1999/00 TO 2018/19

		2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	20 year Forecast
TRANSMISSION AND DISTRIBUTION																						
	TRANSMISSION FOR GENERATION																					
58	WUSKWATIM TRANSMISSION										(0.8)	(0.9)	(2.1)	(2.1)	(7.2)	(24.2)	(23.5)					(60.8)
263	HVDC CONVERSION BIPOLE 3/CONAWAPA TRANSMISSION										2.6	9.2	15.3	15.8	41.5	55.3	215.8	412.4	509.3	372.7	186.7	1,836.6
	INTERCONNECTIONS																					
79	MANITOBA > MINNESOTA 500kV TRANSMISSION UPGRADE (MMTU)																					0.8
95	200MW ONTARIO HYDRO SALE - T/L UPGRADE	0.8																				16.0
268	HARVEY-GLENBORO 230KV LINE		1.6	6.4	8.0																	
	TRANSMISSION																					1.4
87	KETTLE AC TRANSMISSION IMPROVEMENTS	(1.5)	(2.4)	(2.3)	(1.8)	4.3	5.0															(0.8)
16	NORTH CENTRAL MANITOBA PROJECT	(0.7)	0.0	(0.1)	(0.0)																	1.9
30	THOMPSON>HERBLET LAKE 230kV TRANSMISSION	(0.2)	(0.3)	(0.2)	(0.2)	(4.3)	(15.6)	8.0	(0.2)	14.9												1.2
40	FLIN FLON - CLIFF LAKE TRANSFORMER REPLACEMENT	0.3	0.9																			1.0
47	HERBLET LAKE > THE PAS 230kV TRANSMISSION				0.0	0.0	0.1	0.0	0.1	0.1	0.1	0.3	0.2									(3.8)
57	DORSEY > NEEPAWA > CORNWALLIS 230kV LINE	1.1	(4.9)																			3.9
60	WINNIPEG > BRANDON 230kV TRANSMISSION		(0.1)	(0.2)	(3.2)	(1.7)	(5.1)	(4.1)	2.7	5.2	10.3											(0.1)
45	FT GARRY - PERIMETER SOUTH BANK REPLACEMENT		(0.4)	0.2	(1.4)	1.5																0.3
84	RIDGEWAY TRANSFORMER ADDITION					0.0	0.1	0.1	0.1	0.0												0.8
78	RIDGEWAY > ST. VITAL 230kV TRANSMISSION	0.8																				0.5
64	ST. VITAL TRANSFORMER ADDITION	(2.9)	0.9	3.6	(1.0)																	(0.0)
42	DORSEY-ROSSER 230kV TRANSMISSION IMPROVEMENTS	0.0	(0.1)	0.0																		0.7
27	DORSEY > ST. VITAL 230kV AC TRANSMISSION	(5.1)	(0.2)	4.9	1.1	0.0																0.3
96	DORSEY > LAVERENDRYE > ST. VITAL 230kV TRANSMISSION														0.1	0.2	0.0	0.0				2.0
21	ROSSER > SILVER 230kV TRANSMISSION	0.6	(3.6)	(10.7)	(4.2)	9.9	10.0															
9	RAVEN LAKE > BIRTLE 230kV TRANSMISSION																					
94	BRANDON 115kV LOOP																0.1	0.1	0.1	0.0		0.2
39	RAVEN LAKE STATION 230-66kV TRANSFORMATION																					(21.7)
98	VERMILION STATION STATIC VAR GENERATOR	(0.0)	(0.1)	(0.5)	(8.5)	(8.6)	(3.9)															(4.8)
18	NEEPAWA 230 -115kV STN	(0.3)	(0.4)	(1.0)	(10.1)	(10.5)	1.0	7.4	9.1													0.1
201	ASSINIBOINE - WILKES AVE 115-24 KV BANK 1 ADDITION	1.3	(1.2)																			0.2
202	ROSSER > MCPHILLIPS 115kV TRANSMISSION IMPROVEMENTS	(0.1)	(0.3)	(1.3)	1.8																	0.1
204	RICHER SOUTH 230-66kV TRANSFORMER ADDITION				0.0	0.1	0.0	0.0														4.4
205	PINE FALLS > BLOODVEIN 115kV TRANSMISSION LINE	(0.1)	(0.1)	(0.8)	(1.4)	(5.3)	(13.9)	(3.0)	0.2	0.2	1.0	1.7	7.0	15.6	3.4							0.6
207	ST. VITAL > STEINBACH 230kV TRANSMISSION						0.0	0.0	0.1	0.1	0.2	0.1										0.6
208	RIDGEWAY > SELKIRK 230kV TRANSMISSION				0.1	0.1	0.1	0.2	0.1	0.1												0.7
210	SOURIS > PEMBINA VALLEY 230kV TRANSMISSION								0.0	0.0	0.1	0.1	0.2	0.3								0.3
4	WINNIPEG AREA TRANSMISSION REFURBISHMENT	0.4	(0.2)	(0.3)	0.1	0.2	0.0															0.6
28	DORSEY STATION 230kV BREAKER REPLACEMENT	0.6																				(1.0)
43	DORSEY > US BORDER D602F 500KV AC T/L INSULATOR REPLACEMENT	0.4	(0.3)	(0.5)	(0.6)																	(5.7)
7	BIPOLE 1 & 2 LINE SPACER DAMPERS REPLACEMENT	(3.0)	(1.2)	(1.6)	0.0																	1.5
247	DORSEY 230kV BUS ENHANCEMENTS	0.0	0.1	0.6	0.6	0.2																17.3
251	FLIN FLON AREA TRANSMISSION IMPROVEMENTS	0.3	2.0	5.2	1.6	5.2	2.9															9.4
257	PINE FALLS-GREAT FALLS 115-66kV SUPPLY		0.9	2.7	3.4	1.2	1.1															
	SUBTRANSMISSION																					1.1
55	JENPEG > NORWAY HOUSE 66 kV SUB TRANSMISSION LINE	(0.2)	(1.7)	(2.0)	(6.3)	4.9	6.3															0.3
53	RUTTAN > SOUTH INDIAN LAKE 66 kV LINE	0.2	(0.4)	(1.8)	(0.7)	3.0																0.1
17	CENTRAL SUPPLY > PIKWITONEI & THICKET PORTAGE	0.0	0.0																			0.5
206	PINEY > SPRAGUE 66kV LINE	0.5	0.0																			(0.2)
209	BIRTLE SOUTH > ROSSBURN 66kV LINE				0.0	0.0	(0.1)	(0.1)														1.1
237	SPRINGFIELD-ST. BONIFACE 115-25KV STATION	2.8	5.0	(6.7)																		0.6
238	ROSSER - OAK POINT 115-24KV STATION		(0.0)	(0.5)	(0.2)	(8.5)	4.2	5.7														0.0
239	ROSSER - OAK POINT BANK 2 ADDITION										0.1	(0.0)	(0.0)									0.5
240	SPRINGFIELD-ST. BONIFACE BANK 2 ADDITION	0.0	(0.0)	0.5																		(0.1)
241	NEEPAWA 66KV SYSTEM			(0.0)	(0.1)																	0.1
242	RESTON/GLENBORO CAPACITY INCREASE	0.1	0.0	0.0																		0.3
80	ST. LEON 230-66KV TRANSFORMER ADD'N AND IPL EXPANSION	0.3	0.2	0.3	0.0	0.1	(0.6)															0.1
253	BRANDON EAST 115kV IMPROVEMENTS	0.1																				0.3
250	BRANDON CROCUS PLAINS 115-24kV BANK ADDITION		0.0	0.0	0.3	0.1	(0.0)															
	DISTRIBUTION																					0.4
86	DIESEL UPGRADING ENHANCEMENT	(0.9)	0.6	4.2	(3.5)																	1.2
221	VIRDEN AREA DISTRIBUTION CHANGES	0.9	(0.0)	0.1	0.1	0.1	0.1															(0.8)
217	DEFECTIVE RINJ CABLE REPLACEMENT	(0.1)	(0.1)	(0.2)	(0.2)	(0.3)																6.6
261	BRERETON LAKE STATION AREA STUDY		2.6	2.2	0.7	0.5	0.5	0.1														1.6
267	PAINT LAKE NEW FEEDER			1.8	(0.2)																	
	COMMUNICATIONS, CONTROLS AND INFO TECHNOLOGY																					1.6
10	EMS SCADA	1.6																				6.0
12	MICROWAVE RADIO REPLACEMENTS	3.2	0.8	(3.3)	4.7		0.1	0.6														0.9
218	LAN NETWORK EXPANSION																					
219	MAPINFO IMPLEMENTATION	(0.3)	1.5	(0.4)																		

CAPITAL EXPENDITURE FORECAST REVISIONS (CEF99-1)
(IN MILLIONS OF DOLLARS)
FOR THE YEARS 1999/00 TO 2018/19

		2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	20 year Forecast
	OTHER																					
2	SITE REMEDIATION	0.3	0.8	0.0	0.0																	1.1
81	OIL CONTAINMENT	0.0	0.1	0.1	0.2	0.0																0.5
92	FIRE PROTECTION PROJECTS											1.0	2.0	3.0	4.0	5.0	6.0	7.0	8.0	9.0	10.0	55.0
	DOMESTIC ITEMS - TRANMISSION AND DISTRIBUTION	(0.0)	(3.2)	(3.1)	(3.1)								(0.0)						(0.0)			(9.4)
	SUB-TOTAL TRANSMISSION AND DISTRIBUTION	**1.0**	**(3.0)**	**(4.5)**	**(23.9)**	**(7.8)**	**(7.8)**	**14.9**	**12.1**	**20.6**	**13.4**	**11.6**	**22.7**	**32.6**	**41.7**	**36.3**	**198.4**	**419.5**	**517.4**	**381.7**	**196.7**	**1,873.7**

CAPITAL EXPENDITURE FORECAST REVISIONS (CEF99-1)
(IN MILLIONS OF DOLLARS)
FOR THE YEARS 1999/00 TO 2018/19

		2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	20 year Forecast
CUSTOMER SERVICE																						
991	DEMAND SIDE MANAGEMENT CAPITAL COSTS	(0.0)	2.1	2.2	1.0	2.0	1.6	1.8	1.7	1.8	2.0	0.8	0.6	0.8	0.8	0.8	0.9	1.0	1.0	1.0	1.1	25.0
97	AUTOMATIC METER READING IMPLEMENTATION		(1.5)	(0.9)	(0.1)	(0.0)	(0.0)	(0.1)	(0.0)	(0.1)	(0.1)	2.3										(0.6)
	DOMESTIC ITEMS - CUSTOMER SERVICE	0.1	(1.4)	(1.5)	(1.5)																	(4.4)
	SUB-TOTAL CUSTOMER SERVICE	**0.1**	**(0.8)**	**(0.2)**	**(0.6)**	**1.9**	**1.6**	**1.7**	**1.6**	**1.6**	**1.9**	**3.1**	**0.6**	**0.8**	**0.8**	**0.8**	**0.9**	**1.0**	**1.0**	**1.0**	**1.1**	**20.0**

CAPITAL EXPENDITURE FORECAST REVISIONS (CEF99-1)
(IN MILLIONS OF DOLLARS)
FOR THE YEARS 1999/00 TO 2018/19

		2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	20 year Forecast
CORPORATE GROUP																						
230	FIRE PROTECTION PROJECTS	(0.0)	(0.0)																			(0.0)
231	CORPORATE BUILDING PROGRAM	0.0				(0.1)	(0.0)															(0.1)
244	YEAR 2000 CONVERSION	0.0	(0.7)																			(0.7)
245	NEW CUSTOMER SERVICE SYSTEM			(0.0)	(0.0)	(0.0)																(0.1)
	DOMESTIC ITEMS - CORPORATE GROUP	5.1	(0.4)	(0.4)	(0.4)																	3.9
	SUB-TOTAL CORPORATE GROUP	5.1	(1.1)	(0.4)	(0.4)	(0.2)	(0.0)															3.0
	TOTAL CAPITAL EXPENDITURES	**(12.7)**	**(5.0)**	**(5.1)**	**(9.3)**	**6.5**	**(3.5)**	**18.1**	**16.2**	**25.7**	**24.2**	**32.5**	**50.0**	**117.4**	**37.6**	**168.7**	**516.3**	**999.7**	**1,089.5**	**819.9**	**454.3**	**4,341.1**

CAPITAL EXPENDITURE FORECAST (CEF99-1)
(IN MILLIONS OF DOLLARS)
FOR THE YEARS 1999/00 TO 2018/19

		Total	Prev	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	20 year Forecast
POWER SUPPLY																								
	FUTURE ENERGY SUPPLY																							
24	WUSKWATIM GENERATING STATION	632.5														24.1	11.7	76.0	158.3	182.5	179.9			632.5
264	CONAWAPA GENERATING STATION	2,695.6												45.1	49.9	131.1	151.7	246.4	346.2	393.8	390.1	436.4	359.5	2,550.3
	HVDC FACILITIES																							
223	HVDC BIPOLE RELIABILITY ENHANCEMENTS	32.3	16.4	10.9	5.0																			15.9
88	BIPOLE 1 CONVERTER TRANSFORMERS	4.9	4.9																					
11	BIPOLE 1 MERCURY ARC VALVES STAGE 3	151.0				1.0	3.8	43.5	60.5	41.6	0.7													151.0
5	HVDC BIPOLE 2 THYRISTOR POLY PIPE REPLACEMENTS	5.5	3.4	1.4	0.8																			2.2
54	CONVERTER TRANSFORMER BUSHING REPLACEMENT	6.4	4.0	0.4	1.3	0.6	0.1																	2.4
203	DORSEY BIPOLE 1 SYNCH CONDENSER BREAKER REPLACEMENT	7.0	0.6	1.5	0.4	2.3	2.2																	6.4
216	BIPOLE 1 DC FILTER CAPACITOR REPLACEMENT	5.0	0.2	0.8	1.7	2.0	0.3																	4.7
213	S.E.R. REPLACEMENT	2.0	1.3	0.7																				0.7
214	BIPOLE 1 VALVE HALL WALL BUSHING REPLACEMENT	9.1	2.0	4.9	2.0	0.2																		7.1
249	DORSEY BRINE EFFLUENT DISPOSAL STUDY AND IMPROVEMENT	0.8	0.8																					
258	BIPOLE 1 &2 ELECTRODE LINE MONITORING	1.4				0.2	1.2																	1.4
259	HVDC SWITCHGEAR ARCPROOF/SAFETY UPGRADES (PHASE I)	1.1			0.4	0.5	0.1																	1.1
260	HVDC AUXILIARY POWER SUPPLY UPGRADES	1.8			0.5	0.5	0.4	0.4																1.8
272	DORSEY SYNCHRONOUS CONDENSER REFURBISHMENT	7.3			1.1	1.3	1.3	1.3	1.2	1.2														7.3
	HYDRAULIC REHABILITATION																							
3	GREAT FALLS G.S. REHABILITATION	23.6	0.1	0.3	2.7	10.6	7.4	2.5																23.5
52	SEVEN SISTERS G.S. REHABILITATION	19.5	18.0	1.5																				1.5
32	PINE FALLS G.S. REHABILITATION	18.1	2.8	0.8	0.8	1.5	7.1	5.0	0.1															15.3
33	McARTHUR G.S. REHABILITATION	11.9	11.1	0.8																				0.8
1	LAURIE RIVER PLANT 1 AND 2 REHABILITATION	16.1	9.3	0.5	2.2		0.1	0.5	0.5						1.2	0.9	0.9							6.9
48	GRAND RAPIDS G.S. REHABILITATION	100.7	75.7	5.4	13.8	5.8																		25.0
25	JENPEG G.S. UNIT OVERHAULS (UNITS 1 - 6)	29.0	6.7	2.2	0.7	3.7	3.7	3.6	0.3	3.8	0.3	3.9												22.3
22	KETTLE & LONG SPRUCE G.S. STATOR REWEDGING	7.1	5.8	1.0	0.3																			1.3
82	PRODUCTION NORTH DAM SAFETY UPGRADES	14.8	3.3	2.1	1.7	2.2	2.2	2.3	1.1															11.6
26	WINNIPEG RIVER CONTROL SYSTEM	13.5	2.4	2.6	2.0	5.6	0.9																	11.1
234	LIMESTONE OUTSTANDING WORK	17.9	11.5	1.7	2.8	0.6	0.6	0.6																6.4
243	WINNIPEG RIVER RIVERBANK PROTECTION PROGRAM	8.3	2.0	0.8	0.7	0.7	0.8	0.8	0.8	0.8	0.8													6.2
246	KETTLE GS - STATOR REWIND	33.8			0.2	0.9	2.5	2.5	2.6	2.6	2.6	2.7	2.7	2.8	2.8	2.9	2.9	3.0						33.8
252	KELSEY G.S. GATE REHABILITATION	3.5				0.6		0.7		0.7		0.7		0.8										3.5
256	KETTLE ANNUNCIATION SYSTEM RENEWAL	1.5			1.0	0.5																		1.5
	THERMAL REHABILITATION																							
38	THERMAL G.S. ASSURANCE	134.1	129.2	4.0	0.9																			4.9
226	BRANDON G.S. UNIT 5 LCENSE RENEWAL	23.3						2.1	0.9	5.8	0.9	1.7	1.0	2.7	1.5	0.9	2.1	0.5	1.2	0.5	0.5	0.5	0.7	23.3
220	BRANDON G.S. SWITCHYARD JETAIRE BREAKER REPLACEMENT	3.6	2.2	1.4																				1.4
	OTHER																							
224	200MW ONTARIO HYDRO SALE - SYNC COND CONVERSION	7.7	4.2	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.5													3.5
227	SITE REMEDIATION OF CONTAMINATED CORPORATE FACILITIES	12.9	0.9	0.8	0.8	0.8	0.8	0.9	0.9	0.9	0.9	0.9	1.0	1.0	1.0	1.0	0.3							12.0
225	OIL CONTAINMENT	15.6	8.2	0.3	0.6	2.3	1.0	1.6	1.6															7.4
228	FIRE PROTECTION PROJECTS	6.7	2.6	0.5	3.1	0.6																		4.1
13	POWER SUPPLY BUILDINGS	35.4	19.1	5.7	2.3	2.8	3.6	1.8																16.2
990	PLANNING STUDY COSTS			16.1	16.5	3.1	2.7	0.9	2.8	2.8	9.7	9.1	18.9	(14.4)	2.8	(15.0)	2.6	2.6	2.8	2.8	2.9	3.0	3.0	75.7
	DOMESTIC ITEMS - POWER SUPPLY			10.0	10.2	10.5	10.7	11.0	11.2	11.5	11.7	12.0	12.2	12.5	12.8	13.1	13.4	13.7	14.0	14.3	14.6	14.9	15.3	249.5
	SUB-TOTAL POWER SUPPLY			79.4	77.1	61.8	54.0	82.3	84.9	72.1	28.1	30.9	35.8	50.4	72.0	159.0	185.6	342.2	522.5	593.9	588.1	454.8	378.5	3,953.2

CAPITAL EXPENDITURE FORECAST REVISIONS (CEF99-1)
(IN MILLIONS OF DOLLARS)
FOR THE YEARS 1999/00 TO 2018/19

		2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	20 year Forecast
POWER SUPPLY																						
	FUTURE ENERGY SUPPLY																					
24	WUSKWATIM GENERATING STATION											(31.0)	(24.8)	(30.4)	(159.9)	(118.2)	(30.2)	182.5	179.9			(32.1)
264	CONAWAPA GENERATING STATION											45.1	49.9	131.1	151.7	246.4	346.2	393.8	390.1	436.4	359.5	2,550.3
	HVDC FACILITIES																					
223	HVDC BIPOLE RELIABILITY ENHANCEMENTS	(4.2)	(4.1)	(2.1)																		(10.4)
88	BIPOLE 1 CONVERTER TRANSFORMERS	(1.6)																				(1.6)
11	BIPOLE 1 MERCURY ARC VALVES STAGE 3			0.0	0.1	0.7	1.0	0.7	0.0													2.5
5	HVDC BIPOLE 2 THYRISTOR POLY PIPE REPLACEMENTS	(0.8)	0.1																			(0.7)
54	CONVERTER TRANSFORMER BUSHING REPLACEMENT	(0.9)	0.7	0.4	0.1																	0.3
203	DORSEY BIPOLE 1 SYNCH CONDENSER BREAKER REPLACEMENT	0.2	(1.0)	(0.2)	(0.4)																	(1.3)
216	BIPOLE 1 DC FILTER CAPACITOR REPLACEMENT	0.1	0.7	1.0	0.3																	2.1
213	S.E.R. REPLACEMENT	0.7																				0.7
214	BIPOLE 1 VALVE HALL WALL BUSHING REPLACEMENT	1.8	(2.0)	0.2																		0.1
249	DORSEY BRINE EFFLUENT DISPOSAL STUDY AND IMPROVEMENT																					
258	BIPOLE 1 &2 ELECTRODE LINE MONITORING			0.2	1.2																	1.4
259	HVDC SWITCHGEAR ARCPROOF/SAFETY UPGRADES (PHASE 1 & 2)		0.4	0.5	0.1																	1.1
260	HVDC AUXILIARY POWER SUPPLY UPGRADES		0.5	0.5	0.4	0.4																1.8
272	DORSEY SYNCHRONOUS CONDENSER REFURBISHMENT		1.1	1.3	1.3	1.3	1.2	1.2														7.3
	HYDRAULIC REHABILITATION																					
3	GREAT FALLS G.S. REHABILITATION	(0.6)	(6.7)	(0.5)	5.1	2.5																(0.1)
52	SEVEN SISTERS G.S. REHABILITATION	0.8																				0.8
32	PINE FALLS G.S. REHABILITATION	(2.3)	(6.2)	(3.5)	6.9	5.0	0.1															0.1
33	McARTHUR G.S. REHABILITATION	0.1																				0.1
1	LAURIE RIVER PLANT 1 AND 2 REHABILITATION	(0.0)	0.1		(0.0)	(0.0)	(0.0)						(0.0)	(0.0)	(0.0)							0.0
48	GRAND RAPIDS G.S. REHABILITATION	(10.9)	8.8	1.3	(4.6)	(3.6)	(2.4)															(11.5)
25	JENPEG G.S. UNIT OVERHAULS (UNITS 1 - 6)	(1.7)	(3.2)	0.6	3.7	0.3	0.3	0.3	0.3	0.3												0.9
22	KETTLE & LONG SPRUCE G.S. STATOR REWEDGING	0.1	0.0																			0.1
82	PRODUCTION NORTH DAM SAFETY UPGRADES	0.8	1.6	2.2	2.2	2.3	1.1															10.2
26	WINNIPEG RIVER CONTROL SYSTEM	0.7	(4.7)	4.0	0.5																	0.6
234	LIMESTONE OUTSTANDING WORK	(2.2)	2.4	0.0	0.0	0.0																0.2
243	WINNIPEG RIVER RIVERBANK PROTECTION PROGRAM	0.4	0.1	0.1	0.2	0.2	0.2	0.2	0.2													1.5
246	KETTLE GS - STATOR REWIND	(0.9)	(1.2)	(1.3)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.3)	(0.3)	(0.3)	1.0	3.0						(1.6)
252	KELSEY G.S. GATE REHABILITATION		(0.6)	0.6	(0.7)	0.7	(0.7)	0.7	(0.7)	0.7	(0.7)	0.8										0.1
256	KETTLE ANNUNCIATION SYSTEM RENEWAL		1.0	0.5																		1.5
	THERMAL REHABILITATION																					
38	THERMAL G.S. ASSURANCE	3.2	0.9																			4.2
226	BRANDON G.S. UNIT 5 LCENSE RENEWAL		(1.1)	(3.6)	(2.5)	0.9	(0.4)	(1.7)	(1.3)	(0.3)	(0.8)	2.7	1.5	0.9	2.1	0.5	1.2	0.5	0.5	0.5	0.7	0.1
220	BRANDON G.S. SWITCHYARD JETAIRE BREAKER REPLACEMENT	(0.6)																				(0.6)
	OTHER																					
224	200MW ONTARIO HYDRO SALE - SYNC COND CONVERSION	(0.7)	(0.1)	(0.1)	(0.1)	0.1	0.4	0.4	0.5													0.6
227	SITE REMEDIATION OF CONTAMINATED CORPORATE FACILITIES	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0							0.4
225	OIL CONTAINMENT	(0.3)	(1.6)	(2.6)	0.1	1.6	1.6															(1.1)
228	FIRE PROTECTION PROJECTS	0.1	0.7	0.6																		1.3
13	POWER SUPPLY BUILDINGS	(0.2)	(1.6)	(1.1)	1.4	1.8																0.3
990	PLANNING STUDY COSTS	0.0	14.5	0.8	0.4	(1.4)	0.5	(0.2)	3.7	3.0	10.7	0.5	0.5	(17.4)	0.1	(0.2)	(0.1)	2.5	0.5	0.3	0.3	19.0
	DOMESTIC ITEMS - POWER SUPPLY	(0.0)	0.0	0.0																		(0.0)
	SUB-TOTAL POWER SUPPLY	(19.0)	(0.1)	0.0	15.6	12.6	2.7	1.4	2.5	3.5	8.9	17.8	26.8	84.0	(5.0)	131.6	317.1	579.2	571.1	437.2	360.5	2,548.4

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

1.

COMPLEX STATUS	Complex no.	REVISION STATUS
☒ Planned ☐ In progress	24	☐ New complex ☒ In service change ☒ Concept change ☐ Estimate change only

COMPLEX	WUSKWATIM GENERATING STATION

Proposal

Design and construct Wuskwatim Generating Station on the Burntwood River upstream of Thompson. This will include the complete installation of equipment for 3 generators with a total installed capacity of approximately 210 MW, in accordance with the following schedule:

Unit #1 - 2016 12 31 Unit #2 - 2017 01 31 Unit #3 - 2017 03 31

JUSTIFICATION	Explanation
☒ Load ☐ Service ☐ Safety ☐ Efficiency ☒ Reliability ☐ Other	Based on the 1999 load forecast, the Power Resource Plan studies show that an additional dependable energy source will be required in 2016/17. According to current available information, Wuskwatim is the preferred choice.

Estimate Level	COMPLEX START (yyyy mm)
L2	2009 04

IN SERVICE DATES AND AMOUNTS					
2016 12	$210841	2017 01	$210841	2017 03	$210841

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend								
Year 99/00								
00/01								
01/02								
02/03								
03/04								
04/05								
05/06								
06/07								
07/08								
08/09								
09/10						30,986	-30,986	-100
10/11						24,806	-24,806	-100
11/12	21,275	1014	1,860		24,149	54,558	-30,409	-56
12/13	6,735	1996	2,922		11,653	171,537	-159,884	-93
13/14	52,386	16884	6,713		75,983	194,170	-118,187	-61
14/15	104,771	36538	17,036		158,345	188,541	-30,196	-16
15/16	108,513	40770	33,172		182,455		182,455	
16/17	97,287	39229	43,422		179,938		179,938	
17/18								
18/19								
Beyond								
TOTAL	390,967	136,431	105,125		632,523	664,598	-32,075	-5

REVISION	In service deferred from 2014/15 to 2016/17. Project capitalized upon receipt of regulatory approvals/Licence.

Reviewed by ORIGINATOR	yyyy mm dd 99 11 02	Reviewed by COORDINATOR	yyyy mm dd
Reviewed by CONSTRUCTOR	yyyy mm dd	Approved by VICE-PRESIDENT	yyyy mm dd 99 11 12

H2856/r Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Complex no. 24

Advance or deferral impact

Required as a future source of generation; schedule provisional, subject to contiuing review and revision.

Factors affecting timing or viability

Manitoba Load Forecast
Diversity Agreements
Export Power Sales
Demand-side Management (DSM)
System Efficiency Improvements

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Wuskwatim Generating Station		419,445	427,834	390,967	-36,867	-9
TOTAL		419,445	427,834	390,967	-36,867	-9

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
9510	1,124,080	Reflects revised escalation and interest rates.
9610	1,344,618	In service date deferred from 2011 to 2015 and earlier capitalization of costs..
1997 10	723,551	In service date deferred from 2015 to 2016 and re-assessment of plant concept, cost and schedule.
1998 10	664,598	In service advanced from 2016/17 to 2014/15. Project capitalized upon receipt of regulatory approvals/Licence.
1999 10	632,523	In service deferred from 2014/15 to 2016/17. Project capitalized upon receipt of regulatory approvals/Licence. Reduction reflects amortization of study costs.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION
Complex 58	Wuskwatim Transmission

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

2.

COMPLEX STATUS	Complex no.	REVISION STATUS
☒ Planned ☐ In progress	264	☒ New complex ☐ In service change ☐ Concept change ☐ Estimate change only

COMPLEX	CONAWAPA GENERATING STATION

Proposal

DESIGN AND CONSTRUCT THE CONAWAPA GENERATING STATION ON THE NELSON RIVER. THIS WILL INCLUDE THE COMPLETE INSTALLATION OF EQUIPMENT FOR 10 GENERATORS WITH A TOTAL INSTALLED CAPACITY OF APPROXIMATELY 1390MW, IN ACCORDANCE WITH THE FOLLOWING IN SERVICE DATES:

UNIT NO. 1	2018 05 31	UNIT NO. 6	2019 06 30
UNIT NO. 2	2018 07 31	UNIT NO. 7	2019 08 31
UNIT NO. 3	2018 10 31	UNIT NO. 8	2019 11 30
UNIT NO. 4	2018 12 31	UNIT NO. 9	2020 02 28
UNIT NO. 5	2019 03 31	UNIT NO. 10	2020 04 30

JUSTIFICATION	Explanation
☒ Load ☐ Service ☐ Safety ☐ Efficiency ☐ Reliability ☐ Other	BASED ON THE 1999 LOAD FORECAST, THE POWER RESOURCE PLAN STUDIES INDICATE THAT AN ADDITIONAL DEPENDABLE ENERGY SOURCE WILL REQUIRED IN 2018/19. NOTE: THE CER INCLUDES AN UNAMORTIZED BALANCE OF PRELIMINARY PLANNING STUDIES ESTIMATED AT $23.4 MILLION (CURRENT DOLLARS).

Estimate Level	COMPLEX START (yyyy mm)
L2	1999 10

IN SERVICE DATES AND AMOUNTS							
2018 05	$269557	2018 07	$269557	2018 10	$269557	2018 12	$269557
2019 03	$269557	2019 06	$269557	2019 08	$269557	2019 11	$269557
2020 02	$269557	2020 04	$269557				

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend								
Year 99/00								
00/01								
01/02								
02/03								
03/04								
04/05								
05/06								
06/07								
07/08								
08/09								
09/10	42,584	382	2,112		45,078		45,078	
10/11	43,605	1762	4,520		49,887		49,887	
11/12	114,402	7002	9,740		131,144		131,144	
12/13	118,399	9760	23,543		151,702		151,702	
13/14	188,869	19658	37,917		246,444		246,444	
14/15	253,540	31987	60,690		346,217		346,217	
15/16	259,715	38616	95,485		393,816		393,816	
16/17	215,193	36940	137,998		390,131		390,131	
17/18	213,702	41692	181,003		436,397		436,397	
18/19	158,008	34603	166,853		359,464		359,464	
Beyond	53,549	13245	78,497		145,291		145,291	
TOTAL	1,661,566	235,647	798,358		2,695,571		2,695,571	

REVISION	ITEM REINTRODUCED AFTER PREVIOUS DEFERRAL.

Reviewed by ORIGINATOR	yyyy mm dd 99 11 02	Reviewed by COORDINATOR	yyyy mm dd
Reviewed by CONSTRUCTOR	yyyy mm dd	Approved by VICE-PRESIDENT	yyyy mm dd 99 11 12

H2856/r Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Complex no. 264

Advance or deferral impact

Deferral would jeopardize meeting load.

Factors affecting timing or viability

Timing; Regulatory/Licencing Approvals.
Changes in Manitoba load forecast or DSM target.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Conawapa Generating Station				1,661,566	1,661,566	
TOTAL				1,661,566	1,661,566	

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
1999 10	2,695,571	ITEM REINTRODUCED AFTER PREVIOUS DEFERRAL.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION
262	Conawapa Transmission
263	HVDC Bipole 3
265	Riel > Winnipeg AC Transmission
266	Dorsey > Riel 500kV AC T/L

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

3.

COMPLEX STATUS	Complex no.	REVISION STATUS
☐ Planned ☒ In progress	223	☐ New complex ☐ In service change ☐ Concept change ☒ Estimate change only

COMPLEX	HVDC BIPOLE RELIABILITY ENHANCEMENTS

Proposal

Relocate and reterminate service transformer #1 (SST1) and associated equipment within Radisson Stn. Purchase and install spare converter transformers on new pads as follows: Dorsey single phase 1-300kV & 1-450kV, three phase 1-375kV& 1-500kV; Radisson single phase 1-450kV, Henday three phase 1-500kV.Purchase and install two spare air cooled smoothing reactors set rated at 750 MH reactance and 500kV DC on new pad ,one each for Dorsey and Henday.Upgrade cooling system valves and converter transformers by installing additional cooling capacity to achieve rating and provide necessary degree of redundancy on Bipole 2 at Dorsey and Henday.

JUSTIFICATION	Explanation
☐ Load ☐ Service ☐ Safety ☒ Efficiency ☒ Reliability ☐ Other	Relocating SST1 ensures that Bipole 1 is not left in a single contingency bipole loss situation by permitting syncronization of all 3 transformers. Spare transformers and smoothing reactors provide transmission enhancements required due to the addition of Limestone, delay of Bipole 3, increased capacity for export sales, and provide improved system adequacy and reliability. Cooling system upgrades will increase DC summer output capacity by 200 MW. This will increase benefits from summer export sales, enhance maintenance scheduling/operations and DC transient performance.

Estimate Level	COMPLEX START (yyyy mm)
L2-4	1994 10

IN SERVICE DATES AND AMOUNTS							
1997 08	$5295	1997 11	$1957	199712	$2858	1998 03	$511
1998 07	$581	1999 03	$52	1999 09	$6819	1999 10	$543
1999 11	$6892	2000 11	$6836				

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	15,504		927	4	16,427	13,266	3,161	24
Year 99/00	10,433	73	413		10,919	15,100	-4,181	-28
00/01	4,695	73	225		4,993	9,073	-4,080	-45
01/02						2,103	-2,103	-100
02/03								
03/04								
04/05								
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	30,632	146	1,565	4	32,339	39,542	-7,203	-18

REVISION	Reflects increases to put transformer in service if required, and decreases due to charging transformers to inventory, and material costs less than forecast.

Reviewed by ORIGINATOR	yyyy mm dd 99 11 03	Reviewed by COORDINATOR	yyyy mm dd
Reviewed by CONSTRUCTOR	yyyy mm dd	Approved by VICE-PRESIDENT	yyyy mm dd 99 11 12

H2856/r Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Complex no. 223

Advance or deferral impact

Loss of revenue when existing transformers out for repairs.

Factors affecting timing or viability

Delivery of transformers.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Radisson Stn SST1 relocation & SST2&3 cable repl	2,292	2,504	2,554	2,385	-169	-7
Dorsey Bipole 1 spare 300kV converter transformer	3,121	975	995	3,049	2,054	206
Dorsey Bipole 1 spare 450kV converter transformer	3,942	634	647	0	-647	-100
Radisson Bipole 1 spare 450kV converter transform	3,408	1,168	1,191	25	-1,166	-98
Dorsey spare converter transformer foundations	10,709	1,161	1,184	210	-974	-82
Henday Bipole 2 spare 500kV converter transf	5,213	5,607	5,719	5,635	-84	-1
Dorsey Bipole 2 spare smoothing reactor	6,899	6,879	7,017	6,586	-431	-6
Henday Bipole 2 spare smoothing reactor	7,101	7,065	7,206	6,270	-936	-13
Dorsey Bipole 2 cooling upgrade	7,527	3,311	3,377	3,398	21	1
Henday Bipole 2 cooling upgrade	7,830	3,378	3,446	3,076	-370	-11
Dorsey Bipole 1 spare 300kV converter transf (SP#3)		2,871	2,928	0	-2,928	-100
Henday Bipole 2 spare 500kV converter transf (SP #2)		734	749	0	-749	-100
TOTAL	58,042	36,287	37,013	30,634	-6,379	-17

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
96 10	61,156	New complex, items transferred from complex # 67.
9710	63,275	Reflects revised costing methodology of the new financial reporting system. Increase is also due to factory problems with Henday transf, & const and switchgear mods at Radisson.
9810	39,542	Reflects 97/98 underexp 2.6M, transf ISD def 10 Mth, spares charged to inventory, cooling removed, shipping damages (Radisson), and add'n of 5kV repl cables for SST2&3.
1999 10	32,339	Reflects increases to put transformer in service if required, and decreases due to charging transformers to inventory, and material costs less than forecast.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION
PSPD 95-7	Radisson Stn service transformer No.1 re-termination.
PSPD 94-2	Enhancement of the Nelson River transmission system.
Minutes	HVDC task force meeting of 95 04 13 (relocation) & 95 06 28 (cooling upgr)

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

4.

COMPLEX STATUS	Complex no.	REVISION STATUS
☐ Planned ☒ In progress	88	☐ New complex ☐ In service change ☒ Concept change ☐ Estimate change only

COMPLEX	BIPOLE 1 - CONVERTER TRANSFORMERS

Proposal

Repairs to Dorsey BP1 T13A & T21A converter transformers, and completion of Radisson windings and winding clampings on one single phase converter transformer.

JUSTIFICATION	Explanation
☐ Load ☐ Service ☐ Safety ☐ Efficiency ☒ Reliability ☐ Other	Arc backs and consequential arc backs from the mercury arc valves are causing the tertiary windings to shift. This movement can cause the insulation to be damaged and result in failures.

Estimate Level	COMPLEX START (yyyy mm)
L2	1994 04

IN SERVICE DATES AND AMOUNTS					
1997 03	$1245	1999 02	$3526	1999 03	$164

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	4,804		131		4,935	5,873	-938	-16
Year 99/00						1,585	-1,585	-100
00/01								
01/02								
02/03								
03/04								
04/05								
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	4,804		131		4,935	7,458	-2,523	-34

REVISION	Reflects actual cost to repair T13A converter transformer, and to change accounting treatment by charging Conv Tfr T21A (spare #2) to inventory.

Reviewed by ORIGINATOR	yyyy mm dd 99 11 01	Reviewed by COORDINATOR	yyyy mm dd		
Reviewed by CONSTRUCTOR	yyyy mm dd	Approved by VICE-PRESIDENT	yyyy mm dd 99 11 12		

H2856/r Rev 99 03

Complex no. 88

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Advance or deferral impact

Tertiary winding shift can cause the insulation to be damaged and result in failures.

Factors affecting timing or viability

Delivery of new spare converter transformer at site (slated for 1994)

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Dorsey BP1 T21A Converter Transformer Repairs	2,437	2,621	2,673	0	-2,673	-100
Dorsey BP1 T13A Converter Transformer Repairs	3,091	3,327	3,394	3,590	196	6
Radisson Stn Converter Transformer Modification				1,215	1,215	
TOTAL	5,528	5,948	6,067	4,805	-1,262	-21

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
9510	4,616	Base date updated. Divisional overhead rate increase applied Last 2 transformer deliveries delayed one year..
9610	1,481	Cancel remaining two transformer modifications based on inspection of first transformer by Pauwels Canada Inc. Revised escalation and interest rates and re-cashflowed.
9710	7,053	Reflects completion of Radisson transformer modification, & addition of items covering repairs to Dorsey BP1 T13A, & T21A converter transformers.
9810	7,458	Scope of work revised to reflect the decision to purchase a new transformer rather than extensive repairs.
1999 10	4,935	Reflects actual cost to repair T13A converter transformer, and to change accounting treatment by charging Conv Tfr T21A (spare #2) to inventory.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

5.

(IN THOUSANDS OF DOLLARS)

COMPLEX STATUS	Complex no.	REVISION STATUS
☒ Planned ☐ In progress	11	☐ New complex ☐ In service change ☐ Concept change ☒ Estimate change only

COMPLEX	BIPOLE 1 MERCURY ARC VALVES - STAGE 3

Proposal

Replace Bipole 1 HVDC Mercury Arc Valve Groups 21, 22 and 23 with Thyristor Valves at Dorsey and Radisson stations.

JUSTIFICATION	Explanation
☐ Load ☐ Service ☐ Safety ☐ Efficiency ☒ Reliability ☐ Other	Continuing deterioration of the Mercury Arc Valves will make change-out of the remaining valve groups necessary. State-of-the-art Thyristor Valves will be used to replace all Mercury Arc Valves in three stages. This complex is the 3rd stage.

Estimate Level	COMPLEX START (yyyy mm)
L2	2001 06

IN SERVICE DATES AND AMOUNTS						
2004 09	$54490	2005 03	$54490	2005 09	$42064	

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend								
Year 99/00								
00/01								
01/02	870	84	37		991	975	16	2
02/03	3,218	383	230		3,831	3,768	63	2
03/04	36,299	5129	2,078		43,506	42,774	732	2
04/05	48,364	7937	4,194		60,495	59,470	1,025	2
05/06	34,699	6503	366		41,568	40,897	671	2
06/07	539	114			653	643	10	2
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	123,989	20,150	6,905		151,044	148,527	2,517	2

REVISION	Reflects updated escalation and interest.

Reviewed by ORIGINATOR	yyyy mm dd 99 11 03	Reviewed by COORDINATOR	yyyy mm dd		
Reviewed by CONSTRUCTOR	yyyy mm dd	Approved by VICE-PRESIDENT	yyyy mm dd 99 11 12		

H2856/r Rev 99 03

Complex no. 11

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Advance or deferral impact

Deferral would reduce HVDC Bipole 1 availability due to frequent outages of the Mercury Arc Valves. Loss of export revenues would result.

Factors affecting timing or viability

Rate of deterioration of Mercury Arc Valves.
Delays from Valve suppliers.
Opportunities for outages to do valve changeouts.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Dorsey-Bipole 1 Mercury Arc Valve Repl.-Stage 3		57,191	58,335	58,789	454	1
Radisson-Bipole 1 Mercury Arc Valve Repl-Stage 3		63,558	64,829	65,201	372	1
TOTAL		120,749	123,164	123,990	826	1

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
9510	156,451	In-service dates deferred 2 years to 2003 09 30, 2004 03 31 and 2004 09 30.
9610	158,593	In-service dates deferred 1 year to 2004 09 30, 2005 03 31 and 2005 09 30.
9710	152,465	Revised to reflect current escalation and interest rates.
9810	148,527	Reflects updated escalation and interest.
1999 10	151,044	Reflects updated escalation and interest.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION
Complex 44	Bipole 1 Mercury Arc Valves - Stage 1
Complex 37	Bipole 1 Mercury Arc Valves - Stage 2

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

6.

COMPLEX STATUS	Complex no.	REVISION STATUS
☐ Planned ☒ In progress	5	☐ New complex ☒ In service change ☐ Concept change ☒ Estimate change only

COMPLEX	HVDC BIPOLE 2 THYRISTOR POLY PIPE REPLACEMENTS

Proposal

Complete replacement of all polyamide piping associated with the thyristor module and header system on valve halls 31, 32, 41 and 42 at Henday and Dorsey converter stations.

Material will be purchased in Aug/Sept 96 and 97. Piping replacement will be installed equally over two years beginning Aug 96.

JUSTIFICATION

☐ Load ☐ Service
☐ Safety ☐ Efficiency
☒ Reliability ☐ Other

Explanation

The polyamide tubing directs cooling water essential for the operation of the valves. This tubing has reached the end of it's useful life and must be replaced before it fails, becomes brittle and breaks, plugging and overheating the thyristor and reactor modules.

Estimate Level	COMPLEX START (yyyy mm)
L4	1995 05

IN SERVICE DATES AND AMOUNTS							
1998 03	$2294	1999 01	$880	1999 06	$476	1999 10	$695
2000 10	$1170						

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	3,091		269		3,360	4,613	-1,253	-27
Year 99/00	1,306	25	29		1,360	2,184	-824	-38
00/01	732	27	35		794	702	92	13
01/02								
02/03								
03/04								
04/05								
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	5,129	52	333		5,514	7,499	-1,985	-26

REVISION	Reflects lower actual cost of polyamide tubing and reduction in installation estimates.

Reviewed by ORIGINATOR	yyyy mm dd 99 11 03	Reviewed by COORDINATOR	yyyy mm dd
Reviewed by CONSTRUCTOR	yyyy mm dd	Approved by VICE PRESIDENT	yyyy mm dd 99 11 12

H2856/r Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Complex no. 5

Advance or deferral impact

Loss of bipole 2 capability.

Factors affecting timing or viability

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
DORSEY BP2 POLY PIPE REPLACEMENT	3,687	3,393	3,461	2,417	-1,044	-30
HENDAY BP2 POLY PIPE REPLACEMENT	4,384	3,738	3,813	2,712	-1,101	-29
TOTAL	8,071	7,131	7,274	5,129	-2,145	-29

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
9510	8,140	Increased overhead rates, higher estimate level (includes quoted prices). Advanced work schedule.
9610	8,169	Revised estimate based on current replacement schedule, escalation and interest rates and recashflowed.
9710	8,722	Reflects revised costing methodology of the new financial reporting system. Increased costs are also due to in-service date deferrals (approx 2 yr) for each remaining installation.
9810	7,499	Revised to reflect 97/98 underexpenditure of 0.9M and lower projected cost of polyamide tubing installation.
1999 10	5,514	Reflects lower actual cost of polyamide tubing and reduction in installation estimates.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

7.

COMPLEX STATUS	Complex no.	REVISION STATUS
☐ Planned ☒ In progress	54	☐ New complex ☐ In service change ☐ Concept change ☒ Estimate change only

COMPLEX	CONVERTER TRANSFORMER BUSHING REPLACEMENT

Proposal

Replace converter transformer bushings with NGK bushings, and purchase spares as follows: at Dorsey replace six 230kv AC, and six 25kv tertiary bushings; and at Radisson/Henday replace five 138kv, two 150kv, four 230kv, and three 15kv tertiary bushings, and purchase two 300kv and two 450kv spares.

JUSTIFICATION		Explanation
☒ Load	☐ Service	The bushing replacement program was undertaken due to failure of a 230kv bushing in Dorsey T21 A-phase converter transformer which resulted in costly repairs to the transformer, and loss of revenue due to the outage. Also during repair of Dorsey T31S converter transformer in Pauwel's Canada plant two out of two 230kv bushings being tested failed at far below the full test voltage. The manufacturers expected service life is 25 years. These bushings have all been in service more than 17 years. Replacement cost is justified when compared to transformer damage due to an in service failure.
☐ Safety	☐ Efficiency	
☒ Reliability	☐ Other	

Estimate Level	COMPLEX START (yyyy mm)
L3	1994 11

IN SERVICE DATES AND AMOUNTS							
1995 03 31	$134	1996 03	$946	1996 05	$575	1997 03	$403
1997 10	$357	1998 04	$275	1998 06	$123	1999 01	$1359
1999 02	($342)	1999 04	$199	1999 12	$236	2000 on	$2170

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	3,776		264		4,040	4,079	-39	-1
Year 99/00	327	2	22		351	1,215	-864	-71
00/01	1,286	31	23		1,340	676	664	98
01/02	545	24	11		580	218	362	166
02/03	120	7	1		128		128	
03/04								
04/05								
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	6,054	64	321		6,439	6,188	251	4

REVISION	Revised to reflect a seven month ISD and forecast deferral at Dorsey.

Reviewed by	yyyy mm dd	Reviewed by	yyyy mm dd
ORIGINATOR	94 11 03	COORDINATOR	
Reviewed by	yyyy mm dd	Approved by	yyyy mm dd
CONSTRUCTOR		VICE-PRESIDENT	94 11 12

H2856/r Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Complex no. 54

Advance or deferral impact

Deferral will increase the number of bushing failures, and occurances of damage to converter transformers, outages, and associated revenue loss.

Factors affecting timing or viability

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Dorsey AC converter transformer bushing repl	2,911	3,269	3,334	3,428	94	3
Radisson/Henday converter transformer bushing rep	3,376	2,596	2,648	2,626	-22	-1
TOTAL	6,287	5,865	5,982	6,054	72	1

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
95 10	6,114	New Complex transferred from domestic.
96 10	6,591	Revised to add regasketing of T41 & T31 transformers at Henday, in service date at Dorsey, and update cashflows, escalation & interest.
9710	5,852	Reflects revised costing methodology of the new financial reporting system, reduction for favourable install costs at Rad/Hen, & increase due to work deferral 3-6 mo. at Dorsey.
9810	6,188	Reflects 97/98 underexpenditure .5M and increases to include the purchase of additional spare bushings for Henday converter and Dorsey DC transformers.
1999 10	6,439	Revised to reflect a seven month ISD and forecast deferral at Dorsey.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

8.

COMPLEX STATUS	Complex no.	REVISION STATUS
☒ Planned ☐ In progress	203	☐ New complex ☒ In service change ☐ Concept change ☐ Estimate change only

COMPLEX	DORSEY BIPOLE 1 SYNCH CONDENSER BREAKER REPL

Proposal
Design & replacement of six 17kV breakers and associated equipment for English Electric and ASEA synchronous condensers at Dorsey stn with new 120,000A breakers. To be replaced 2 per year over 3 years.

JUSTIFICATION		Explanation
☒ Load	☐ Service	The existing 17kV breakers have become under rated due to system changes. New breakers with increased rating are required to eliminate potential breaker damage and other adverse system and safety implications.
☒ Safety	☐ Efficiency	
☒ Reliability	☐ Other	

Estimate Level	COMPLEX START (yyyy mm)
L2	1996 11

IN SERVICE DATES AND AMOUNTS							
1999 06	$1120	2000 04	$1149	2001 06	$1169	2001 07	$1171
2002 06	$1192	2002 07	$1194				

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	583		5		588	171	417	244
Year 99/00	1,473	20	23		1,516	1,287	229	18
00/01	334	9	8		351	1,311	-960	-73
01/02	2,235	91	18		2,344	2,499	-155	-6
02/03	2,056	122	18		2,196	2,588	-392	-15
03/04								
04/05								
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	6,681	242	72		6,995	7,856	-861	-11

REVISION	Reflects ISD'S advanced 3 months due to SCC requirements.

Reviewed by ORIGINATOR	yyyy mm dd		Reviewed by COORDINATOR	yyyy mm dd 99 11 12	
Reviewed by CONSTRUCTOR	yyyy mm dd		Approved by VICE-PRESIDENT	yyyy mm dd 99 11 12	

H2856/r Rev 99 03

Complex no. 203

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Advance or deferral impact

Deferral will maintain reliance on six underrated breakers , the potential for breaker damage, and adverse system and safety implications.

Factors affecting timing or viability

Requirement to not have all breakers down at one time.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE	
					Amount	%
Dorsey bipole 1 synch condenser breaker repl	6,681	7,215	7,359	6,681	-678	-9
TOTAL	6,681	7,215	7,359	6,681	-678	-9

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
96 10	7,818	NEW COMPLEX
9710	7,858	In service date deferred 14 mo., and estimate base changed to 1997
9810	7,856	ISD'S DEFERRED 14 MONTHS.
1999 10	6,995	Reflects ISD'S advanced 3 months due to SCC requirements.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION
SPED rpt 96-2	Dorsey Stn 17kV synchronous condenser breaker replacement.

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

9.

COMPLEX STATUS: ☐ Planned ☒ In progress

Complex no. 216

REVISION STATUS: ☐ New complex ☐ In service change ☒ Concept change ☐ Estimate change only

COMPLEX	BIPOLE 1 & 2 DC FILTER CAPACITOR REPLACEMENT

Proposal
Replace all bipole 1 & 2 DC PCB filled capacitors at Dorsey , Radisson and Henday Stns, with non-PCB replacement capacitors.

JUSTIFICATION: ☐ Load ☐ Service ☒ Safety ☐ Efficiency ☒ Reliability ☐ Other

Explanation
Existing filter capacitors are PCB filled. New capacitors contain a more flamable oil and mixing them could result in a fire if toxic compounds from the PCB's are released. There is no sensitive protection to protect them against failure, and they will be 25 years old and approaching the end of their usable life.

Estimate Level	COMPLEX START (yyyy mm)
L2	1998 04

IN SERVICE DATES AND AMOUNTS

1999 10	$590	2000 04	$710	2000 09	$338	2000 10	$290
2001 04	$848	2001 10	$1726	2002 04	$172	2002 10	$281

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	231		5		236	264	-28	-11
Year 99/00	755	9	16		780	689	91	13
00/01	1,594	39	21		1,654	956	698	73
01/02	1,863	73	28		1,964	1,007	957	95
02/03	302	17	3		322		322	
03/04								
04/05								
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	4,745	138	73		4,956	2,916	2,040	70

REVISION	Scope change to include replacement of BP2 DC PCB filled capacitors at Dorsey and Henday Converter Stations.

Reviewed by ORIGINATOR	yyyy mm dd 99 11 03	Reviewed by COORDINATOR	yyyy mm dd		
Reviewed by CONSTRUCTOR	yyyy mm dd	Approved by VICE-PRESIDENT	yyyy mm dd 99 11 12		

H2856/r Rev 99 03

Complex no. 216

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Advance or deferral impact

Factors affecting timing or viability

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE	
					Amount	%
Bipole 1 & 2 DC filter capacitor replacement	4,745	2,806	2,862	4,745	1,883	66
TOTAL	4,745	2,806	2,862	4,745	1,883	66

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
96 10	2,817	NEW COMPLEX
9710	2,791	Revised escalation and interest rates.
9810	2,916	Revised to reflect the start date is advanced 1 year, and updated escalation and interest.
1999 10	4,956	Scope change to include replacement of BP2 DC PCB filled capacitors at Dorsey and Henday Converter Stations.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

10.

COMPLEX STATUS	Complex no.	REVISION STATUS
☒ Planned ☐ In progress	213	☐ New complex ☒ In service change ☐ Concept change ☒ Estimate change only

COMPLEX	S.E.R. REPLACEMENT

Proposal

Design, purchase and install new sequence of events recorders at Dorsey & Radisson to replace the existing ones.

JUSTIFICATION	Explanation
☐ Load ☐ Service ☐ Safety ☒ Efficiency ☒ Reliability ☐ Other	The SER provides station operators with a central alarm annunciation to aid in the operation of the station and provide plant engineers with the means to analyse system disturbances. The existing SER has reached the end of its useful life and must be replaced. In addition the manufacturers no longer support this equipment and spare parts are unavailable.

Estimate Level	COMPLEX START (yyyy mm)
L2	1996 11

IN SERVICE DATES AND AMOUNTS					
1998 12	$921	1999 01	$9	1999 02	$6	1999 03	$27
1999 08	$254	1999 11	$820				

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	1,255		84		1,339	1,926	-587	-30
Year 99/00	663	5	31		699		699	
00/01								
01/02								
02/03								
03/04								
04/05								
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	1,918	5	115		2,038	1,926	112	6

REVISION	Reflects 8 month ISD deferral.

Reviewed by ORIGINATOR	yyyy mm dd 99 11 03	Reviewed by COORDINATOR	yyyy mm dd
Reviewed by CONSTRUCTOR	yyyy mm dd	Approved by VICE-PRESIDENT	yyyy mm dd 99 11 12

3104

H2856/r Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Complex no. 213

Advance or deferral impact

Factors affecting timing or viability

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Dorsey bipole 1 S.E.R. replacement	764	812	828	764	-64	-8
Radisson bipole 1 S.E.R. replacement	1,027	1,034	1,055	1,154	99	9
TOTAL	1,791	1,846	1,883	1,918	35	2

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
96 10	1,718	NEW COMPLEX
9710	1,892	Reflects revised costing methodology of the new financial reporting system, 6 mo advancement of Radisson, & 1 yr deferral of Dorsey S.E.R. replacement.
9810	1,926	Revised to reflect 97/98 underexpenditure .7M and 5 and 6 month ISD deferrals.
1999 10	2,038	Reflects 8 month ISD deferral.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

11.

COMPLEX STATUS	Complex no.	REVISION STATUS
☒ Planned ☐ In progress	214	☐ New complex ☒ In service change ☐ Concept change ☐ Estimate change only

COMPLEX	BIPOLE 1 VALVE HALL WALL BUSHING REPLACEMENT

Proposal
Replacement of existing valve hall oil filled wall bushings with composite dry type bushings.

JUSTIFICATION		Explanation
☐ Load	☐ Service	Replacement of these wall bushings is needed because of their age, maintenance concerns and the excessive cost of fire protection that would have to be installed if the oil filled bushings were retained.
☒ Safety	☒ Efficiency	
☒ Reliability	☐ Other	

Estimate Level	COMPLEX START (yyyy mm)
L2	1996 11

IN SERVICE DATES AND AMOUNTS					
1999 04	$3021	2000 04	$3021	2001 04	$3021

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	1,937		61		1,998	1,810	188	10
Year 99/00	4,634	47	175		4,856	3,061	1,795	59
00/01	1,791	64	110		1,965	3,924	-1,959	-50
01/02	215	9	19		243		243	
02/03								
03/04								
04/05								
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	8,577	120	365		9,062	8,795	267	3

REVISION	Increased to reflect receipt of material earlier than previously forecast.

Reviewed by ORIGINATOR	yyyy mm dd 99 11 03	Reviewed by COORDINATOR	yyyy mm dd		
Reviewed by CONSTRUCTOR	yyyy mm dd	Approved by VICE-PRESIDENT	yyyy mm dd 99 11 12		

H2856/r Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Complex no. 214

Advance or deferral impact

Factors affecting timing or viability

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Dorsey bipole 1 valve hall wall bushings repl	3,768	3,790	3,866	3,975	109	3
Radisson bipole 1 valve hall wall bushings repl	4,282	4,361	4,448	4,601	153	3
TOTAL	8,050	8,151	8,314	8,576	262	3

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
96 10	8,574	NEW COMPLEX
9710	8,802	Reflects revised costing methodology of the new financial reporting system
9810	8,795	Reflects 97/98 underexpenditure 1.7M and revised ISD's and cost flows.
1999 10	9,062	Increased to reflect receipt of material earlier than previously forecast.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION
PS-96.07	

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

12.

COMPLEX STATUS	Complex no.	REVISION STATUS
[X] Planned [ ] In progress	249	[ ] New complex [X] In service change [ ] Concept change [X] Estimate change only

COMPLEX	DORSEY BRINE EFFLUENT IMPROVEMENT

Proposal

Design supply and drilling of a pilot well to determine feasibility of the deep well injection method. After satisfactory evaluation of the pilot well test results , design, supply, install and commission it with associated tanks, pumps and pipe works to transfer the salt brine effluent from the water softeners of the two bipoles. (It is assumed that Government Approval is not needed for this work.) Design and install cathodic protection for the wells.

JUSTIFICATION		Explanation
[ ] Load	[ ] Service	The existing deep well is not functioning properly. It was originally installed in 1984. In 1986 it lost its ability to accomodate the flow of effluent. Presently some effluent is being dumped to the station drainage ditches. It is now essential that a new well be drilled incorporating the latest design.
[ ] Safety	[ ] Efficiency	
[ ] Reliability	[X] Other	

Estimate Level	COMPLEX START (yyyy mm)
L2	1998 08

IN SERVICE DATES AND AMOUNTS							
1998 10	$762	1998 11	$26	1999 01	$6		

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	776		18		794	792	2	0
Year 99/00								
00/01								
01/02								
02/03								
03/04								
04/05								
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	776		18		794	792	2	0

REVISION	Revised to reflect actual costs to completion.

Reviewed by	yyyy mm dd	Reviewed by	yyyy mm dd
ORIGINATOR	99 11 03	COORDINATOR	
Reviewed by	yyyy mm dd	Approved by	yyyy mm dd
CONSTRUCTOR		VICE-PRESIDENT	99 11 12

H2856/r Rev 99 03

Complex no. 249

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Advance or deferral impact

Inability to properly dispose of brine effluent.

Factors affecting timing or viability

Complete failure of existing deep well.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Dorsey Brine Effluent Disposal Well Replacement	776	779	795	776	-19	-2
TOTAL	776	779	795	776	-19	-2

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
9710	2,403	New complex.
9810	792	Revised to reflect in servce date advanced 1 year, and reduced cost of well drilling contract.
1999 10	794	Revised to reflect actual costs to completion.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

/3.

COMPLEX STATUS	Complex no.	REVISION STATUS
☒ Planned ☐ In progress	258	☒ New complex ☐ In service change ☐ Concept change ☐ Estimate change only

COMPLEX	BIPOLE 1 & 2 ELECTRODE LINE MONITORING

Proposal
Install a Siemens pulse-echo electrode line fault detection system on Dorsey Bipole 1 and 2, Radisson Bipole 1 and Henday Bipole 2 Electrode lines.

JUSTIFICATION	Explanation
☐ Load ☐ Service ☒ Safety ☒ Efficiency ☒ Reliability ☐ Other	There is a need for detection of open circuit, faulted, or partially down electrode line conductors based on public safety concerns, possible damage to equipment, and the security of Bipole 1 and 2.

Estimate Level	COMPLEX START (yyyy mm)
L2	2001 04

IN SERVICE DATES AND AMOUNTS			
2002 10	$1352		

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend								
Year 99/00								
00/01								
01/02	161	8	6		175		175	
02/03	1,086	64	27		1,177		1,177	
03/04								
04/05								
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	1,247	72	33		1,352		1,352	

REVISION	New Complex

Reviewed by ORIGINATOR	yyyy mm dd 99 11 03	Reviewed by COORDINATOR	yyyy mm dd		
Reviewed by CONSTRUCTOR	yyyy mm dd	Approved by VICE-PRESIDENT	yyyy mm dd 00 11 12		

H2856/r Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Complex no. 258

Advance or deferral impact

Factors affecting timing or viability

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Bipole 1 & 2 Electrode Line Monitoring				1,247	1,247	
TOTAL				1,247	1,247	

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
1999 10	1,352	New Complex

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION
E.C. # 789.01	CPJ for BP 1 & 2 Electrode Line Monitoring.

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

14.

COMPLEX STATUS: [X] Planned [ ] In progress

Complex no. 259

REVISION STATUS: [X] New complex [ ] In service change [ ] Concept change [ ] Estimate change only

COMPLEX: HVDC SWITCHGEAR ARCPROOF/SAFETY UPGRADES (PH 1 & 2)

Proposal
Arcproof the 5kV switchgear at Dorsey and Radisson Converter stations and the 15kV switchgear at Henday Converter station.

JUSTIFICATION: [ ] Load [ ] Service [X] Safety [ ] Efficiency [ ] Reliability [ ] Other

Explanation
The existing metal clad switchgear have no means of containing fire or smoke within individual cubicle cells or the switchgear itself in the event of a breaker failure. Explosion, smoke, fire and gas emissions pose a health hazard to staff if working in the vicinity should a failure occur.

Estimate Level	COMPLEX START (yyyy mm)
L2	2000 02

IN SERVICE DATES AND AMOUNTS					
2001 05	$741	2002 05	$317		

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend								
Year 99/00								
00/01	407	10	13		430		430	
01/02	493	19	12		524		524	
02/03	95	5	3		103		103	
03/04								
04/05								
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	995	34	28		1,057		1,057	

REVISION: New Complex

Reviewed by ORIGINATOR	yyyy mm dd 99 11 03	Reviewed by COORDINATOR	yyyy mm dd
Reviewed by CONSTRUCTOR	yyyy mm dd	Approved by VICE-PRESIDENT	yyyy mm dd 99 11 12

H2856/r Rev 99 03

Complex no.
259

CAPITAL EXPENDITURE FORECAST COMPLEX
(IN THOUSANDS OF DOLLARS)

Advance or deferral impact

Risk of injury.

Factors affecting timing or viability

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE	
					Amount	%
Bipole 1 & 2 5/15kv Arcproofing				995	995	
TOTAL				995	995	

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
1999 10	1,057	New Complex

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

15.

COMPLEX STATUS	Complex no.	REVISION STATUS
☒ Planned ☐ In progress	260	☒ New complex ☐ In service change ☐ Concept change ☐ Estimate change only

COMPLEX	HVDC AUXILIARY POWER SUPPLY UPGRADES

Proposal

The review and upgrading of eight battery banks and four power centres at Dorsey, Radisson, and Henday Converter stations. Replacement of +/- 25VDC & 60VDC battery chargers and the 129VDC/60VDC inverters in Bipole 2 at Dorsey & Henday.

JUSTIFICATION		Explanation
☒ Load	☐ Service	Upgrading of the HVDC System Auxiliary Power Supplies is necessary to obtain maintenance outages for them without additional system costs and to maintain reliability of the HVDC System. This will allow Manitoba Hydro to maintain/increase firm energy sales and keep spinning reserve requirements to a minimum.
☐ Safety	☒ Efficiency	
☒ Reliability	☐ Other	

Estimate Level	COMPLEX START (yyyy mm)
L2	1999 05

IN SERVICE DATES AND AMOUNTS							
2000 11	$535	2001 11	$468	2002 11	$436	2003 11	$351

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend								
Year 99/00								
00/01	519	12	4		535		535	
01/02	446	19	3		468		468	
02/03	407	26	3		436		436	
03/04	322	26	3		351		351	
04/05								
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	1,694	83	13		1,790		1,790	

REVISION	New Complex

Reviewed by	yyyy mm dd	Reviewed by	yyyy mm dd
ORIGINATOR	99 11 03	COORDINATOR	
Reviewed by	yyyy mm dd	Approved by	yyyy mm dd
CONSTRUCTOR		VICE-PRESIDENT	99 11 12

H2856/r Rev 99 03

Complex no. 260

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Advance or deferral impact

Factors affecting timing or viability

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
HVDC BP 1 & 2 Auxiliary Power Supply Upgrades				1,694	1,694	
TOTAL				1,694	1,694	

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
1999 10	1,790	New Complex

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

16.

COMPLEX STATUS	Complex no.	REVISION STATUS
☒ Planned ☐ In progress	272	☒ New complex ☐ In service change ☐ Concept change ☐ Estimate change only

COMPLEX	DORSEY SYNCHRONOUS CONDENSER REFURBISHMENT

Proposal

Major inspection and overhaul of synchronous condensers SC7Y, SC8Y, SC9Y, SC21Y, SC22Y, and SC23Y. Replacement of coolers to restore original thermal performance on SC21Y, SC22Y, and SC23Y.

JUSTIFICATION	Explanation
☐ Load ☐ Service ☐ Safety ☐ Efficiency ☒ Reliability ☐ Other	Synchronous condensers are required for proper operation of the HVDC system, voltage regulation of the southern AC system and to provide reactive power for power export to the USA. A major inspection and overhaul of each machine is necessary to prevent catastrophic failure, involving the rotors and rotor bolts as indicated by the failures of SC12Y in 1987 and SC11Y in 1988. The cost of repairing a failure when conbined with our inability to export power will well exceed the cost of major inspection and overhaul.

Estimate Level	COMPLEX START (yyyy mm)
L2	2000 04

IN SERVICE DATES AND AMOUNTS							
2000 10	$1066	2001 10	$1274	2002 10	$1298	2003 10	$1325
2004 10	$1154	2005 10	$1177				

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend								
Year 99/00								
00/01	1,006	31	29		1,066		1,066	
01/02	1,179	59	36		1,274		1,274	
02/03	1,179	82	37		1,298		1,298	
03/04	1,179	109	37		1,325		1,325	
04/05	1,007	115	32		1,154		1,154	
05/06	1,007	137	33		1,177		1,177	
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	6,557	533	204		7,294		7,294	

REVISION	New complex.

Reviewed by ORIGINATOR	yyyy mm dd		Reviewed by COORDINATOR	yyyy mm dd 99 11 12	
Reviewed by CONSTRUCTOR	yyyy mm dd		Approved by VICE-PRESIDENT	yyyy mm dd 99 11 12	

H2856/r Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Complex no. 272

Advance or deferral impact

Deferral will maintain the potential for a failure that disrupts export sales.

Factors affecting timing or viability

Export sales.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Dorsey synchronous condenser refurbishment				6,557	6,557	
TOTAL				6,557	6,557	

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
1999 10	7,294	New complex.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION
HVDC 99-02	Dorsey Stn synchronous condenser major refurbishment

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

17.

COMPLEX STATUS: ☐ Planned ☒ In progress

Complex no. 3

REVISION STATUS: ☐ New complex ☒ In service change ☐ Concept change ☒ Estimate change only

COMPLEX	GREAT FALLS G.S.REHABILITATION

Proposal

Replace existing gates, roller paths and hoists (installed between 1920 - 1928) with new fixed-roller,vertical lift gates, stainless steel roller paths and wire rope type hoists. Anchor the intake piers to bedrock, to stabilize the intake. Replace main water passage components (bottom ring, discharge ring and draft tube liner) ,install new propeller type runner, rewind generator, provide new transformer and modernize to present standards.

JUSTIFICATION

☐ Load ☐ Service
☒ Safety ☒ Efficiency
☒ Reliability ☐ Other

Explanation

The existing a) intake gates and hoists cannot be expected to provide reliable emergency closure functions as they have the potential to malfunction during an emergency. b) draft tube liner is failing in spite of expensive repairs and is in urgent need of replacement. The potential to utilize the outage to replace the seventy year old runner with a larger, more efficient unit has been reviewed and approved by the re-runnering committee. While the generator was rewound forty years ago, many of the electrical components are original equipment from the 1920's.

Estimate Level	COMPLEX START (yyyy mm)
L1	1998 08

IN SERVICE DATES AND AMOUNTS

2001 03	$393	2001 11	$7212	2002 03	$6011	2003 03	$7301
2004 03	$2621						

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	128		3		131	208	-77	-37
Year 99/00	267	2	19		288	847	-559	-66
00/01	2,513	46	137		2,696	9,366	-6,670	-71
01/02	9,792	346	457		10,595	11,055	-460	-4
02/03	6,748	374	295		7,417	2,342	5,075	217
03/04	2,206	169	107		2,482		2,482	
04/05								
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	21,654	937	1,018		23,609	23,818	-209	-1

REVISION	Reflects revised work schedules, and deferred in service dates.

Reviewed by ORIGINATOR	yyyy mm dd	Reviewed by COORDINATOR	yyyy mm dd
Reviewed by CONSTRUCTOR	yyyy mm dd	Approved by VICE-PRESIDENT	yyyy mm dd 96/11/12

H2856/r Rev 99 03

Complex no. 3

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Advance or deferral impact

Lost opportunity to coordinate two required repair jobs on unit #3 with only one shut down.
Danger of experiencing an intake gate malfunction during an emergency.

Factors affecting timing or viability

Urgency of requirement to replace intake gate and hoist.
Failing condition of the draft tube liner and age of electrical components.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Great Falls G.S. Unit #3 Draft Tube Liner & Rerunner		6,474	6,603	6,700	97	1
Great Falls G.S. Intake Gates		14,931	15,230	14,953	-277	-2
TOTAL		21,405	21,833	21,653	-180	-1

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
9710	23,583	New complex.
9810	23,818	Replacement of existing intake gates deferred one year, and unit #3 overhaul recostflowed.
1999 10	23,609	Reflects revised work schedules, and deferred in service dates.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

18.

COMPLEX STATUS	Complex no.	REVISION STATUS
☐ Planned ☒ In progress	52	☐ New complex ☐ In service change ☐ Concept change ☒ Estimate change only

COMPLEX	SEVEN SISTERS G.S. REHABILITATION

Proposal

Replace Unit # 1, 2 & 3 turbine runners together with rehabilitation of the generator field poles and rewinding of the stators. Conduct turbine model tests. Modify the draft tube on Unit 1 by adding a Moody Spreading Cone, and partially fill in the draft tube elbow with concrete. Perform restoration work on the generator rotor poles, rewind exciters and install new transformer sprinkler systems. Rehabilitation, replacement of and addition to various electrical and mechanical equipment and systems such as; station lighting, 110kv line protection, bus disconnects, station grounding, oil interceptor, spillway hoist housing upgrade, powerhouse ventilation, generator cable replacement, powerhouse and tailrace cranes, standby generator and EPS, control room air conditioning, generator terminal equipment, governor system, compressed air system, line & bus potential transformers, and spillway gate limit switches.

JUSTIFICATION		Explanation
☐ Load	☒ Service	New runners would produce rated power under lower head at greater efficiency levels. A redesigned draft tube would allow increased output. The original asphalt type stator windings should be replaced by modern epoxy materials before serious coil failures occur without warning. Assessment of the electrical and mechanical systems has identified concerns in terms of obsolete equipment, safety, fire risk and adaptability to present day operating conditions and standards. Upgrading is necessary to ensure reliable safe and economical operation.
☒ Safety	☒ Efficiency	
☒ Reliability	☐ Other	

Estimate Level	COMPLEX START (yyyy mm)
L3-5	1986 04

IN SERVICE DATES AND AMOUNTS							
1997 03	$8870	1997 07	$144	1997 10	$71	1997 11	$357
1997 12	$50	1998 02	$280	1998 08	$90	1998 10	$68
1998 12	$67	1999 03	$67	1999 06	$9369	1999 08	$48

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	16,945		1,049		17,994	35,630	-17,636	-49
Year 99/00	1,311	2	175		1,488	709	779	110
00/01								
01/02								
02/03								
03/04								
04/05								
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	18,256	2	1,224		19,482	36,339	-16,857	-46

REVISION	Reflects costs to reassemble and commission unit 4, and clean up concrete rehab and spillway spud hoist deficiencies. Three completed & closed turbine runner items have been removed.

Reviewed by ORIGINATOR	yyyy mm dd	Reviewed by COORDINATOR	yyyy mm dd
Reviewed by CONSTRUCTOR	yyyy mm dd	Approved by VICE-PRESIDENT	yyyy mm dd 99 11 12

H2856/r Rev 99 03

Complex no. 52

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Advance or deferral impact

Component failures
Loss of capability/ derate
Inefficiency
Accelerated wear creating additional rehab cost

Factors affecting timing or viability

Drought conditions (may postpone or accelerate activities)
Forebay/ tailrace levels
Unit maintenance schedules

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	%
Seven Sisters G.S. Electrical/Mechanical Systems	6,241	4,034	4,115	4,048	-67	-2
Seven Sisters G.S. Unit #4 Rehabilitation	6,205	6,623	6,755	8,788	2,033	30
Seven Sisters G.S. Major Concrete Rehab	2,132	3,178	3,242	3,025	-217	-7
Seven Sisters G.S. Cranes & Spillway Anchors	2,261	2,288	2,334	2,396	62	3
TOTAL	16,839	16,123	16,446	18,257	1,811	11

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
9510	36,738	Runner #3 ISD delayed. Revised to add widen tailrace deck, ramp, extend spillway deck and tailrace crane. Unit control metering & relaying and AVR repl transf'd to Cx26
9610	36,169	Reflects actual costs on completed work orders, correction to unit #4 rehab escalation calculation, and cash flow adjustments.
9710	36,760	Increased to provide funding for outstanding items, and extended to include repairs to spillway deck.
9810	36,339	Reflects 97/98 underexpenditure 2.3M and cash flows revised to reflect current work schedules, and outstanding deficiency requirements.
1999 10	19,482	Reflects costs to reassemble and commission unit 4, and clean up concrete rehab and spillway spud hoist deficiencies. Three completed & closed turbine runner items have been removed.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

19.

COMPLEX STATUS	Complex no.	REVISION STATUS
☐ Planned ☒ In progress	32	☐ New complex ☒ In service change ☐ Concept change ☐ Estimate change only

COMPLEX	PINE FALLS G.S. REHABILITATION

Proposal

Rehabilitation, replacement of and addition to various electrical and mechanical equipment and systems such as; spillway mechanical components, station service upgrade, station lighting, 11kv cable replacement, spillway electrical distribution, water system, air system, transformer lightning arrestors and station drawings. Replace Unit #1and #2 turbine runners with more efficient new design runners, rebuild existing servomotors for increased wicket gate opening allowing more discharge, and rewind the generator stators utilizing modern insulating materials.

JUSTIFICATION		Explanation
☐ Load	☒ Service	Assessment of the electrical and mechanical systems has identified concerns in terms of obsolete equipment, safety, fire risk and adaptability to present day operating conditions and standards. Upgrading is necessary to ensure reliable safe and economical operation.Pine Falls consistantly spills more water than the other Winnipeg River plants. Additional generation can be obtained (approximately 17%) with increased discharge capability. Tests have confirmed that the 2 stator windings are in danger of failure at any time.
☒ Safety	☒ Efficiency	
☒ Reliability	☐ Other	

Estimate Level	COMPLEX START (yyyy mm)
L3-5	1988 12

IN SERVICE DATES AND AMOUNTS							
1997 03 31	$2700	2002 03	$25	2002 11	$8163	2003 11	$7234

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	2,672		160		2,832	2,928	-96	-3
Year 99/00	795	5	36		836	3,158	-2,322	-74
00/01	655	14	113		782	6,934	-6,152	-89
01/02	1,259	46	198		1,503	4,955	-3,452	-70
02/03	6,446	289	355		7,090	163	6,927	NA
03/04	4,543	214	209		4,966		4,966	
04/05	110	6			116		116	
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	16,480	574	1,071		18,125	18,138	-13	-0

REVISION	Revised to include funding for review of MFG's,prep design & spec's assistance during dis/ assembly & commissioning of unit, as built drawing prep, and deferral of Stn service upgrade.

Reviewed by ORIGINATOR	yyyy mm dd		Reviewed by COORDINATOR	yyyy mm dd	
Reviewed by CONSTRUCTOR	yyyy mm dd		Approved by VICE-PRESIDENT	yyyy mm dd	99 11 12

H2856/r Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Complex no. 32

Advance or deferral impact

Component failures
Loss of capability/ derate
Inefficiency
Accelerated wear creating additional rehab cost

Factors affecting timing or viability

Drought conditions (may postpone or accelerate activities)
Forebay/ tailrace levels
Unit maintenance schedules

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Pine Falls G.S. Electrical/Mechanical Systems	3,535	3,387	3,455	3,312	-143	-4
Pine Falls G.S. Units #1 &2 Gen Rewind & Rerunner		13,003	13,263	13,169	-94	-1
TOTAL	3,535	16,390	16,718	16,481	-237	-1

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
9510	8,918	250 VDC distribution upgrade transferred to WPG R CNTRL SYS - SEVEN SISTERS, and units 5 & 6 rehab completed.
9610	8,837	Revised interest rates. Costs revised to reflect 95/96 actual costs.
9710	17,936	Reflects revised costing implemented with the new financial reporting system, and addition of a new item for units 1 & 2 generator rewind & rerunner at Pine Falls.
9810	18,138	Units # 1 and 2 rerunnering/rewind deferred one year.
1999 10	18,125	Revised to include funding for review of MFG's,prep design & spec's assistance during dis/ assembly & commissioning of unit, as built drawing prep, and deferral of Stn service upgrade.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

20.

COMPLEX STATUS	Complex no.	REVISION STATUS
☐ Planned ☒ In progress	33	☐ New complex ☐ In service change ☐ Concept change ☒ Estimate change only

COMPLEX	MCARTHUR G.S. REHABILITATION

Proposal

Rehabilitation, replacement of and addition to various electrical and mechanical equipment and systems such as ; spillway mechanical components, station service upgrade, station lighting, spillway electrical distribution, water system, transformer upgrade, powerhouse gantry crane, governor system, spillway gate and guide rehab., and station drawings.

JUSTIFICATION		Explanation
☐ Load	☒ Service	Assessment of the electrical and mechanical systems has identified concerns in terms of obsolete equipment, safety, fire risk and adaptability to present day operating conditions and standards. Upgrading is necessary to ensure reliable safe and economical operation.
☒ Safety	☒ Efficiency	
☒ Reliability	☐ Other	

Estimate Level	COMPLEX START yyyy mm
L4	1989 04

IN SERVICE DATES AND AMOUNTS							
1997 03	$8071	1998 02	$1897	1998 09	$144	1999 10	$1747

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	10,536		522		11,058	11,052	6	0
Year 99/00	736	1	64		801	741	60	8
00/01								
01/02								
02/03								
03/04								
04/05								
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	11,272	1	586		11,859	11,793	66	1

REVISION	Revised to reflect funding requirements to completion.

Reviewed by ORIGINATOR	yyyy mm dd	Reviewed by COORDINATOR	yyyy mm dd
Reviewed by CONSTRUCTOR	yyyy mm dd	Approved by VICE-PRESIDENT	yyyy mm dd 99 / 11 / 12

H2856/r Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Complex no. 33

Advance or deferral impact

If allowed to deteriorate further, operation of the gates will be impaired.

Factors affecting timing or viability

An orderly schedule of gate roller path and roller replacement is planned over the next 5 years.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
McArthur G.S. Electrical/Mechanical Systems	5,008	11,199	11,423	11,272	-151	-1
TOTAL	5,008	11,199	11,423	11,272	-151	-1

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
9510	11,864	Stn annunciator upgr and 250 VDC distn upgr transferred to Complex 26, and spillway gate and guide rehab revised to cost and work remaining.
9610	12,180	Correction of interest and overhead calculations.
9710	11,764	Revised to reflect actual costs to date.
9810	11,793	Revised to adjust cost flows.
1999 10	11,859	Revised to reflect funding requirements to completion.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

21.

COMPLEX STATUS	Complex no.	REVISION STATUS
☐ Planned ☒ In progress	1	☐ New complex ☒ In service change ☐ Concept change ☒ Estimate change only

COMPLEX	LAURIE RIVER PLANT # 1 AND # 2 - REHABILITATION

Proposal

Rehabilitation, replacement of and addition to various civil works, electrical and mechanical equipment and systems such as ; concrete and structures, supervisory control system, vehicle storage building, bailey bridge, road, airstrip, electrical/ mechanical systems upgrade and 2.3kv breakers.

JUSTIFICATION		Explanation
☐ Load	☒ Service	Assessment of the civil, electrical and mechanical systems has identified concerns in terms of deterioration, obsolete equipment, safety, fire risk and adaptability to present day operating conditions and standards. Upgrading is necessary to ensure reliable safe and economical operation.
☒ Safety	☐ Efficiency	
☒ Reliability	☐ Other	

Estimate Level	COMPLEX START (yyyy mm)
L2	1991 05

IN SERVICE DATES AND AMOUNTS							
up to 1997 12	$7093	1999 02	$1986	1999 12	$178	2000 12	$2724
2003 03	$117	2004 03	$511	2005 03	$524	2011 03	$1256
2012 03	$875	2013 03	$872				

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	8,394		858	1	9,251	9,261	-10	-0
Year 99/00	465	4	28		497	544	-47	-9
00/01	2,114	35	86		2,235	2,149	86	4
01/02								
02/03	99	10	9		118	118	0	0
03/04	424	50	38		512	515	-3	-1
04/05	424	60	39		523	526	-3	-1
05/06								
06/07								
07/08								
08/09								
09/10								
10/11	879	250	103		1,232	1,236	-4	-0
11/12	613	190	73		876	878	-2	-0
12/13	613	206	75		894	897	-3	-0
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	14,025	805	1,309	1	16,138	16,124	14	0

REVISION	Revised to reflect a deferral and estimate increase for bridge abutment, automation, and remote control work.

Reviewed by ORIGINATOR	yyyy mm dd 99 11 07	Reviewed by COORDINATOR	yyyy mm dd		
Reviewed by CONSTRUCTOR	yyyy mm dd	Approved by VICE-PRESIDENT	yyyy mm dd 99 11 12		

H2856/r Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Complex no. 1

Advance or deferral impact

Component failures
Loss of capability/ derate
Inefficiency
Accelerated wear creating additional rehab cost

Factors affecting timing or viability

Drought conditions (may postpone or accelerate activities)
Forebay/ tailrace levels
Unit maintenance schedules

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	%
Laurie River Plant #1 and Plant #2 - Phase1	10,119	10,523	10,733	10,973	240	2
Laurie River Plant #1 and Plant #2 - Phase2		947	966	947	-19	-2
Laurie River Plant #1 and Plant #2 - Phase3		2,105	2,147	2,105	-42	-2
TOTAL	10,119	13,575	13,846	14,025	179	1

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
9510	16,257	.Elec/Mech & RTU work deferred to 1996. Scope revised to add Civil & Elect/Mech items.
9610	16,106	In service dates deferred: Bailey Bridge to 1997, Automation & Supervisory Control to 1998. Revised interest rates.
9710	16,158	In service date deferred for automation and supervisory control in phase 1,and revised escalation and interest rates.
9810	16,124	Revised to reflect increased cash flows required to complete bridge work in 98/99 and advance engineering for automation & remote control, which is deferred 1 year.
9910	16,138	Revised to reflect a deferral and estimate increase for bridge abutment, automation, and remote control work.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

22.

COMPLEX STATUS: ☐ Planned ☒ In progress

Complex no. 48

REVISION STATUS: ☐ New complex ☒ In service change ☐ Concept change ☒ Estimate change only

COMPLEX: GRAND RAPIDS G.S. REHABILITATION

Proposal

Disassemble Unit 1 and assess damage. Replace outer, intermediate and inner head covers, turbine guide bearings, servomotors, operating ring and links. Repair various other components and reassemble the unit utilizing the repaired existing runner for an in-service date of 1994 05 12.

Replace Kaplan turbine runners on Units 1,2 and 3 and modify servomotors, head covers, operating ring and governor pressure system on Unit 4. Rewind generators on Units 1, 2 and 3. Modify the stator frame support and add 13.8 kv ciruit breakers on all four generators. Upgrade the controls, annunciation and protection, to provide synchronous condencer capability.

JUSTIFICATION

☐ Load ☐ Service
☒ Safety ☒ Efficiency
☒ Reliability ☐ Other

Explanation

To repair the Unit 1 damage which occurred as a result of the head cover failure and return the unit to service prior to the 1993/94 winter peak.

Excessive wear of the turbine units requires complete repair or replacement with new more powerful and efficient runners on Units 1, 2 and 3. Unit 4 will be upgraded by wicket gate opening enlargement. Breakers will improve system reliability. DC zoning rearrangement will enhance security.

Estimate Level	COMPLEX START (yyyy mm)
L3	1990 06

IN SERVICE DATES AND AMOUNTS

1997 03	$35035	1997 06	$17098	1997 12	$942	1998 02	$7034
1998 09	$603	1998 11	$3324	1999 03	$1083	1999 10	$3507
2000 03	$86	2001 03	$112	2001 04	$25385	2002 03	$6541

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	66,107		9,620	30	75,697	76,128	-431	-1
Year 99/00	4,398	26	980		5,404	16,297	-10,893	-67
00/01	12,168	185	1,491		13,844	5,020	8,824	176
01/02	5,247	171	356		5,774	4,509	1,265	28
02/03						4,636	-4,636	-100
03/04						3,594	-3,594	-100
04/05						2,417	-2,417	-100
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	87,920	382	12,447	30	100,719	112,601	-11,882	-11

REVISION: Reflects add'n of repl of wicket gate bushings & shaft rod seal-u 4, repair internal problems -u 1,des mods & def -gen brkrs, reschedule units 2 & 3,& transfer of Dam Safety prog.to Cx82

Reviewed by ORIGINATOR	yyyy mm dd 99 11 08	Reviewed by COORDINATOR	yyyy mm dd
Reviewed by CONSTRUCTOR	yyyy mm dd	Approved by VICE-PRESIDENT	yyyy mm dd 02 11 02

H2856/r Rev 99 03

Complex no. 48

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Advance or deferral impact

Grand Rapids GS was designed and built to provide various uses such as automatic generation control (AGC), spinning reserves, and as a daily peaking plant. Unit 1 and 2 are for peak loading, and Unit 3 and 4 are on AGC.

Factors affecting timing or viability

Schedule of equipment delivery and installation.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE	
					Amount	%
Grand Rapids Unit 1 Overhaul	9,048	15,811	16,127	16,058	-69	-0
Grand Rapids Unit 2 Overhaul	8,397	18,515	18,885	17,966	-919	-5
Grand Rapids Unit 3 Overhaul	8,486	19,685	20,079	18,957	-1,122	-6
Grand Rapids Unit 4 Overhaul	6,527	9,797	9,993	13,103	3,110	31
Grand Rapids Unit 1 Repairs	5,194	11,636	11,869	11,565	-304	-3
Grand Rapids Gen Brkrs & Sync Cond Conv	5,398	9,134	9,317	10,269	952	10
TOTAL	43,050	84,578	86,270	87,918	1,648	2

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
9510	70,749	Overhaul of units 1-3 def'd to Nov 95, tendered prices, deficiency requirements, install'n of accumulator tanks, and anticipated insurance claim legal fees were added.
9610	72,200	Adjusted to reflect actual expenditures, to complete deficiencies, and to include increased generator components repair in units 2 & 3.
9710	98,489	Reflects deficiency requirements, actual costs, anticipated insurance claim legal fees (unit 1 repairs) , addition of repairing spare turbine bearing, and new dam safety deficiency program
9810	112,601	Reflects 97/98 underexpenditure 1.3M, work deferral, deficiency compl'n req, reest for unit 2 , runner repairs - unit 3, reliab and perform mods, and int correction to dam safety prog.
1999 10	100,719	Reflects add'n of repl of wicket gate bushings & shaft rod seal-u 4, repair internal problems -u 1,des mods & def -gen brkrs, reschedule units 2 & 3,& transfer of Dam Safety prog.to Cx82

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

23.

COMPLEX STATUS	Complex no.	REVISION STATUS
☐ Planned ☒ In progress	25	☐ New complex ☒ In service change ☐ Concept change ☒ Estimate change only

COMPLEX	JENPEG G.S. UNIT OVERHAULS

Proposal

Major overhaul of units 1-6 to inspect, repair, modify and replace components of the turbine/generator.

Areas of concern; journal bearings, thrust bearings, turbine seals, servo-motors, wicket gate seals and bushings, waterhead and oil head, stator and rotor, auxiliary systems.

JUSTIFICATION		Explanation
☐ Load	☒ Service	A complete overhaul is required to ensure reliable operation of the units when maximum power requirements on the system are essential.
☐ Safety	☐ Efficiency	
☒ Reliability	☐ Other	

Estimate Level	COMPLEX START (yyyy mm)
L1	1995 04

IN SERVICE DATES AND AMOUNTS							
1998 07	$5060	1998 09	$75	1999 02	$1166	1999 03	($44)
1999 04	$59	2000 03	$3275	2002 01	$3611	2003 01	$3685
2004 01	$3909	2006 01	$4038	2008 01	$4173		

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	6,249		495		6,744	7,260	-516	-7
Year 99/00	2,012	47	155	-3	2,217	3,935	-1,718	-44
00/01	713	26	1		740	3,973	-3,233	-81
01/02	3,584	29	120		3,733	3,172	561	18
02/03	3,573	30	129		3,732		3,732	
03/04	3,469	32	133		3,634	3,285	349	11
04/05	281	1	4		286		286	
05/06	3,580	32	139		3,751	3,421	330	10
06/07	292	1	5		298		298	
07/08	3,694	34	147		3,875	3,561	314	9
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	27,447	232	1,328	-3	29,010	28,607	403	1

REVISION	Reflects continuing unit 6 costs to completion, re-estimate of remaining units based on experience with unit 6 and schedule revision.

Reviewed by ORIGINATOR	yyyy mm dd 99 11 08	Reviewed by COORDINATOR	yyyy mm dd
Reviewed by CONSTRUCTOR	yyyy mm dd	Approved by VICE-PRESIDENT	yyyy mm dd 99 11 12

H2856/r Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Complex no. 25

Advance or deferral impact

Factors affecting timing or viability

Maintenance schedule.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
JENPEG GS UNIT 1-6 OVERHAUL	11,992	15,501	16,011	27,449	11,438	71
TOTAL	11,992	15,501	16,011	27,449	11,438	71

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
9510	12,427	Increased costs due to higher overhead rates.
9610	13,494	Scope of work changed for unit 6 to schedule the overhaul during 96/97 and 97/98 so it is available by Nov/96 for winter generation.
9710	16,679	Reflects actual costs to date , cost of trailers for additional staff accommodations, and deferral of start of next unit by one year.
9810	28,607	Reflects unit 6 costs to completion, re-estimate of remaining units based on experience with unit 6 and schedule revision to overhaul one unit every two years.
1999 10	29,010	Reflects continuing unit 6 costs to completion, re-estimate of remaining units based on experience with unit 6 and schedule revision.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

24.

COMPLEX STATUS	Complex no.	REVISION STATUS
☐ Planned ☒ In progress	22	☐ New complex ☐ In service change ☐ Concept change ☒ Estimate change only

COMPLEX	KETTLE & LONG SPRUCE GS STATOR REWEDGING

Proposal

Kettle GS - Rewedge stators on unit 5 (93/94) unit 4 (95/96) unit 3 & 11 (96/97) units 7, 8, 10, and 12 to follow at the rate of one per year. Sequence determined by insulation tests.

Long Spruce GS - Rewedge stators on unit 3 (92/93), unit 5 and 1 (93/94) unit 6 (94/95) and unit 9 (95/96). Units 7, 8 and 10 are scheduled one per year over the next four years, based on insulation tests.

JUSTIFICATION	Explanation
☐ Load ☐ Service ☐ Safety ☐ Efficiency ☒ Reliability ☐ Other	The stator wedges on several units are becoming loose. The insulation readings are deteriorating rapidly, thus indicating looseness of wedges and stator coils in their respective slots. Looseness can cause a coil failure due to ground fault and result in an extended generator outage.

Estimate Level	COMPLEX START (yyyy mm)
L3	1992 04

IN SERVICE DATES AND AMOUNTS							
1997 03	$3881	1997 04	$92	1998 03	$47	1998 04	$437
1998 05	$70	1998 06	$397	1999 01	$81	1999 02	$454
1999 03	$34	1999 04	$611	1999 09	$443	2000 04	$526

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	5,763		39		5,802	5,706	96	2
Year 99/00	937	18	4		959	869	90	10
00/01	300	9	2		311	307	4	1
01/02								
02/03								
03/04								
04/05								
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	7,000	27	45		7,072	6,882	190	3

REVISION	Revised to correct 98/99 document transfer caused overstatement,and apply cost experience to date, to the forecast.

Reviewed by ORIGINATOR	yyyy mm dd 99 11 07	Reviewed by COORDINATOR	yyyy mm dd
Reviewed by CONSTRUCTOR	yyyy mm dd	Approved by VICE-PRESIDENT	yyyy mm dd 99 12 02

H2856/r Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Complex no. 22

Advance or deferral impact

Deteriorated insulation levels could result in extended unit outages.

Factors affecting timing or viability

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE	
					Amount	%
LONG SPRUCE REWDGING	2,989	2,795	2,851	3,118	267	9
KETTLE STATOR REWEDGING	3,795	4,003	4,083	3,884	-199	-5
TOTAL	6,784	6,798	6,934	7,002	68	1

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
9510	7,123	Revised escalation and interest rates.
9610	7,003	Long Spruce deferred and Kettle advanced one year, per insulation testing. Revised escalation and interest rates.
9710	6,654	Reflects advancement of Kettle unit 10 by 1 year to 96/97, a one year deferral of a unit at Long Spruce to 98/99, and updated base dates.
9810	6,882	Revised to adjust Kettle Stator Rewedging 97/98 actuals, and to update base dates.
1999 10	7,072	Revised to correct 98/99 document transfer caused overstatement,and apply cost experience to date, to the forecast.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

25.

COMPLEX STATUS	Complex no.	REVISION STATUS
☐ Planned ☒ In progress	82	☐ New complex ☒ In service change ☒ Concept change ☐ Estimate change only

COMPLEX	PRODUCTION NORTH DAM SAFETY UPGRADES

Proposal

Perform necessary engineering design and remedial construction, to upgrade Northern generating stations to present day dam safety standards, to allow them to continue safe and reliable operation.
Work description to include the following:
(1) Kettle Generating Station - upgrade main and saddle dams for freeboard
(2) Kelsey Generating Station - armour plating at spillway rollways, erection of heated hoist housing, insulating of spillway gates, upgrading of dykes, upgrading of spillway feeders and electrical systems at the spillway and upgrading of the station service transformers due to increased loading.

JUSTIFICATION	Explanation
☐ Load ☐ Service ☒ Safety ☐ Efficiency ☒ Reliability ☐ Other	Manitoba Hydro has underway a formal dam safety program covering all its plants. Ulilizing present day standards, various deficiencies have been reported in the Production North generating stations. Work is therefore required to correct the deficiencies to all the plants, to operate in a safe and reliable manner.

Estimate Level	COMPLEX START (yyyy mm)
L2	1995 11

IN SERVICE DATES AND AMOUNTS							
1997 03	$351	1997 07	$356	1997 12	$1995	1998 04	($114)
1998 10	$60	1998 11	$88	1999 03	$39	1999 10	$2542
2000 03	$628	2001 03	$1135	2002 03	$2216	2003 on	$5540

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	3,168		116		3,284	3,719	-435	-12
Year 99/00	2,009	24	59		2,092	1,283	809	63
00/01	1,606	38	42		1,686	105	1,581	NA
01/02	2,000	88	79		2,167		2,167	
02/03	2,000	130	78		2,208		2,208	
03/04	2,000	172	80		2,252		2,252	
04/05	1,000	108	41		1,149		1,149	
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	13,783	560	495		14,838	5,107	9,731	191

REVISION	Scope change to include items for both Generations North and South , and revised to reflect deferral of the Kettle, Long Spruce, and Kelsey stand pipes.

Reviewed by ORIGINATOR	yyyy 99	mm 11	dd 07	Reviewed by COORDINATOR	yyyy mm dd
Reviewed by CONSTRUCTOR	yyyy	mm	dd	Approved by VICE-PRESIDENT	yyyy 99 mm 11 dd 30

H2856/r Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Complex no. 82

Advance or deferral impact

Loss of capability / derate
Safety liability

Factors affecting timing or viability

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Generation North dam safety upgrades	4,315	4,867	4,964	5,134	170	3
Generation South dam safety deficiency program		14,000	14,280	8,649	-5,631	-39
TOTAL	4,315	18,867	19,244	13,783	-5,461	-28

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
95 10	3,839	New Complex to cover the cost of correcting Dam Safety Program deficiencies.
96 10	3,800	Reflects change from level 1 to level 3 estimate.
9710	4,413	Scope increased to include dyke monitoring instrumentation at Kettle, Long Spruce, Laurie River, and Notigiand dyke repairs at Long Spruce.
9810	5,107	Scope revised to includebathemetric surveys; spillway hoist housing fire prot imp's; & to defer Kelsey stn service work; instrument install'n at various sites & stability studies at Kettle.
1999 10	14,838	Scope change to include items for both Generations North and South , and revised to reflect deferral of the Kettle, Long Spruce, and Kelsey stand pipes.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

26.

COMPLEX STATUS	Complex no.	REVISION STATUS
☐ Planned ☒ In progress	26	☐ New complex ☒ In service change ☐ Concept change ☒ Estimate change only

COMPLEX	WINNIPEG RIVER CONTROL SYSTEM

Proposal

Upgrading or replacement of, and additions to, various items of electrical and mechanical systems and equipment.

Items included are:

Great Falls GS - DC distribution, and unit control, metering and relaying.
Seven Sisters GS - U#4-U#6 AVR replacement, and unit control, metering and relaying.
Pine Falls GS - 250 VDC distribution, and station control.
Mcarthur Falls GS - station annunciator upgrade, 250 VDC distribution, and station control.

JUSTIFICATION		Explanation
☐ Load	☒ Service	Previous engineering assessment of the electrical and mechanical systems in these stations have identified various areas of concern in terms of obsolete equipment, safety, fire risk and adaptability to present day operating conditions and standards and the requirement for upgrading work. Production south have identified the need for an integrated system for control of all the Winnipeg River stations, therefor this complex has been created to co-ordinate the design and installation of the various systems and System Control Centre's requirement for data acquisition.
☒ Safety	☒ Efficiency	
☒ Reliability	☐ Other	

Estimate Level	COMPLEX START (yyyy mm)
L3	1987 05

IN SERVICE DATES AND AMOUNTS							
1997 03	$1543	1999 12	$1611	2001 03	$1561	2002 03	$3230
2002 06	$5564						

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	1,602		810		2,412	3,081	-669	-22
Year 99/00	2,436	20	141		2,597	1,900	697	37
00/01	1,779	26	228		2,033	6,691	-4,658	-70
01/02	4,969	177	432		5,578	1,529	4,049	265
02/03	760	25	102		887	405	482	119
03/04								
04/05								
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	11,546	248	1,713		13,507	13,606	-99	-1

REVISION	Revised to allign cash flow requirements with progress of work, and to defer Pine and McArthur Falls items by one year.

Reviewed by ORIGINATOR	yyyy mm dd 99 11 08	Reviewed by COORDINATOR	yyyy mm dd		
Reviewed by CONSTRUCTOR	yyyy mm dd	Approved by VICE-PRESIDENT	yyyy mm dd 99 11 12		

H2856/r Rev 99 03

Complex no. 26

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Advance or deferral impact

Factors affecting timing or viability

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
WINNIPEG RIVER CONTROL SYSTEM COMPLEX:						
- Great Falls GS	5,547	5,158	5,261	5,691	430	8
- Seven Sisters GS	2,481	3,082	3,144	2,937	-207	-7
- Pine Falls GS		1,372	1,399	1,390	-9	-1
- Mcarthur Falls GS		1,519	1,549	1,528	-21	-1
TOTAL	8,028	11,131	11,353	11,546	193	2

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
95 10	12,516	New Complex to co-ordinate the design & installation of an integrated system for control of all the Winnipeg River Stations.
96 10	12,515	Cashflow modified to reflect schedule for defined items - scope and schedule for balance to be established.
9710	12,900	Reflects revised costing methodology with the new financial reporting system.
9810	13,606	Scope of Seven Sisters AVR replacement expanded to include units 1 - 3 and the house unit.
1999 10	13,507	Revised to allign cash flow requirements with progress of work, and to defer Pine and McArthur Falls items by one year.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

27.

COMPLEX STATUS	Complex no.	REVISION STATUS
☐ Planned ☒ In progress	234	☐ New complex ☒ In service change ☐ Concept change ☒ Estimate change only

COMPLEX	LIMESTONE OUTSTANDING WORK

Proposal

To complete outstanding work including final disposition of buildings, and final site cleanup.

To perform modifications to thrust bearings, air admissions, cooling systems, governors and install a rotor mounted scanner.

To design and construct a channel improvement in the Nelson River at Sundance Rapids, to reduce ice staging in the tailrace.

JUSTIFICATION		Explanation
☒ Load	☐ Service	To provide funding for the completion of outstanding work at Limestone G.S., and modifications to a number of the original systems. The modifications are designed to reduce failures, and eliminate revenue reducing operating restrictions. Ice staging of the tailwater is causing a loss of up to 1.5 meters of energy head, and associated generation capacity, throughout the winter.
☐ Safety	☐ Efficiency	
☒ Reliability	☐ Other	

Estimate Level	COMPLEX START (yyyy mm)
L3	1996 04

IN SERVICE DATES AND AMOUNTS							
1997 03	$5893	1997 09	$1660	1997 12	$861	1998 07	$1704
1999 02	$654	1999 03	($378)	1999 06	$343	1999 09	$488
1999 12	$1059	2000 06	$672	2000 11	$2749	2001 on	$2009

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	11,641		304	445	11,500	11,497	3	0
Year 99/00	1,614	7	65		1,686	3,900	-2,214	-57
00/01	2,568	146	58		2,772	337	2,435	723
01/02	603	32	1		636	634	2	0
02/03	603	42	2		647	645	2	0
03/04	591	51	1		643	642	1	0
04/05								
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	17,620	278	431	445	17,884	17,655	229	1

REVISION	Revised to allign cash flows with optimum outage schedules, and to defer channel improvements one year.

Reviewed by ORIGINATOR	yyyy mm dd 99 11 10	Reviewed by COORDINATOR	yyyy mm dd		
Reviewed by CONSTRUCTOR	yyyy mm dd	Approved by VICE-PRESIDENT	yyyy mm dd 99 11 12		

H2856/r Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Complex no. 234

Advance or deferral impact

Plant is almost completed and is producing power.

Factors affecting timing or viability

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Limestone G.S. Area Cleanup	7,951	7,859	8,016	7,645	-371	-5
Limestone G.S. Modifications	6,966	7,507	7,657	7,875	218	3
Limestone G.S. Channel Improvements		2,088	2,130	2,100	-30	-1
TOTAL	14,917	17,454	17,803	17,620	-183	-1

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
96 10	7,609	Addition of Gillam-Limestone road resurfacing, environmental monitoring, thrust bearing repairs, air cooling/data sys and governor mods and the cleanup deferral to 97/98
9710	17,759	Scope revised to include additional modifications to original equipment to correct identified deficiencies and include a new item covering channel improvements.
9810	17,655	Reflects 97/98 underexpenditure 0.8M, deferral of building site cleanup, channel improve's, mods + revised for outage schedules and to reflect anticipated costs to completion.
1999 10	17,884	Revised to allign cash flows with optimum outage schedules, and to defer channel improvements one year.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION
Complex 43	Limestone System Requirements
Complex 14	Limestone Generating Station

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

28.

COMPLEX STATUS	
☐ Planned	☒ In progress

Complex no. 243

REVISION STATUS	
☐ New complex	☐ In service change
☒ Concept change	☐ Estimate change only

COMPLEX	WINNIPEG RIVER RIVERBANK PROTECTION PROGRAM

Proposal

Placement of rock protection and construction of slope stabilization to reduce erosion of riverbank along the Winnipeg River. The work includes inspection, design, mapping, land acquisition and remedial construction at Pine Falls and McArthur Falls.

JUSTIFICATION	
☐ Load	☐ Service
☐ Safety	☐ Efficiency
☐ Reliability	☒ Other

Explanation

Provision of riverbank protection and stabilization work along the Winnipeg River and tributaries between Seven Sisters forebay and Manitou Rapids from erosion partially due to hydraulic operations.

Estimate Level	COMPLEX START
	yyyy mm

IN SERVICE DATES AND AMOUNTS							
1998 03	$585	1999 04	$420	2000 03	$1856	2001 03	$729
2002 03	$742	2003 03	$757	2004 03	$771	2005 03	$787
2006 03	$802	2007 03	$818				

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	1,948		72	14	2,006	1,802	204	11
Year 99/00	714	6	120		840	460	380	83
00/01	684	17	28		729	580	149	26
01/02	684	30	28		742	592	150	25
02/03	684	44	29		757	604	153	25
03/04	684	58	30		772	616	156	25
04/05	684	72	30		786	628	158	25
05/06	684	87	31		802	641	161	25
06/07	684	102	32		818	654	164	25
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	7,450	416	400	14	8,252	6,577	1,675	25

REVISION	Reflects reduced land acquisition costs, refinement of scope and resource allocation and removal of the McArthur programto be completed under 01-03-8055.

Reviewed by [signature] ORIGINATOR	yyyy mm dd 99 11 08	Reviewed by COORDINATOR	yyyy mm dd
Reviewed by CONSTRUCTOR	yyyy mm dd	Approved by [signature] VICE-PRESIDENT	yyyy mm dd 99 11 12

H2856/r Rev 99 03

Complex no. 243

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Advance or deferral impact

Degree of erosion along the Winnipeg River riverbank.

Factors affecting timing or viability

Season of the year.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Winnipeg R Riverbank Protection Program - Pine Falls	3,193	3,191	3,255	6,865	3,610	111
Winnipeg R Riverbank Protection Program - McArthur	2,630	2,671	2,724	585	-2,139	-79
TOTAL	5,823	5,862	5,979	7,450	1,471	25

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
9710	7,933	New complex.
9810	6,577	Revised to reflect an annual reduction in land acquisition costs and a refinement of the scope and resource allocation to this program.
1999 10	8,252	Reflects reduced land acquisition costs, refinement of scope and resource allocation and removal of the McArthur program to be completed under 01-03-8055.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

29.

COMPLEX STATUS: [X] Planned [ ] In progress

Complex no. 246

REVISION STATUS: [ ] New complex [X] In service change [ ] Concept change [ ] Estimate change only

COMPLEX	KETTLE G.S. STATOR REWIND

Proposal
Rewind generator stators on units 1 - 12.

JUSTIFICATION: [ ] Load [ ] Service [ ] Safety [ ] Efficiency [X] Reliability [ ] Other

Explanation
The stator windings at Kettle are a polyester bonded mica which is prone to internal degredation as a result of thermal and electrical stresses. There has been a much higher failure rate for stator coils at Kettle than in any of our other generators installed since 1960. Analysis of the internal conditions of the insulation system is ongoing. Rewedging units at Kettle is an opportunity to repair isolated cases of severe slot discharge, necessary to avoid deterioration. Replacing stators as well is under investigation to include a single turn roebel bar winding with class 'f' insulation.

Estimate Level	COMPLEX START (yyyy mm)
L2	1998 04

IN SERVICE DATES AND AMOUNTS							
2002 10	$2814	2003 10	$2814	2004 10	$2814	2005 10	$2814
2006 10	$2814	2007 10	$2814	2008 10	$2814	2009 10	$2814
2010 10	$2814	2011 10	$2814	2012 10	$2814	2013 10	$2814

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend						196	-196	-100
Year 99/00						924	-924	-100
00/01	184	6	2		192	1,356	-1,164	-86
01/02	832	37	50		919	2,170	-1,251	-58
02/03	2,244	135	135		2,514	2,703	-189	-7
03/04	2,244	183	112		2,539	2,733	-194	-7
04/05	2,244	232	91		2,567	2,769	-202	-7
05/06	2,244	281	72		2,597	2,808	-211	-8
06/07	2,244	332	57		2,633	2,852	-219	-8
07/08	2,243	383	44		2,670	2,900	-230	-8
08/09	2,244	436	34		2,714	2,955	-241	-8
09/10	2,243	489	30		2,762	3,015	-253	-8
10/11	2,244	544	29		2,817	3,083	-266	-9
11/12	2,243	599	34		2,876	3,158	-282	-9
12/13	2,244	656	45		2,945	1,915	1,030	54
13/14	2,243	714	60		3,017		3,017	
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	27,940	5,027	795		33,762	35,537	-1,775	-5

REVISION	Reflects one year deferral.

Reviewed by ORIGINATOR	yyyy mm dd 99 11 07	Reviewed by COORDINATOR		yyyy mm dd	
Reviewed by CONSTRUCTOR	yyyy mm dd	Approved by VICE-PRESIDENT		yyyy mm dd 99 11 12	

H2856/r Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX
(IN THOUSANDS OF DOLLARS)

Complex no. 246

Advance or deferral impact

Increased down time due to separation of these jobs from rewedging jobs.
Continue to experience a much higher failure rate for stator coils at Kettle.

Factors affecting timing or viability

Coordination of stator rewinding with rewedging units at Kettle.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Kettle G.S. Generator Stator rewind - units 1 - 12		27,940	28,499	27,944	-555	-2
TOTAL		27,940	28,499	27,944	-555	-2

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
9710	35,581	New complex.
9810	35,537	Revised to reflect the start date deferral from 1997 to 1998
1999 10	33,762	Reflects one year deferral.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION
Complex 22	Kettle & Long Spruce G.S. Stator Rewedging.

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

30.

(IN THOUSANDS OF DOLLARS)

COMPLEX STATUS: [X] Planned [ ] In progress

Complex no. 252

REVISION STATUS: [X] New complex [ ] In service change [ ] Concept change [ ] Estimate change only

COMPLEX	KELSEY GS GATE REHABILITATION

Proposal
Replacement of rollers, installation of cathodic protection, touch up painting, seal replacement, and replacement of the hoist cables if required for units 1-5.

JUSTIFICATION: [X] Load [ ] Service [X] Safety [ ] Efficiency [X] Reliability [ ] Other

Explanation
The unit 2 gate inspection in 1997 established that the above mentioned work is required to ensure that the intake gates function as designed. If they do not function as designed, there is the possibility of a run away unit.

Estimate Level	COMPLEX START (yyyy mm)
L2	2000 07

IN SERVICE DATES AND AMOUNTS

2001 09	$646	2003 09	$673	2005 09	$700	2007 09	$728
2009 09	$758						

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend								
Year 99/00								
00/01								
01/02	603	39	4		646		646	
02/03								
03/04	603	65	5		673		673	
04/05								
05/06	603	92	5		700		700	
06/07								
07/08	603	120	5		728		728	
08/09								
09/10	603	149	6		758		758	
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	3,015	465	25		3,505		3,505	

REVISION	Reflects one year deferral.

Reviewed by ORIGINATOR	yyyy 99 mm 11 dd 07	Reviewed by COORDINATOR	yyyy mm dd		
Reviewed by CONSTRUCTOR	yyyy mm dd	Approved by VICE-PRESIDENT	yyyy 99 mm 11 dd 12		

H2856/r Rev 99 03

Complex no. 252

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Advance or deferral impact

Possibility of a run away unit.

Factors affecting timing or viability

Must be completed prior to freeze up.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Kelsey Gate Rehabilitation.		3,010	3,070	3,015	-55	-2
TOTAL		3,010	3,070	3,015	-55	-2

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
1998 06	3,447	NEW ITEM
1999 10	3,505	Reflects one year deferral.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

31.

COMPLEX STATUS	Complex no.	REVISION STATUS
☒ Planned ☐ In progress	256	☒ New complex ☐ In service change ☐ Concept change ☐ Estimate change only

COMPLEX	KETTLE CENTRAL ANNUNCIATION SYSTEM UPGRADES

Proposal

A new system consisting of GE Fanuc PLCs and a Windows NT based human-machine interface (HMI) should be installed to replace the existing Central Annunciation System (CAS) at Kettle GS.

JUSTIFICATION		Explanation
☒ Load	☐ Service	A condition assessment of the existing Central Annunciation System (CAS) has revealed that,due to deterioration, lack of spare parts and manufacturer support, the system is at the end of its life. Replacement of the CAS with a new system similar to systems installed at other generating stations has the best net present value of possible options.
☐ Safety	☐ Efficiency	
☒ Reliability	☐ Other	

Estimate Level	COMPLEX START (yyyy mm)
3	1999 10

IN SERVICE DATES AND AMOUNTS			
2001 09	$1499		

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend								
Year 99/00								
00/01	933	28	22		983		983	
01/02	447	20	49		516		516	
02/03								
03/04								
04/05								
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	1,380	48	71		1,499		1,499	

REVISION	New complex.

Reviewed by ORIGINATOR		yyyy mm dd 99 11 07	Reviewed by COORDINATOR		yyyy mm dd
Reviewed by CONSTRUCTOR		yyyy mm dd	Approved by VICE-PRESIDENT		yyyy mm dd 99 11 12

H2856/r Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Complex no. 256

Advance or deferral impact

Continued deterioration, and increased difficulty in obtaining replacement parts.

Factors affecting timing or viability

Schedule of equipment delivery.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Kettle GS CAS System Upgrades				1,380	1,380	
TOTAL				1,380	1,380	

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
1999 10	1,499	New complex.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION
GN98-11	KETTLE GS CENTRAL ANNUNCIATION SYST COND ASSESSMENT & RENEWAL

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

32.

COMPLEX STATUS		Complex no.	REVISION STATUS	
☐ Planned	☒ In progress	38	☐ New complex	☒ In service change
			☒ Concept change	☐ Estimate change only

COMPLEX	THERMAL G.S. ASSURANCE

Proposal

Refurbish the thermal generating units at Brandon and Selkirk Generating Stations as follows;

Brandon - Refurbish Units 1-5. Install electrostatic precipitators and a cooling tower for Unit 5, meet environmental licence requirements, upgrade coal handling facilities, and perform unit 5 mechanical upgrades (1998/99).

Selkirk - Refurbish Units 1 and 2, install ash lagoon and effluent management systems, and modify coal handling facilities.

JUSTIFICATION

☐ Load ☐ Service
☐ Safety ☐ Efficiency
☒ Reliability ☐ Other

Explanation

Based on WP London's report, Brandon and Selkirk Generating Stations require refurbishment of equipment, installation of environmental protection equipment, and modification of the fuel handling system in order to assure; service life to planned retirement, operation under more stringent environmental standards and a continuing supply of fuel.

Estimate Level	COMPLEX START (yyyy mm)
L3	1990 03

IN SERVICE DATES AND AMOUNTS

1992 07 31	$3737	1992 11 30	$7106	1993 11 30	$6741	1994 11 30	$31630
1995 05 31	$4338	1996 02 29	$52156	1996 03 31	$1409	1996 12	$12767
1998 01	$3993	1999 03	$1501	1999 12	$2808	2000 06	$5921

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	117,432		11,787		129,219	129,847	-628	-0
Year 99/00	3,529	14	417		3,960	722	3,238	448
00/01	801	16	112		929		929	
01/02								
02/03								
03/04								
04/05								
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	121,762	30	12,316		134,108	130,569	3,539	3

REVISION	Reflects deferrals pending unit outage clearance,and addition of: retubing Bdn unit 5 condencer & Selkirk unit 1 & 2 lube oil cooler & fish impingement mitigation work.

Reviewed by	yyyy mm dd	Reviewed by	yyyy mm dd
ORIGINATOR	99 11 08	COORDINATOR	
Reviewed by	yyyy mm dd	Approved by	yyyy mm dd
CONSTRUCTOR		VICE-PRESIDENT	99 11 12

H2856/r Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Complex no. 38

Advance or deferral impact

The thermal plants are an integral part of the Manitoba System and should remain operational.

Factors affecting timing or viability

Environmental constraints/ standards.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Brandon G.S. Units 1-5 Life Assurance Phase III	49,861	78,176	79,740	79,760	20	0
Selkirk G.S. Units 1&2 Life Assurance Phase III	36,399	40,575	41,387	42,002	615	1
TOTAL	86,260	118,751	121,127	121,762	635	1

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
9510	129,882	Reflects costs to date, scope change to include Bdn 1-4 unit layup mods,Selk boiler front equip, and miscellaneous upgrades offset by reduced contingency.
9610	130,875	Incr's: Bdn - #5 gen overhaul, RTU for control room, hazardous mat storage, & site drainage. Selk - rail repairs, boiler camera. Decr's: both locomotive refurb, & more.
9710	129,364	Reflects potential scope increases at Brandon, asbestos removal,and paving, at Selkirk,main boiler sheet metal cladding,, increase in coal dust contract costs, and additional fire upgrades.
9810	130,569	Reflects 97/98 underexpend 1.8M, higher costs for asbestos abatem't -Bdn , dust mitigat'n-Selkirk, add'n of unit 5 study + drain rehab-Bdn,+ comm, heating, fire upgrades-Selkirk.
1999 10	134,108	Reflects deferrals pending unit outage clearance,and addition of: retubing Bdn unit 5 condencer & Selkirk unit 1 & 2 lube oil cooler & fish impingement mitigation work.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

33.

COMPLEX STATUS	Complex no.	REVISION STATUS
☒ Planned ☐ In progress	226	☐ New complex ☐ In service change ☐ Concept change ☒ Estimate change only

COMPLEX	BRANDON G.S. LICENCE RENEWAL

Proposal

Refurbish unit #5, extending the useful life of the plant to 2019. Life extension requires: procurement of a new environmental licence for the period 2006 - 2019, replacement of last two rows of L.P. turbine blading, retube condenser, upgrade electrical services, install nitrous oxides control & continuous emission monitoring. Build new ash lagoon.

JUSTIFICATION

☒ Load ☐ Service
☐ Safety ☐ Efficiency
☒ Reliability ☐ Other

Explanation

The 1998 power resource plan report recommends Brandon #5 life extension as an option to meet future load requirements and increase system reliability.

Estimate Level	COMPLEX START (yyyy mm)
L2	2000 04

IN SERVICE DATES AND AMOUNTS							
2006 04	$8892	2007 03	$784	2008 03	$1696	2009 03	$1009
2010 03	$2699	2011 03	$1469	2012 03	$864	2013 03	$2071
2014 03	$455	2015 03	$1205	2016 03	$473	2017 on	$1657

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend								
Year 99/00								
00/01						1,089	-1,089	-100
01/02						3,606	-3,606	-100
02/03						2,500	-2,500	-100
03/04	1,909	5	152		2,066	1,136	930	82
04/05	586	63	210		859	1,254	-395	-31
05/06	4,747	610	479		5,836	7,516	-1,680	-22
06/07	716	108	92		916	2,173	-1,257	-58
07/08	1,387	242	67		1,696	2,011	-315	-16
08/09	809	160	40		1,009	1,843	-834	-45
09/10	2,116	469	114		2,699		2,699	
10/11	1,128	278	63		1,469		1,469	
11/12	650	176	38		864		864	
12/13	1,526	453	92		2,071		2,071	
13/14	329	106	20		455		455	
14/15	856	298	50		1,204		1,204	
15/16	329	124	20		473		473	
16/17	329	133	21		483		483	
17/18	329	142	22		493		493	
18/19	445	205	30		680		680	
Beyond								
TOTAL	18,191	3,572	1,510		23,273	23,128	145	1

REVISION	Reflects a two year start deferral.

Reviewed by ORIGINATOR	yyyy mm dd 99 11 02	Reviewed by COORDINATOR		yyyy mm dd	
Reviewed by CONSTRUCTOR	yyyy mm dd	Approved by VICE PRESIDENT		yyyy mm dd 99 11 30	

H2856/r Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Complex no. 226

Advance or deferral impact

Increased imports to meet load requirements.

Factors affecting timing or viability

Local load demands.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Brandon GS Licence Renewal		16,990	17,330	18,191	861	5
TOTAL		16,990	17,330	18,191	861	5

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
96 10	26,992	NEW COMPLEX
9710	23,289	Revised to remove estimate for ash lagoon work transferred from Life Assurance item, and already included.
9810	23,128	Estimate remains valid.
1999 10	23,273	Reflects a two year start deferral.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

34.

COMPLEX STATUS: ☐ Planned ☒ In progress

Complex no. 220

REVISION STATUS: ☐ New complex ☐ In service change ☒ Concept change ☒ Estimate change only

COMPLEX: BRANDON G.S. SWITCHYARD JETAIRE BREAKER REPL

Proposal
Replacement of all thirteen 115kV Jetaire circuit breakers at Brandon G.S.

JUSTIFICATION: ☐ Load ☐ Service ☐ Safety ☒ Efficiency ☒ Reliability ☐ Other

Explanation
These breakers have been in service for 40 years and have reached the end of their useful life. Obsolescence (interim system upgrades and their age have decreased their capability), high fault levels, decreasing reliability, and high maintenance costs (8.4 times higher than similar breakers at Bdn with parts very expensive or unavailable) indicate these breakers should be replaced with existing surplus breakers, after their refurbishment.

Estimate Level	COMPLEX START yyyy mm
L2	1997 04

IN SERVICE DATES AND AMOUNTS					
1999 01	$1306	1999 10	$2287		

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	2,061		122	26	2,157	1,562	595	38
Year 99/00	1,293	34	82		1,409	1,986	-577	-29
00/01								
01/02								
02/03								
03/04								
04/05								
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	3,354	34	204	26	3,566	3,548	18	1

REVISION: Revised to update cash flows. More work was completed in 1998/99 than previously forecast

Reviewed by ORIGINATOR	yyyy mm dd 99 11 08	Reviewed by COORDINATOR	yyyy mm dd		
Reviewed by CONSTRUCTOR	yyyy mm dd	Approved by VICE-PRESIDENT	yyyy mm dd 99 12 15		

H2856/r Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Complex no. 220

Advance or deferral impact

Continued high failure rate.

Factors affecting timing or viability

Schedule for refurbishing the replacements.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Brandon G.S. switchyard Jetaire breaker repl	3,521	3,412	3,480	3,354	-126	-4
TOTAL	3,521	3,412	3,480	3,354	-126	-4

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
96 10	2,582	NEW COMPLEX
9710	2,450	Reflects revised costing methodology with the new financial reporting system.
9810	3,548	SCOPE REVISED TO INCLUDE BUSHING CT ADDITION, PURCHASE OF EIGHT BREAKERS INSTEAD OF REFURBISHING AND SALEABLE SPARE PARTS.
1999 10	3,566	Revised to update cash flows. More work was completed in 1998/99 than previously forecast.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

35.

(IN THOUSANDS OF DOLLARS)

COMPLEX STATUS: ☐ Planned ☒ In progress

Complex no. 224

REVISION STATUS: ☐ New complex ☒ In service change ☐ Concept change ☒ Estimate change only

COMPLEX	200MW ONTARIO HYDRO SALE

Proposal

Make necessary adjustments to units 1 to 6 at Seven Sisters G.S. to allow conversion of units to synchronous condenser operation.

JUSTIFICATION

☒ Load ☐ Service ☐ Safety ☒ Efficiency ☒ Reliability ☐ Other

Explanation

During low Winnipeg River generation and single contingency outage conditions, additional voltage support is required in Whiteshell area to maintain 200MW sale to Ontario. This item provides for capability to convert Seven Sisters generating units to synchronous condenser operation to provide required voltage support.

Estimate Level	COMPLEX START (yyyy mm)
L3	1995 06

IN SERVICE DATES AND AMOUNTS

1998 03	$2742	1999 03	$711	1999 04	($43)	1999 06	$746
1999 10	$441	2000 10	$441	2001 10	$441	2002 10	$441
2003 10	$441	2004 10	$441	2005 10	$441	2006 10	$441

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	3,941		284	29	4,196	3,995	201	5
Year 99/00	338	1	26		365	1,045	-680	-65
00/01	424	3	8		435	490	-55	-11
01/02	424	5	8		437	492	-55	-11
02/03	424	8	7		439	494	-55	-11
03/04	424	10	7		441	335	106	32
04/05	424	13	8		445		445	
05/06	424	16	8		448		448	
06/07	424	19	9		452		452	
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	7,247	75	365	29	7,658	6,851	807	12

REVISION	Reflects the experience gained while refurbishing the first breaker.

Reviewed by ORIGINATOR	yyyy mm dd 99 11 08	Reviewed by COORDINATOR	yyyy mm dd		
Reviewed by CONSTRUCTOR	yyyy mm dd	Approved by VICE-PRESIDENT	yyyy mm dd 99 11 12		

H2856/r Rev 99 03

Complex no. 224

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Advance or deferral impact

Factors affecting timing or viability

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE	
					Amount	%
Seven S generator 1-6 synchronous condenser conv	2,731	3,097	3,159	3,239	80	3
Seven S 115kV Breaker and Wall Bushing Upgrade	3,132	3,120	3,182	4,008	826	26
TOTAL	5,863	6,217	6,341	7,247	906	14

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
96 10	2,133	New complex, originally included in complex 95.
9710	6,378	Reflects changes in design, actual costs of first unit conversion, & addition of a 115kV breaker & wall bushing upgrade item.
9810	6,851	Reflects 97/98 overexpenditure .4M. Cashflow revised to reflect extended timeframe of brkr and wall bushing program, and actual costs of first units and associated deficiencies.
1999 10	7,658	Reflects the experience gained while refurbishing the first breaker.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

36.

COMPLEX STATUS	Complex no.	REVISION STATUS
☒ Planned ☐ In progress	227	☐ New complex ☐ In service change ☐ Concept change ☒ Estimate change only

COMPLEX	SITE REMEDIATION - CONTAMINATED CORPORATE FACILITIES

Proposal

Conduct geotechnical investigation of the various contaminated Corporate facilities to deliniate the extent of any contamination on/around the site and prepare a report each with recommendations for cleanup. Remediate contaminated areas to environmentally acceptable limits and issue a final report confirming the site remediated in accordance with applicable environmental regulations.

JUSTIFICATION		Explanation
☐ Load	☐ Service	Environmental concerns and/or regulations require that Corporate facilities be investigated and remediated as required to restore them to a level which permits unrestricted use of the site.
☒ Safety	☐ Efficiency	
☐ Reliability	☒ Other	

Estimate Level	COMPLEX START (yyyy mm)
L1	1997 04

IN SERVICE DATES AND AMOUNTS							
2000 03	$1720	2001 03	$812	2002 03	$827	2003 03	$844
2004 03	$861	2005 03	$878	2006 03	$896	2007 03	$914
2008 03	$932	2009 03	$950	2010 03	$969	2011 on	$2330

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	926				926	1,069	-143	-13
Year 99/00	787	6			793	773	20	3
00/01	792	19			811	790	21	3
01/02	793	35			828	805	23	3
02/03	793	51			844	821	23	3
03/04	793	68			861	838	23	3
04/05	793	85			878	855	23	3
05/06	793	103			896	872	24	3
06/07	793	121			914	889	25	3
07/08	793	139			932	907	25	3
08/09	793	158			951	925	26	3
09/10	793	177			970	944	26	3
10/11	793	196			989	963	26	3
11/12	793	216			1,009	982	27	3
12/13	255	75			330	292	38	13
13/14		0			0		0	
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	11,483	1,449			12,932	12,725	207	2

REVISION	Represents 1999 submission.

Reviewed by ORIGINATOR	yyyy mm dd 99 10 02	Reviewed by COORDINATOR	yyyy mm dd		
Reviewed by CONSTRUCTOR	yyyy mm dd	Approved by VICE-PRESIDENT	yyyy mm dd 99 11 12		

H2856/r Rev 99 03

Complex no. 227

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Advance or deferral impact

Potential for legal actions.

Factors affecting timing or viability

Subject to environmental regulations.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE	
					Amount	%
Site remediation of contaminated Corp facilities	10,730	10,905	11,123	11,485	362	3
TOTAL	10,730	10,905	11,123	11,485	362	3

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
96 10	13,534	This is a new complex (prev part of cx 2) which covers Power Supply related site remediation of contaminated Corporate facilities , base 1996, extended work period.
9710	13,277	Revised base year, cost flows, escalation and interest rates.
9810	12,725	Revised to reflect removal of interest from this item.
1999 10	12,932	Represents 1999 submission.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

37.

COMPLEX STATUS	Complex no.	REVISION STATUS
☐ Planned ☒ In progress	225	☐ New complex ☒ In service change ☐ Concept change ☐ Estimate change only

COMPLEX	OIL CONTAINMENT - POWER SUPPLY

Proposal

Modifications and/or additions are required to prevent and contain oil spills:

1) southern and northern hydraulic generating stations, install oil/water separators, modify drainage systems, and upgrade sump, fuel storage facilities and dyking systems.

2) converter stations, install an oil containment system to collect and recover any oil spilled within the station.

JUSTIFICATION	Explanation
☐ Load ☐ Service ☒ Safety ☐ Efficiency ☐ Reliability ☒ Other	Previous experience with oil spills requires the Corporation to demonstrate "due diligence" with respect to containing and minimizing the potential for any further occurances. In addition, any plant outage as a result of a spill represents a minimum loss of $5000/hr.

Estimate Level	COMPLEX START (yyyy mm)
L2-3	1994 12

IN SERVICE DATES AND AMOUNTS							
1996 11	$107	1997 03	$2433	1997 04	$864	1997 08	$785
1997 12	$2125	1998 03	$140	1998 04	$128	1998 10	$961
1998 12	$188	2000 11	$931	2001 10	$1726	2003 on	$5194

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	7,757		409		8,166	8,958	-792	-9
Year 99/00	303	4	22		329	644	-315	-49
00/01	550	17	37		604	2,186	-1,582	-72
01/02	2,094	84	75		2,253	4,846	-2,593	-54
02/03	811	53	97		961	860	101	12
03/04	1,378	93	178		1,649		1,649	
04/05	1,426	118	76		1,620		1,620	
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	14,319	369	894		15,582	17,494	-1,912	-11

REVISION	Reflects tailrace & splash shield, and 'Oil Spill Containment Working Group' scope reductions, favourable actual costs, and costs to completion.

Reviewed by ORIGINATOR	yyyy mm dd	Reviewed by COORDINATOR	yyyy mm dd
Reviewed by CONSTRUCTOR	yyyy mm dd	Approved by VICE-PRESIDENT	yyyy mm dd 99 11 12

H2856/r Rev 99 03

Complex no. 225

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Advance or deferral impact

Potential for legal action.

Factors affecting timing or viability

Subject to environmental regulations.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Generation South G S's oil spill containment	2,566	2,711	2,765	2,492	-273	-10
Generation North G S's oil spill containment	5,375	5,857	5,974	5,526	-448	-7
Dorsey Stn oil containment system		1,905	1,943	1,579	-364	-19
Henday Stn oil containment system		2,421	2,469	2,075	-394	-16
Radisson Stn oil containment system		2,684	2,738	2,396	-342	-12
Generation North spill response equipment	300	187	191	164	-27	-14
Generation South spill response equipment	93	93	95	89	-6	-6
TOTAL	8,334	15,858	16,175	14,321	-1,854	-11

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
96 10	19,730	New complex (previously part of 81) which covers Power Supply portion of oil containment & two new spill response equipment purchase items, base year 1996.
9710	18,504	Increased for 7 mo deferral of Great Falls, Jenpeg, and Grand Rapids, cost of approved Generation South spill response equipment and decreased for favourable contract prices for
9810	17,494	Reflects 97/98 underexpenditure 0.5M, reduced scope + contract prices at Long Spruce and Limestone, addition of risk analysis by consultant at 3 sites and deferred in-service dates.
1999 10	15,582	Reflects tailrace & splash shield, and 'Oil Spill Containment Working Group' scope reductions, favourable actual costs, and costs to completion.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

38.

COMPLEX STATUS	Complex no.	REVISION STATUS
☐ Planned ☒ In progress	228	☐ New complex ☒ In service change ☐ Concept change ☒ Estimate change only

COMPLEX	FIRE PROTECTION PROJECTS - POWER SUPPLY

Proposal

Design and install passive and/or active fire prevention and protection systems at all generating stations, and key transmission terminating stations as outlined by The Fire Prevention and Protection Committee and defined in the Fire Manual Part II.

Locations covered by this capital item complex are;
Pine Falls, McArthur, Kelsey, Limestone, Kettle, and Long Spruce Generating Stations, and Dorsey, Radisson, and Henday Stations.

JUSTIFICATION		Explanation
☐ Load	☐ Service	In accordance with the rules and guidelines established by The Fire Prevention and Protection Committee, implementation of this program will reduce the risk of fire to an acceptable level and mitigate the effects of any such occurance.
☒ Safety	☐ Efficiency	
☒ Reliability	☐ Other	

Estimate Level	COMPLEX START (yyyy mm)
L3	1990 06

IN SERVICE DATES AND AMOUNTS							
1997 10	$811	1997 12	$286	1998 10	$342	1999 01	$1001
1999 06	$143	1999 11	$404	2000 09	$771	2000 10	$771
2000 11	$771	2000 12	$121	2001 03	$1104	2001 08	$153

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	2,380		191		2,571	3,838	-1,267	-33
Year 99/00	440	15	14		469	395	74	19
00/01	2,980	92	17		3,089	2,386	703	29
01/02	526	22	3		551		551	
02/03								
03/04								
04/05								
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	6,326	129	225		6,680	6,619	61	1

REVISION	Revised to include 4 new Wpg R. & Jenpeg FP&P sites, the completion of Kettle, Long Spr, &Radisson, and a reduced construction estimate for Radisson thyristor fire protection upgr.

Reviewed by ORIGINATOR	yyyy mm dd	Reviewed by COORDINATOR	yyyy mm dd
Reviewed by CONSTRUCTOR	yyyy mm dd	Approved by VICE-PRESIDENT	yyyy mm dd 99 11 12

H2856/r Rev 99 03

Complex no. 228

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Advance or deferral impact

Work well advanced, deferrals not possible.

Factors affecting timing or viability

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	%
Kettle G S fire alarm system	277	277	283	277	-6	-2
Long Spruce G S fire alarm system	315	346	353	315	-38	-11
Limestone G S fire alarm system	374	371	378	374	-4	-1
Dorsey BP 1&2 addressable fire alarm system	656	818	834	750	-84	-10
Radisson Stn addressable fire alarm system	587	578	590	503	-87	-15
Henday Stn addressable fire alarm system	502	572	583	551	-32	-5
Dorsey BP 1 thyristor valves fire prot upgrade		1,078	1,100	1,099	-1	-0
Radisson BP 1 thyristor valves fire prot upgrade		1,283	1,309	1,144	-165	-13
Jenpeg fire prevention and protection				581	581	
Seven Sisters fire prevention and protection				201	201	
Mc Arthur Falls fire prevention and protection				213	213	
Great Falls fire prevention and protection				175	175	
Pine Falls fire prevention and protection				142	142	
TOTAL	2,711	5,323	5,430	6,325	895	16

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
96 10	8,274	Reduction, cancel'n of converter stn valve hall items., & increase, new/upgrade alarm systems for Limestone, Kettle, Long Spruce, Dorsey & Radisson. Prev part Cx 92.
9710	6,538	Reflects revised methodology with the new reporting system, increases in const & design costs, deferred in service dates, and addition of project management & field inspection costs.
9810	6,619	Reflects 1 year deferral of Dorsey and Radisson thyristor valve fire protection upgrade.
1999 10	6,680	Revised to include 4 new Wpg R. & Jenpeg FP&P sites, the completion of Kettle, Long Spr, &Radisson, and a reduced construction estimate for Radisson thyristor fire protection upgr.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

39.

COMPLEX STATUS	Complex no.	REVISION STATUS
☐ Planned ☒ In progress	13	☐ New complex ☒ In service change ☒ Concept change ☐ Estimate change only

COMPLEX	BUILDINGS - POWER SUPPLY

Proposal

1. Construct a 23500sq.ft. service building for admin, maintenance, and stores for Wpg R. gen. stations. (1998/99-1999/00)
2. Construct 32 permanent housing units, and a 6 point infrastructure renewal (5 yr plans) at Gillam. (1995/96-2000-01)
3. Build 18 new single family homes in Gillam to replace temporary modular units that cannot be rehabilitated. (1993/94-1994/95)
4. Construct a staffhouse at Grand Rapids containing 12 single and 4 suites, kitchen, dining, rec. and lounge. (1996/97-1997/98)

JUSTIFICATION	Explanation
☐ Load ☒ Service ☐ Safety ☐ Efficiency ☐ Reliability ☒ Other	To consolidate staff currently leasing space or conducting activities from substandard facilities, the corporation has a sequenced program of major building additions staged at one per year. In addition, the corporation is continuing to provide accommodations at remote or northern locations where acceptable alternatives or conditions are unavailable. Gillam housing requirements are: Production North (26), Construction (4), and Northern Region (2). Gillam infrastructure evaluation lists substandard: water quality, sewage treatment, fire hydrants, rec facility, and trailer park insulation.

Estimate Level	COMPLEX START (yyyy mm)
L2	1990 08

IN SERVICE DATES AND AMOUNTS							
1997 03	$6970	1997 11	$5404	1998 01	$4416	1998 02	$278
1998 04	$208	1998 07	$377	1999 02	$294	1999 04	$4817
1999 10	$1945	2000 01	$3399	2000 10	$2341	2001 on	$8359

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	18,318		818	1	19,135	19,078	57	0
Year 99/00	5,418	132	190		5,740	5,955	-215	-4
00/01	2,194	99	52		2,345	3,907	-1,562	-40
01/02	2,564	176	79		2,819	3,868	-1,049	-27
02/03	3,141	290	124		3,555	2,182	1,373	63
03/04	1,554	185	21		1,760		1,760	
04/05								
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	33,189	882	1,284	1	35,354	34,990	364	1

REVISION	Reflects add'n of mezzanine & furniture for Wpg R stores, increased cost of concrete at Gillam, deferral of Grd Rpds & Gillam infrastructure upgrade work,& est's adj to actuals.

Reviewed by ORIGINATOR	yyyy mm dd	Reviewed by COORDINATOR	yyyy mm dd
Reviewed by CONSTRUCTOR	yyyy mm dd	Approved by VICE-PRESIDENT	yyyy mm dd 99 11 12

H2856/r Rev 99 03

Complex no. 13

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Advance or deferral impact

Continuation of leased premises

Factors affecting timing or viability

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	%
Winnipeg River Operating Ctr	2,597	3,995	4,075	4,364	289	7
Gillam Infrastructure Upgrade	11,062	14,638	14,931	14,593	-338	-2
Grand Rapids Infrastructure Upgrades		2,067	2,108	2,105	-3	-0
Gillam Permanent Housing	10,864	7,491	7,641	7,706	65	1
Grand Rapids GS - Staff House Replacement	4,254	4,378	4,466	4,422	-44	-1
TOTAL	28,777	32,569	33,221	33,190	-31	-0

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
9510	59,891	Complex increased to include Gillam Permanent Housing, and Gillam Infrastructure Upgrade.
9610	33,372	Radisson Storage & Equip Bldg added, Northern & Central Region Offices cancelled, & Trades Training Ctr & 820 Taylor Ave Refurbish moved to Complex 231.
9710	31,024	Reflects removal of completed 18 temporary housing units item, scope increased to include paving, recirculation loop,and staffhouse conversion to appartments.
9810	34,990	Reflects 97/98 underexpenditure 1.1M, add'n of Grd Rpds Hybord sewer + water rehab, cancell'n of Radisson equip bldg , inc scope to Wpg R Op Ctr + Gillam,+ deferrals to Gillam.
1999 10	35,354	Reflects add'n of mezzanine & furniture for Wpg R stores, increased cost of concrete at Gillam, deferral of Grd Rpds & Gillam infrastructure upgrade work, & est's adj to actuals.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

40.

COMPLEX STATUS	Complex no.	REVISION STATUS
☐ Planned ☒ In progress	990	☐ New complex ☒ In service change ☒ Concept change ☐ Estimate change only

COMPLEX: PRELIMINARY PLANNING STUDIES

Proposal

Carry out assessments, conceptual designs and planning studies of potential supply options, and associated transmission.
Areas of study include establishment of design parameters, structure layouts, support facilities, hydraulic model testing, exploration, data collection, environmental assessments and public input, schedules and cost estimates.

JUSTIFICATION

☐ Load ☐ Service
☐ Safety ☐ Efficiency
☐ Reliability ☒ Other

Explanation

In order to plan the development of the Province's resource potential and related projects, office studies, environmental assessments and field exploration have to be carried out. The results and technical designs are required to support the planning process.

Estimate Level	COMPLEX START (yyyy mm)
L2	1993 04

IN SERVICE DATES AND AMOUNTS

1999 03	$5410	2000 03	$16131	2001 03	$16494	2002 03	$3111
2003 03	$2651	2003 04	($1774)	2004 03	$2681	2005 03	$2764
2006 03	$2818	2007 03	$9690	2008 03	$9051	2009 on	$71966

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	5,410				5,410	8,097	-2,687	-33
Year 99/00	16,005	125			16,130	16,112	18	0
00/01	16,123	371			16,494	1,955	14,539	744
01/02	2,982	129			3,111	2,289	822	36
02/03	2,493	158			2,651	2,239	412	18
03/04	697	209			906	2,258	-1,352	-60
04/05	2,501	263			2,764	2,290	474	21
05/06	2,501	317			2,818	3,016	-198	-7
06/07	8,364	1326			9,690	5,963	3,727	63
07/08	7,658	1394			9,052	6,062	2,990	49
08/09	15,703	3233			18,936	8,241	10,695	130
09/10	-16,056	1653			-14,403	-14,863	460	-3
10/11	2,228	540			2,768	2,316	452	20
11/12	-15,505	543			-14,962	2,400	-17,362	-723
12/13	2,028	594			2,622	2,557	65	3
13/14	1,978	629			2,607	2,759	-152	-6
14/15	2,078	716			2,794	2,938	-144	-5
15/16	2,078	771			2,849	398	2,451	616
16/17	2,078	827			2,905	2,402	503	21
17/18	2,078	885			2,963	2,665	298	11
18/19	2,078	943			3,021		3,021	
Beyond	34,642	25224			59,866	50,100	9,766	19
TOTAL	100,142	40,850			140,992	112,194	28,798	26

REVISION: REFLECTS REQUIREMENT OF THE 1999 POWER RESOURCE PLAN.

Reviewed by ORIGINATOR	yyyy mm dd 99 11 02	Reviewed by COORDINATOR	yyyy mm dd
Reviewed by CONSTRUCTOR	yyyy mm dd	Approved by VICE-PRESIDENT	yyyy mm dd 99 11 12

PRELIMINARY PLANNING STUDIES

(in thousands of dollars)

	PREV.	99/00	00/01	01/02	02/03	03/04	04/05	05/06	06/07	07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	TOTAL
BURNTWOOD RIVER:																						
Wuskwatim G.S.	14,547	6,945	7,406	236	241	246	251	256	1,656	799	4,467	6,654	309									44,013
Manasan G.S.	6,531	835	674	301	307	313	319	325	331	338	344	351	358	365	372	379	386	394	402	409	417	14,451
First Rapids G.S.	5,493	113	90	164	167	170	173	176	179	182	185	188	191	195	198	201	205	209	212	216	220	9,127
NELSON RIVER:																						
Kettle Runner	187																					187
Birthday Rapids	12,326																					12,326
Gull Rapids	10,362	3,949	3,254	259	264	269	275	280	286	292	297	303	309	316	322	328	335	342	349	355	363	23,109
Gillam Island																						
Conawapa/BP3	22,759	260	329	105	107	109	111	113	5,817	5,933	12,104											47,747
OTHER:																						
East Channel/Sea River Fall	618																					618
Future Developments	1,881	147	80	154	157	160	163	167	170	173	177	180	184	188	191	195	199	203	207	211	216	5,403
Wpg-Bdn T/L	482																					482
Moose Lake	645																					645
Ear Falls/Lac Seul Dam																						
Sprague	9																					9
Mandan T/L	6,135																					6,135
Brandon #5 Licence Renewal	365	461	464	541	256																	2,087
Combustion Turbine #1	481					261	266	271	277	282	288	294	299	305	311	318	324	331	337	344	351	5,340
Notigi	3,205	2,593	2,854	258	262	266	271	275														9,984
SSM Proposal Evaluation	1,523	791	1,303	1,034	856	874	891	909	927	1,004	1,024	1,045	1,066	1,151	1,174	1,131	1,289	1,314	1,341	1,368	1,395	23,410
HVDC Trans Damper																						
Hydraulic Plant Relicensing																						
Non-Utility Generation	20	37	40	60	34	35	45	46	47	48	49	50	51	52	53	54	55	56	58	59	60	1,009
Electrode Line Reliability Study	50																					50
Chater Station - Land Purchase	425																					425
LGD Churchill																						
Environmental Costing	90																					90
TOTAL EXPENDITURES	88,134	16,131	16,494	3,112	2,651	2,703	2,765	2,818	9,690	9,051	18,935	9,065	2,767	2,572	2,621	2,606	2,793	2,849	2,906	2,962	3,022	206,647
UNAMORTIZED STUDY COSTS TRANSFERRED TO CAPITAL: (Non-Cash)																						
BURNTWOOD RIVER:																						
Wuskwatim G.S. (01-27-6001)														-17,533								-17,533
NELSON RIVER:																						
Conawapa (01-26-8124)												-23,468										-23,468
OTHER:																						
Brandon #5 Life Extension (01-16-7008)						-1,796																-1,796
TOTAL COSTS TO CAPITAL						-1,796						-23,468		-17,533								-42,797
NET PLANNING STUDIES	88,134	16,131	16,494	3,112	2,651	907	2,765	2,818	9,690	9,051	18,935	-14,403	2,767	-14,961	2,621	2,606	2,793	2,849	2,906	2,962	3,022	163,850

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

4/.

COMPLEX STATUS	Complex no.	REVISION STATUS
☐ Planned ☒ In progress	121 - 129	☐ New complex ☐ In service change ☐ Concept change ☒ Estimate change only

COMPLEX	DOMESTIC ITEM - POWER SUPPLY

Proposal

This complex consists of several hundred projects which are not identified as Major Items and whose individual cost is of a relatively small amount. The majority of projects are required to provide safe reliable and efficient power supply and HVDC facilities, and to replace plant facilities whose useful life has been exceeded.

JUSTIFICATION	Explanation
☒ Load ☒ Service ☒ Safety ☒ Efficiency ☒ Reliability ☒ Other	Enhancements or rehabilitation to the power supply facilities will ensure a safe reliable and efficient source of energy.

Estimate Level	COMPLEX START (yyyy mm)
L2	1996 04

IN SERVICE DATES AND AMOUNTS							
1999 03 31	$9824	2000 03 31	$10020	2001 03 31	$10220	2002 03 31	$10465
2003 03 31	$10715	2004 03 31	$10960	2005 03 31	$11208	2006 03 31	$11458
2007 03 31	$11713	2008 03 31	$11969	2009 03 31	$12237	2010 03 31	$12509

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend						9,824	-9,824	-100
Year 99/00	9,485	56	468		10,009	10,020	-11	-0
00/01	9,565	186	471		10,222	10,220	2	0
01/02	9,722	267	476		10,465	10,465	0	0
02/03	9,795	444	476		10,715	10,715	0	0
03/04	9,624	906	185		10,715	10,960	-245	-2
04/05	9,651	1120	189		10,960	11,208	-248	-2
05/06	9,674	1338	196		11,208	11,458	-250	-2
06/07	9,694	1562	202		11,458	11,713	-255	-2
07/08	9,715	1791	207		11,713	11,969	-256	-2
08/09	9,732	2024	213		11,969	12,237	-268	-2
09/10	9,750	2264	223		12,237	12,509	-272	-2
10/11	9,770	2509	230		12,509	12,794	-285	-2
11/12	9,793	2761	240		12,794	13,079	-285	-2
12/13	9,813	3018	248		13,079	13,374	-295	-2
13/14	9,833	3282	259		13,374	13,667	-293	-2
14/15	9,852	3551	264		13,667	13,969	-302	-2
15/16	9,874	3827	268		13,969	14,281	-312	-2
16/17	9,897	4110	274		14,281	14,603	-322	-2
17/18	9,920	4401	282		14,603	14,934	-331	-2
18/19	9,945	4700	289		14,934		14,934	
Beyond								
TOTAL	195,104	44,117	5,660		244,881	243,999	882	0

REVISION	Reflects current forecast costs for the Power Supply Group.

Reviewed by ORIGINATOR	yyyy mm dd	Reviewed by COORDINATOR	yyyy mm dd
Reviewed by CONSTRUCTOR	yyyy mm dd	Approved by VICE-PRESIDENT	yyyy mm dd 99 11 12

H2856/r Rev 99 03

Complex no.
121 - 129

CAPITAL EXPENDITURE FORECAST COMPLEX
(IN THOUSANDS OF DOLLARS)

Advance or deferral impact

Requirements are necessary to meet capacity and energy demands, in accordance with our system design criteria and/or commitments.

Factors affecting timing or viability

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE	
					Amount	%
TOTAL						

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
9510	2,681,204	Reflects reduced load growth.
9610	255,760	This item reflects current forecast costs attributable to the Power Supply Group.
1997 10	252,399	REFLECTS POWER SUPPLY'S REVISED SHARE OF THE DOMESTIC FORECAST BASED ON CURRENT RATES.
1998 10	243,999	Reflects Power Supply's revised share of the Domestic Forecast based on current rates.
1999 10	244,881	Reflects current forecast costs for the Power Supply Group.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

CAPITAL EXPENDITURE FORECAST (CEF99-1)
(IN MILLIONS OF DOLLARS)
FOR THE YEARS 1999/00 TO 2018/19

		Total	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	20 year Forecast
TRANSMISSION AND DISTRIBUTION																							
	TRANSMISSION FOR GENERATION																						
58	WUSKWATIM TRANSMISSION	66.5												1.1	1.2	2.7	2.6	8.2	25.8	25.1			66.5
263	HVDC CONVERSION BIPOLE 3/CONAWAPA TRANSMISSION	1,896.2										2.6	9.2	15.3	15.8	41.5	55.3	215.8	412.4	509.3	372.7	186.7	1,836.6
	INTERCONNECTIONS																						
79	MANITOBA > MINNESOTA 500kV TRANSMISSION UPGRADE (MMTU)																						
95	200MW ONTARIO HYDRO SALE - T/L UPGRADE	0.8	0.8																				0.8
268	HARVEY-GLENBORO 230KV LINE	16.0		1.6	6.4	8.0																	16.0
	TRANSMISSION																						
87	KETTLE AC TRANSMISSION IMPROVEMENTS	10.6	0.1	0.0	0.2	1.0	4.3	5.0															10.6
16	NORTH CENTRAL MANITOBA PROJECT	0.8	0.0	0.3	0.4																		0.8
30	THOMPSON>HERBLET LAKE 230kV TRANSMISSION	57.1			0.2	0.2	0.8	5.4	21.5	14.1	14.9												57.1
40	FLIN FLON - CLIFF LAKE TRANSFORMER REPLACEMENT	1.5	0.6	0.9																			1.5
47	HERBLET LAKE > THE PAS 230kV TRANSMISSION	55.3				0.2	0.5	1.0	0.3	1.1	3.4	16.4	19.0	6.7									48.5
57	DORSEY > NEEPAWA > CORNWALLIS 230kV LINE	18.5	16.8	1.7																			18.5
60	WINNIPEG > BRANDON 230kV TRANSMISSION	73.0			0.1	3.0	4.8	7.4	13.7	18.7	15.1	10.3											73.0
45	FT GARRY - PERIMETER SOUTH BANK REPLACEMENT	4.4			0.4	2.5	1.5																4.4
84	RIDGEWAY TRANSFORMER ADDITION	9.2					0.3	0.6	0.8	4.1	3.4												9.2
78	RIDGEWAY > ST. VITAL 230kV TRANSMISSION	1.7	1.7																				1.7
64	ST. VITAL TRANSFORMER ADDITION	9.0	0.3	3.6	4.0	1.0																	9.0
42	DORSEY-ROSSER 230kV TRANSMISSION IMPROVEMENTS	1.8	0.0	1.4	0.4																		1.8
27	DORSEY > ST. VITAL 230kV AC TRANSMISSION	7.7	0.0	1.3	5.3	1.1	0.0																7.7
96	DORSEY > LAVERENDRYE > ST. VITAL 230kV TRANSMISSION,	25.9														1.7	3.5	10.7	10.0				25.9
21	ROSSER > SILVER 230kV TRANSMISSION	27.6	3.6	0.4	0.5	3.3	9.9	10.0															27.6
9	RAVEN LAKE > BIRTLE 230kV TRANSMISSION																						
94	BRANDON 115kV LOOP																						
39	RAVEN LAKE STATION 230-66kV TRANSFORMATION	8.3																0.6	1.5	3.0	3.3		8.3
98	VERMILION STATION STATIC VAR GENERATOR																						
18	NEEPAWA 230 -115kV STN	17.5					0.1	1.0	7.4	9.1													17.5
201	ASSINIBOINE - WILKES AVE 115-24 KV BANK 1 ADDITION	7.2	7.1	0.1																			7.2
202	ROSSER > MCPHILLIPS 115kV TRANSMISSION IMPROVEMENTS	2.4	0.0	0.1	0.4	1.8																	2.4
204	RICHER SOUTH 230-66kV TRANSFORMER ADDITION	4.9				0.4	0.4	2.3	1.8														4.9
205	PINE FALLS > BLOODVEIN 115kV TRANSMISSION LINE	29.1								0.2	0.2	1.0	1.7	7.0	15.6	3.4							29.1
207	ST. VITAL > STEINBACH 230kV TRANSMISSION	22.3						0.3	0.3	0.6	3.3	4.2	13.6										22.3
208	RIDGEWAY > SELKIRK 230kV TRANSMISSION	25.1				0.6	2.0	3.3	4.5	7.0	7.6												25.1
210	SOURIS > PEMBINA VALLEY 230kV TRANSMISSION	32.6								0.6	0.9	1.4	1.6	12.0	16.1								32.6
4	WINNIPEG AREA TRANSMISSION REFURBISHMENT	4.0	1.1	0.6	0.4	0.8	1.1	0.0															4.0
28	DORSEY STATION 230kV BREAKER REPLACEMENT	1.6	1.6																				1.6
43	DORSEY > US BORDER D602F 500KV AC T/L INSULATOR REPL.	2.7	1.2	0.5	0.4	0.6																	2.7
7	BIPOLE 1 & 2 LINE SPACER DAMPERS REPLACEMENT	5.1	0.7	2.5	1.9	0.0																	5.1
247	DORSEY 230kV BUS ENHANCEMENTS	16.0	0.4	0.9	3.2	7.0	4.6																16.0
251	FLIN FLON AREA TRANSMISSION IMPROVEMENTS	17.3	0.3	2.0	5.2	1.6	5.2	2.9															17.3
257	PINE FALLS-GREAT FALLS 115-66kV SUPPLY	9.4		0.9	2.7	3.4	1.2	1.1															9.4
	SUBTRANSMISSION																						
55	JENPEG > NORWAY HOUSE 66 kV SUB TRANSMISSION LINE	12.5	0.0	0.0	0.3	0.9	4.9	6.3															12.5
53	RUTTAN > SOUTH INDIAN LAKE 66 kV LINE	5.5	0.3	0.3	0.3	1.6	3.0																5.5
17	CENTRAL SUPPLY > PIKWITONEI & THICKET PORTAGE	0.7	0.0	0.7																			0.7
206	PINEY > SPRAGUE 66kV LINE	1.7	1.7	0.0																			1.7
209	BIRTLE SOUTH > ROSSBURN 66kV LINE	5.4				0.1	0.2	3.6	1.5														5.4
237	ST. BONIFACE-PLESSIS ROAD 115-25KV STATION	16.4	7.8	8.3	0.3																		16.4
238	ROSSER - OAK POINT 115-24KV STATION	18.5			0.0	0.7	2.0	10.1	5.7														18.5
239	ROSSER - OAK POINT BANK 2 ADDITION	9.8										0.8	6.2	2.7									9.8
240	ST. BONIFACE - PLESSIS ROAD BANK 2 ADDITION	4.9	0.1	1.6	3.2																		4.9
241	NEEPAWA 66KV SYSTEM	3.4			0.2	3.3																	3.4
242	RESTON/GLENBORO CAPACITY INCREASE	4.9	0.5	2.8	1.6																		4.9
80	ST. LEON 230-66KV TRANSF. ADD'N AND IPL EXPANSION	8.9	0.2	0.9	1.6	5.0	0.7	0.5															8.9
253	BRANDON EAST 115kV IMPROVEMENTS	1.0	1.0																				1.0
250	BRANDON CROCUS PLAINS 115-24kV BANK ADDITION	7.2		0.1	0.6	3.9	2.3	0.4															7.2
	DISTRIBUTION																						
86	DIESEL UPGRADING ENHANCEMENT	10.3	2.1	1.7	4.4	2.0																	10.3
221	VIRDEN AREA DISTRIBUTION CHANGES	10.0	4.2	1.3	1.6	0.9	1.0	1.0															10.0
217	DEFECTIVE RINJ CABLE REPLACEMENT	7.8	0.8	1.2	1.8	1.9	2.1																7.8
261	BRERETON LAKE STATION AREA	6.6		2.6	2.2	0.7	0.5	0.5	0.1														6.6
267	PAINT LAKE NEW FEEDER	1.6			1.8	(0.2)																	1.6
	COMMUNICATIONS, CONTROLS AND INFO TECHNOLOGY																						
10	EMS SCADA	2.1	2.1																				2.1
12	MICROWAVE RADIO REPLACEMENTS	48.1	9.0	3.3	9.6	8.1		1.6	16.5														48.1
218	LAN NETWORK EXPANSION																						
219	MAPINFO IMPLEMENTATION	10.7	4.4	4.3	2.0																		10.7
	OTHER																						
2	SITE REMEDIATION	5.5	1.3	2.2	0.9	1.1																	5.5
81	OIL CONTAINMENT	3.4	0.1	0.8	1.2	1.0	0.3																
92	FIRE PROTECTION PROJECTS																						

CAPITAL EXPENDITURE FORECAST (CEF99-1)
(IN MILLIONS OF DOLLARS)
FOR THE YEARS 1999/00 TO 2018/19

	Total	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	20 year Forecast
DOMESTIC ITEMS - TRANMISSION AND DISTRIBUTION		77.6	75.8	78.6	80.6	86.0	88.3	90.6	92.9	95.2	97.6	100.1	102.7	105.4	108.1	110.8	113.6	116.5	119.6	122.7	125.8	1,988.3
SUB-TOTAL TRANSMISSION AND DISTRIBUTION		149.5	126.6	144.5	148.0	139.7	152.6	164.7	148.3	143.8	134.2	151.4	147.5	154.1	157.4	172.1	348.8	566.1	657.0	498.7	312.5	4,617.7

CAPITAL EXPENDITURE FORECAST REVISIONS (CEF99-1)
(IN MILLIONS OF DOLLARS)
FOR THE YEARS 1999/00 TO 2018/19

		2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	20 year Forecast
TRANSMISSION AND DISTRIBUTION																						
	TRANSMISSION FOR GENERATION																					
58	WUSKWATIM TRANSMISSION										(0.8)	(0.9)	(2.1)	(2.1)	(7.2)	(24.2)	(23.5)					(60.8)
263	HVDC CONVERSION BIPOLE 3/CONAWAPA TRANSMISSION										2.6	9.2	15.3	15.8	41.5	55.3	215.8	412.4	509.3	372.7	186.7	1,836.6
	INTERCONNECTIONS																					
79	MANITOBA > MINNESOTA 500kV TRANSMISSION UPGRADE (MMTU)																					
95	200MW ONTARIO HYDRO SALE - T/L UPGRADE	0.8																				0.8
268	HARVEY-GLENBORO 230KV LINE		1.6	6.4	8.0																	16.0
	TRANSMISSION																					
87	KETTLE AC TRANSMISSION IMPROVEMENTS	(1.5)	(2.4)	(2.3)	(1.8)	4.3	5.0															1.4
16	NORTH CENTRAL MANITOBA PROJECT	(0.7)	0.0	(0.1)	(0.0)																	(0.8)
30	THOMPSON>HERBLET LAKE 230kV TRANSMISSION	(0.2)	(0.3)	(0.2)	(0.2)	(4.3)	(15.6)	8.0	(0.2)	14.9												1.9
40	FLIN FLON - CLIFF LAKE TRANSFORMER REPLACEMENT	0.3	0.9																			1.2
47	HERBLET LAKE > THE PAS 230kV TRANSMISSION				0.0	0.0	0.1	0.0	0.1	0.1	0.1	0.3	0.2									1.0
57	DORSEY > NEEPAWA > CORNWALLIS 230kV LINE	1.1	(4.9)																			(3.8)
60	WINNIPEG > BRANDON 230kV TRANSMISSION		(0.1)	(0.2)	(3.2)	(1.7)	(5.1)	(4.1)	2.7	5.2	10.3											3.9
45	FT GARRY - PERIMETER SOUTH BANK REPLACEMENT		(0.4)	0.2	(1.4)	1.5																(0.1)
84	RIDGEWAY TRANSFORMER ADDITION					0.0	0.1	0.1	0.1	0.0												0.3
78	RIDGEWAY > ST. VITAL 230kV TRANSMISSION	0.8																				0.8
64	ST. VITAL TRANSFORMER ADDITION	(2.9)	0.9	3.6	(1.0)																	0.5
42	DORSEY-ROSSER 230kV TRANSMISSION IMPROVEMENTS	0.0	(0.1)	0.0																		(0.0)
27	DORSEY > ST. VITAL 230kV AC TRANSMISSION	(5.1)	(0.2)	4.9	1.1	0.0																0.7
96	DORSEY > LAVERENDRYE > ST. VITAL 230kV TRANSMISSION														0.1	0.2	0.0	0.0				0.3
21	ROSSER > SILVER 230kV TRANSMISSION	0.6	(3.6)	(10.7)	(4.2)	9.9	10.0															2.0
9	RAVEN LAKE > BIRTLE 230kV TRANSMISSION																					
94	BRANDON 115kV LOOP																					
39	RAVEN LAKE STATION 230-66kV TRANSFORMATION																0.1	0.1	0.1	0.0		0.2
98	VERMILION STATION STATIC VAR GENERATOR	(0.0)	(0.1)	(0.5)	(8.5)	(8.6)	(3.9)															(21.7)
18	NEEPAWA 230 -115kV STN	(0.3)	(0.4)	(1.0)	(10.1)	(10.5)	1.0	7.4	9.1													(4.8)
201	ASSINIBOINE - WILKES AVE 115-24 KV BANK 1 ADDITION	1.3	(1.2)																			0.1
202	ROSSER > MCPHILLIPS 115kV TRANSMISSION IMPROVEMENTS	(0.1)	(0.3)	(1.3)	1.8																	0.2
204	RICHER SOUTH 230-66kV TRANSFORMER ADDITION				0.0	0.1	0.0	0.0														0.1
205	PINE FALLS > BLOODVEIN 115kV TRANSMISSION LINE	(0.1)	(0.1)	(0.8)	(1.4)	(5.3)	(13.9)	(3.0)	0.2	0.2	1.0	1.7	7.0	15.6	3.4							4.4
207	ST. VITAL > STEINBACH 230kV TRANSMISSION						0.0	0.0	0.1	0.1	0.2	0.1										0.6
208	RIDGEWAY > SELKIRK 230kV TRANSMISSION				0.1	0.1	0.1	0.2	0.1	0.1												0.6
210	SOURIS > PEMBINA VALLEY 230kV TRANSMISSION								0.0	0.0	0.1	0.1	0.2	0.3								0.7
4	WINNIPEG AREA TRANSMISSION REFURBISHMENT	0.4	(0.2)	(0.3)	0.1	0.2	0.0															0.3
28	DORSEY STATION 230kV BREAKER REPLACEMENT	0.6																				0.6
43	DORSEY > US BORDER D602F 500KV AC T/L INSULATOR REPLACEMENT	0.4	(0.3)	(0.5)	(0.6)																	(1.0)
7	BIPOLE 1 & 2 LINE SPACER DAMPERS REPLACEMENT	(3.0)	(1.2)	(1.6)	0.0																	(5.7)
247	DORSEY 230kV BUS ENHANCEMENTS	0.0	0.1	0.6	0.6	0.2																1.5
251	FLIN FLON AREA TRANSMISSION IMPROVEMENTS	0.3	2.0	5.2	1.6	5.2	2.9															17.3
257	PINE FALLS-GREAT FALLS 115-66kV SUPPLY		0.9	2.7	3.4	1.2	1.1															9.4
	SUBTRANSMISSION																					
55	JENPEG > NORWAY HOUSE 66 kV SUB TRANSMISSION LINE	(0.2)	(1.7)	(2.0)	(6.3)	4.9	6.3															1.1
53	RUTTAN > SOUTH INDIAN LAKE 66 kV LINE	0.2	(0.4)	(1.8)	(0.7)	3.0																0.3
17	CENTRAL SUPPLY > PIKWITONEI & THICKET PORTAGE	0.0	0.0																			0.1
206	PINEY > SPRAGUE 66kV LINE	0.5	0.0																			0.5
209	BIRTLE SOUTH > ROSSBURN 66kV LINE				0.0	0.0	(0.1)	(0.1)														(0.2)
237	SPRINGFIELD-ST. BONIFACE 115-25KV STATION	2.8	5.0	(6.7)																		1.1
238	ROSSER - OAK POINT 115-24KV STATION		(0.0)	(0.5)	(0.2)	(8.5)	4.2	5.7														0.6
239	ROSSER - OAK POINT BANK 2 ADDITION										0.1	(0.0)	(0.0)									0.0
240	SPRINGFIELD-ST. BONIFACE BANK 2 ADDITION	0.0	(0.0)	0.5																		0.5
241	NEEPAWA 66KV SYSTEM			(0.0)	(0.1)																	(0.1)
242	RESTON/GLENBORO CAPACITY INCREASE	0.1	0.0	0.0																		0.1
80	ST. LEON 230-66KV TRANSFORMER ADD'N AND IPL EXPANSION	0.3	0.2	0.3	0.0	0.1	(0.6)															0.3
253	BRANDON EAST 115kV IMPROVEMENTS	0.1																				0.1
250	BRANDON CROCUS PLAINS 115-24kV BANK ADDITION		0.0	0.0	0.3	0.1	(0.0)															0.3
	DISTRIBUTION																					
86	DIESEL UPGRADING ENHANCEMENT	(0.9)	0.6	4.2	(3.5)																	0.4
221	VIRDEN AREA DISTRIBUTION CHANGES	0.9	(0.0)	0.1	0.1	0.1	0.1															1.2
217	DEFECTIVE RINI CABLE REPLACEMENT	(0.1)	(0.1)	(0.2)	(0.2)	(0.3)																(0.8)
261	BRERETON LAKE STATION AREA STUDY		2.6	2.2	0.7	0.5	0.5	0.1														6.6
267	PAINT LAKE NEW FEEDER			1.8	(0.2)																	1.6
	COMMUNICATIONS, CONTROLS AND INFO TECHNOLOGY																					
10	EMS SCADA	1.6																				1.6
12	MICROWAVE RADIO REPLACEMENTS	3.2	0.8	(3.3)	4.7		0.1	0.6														6.0
218	LAN NETWORK EXPANSION																					
219	MAPINFO IMPLEMENTATION	(0.3)	1.5	(0.4)																		0.9

CAPITAL EXPENDITURE FORECAST REVISIONS (CEF99-1)
(IN MILLIONS OF DOLLARS)
FOR THE YEARS 1999/00 TO 2018/19

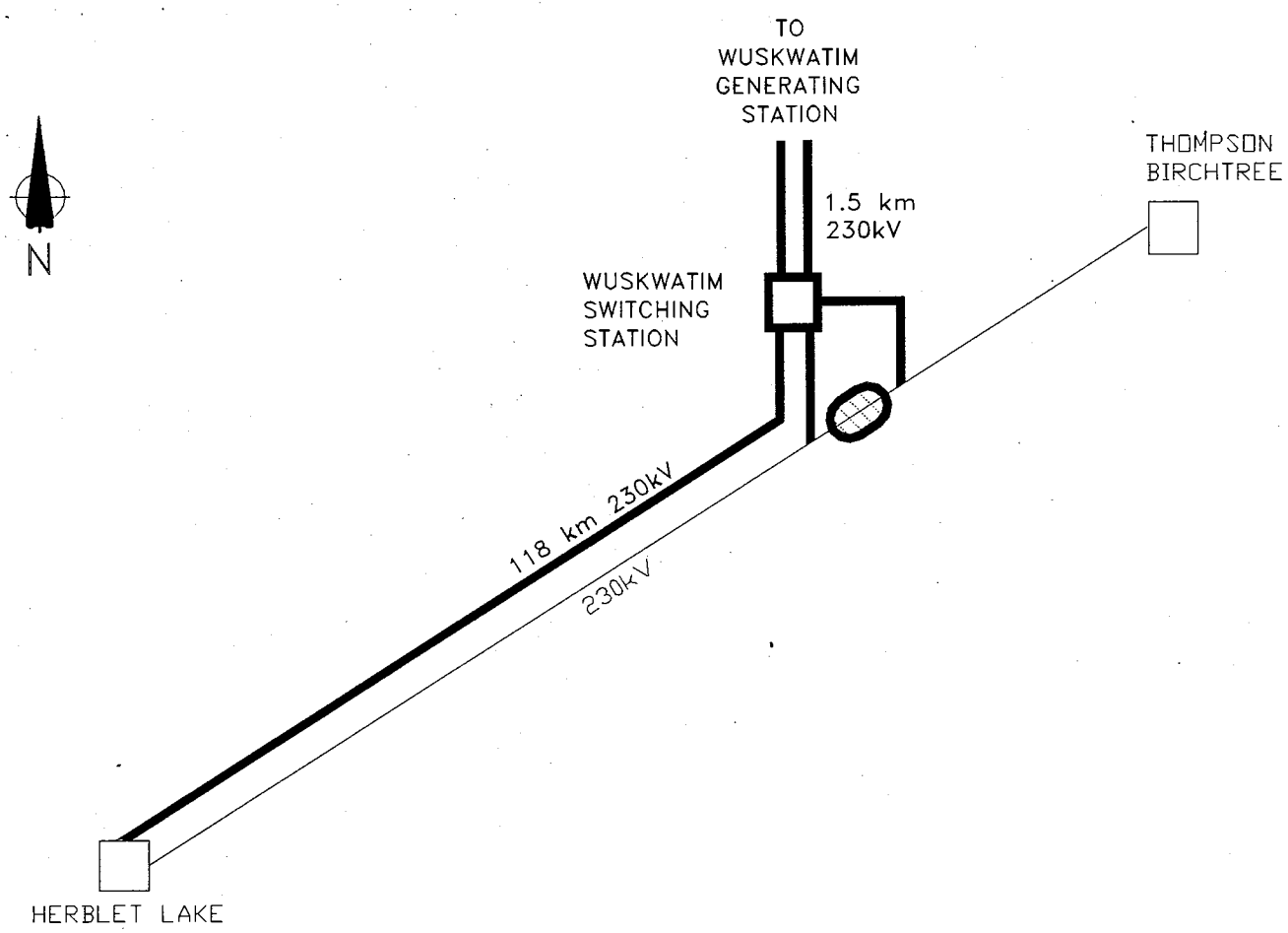
		2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	20 year Forecast
	OTHER																					1.1
2	SITE REMEDIATION	0.3	0.8	0.0	0.0																	0.5
81	OIL CONTAINMENT	0.0	0.1	0.1	0.2	0.0						1.0	2.0	3.0	4.0	5.0	6.0	7.0	8.0	9.0	10.0	55.0
92	FIRE PROTECTION PROJECTS												(0.0)						(0.0)			(9.4)
	DOMESTIC ITEMS - TRANMISSION AND DISTRIBUTION	(0.0)	(3.2)	(3.1)	(3.1)																	
	SUB-TOTAL TRANSMISSION AND DISTRIBUTION	**1.0**	**(3.0)**	**(4.5)**	**(23.9)**	**(7.8)**	**(7.8)**	**14.9**	**12.1**	**20.6**	**13.4**	**11.6**	**22.7**	**32.6**	**41.7**	**36.3**	**198.4**	**419.5**	**517.4**	**381.7**	**196.7**	**1,873.7**

CAPITAL BUDGET COMPLEX CONCEPTUAL DIAGRAM

WUSKWATIM TRANSMISSION

REVISED: 1999 - 10 - 01	ISSUED BY: WNZ

COMPLEX NO. 58



LEGEND

PROPOSED

EXISTING

SALVAGE

GRAND RAPIDS

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

COMPLEX STATUS	Complex no.	REVISION STATUS
☒ Planned ☐ In progress	58	☐ New complex ☒ In service change ☐ Concept change ☐ Estimate change only

COMPLEX	WUSKWATIM TRANSMISSION

Proposal

Perform environmental assessments and route selection, design and construct transmission and terminal facilities for Wuskwatim power transfer as follows:

Transmission: 230 KV lines 1 - 118 KM Wuskwatim - Herblet Lake, 2 - 1.5 KM Wuskwatim Switching Stn - Wuskwatim Generating Stn. Sectionalize existing Thompson Birchtree - Herblet Lake 230 KV line into Wuskwatim Switching Stn.

Terminations: Extend 230 KV facilities at Herblet Lake station. Construct 230 KV station at Wuskwatim. Communications: Microwave system.

JUSTIFICATION		Explanation
☒ Load	☐ Service	Based on the 1999 Load Forecast, generation expansion studies indicate an additional generation source is required in 2016/17 Wuskwatim is the current economic choice. Transmission and terminating facilities are necessary to connect this new power source to the Manitoba network.
☐ Safety	☐ Efficiency	
☒ Reliability	☐ Other	

Estimate Level	COMPLEX START (yyyy mm)
L2	2008 04

IN SERVICE DATES AND AMOUNTS							
2016 11	$25673	2016 12	$7596	2017 02	$25673	2017 03	$7596

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend								
Year 99/00								
00/01								
01/02								
02/03								
03/04								
04/05								
05/06								
06/07								
07/08								
08/09						792	-792	-100
09/10						881	-881	-100
10/11	799	221	46		1,066	2,085	-1,019	-49
11/12	799	241	157		1,197	2,092	-895	-43
12/13	1,765	586	344		2,695	7,249	-4,554	-63
13/14	1,478	533	584		2,595	24,156	-21,561	-89
14/15	5,116	2010	1,034		8,160	23,517	-15,357	-65
15/16	16,368	6790	2,596		25,754		25,754	
16/17	14,499	6424	4,145		25,068		25,068	
17/18								
18/19								
Beyond								
TOTAL	40,824	16,805	8,906		66,535	60,772	5,763	9

REVISION	In-service date deferred two years from 2014 to 2016.

Reviewed by	yyyy mm dd	Reviewed by	yyyy mm dd
ORIGINATOR	99 11 08	COORDINATOR	99 11 03
Reviewed by CONSTRUCTOR	yyyy mm dd 99 11 03	Approved by VICE PRESIDENT	yyyy mm dd 99 11 16

H2856/r Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Complex no. 58

Advance or deferral impact

Delay in components of this transmission complex will curtail or prevent Wuskwatim capacity from being delivered to the Manitoba system.

Factors affecting timing or viability

Timing and rating of Wuskwatim Generating Station.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Wuskwatim G.S.-Wuskwatim Switch. Stn. 230KV T/L		601	613	632	19	3
Wuskwatim - Herblet Lake 230 KV T/L		20,109	20,511	21,110	599	3
Wuskwatim Switching Stn. 230KV Terminations		8,765	8,940	9,136	196	2
Grand Rapids - Line Reactor Circuit Switchers		1,380	1,408	1,449	41	3
Herblet Lake - Terminate Wuskwatim 230 KV T/L		3,693	3,767	3,818	51	1
Communications for Wuskwatim 230 KV T/L		4,373	4,460	4,678	218	5
TOTAL		38,921	39,699	40,823	1,124	3

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
9510	57,625	Estimate increased for sectionalization of Thompson Birchtree - Herblet Lake 230 kV line at Wuskwatim and line protection changes at Herblet Lake.
9610	64,197	Wuskwatim deferred 4 years to 2015
9710	62,819	Wuskwatim deferred 1 years to 2016
9810	60,772	In-service date advanaced two years from 2016 to 2014
9910	66,535	In-service date deferred two years from 2014 to 2016.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

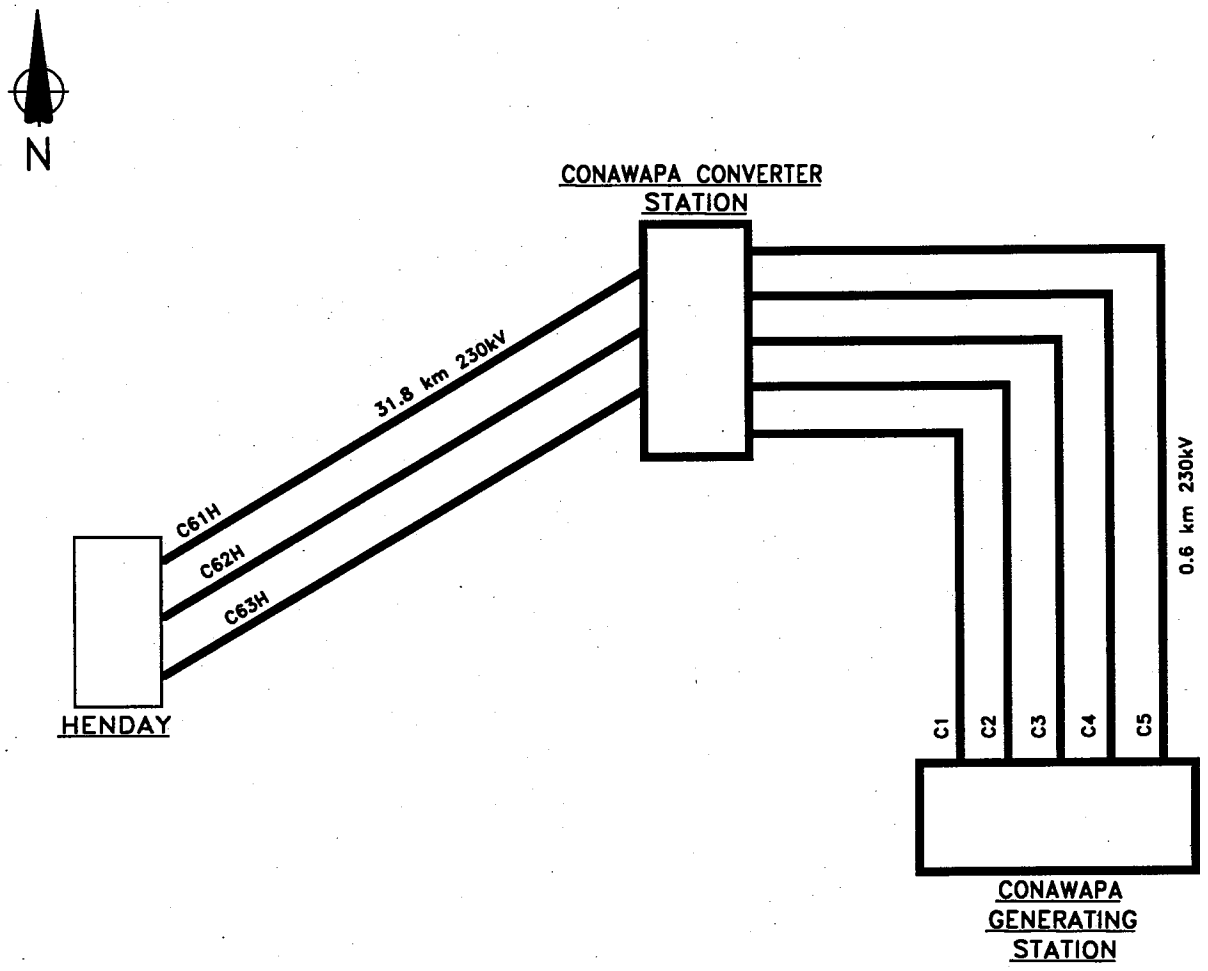
REFERENCE NUMBER	DESCRIPTION
Complex 24	Wuskwatim Generating Station

CAPITAL BUDGET COMPLEX CONCEPTUAL DIAGRAM

CONAWAPA TRANSMISSION

REVISED: 1999 - 10 - 01	ISSUED BY: RWM

COMPLEX NO. 262



manitoba hydro

PLANNING AND CONTROL DIVISION

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

43.

COMPLEX STATUS	Complex no.	REVISION STATUS
☒ Planned ☐ In progress	262	☒ New complex ☐ In service change ☐ Concept change ☐ Estimate change only

COMPLEX	CONAWAPA TRANSMISSION

Proposal

Perform environmental assesments and route selection, design and construct transmission and terminal facilities for Conawapa powe transfer as follows:
Transmission: 230kV lines 3 - 31.8 KM Henday - Conawapa Converter Station, 5 - 0.6 KM Conawapa Converter Station t Conawapa Generating Station.
Terminations: Extend 230kV facilities at Henday station. Construct new 230kV facilities at Conawapa Converter station.
Communications: Integrate with Northern Collector communication system.

JUSTIFICATION		Explanation
☒ Load	☐ Service	Based on the 1999 Load Forecast, generation expansion studies indicate an additional generatio source is required in 2018/19. Conawapa is the current economic choice. Transmission an terminating facilities are necessary to connect this new power source to the Manitoba network.
☐ Safety	☐ Efficiency	
☐ Reliability	☐ Other	

Estimate Level	COMPLEX START yyyy mm
L1	2008 04

IN SERVICE DATES AND AMOUNTS			

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend								
Year 99/00								
00/01								
01/02								
02/03								
03/04								
04/05								
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL								

REVISION	Conawapa reintroduced into the twenty year forecast. Forecast planning estimate is included in complex 263.

Reviewed by ORIGINATOR		yyyy mm dd 99 11 08	Reviewed by COORDINATOR		yyyy mm 99 11 1
Reviewed by CONSTRUCTOR		yyyy mm dd 99 11 03	Approved by VICE PRESIDENT		yyyy mm 99 11 16

H2856/r Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Complex no. 262

Advance or deferral impact

Delay in components of this transmission complex will curtail or prevent Conawapa capacity from being delivered to the Manitoba system.

Factors affecting timing or viability

Timing and rating of Conawapa Generating Station.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Conawapa GS - Conawapa Converter Stn 230kV T/L				1,058	1,058	
Henday - Conawapa Converter Stn 230kV T/L				20,438	20,438	
Henday Termination of Conawapa 230kV T/L						
Conawapa Converter Station						
Conawapa Transmission Telecontrol Facilities						
TOTAL				21,496	21,496	

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
1999 10	1,896,222	Conawapa reintroduced into the twenty year forecast. Forecast planning estimate is included in complex 263.

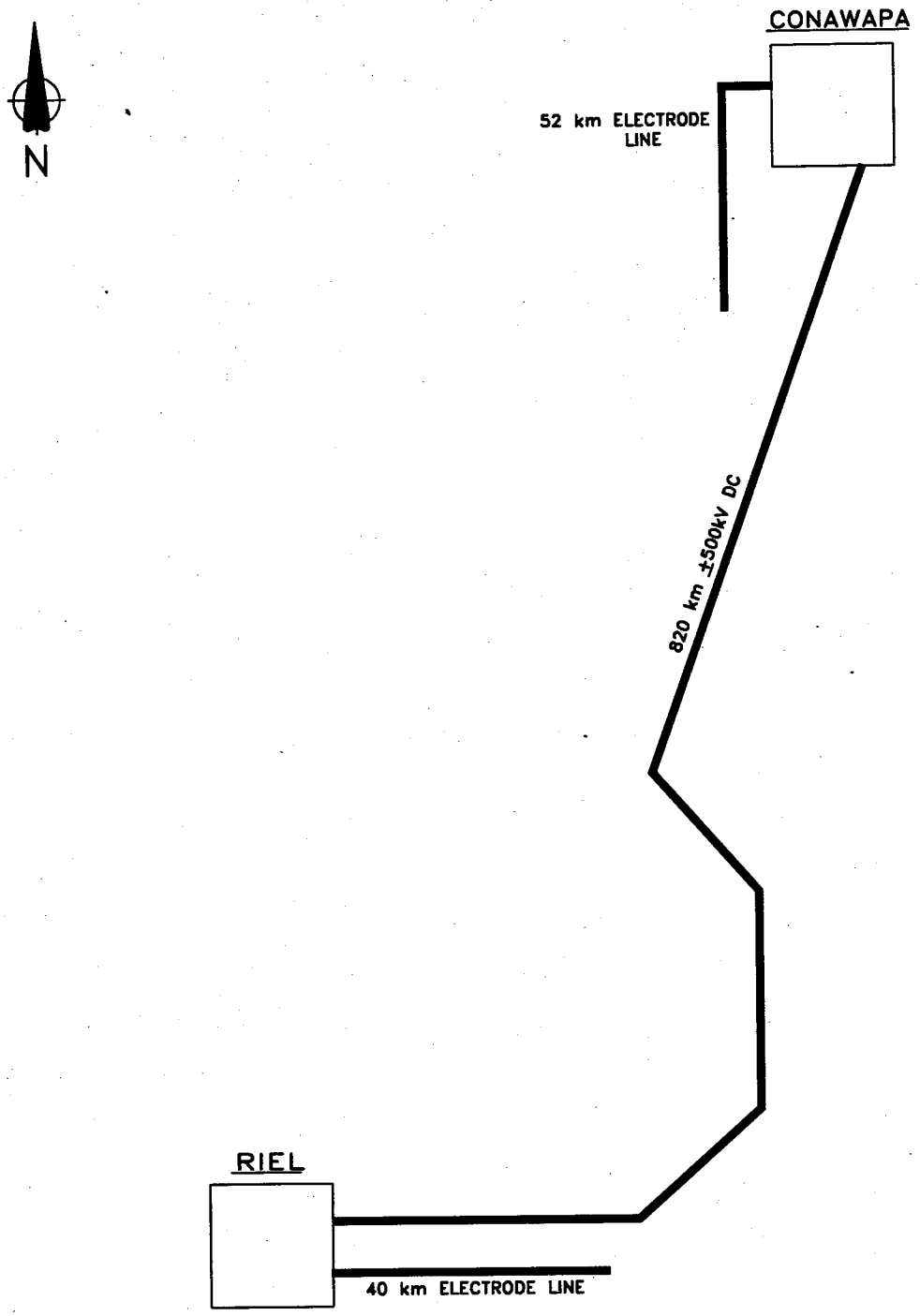
ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION
264	Conawapa Generating Station
263	HVDC Bipole 3
265	Riel > Winnipeg AC Transmission
266	Dorsey > Riel 500kV AC T/L

CAPITAL BUDGET COMPLEX CONCEPTUAL DIAGRAM

HVDC CONVERSION
BIPOLE 3

REVISED: 1999 - 10 - 01	ISSUED BY: RWM
COMPLEX NO. 263	



H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

44.

(IN THOUSANDS OF DOLLARS)

COMPLEX STATUS	Complex no.	REVISION STATUS
[X] Planned [ ] In progress	263	[X] New complex [ ] In service change [ ] Concept change [ ] Estimate change only

COMPLEX: HVDC BIPOLE 3

Proposal
Preform environmental assessments and route selection, design and construct transmission and terminal facilities to accomodate treansfer of Nelson River power to the Southern Manitoba system as follows:
Transmission: 51 KM DC Electrode line fron Conawapa Converter station to existing Electrode station. 40 KM DC electrode line from Riel to a new Electrode station.
Terminations: Construct Bipole 3 HVDC 1300 MW (with 50% overload capability) +/-500 kV stations at Conawapa and Riel. Extend 230 kV facilities at Henday station. Construct new 230kV station at Riel, including 3 - 300 MVAR Synchronous Condensers.
Communications: Fibre Optic or Microwave system.

JUSTIFICATION		Explanation
[X] Load	[ ] Service	Based on the 1999 Load Forecast, generation expansion studies indicate an additional generation source is required in 2018/19. Conawapa is the current economic choice. Bipole 3 facilities are necessary to connect this new power source to the Manitoba network.
[ ] Safety	[ ] Efficiency	
[X] Reliability	[ ] Other	

Estimate Level	COMPLEX START (yyyy mm)
L1	2008 04

IN SERVICE DATES AND AMOUNTS					
2019	$948111	2020	$758489	2021	$189622

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend								
Year 99/00								
00/01								
01/02								
02/03								
03/04								
04/05								
05/06								
06/07								
07/08								
08/09	2,480		104		2,584		2,584	
09/10	8,579		634		9,213		9,213	
10/11	13,490		1,790		15,280		15,280	
11/12	12,443		3,350		15,793		15,793	
12/13	35,379		6,116		41,495		41,495	
13/14	44,776		10,483		55,259		55,259	
14/15	193,763		22,033		215,796		215,796	
15/16	361,473		50,936		412,409		412,409	
16/17	412,938		96,409		509,347		509,347	
17/18	230,269		142,423		372,692		372,692	
18/19	55,524		131,160		186,684		186,684	
Beyond	0		59,670		59,670		59,670	
TOTAL	1,371,114		525,108		1,896,222		1,896,222	

REVISION: Bipole 3 reintroduced into the twenty year forecast.This complex captures all costs associated with Bipole 3, Conawapa transmission & related AC southern system additions.

Reviewed by ORIGINATOR	yyyy mm dd 99 11 08	Reviewed by COORDINATOR	yyyy mm dd 99 11 03
Reviewed by CONSTRUCTOR	yyyy mm dd 99 11 03	Approved by VICE-PRESIDENT	yyyy mm dd 99 11 16

H2856/r Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Complex no. 263

Advance or deferral impact

Delay in components of this transmission complex will curtail or prevent Conawapa capacity from being delivered to the Manitoba system.

Factors affecting timing or viability

Timing and rating of Conawapa Generating Station.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE	
					Amount	%
Conawapa Bipole 3 Electrode Line						
Riel Biploe 3 Electrode Line						
Conawapa - Riel +/- 500kV DC T/L						
Riel Station Bipole 3						
Conawapa Station Bipole 3						
Riel Station Var Compensation						
Bipole 3 Telecontrol Facilities						
TOTAL						

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
1999 10	1,896,222	Bipole 3 reintroduced into the twenty year forecast.This complex captures all costs associated with Bipole 3, Conawapa transmission & related AC southern system additions.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION
264	Conawapa Generating Station
262	Conawapa Transmission
265	Riel > Winnipeg Transmission
266	Dorsey > Riel 500kV AC T/L

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

45.

(IN THOUSANDS OF DOLLARS)

COMPLEX STATUS: [X] Planned [ ] In progress

Complex no. 265

REVISION STATUS: [X] New complex [ ] In service change [ ] Concept change [ ] Estimate change only

COMPLEX	RIEL - WINNIPEG AC TRANSMISSION

Proposal

Design and construct transmission and terminal facilities to accommodate transfer of power from Bipole 3 to the Southern Manitoba system as follows:
Transmission: Sectionalize 230kV St Vital Ridgeway lines and extend into Riel Station. Terminate pre-strung 230kV line from Riel to St Vital at those stations, resulting in 230kV lines from Riel to Ridgeway and 230kV lines from Riel to St Vital.
Terminations: Extend 230kV facilities at Riel and St Vital stations.
Communications: Intergrate with Riel - St Vital - Ridgeway area system.

JUSTIFICATION

[X] Load [ ] Service
[ ] Safety [ ] Efficiency
[X] Reliability [ ] Other

Explanation

These facilities connect HVDC Bipole 3 to the Manitoba 230kV network in the Winnipeg area. They provide flexibility of power supply to Winnipeg from Bipole 3 during normal conditions and contingencies.

Estimate Level	COMPLEX START yyyy mm

IN SERVICE DATES AND AMOUNTS			

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend								
Year 99/00								
00/01								
01/02								
02/03								
03/04								
04/05								
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL								

REVISION	Riel - Winnipeg AC Transmission reintroduced into the twenty year forecast. Forecast planning estimate is included in complex 263.

Reviewed by ORIGINATOR	yyyy 99	mm 11	dd 08	Reviewed by COORDINATOR	yyyy 99 / mm 11 / dd 03
Reviewed by CONSTRUCTOR	yyyy 99	mm 11	dd 03	Approved by	yyyy 99 / mm 11 / dd 16

H2856/r Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Complex no. 265

Advance or deferral impact

This transmission is required to connect HVDC Bipole 3 230kV AC facilities at Riel station to the Manitoba southern system. Delays of these facilities will prevent power from Bipole being delivered to the southern Manitoba system.

Factors affecting timing or viability

Change in HVDC Bipole 3
Manitoba Load

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE	
					Amount	%
Riel-St Vital & Riel-Ridgeway 230kV T/L						
St Vital 230kV Line Termination & Protection Changes						
Ridgeway Protection Changes						
Riel 230kV Stn-Term. of St Vital & Ridgeway Lines						
Riel-St Vital-Ridgeway 230kV Telecontrol						
TOTAL						

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
1999 10		Riel - Winnipeg AC Transmission reintroduced into the twenty year forecast. Forecast planning estimate is included in complex 263.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

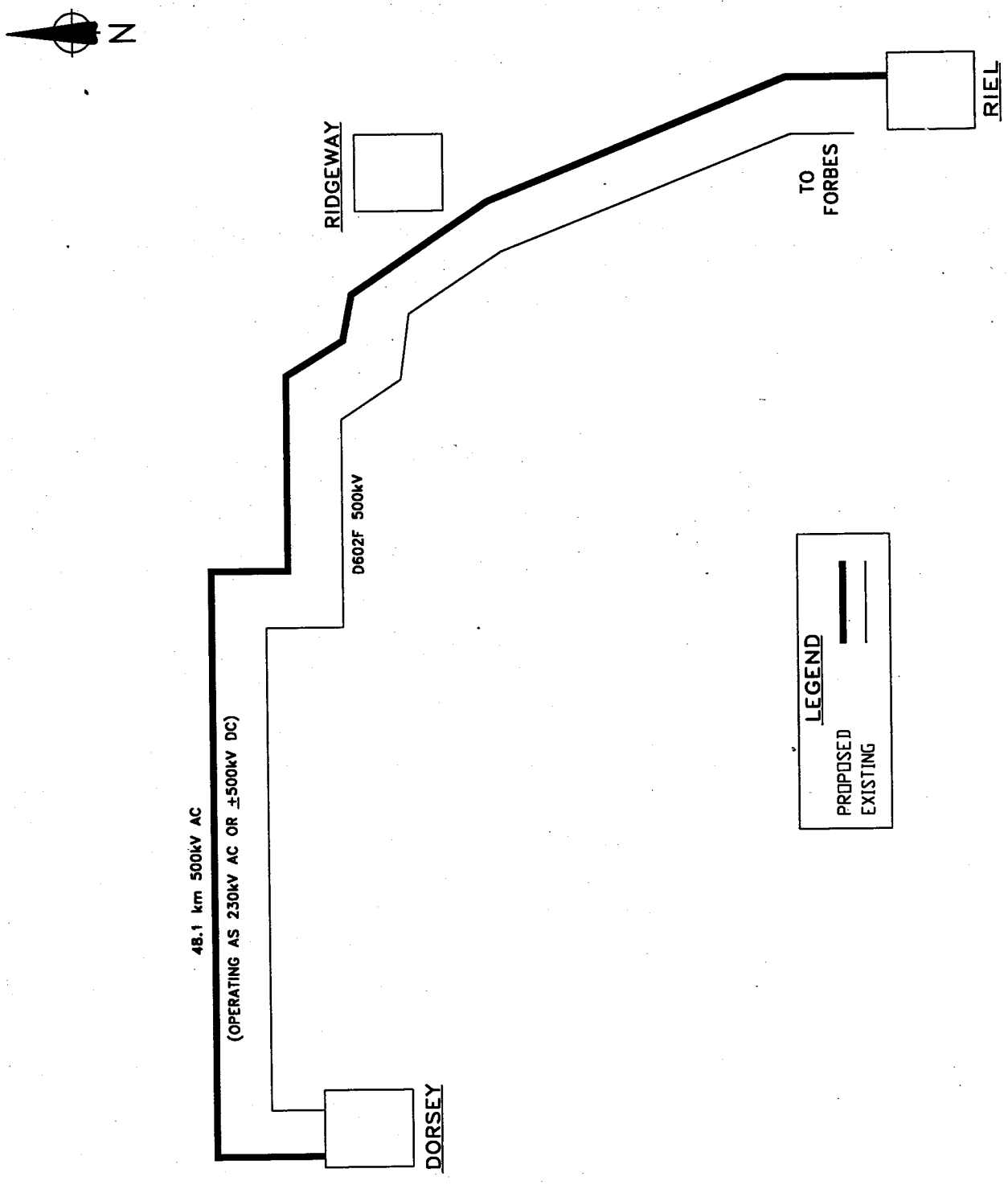
REFERENCE NUMBER	DESCRIPTION
264	Conawapa Generating Station
262	Conawapa Transmission
263	HVDC Biploe 3
266	Dorsey > Riel 500kV AC T/L

CAPITAL BUDGET COMPLEX CONCEPTUAL DIAGRAM

DORSEY–RIEL 500kV AC TRANSMISSION

REVISED: 1999 - 10 - 01	ISSUED BY: RWM

COMPLEX NO. 266



manitoba hydro

PLANNING AND CONTROL DIVISION

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

46.

COMPLEX STATUS: [X] Planned [ ] In progress

Complex no. 266

REVISION STATUS: [X] New complex [ ] In service change [ ] Concept change [ ] Estimate change only

COMPLEX	DORSEY - RIEL 500kV AC T/L

Proposal

Design and construct transmission and terminal facilities to firm up supply to stations in east Winnipeg, and provide for paralleling of Dorsey and Riel HVDC convertors during emergencies in the future as follows:

Transmission: 500kV line (initially operated at 230kV) 48.1 KM Dorsey - Riel.
Terminations: 230kV circuit breakers at Dorsey and Riel stations. 500kV DC high speed switches at Dorsey and Riel Station. The switches will allow connection of the Dorsey - Riel line to Bipoles 2 and 3 to perform parallel operation of the bipoles.
Communications: Intergrated with existing facilities at Dorsey and Riel.

JUSTIFICATION

[X] Load [ ] Service
[ ] Safety [ ] Efficiency
[X] Reliability [ ] Other

Explanation

This line will initially operate at 230kV to supply to east Winnieg stations from Dorsey via Riel station. The 500kV switches on the Dorsey - Riel 500kV AC line will permit parallel operation of Bipoles 2 and 3 under emergency conditions involving loss of any HVDC line from the north, increasing system reliability.

Estimate Level	COMPLEX START yyyy mm

IN SERVICE DATES AND AMOUNTS			

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend								
Year 99/00								
00/01								
01/02								
02/03								
03/04								
04/05								
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL								

REVISION	Dorsey - Riel 500kV AC Transmission reintroduced into the twenty year forecast. Forecast planning estimate is included in complex 263.

Reviewed by ORIGINATOR		yyyy 99	mm 11	dd 08	Reviewed by COORDINATOR	yyyy 99	mm 11 dd 03
Reviewed by CONSTRUCTOR		yyyy 99	mm 11	dd 03	Approved by VICE PRESIDENT	yyyy 99	mm 11 dd 16

H2856/r Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Complex no. 266

Advance or deferral impact

This transmission is required for supply to stations in east Winnipeg, and for HVDC paralleling. Deferrel will result in overloads or curtailment of load during outages of Winnipeg area AC lines, and reduce HVDC operating reliability.

Factors affecting timing or viability

Manitoba Load.
HVDC Bipole3

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Dorsey - Riel 500kV T/L						
Dorsey - AC Termination of 500kV line from Riel						
Riel - AC Termination of 500kV line from Dorsey						
Dorsey - DC Termination of 500kV line from Riel						
Riel - DC Termination of 500kV line from Dorsey						
Dorsey - Riel 500kV Telecontrol						
TOTAL						

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
1999 10		Dorsey - Riel 500kV AC Transmission reintroduced into the twenty year forecast. Forecast planning estimate is included in complex 263.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION
264	Conawapa Generating Station
262	Conawapa Transmission
263	HVDC Bipole 3
265	Riel > Winnipeg AC Transmission

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Complex no. 95

COMPLEX STATUS: ☐ Planned ☒ In progress

REVISION STATUS: ☐ New complex ☐ In service change ☒ Concept change ☐ Estimate change only

COMPLEX: 200 MW ONTARIO HYDRO SALE - TRANSMISSION UPGRADE

Proposal

Design and construct terminal facilities to accommodate 200 MW Ontario Hydro Sale as follows:

Transmission: Investigate current carrying capacity of sections of 115 KV lines GT1 & ST2 extending from Great Falls to Seven Sisters. Refurbish lines as required to support high load currents.
Terminations: Reconductor line end spans of parallel double circuit 115 KV line WT34 at Whiteshell and Transcona stations to accommodate increased line current.
Stations: Replace bank 8 115kV phase shifting transformer at Whiteshell station and make site improvements to upgrade drainage and oil containment for bank 7 & 8.

JUSTIFICATION: ☐ Load ☐ Service ☐ Safety ☐ Efficiency ☐ Reliability ☒ Other

Explanation

Line GT1 & ST2 refurbishment and line WT34 end span reconductoring permit high current loading of supply lines into Seven Sisters to maintain Ontario export during low Winnipeg River generation and line outages. A new phase-shifting transformer is required to ensure maximum benefits during the 200 MW Ontario Hydro sale.

Estimate Level	COMPLEX START (yyyy mm)
L2-3	1995 05

IN SERVICE DATES AND AMOUNTS

1998 09	$3803	1998 10	$170	1998 11	$35	1998 12	($240)
1999 01	$12	1999 02	$13	1999 03	$159	1999 04	$103
1999 06	$477	1999 09	$2901				

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	6,291		378	2,214	4,455	4,471	-16	-0
Year 99/00	720	18	25		763		763	
00/01								
01/02								
02/03								
03/04								
04/05								
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	7,011	18	403	2,214	5,218	4,471	747	17

REVISION: Reflects increased costs due to mild winter and high water table, and higher complexity of phase shifter control replacement.

Reviewed by ORIGINATOR	yyyy mm dd 99 11 08	Reviewed by COORDINATOR	yyyy mm dd 99 11 03
Reviewed by CONSTRUCTOR	yyyy mm dd 99 11 03	Approved by VICE PRESIDENT	yyyy mm dd 99 11 16

H2856/r Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Complex no. 95

Advance or deferral impact

The proposed modifications are required to accommodate the 200 MW firm power sale to Ontario Hydro starting in 1998. Deferral would prevent delivery of contracted capacity during contingencies.

Factors affecting timing or viability

200 MW Ontario Sale Agreement.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Whiteshell>Transcona 110KV Reconductor WT34 Ends	104	77	79	104	25	32
Winnipeg River & Winnipeg 110KV T/L Refurbishmnt	465	459	468	422	-46	-10
Whiteshell Replace Bk 8 115kV Phase Shifting Transf	5,883	5,805	5,921	6,485	564	10
TOTAL	6,452	6,341	6,468	7,011	543	8

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
9510	2,662	Line refurbishment costs based on re-sagging conductors. Line refurbishment advanced 19 months and generator mods advanced 1 yr to co-ordinate with other work schedules.
9610	682	110 KV T/L refurbishment deferred 6 months to 1997 09 30. Cost est. decreases due to detailed field survey. Gen. synch. condenser conversion transferred to complex # 224.
9710	4,052	Replace bank 8 115kV phase shifting transformer at Whiteshell station and make site improvements to upgrade drainage and oil containment for bank 7 & 8.
9810	4,471	Reflects 97/98 underexpend 0.5M, add'n of a phase shift'g transf, fibre optics, spare bushings, overload studies, more complex control work, inc const costs , + updated estimate bases.
1999 10	5,218	Reflects increased costs due to mild winter and high water table, and higher complexity of phase shifter control replacement.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

48.

COMPLEX STATUS: [X] Planned [ ] In progress

Complex no. 268

REVISION STATUS: [X] New complex [ ] In service change [ ] Concept change [ ] Estimate change only

COMPLEX: GLENBORO > HARVEY 230kV T/L

Proposal
Preform environmental assessment and route selection, design and construct transmission and terminal facilities for Harvey-Glenboro interconnection power transfer as follows:
Transmission: New 230kV line of 95 KM Glenboro > Harvey(border crossing)
Terminations: Extend 230kV facilities at Glenboro station.
Comminication: Intergrate with Glenboro area system.

JUSTIFICATION: [ ] Load [ ] Service [ ] Safety [ ] Efficiency [X] Reliability [X] Other

Explanation
A new interconnection is required for enhancement of import capability of 500 MW under the diversity agreement.

Estimate Level	COMPLEX START (yyyy mm)
L2	2000 04

IN SERVICE DATES AND AMOUNTS			
2002 10	$15980		

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend								
Year 99/00								
00/01	1,483	25	60		1,568		1,568	
01/02	5,815	211	364		6,390		6,390	
02/03	7,117	399	506		8,022		8,022	
03/04								
04/05								
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	14,415	635	930		15,980		15,980	

REVISION: New Complex

Reviewed by ORIGINATOR	yyyy mm dd 99 11 08	Reviewed by COORDINATOR	yyyy mm dd 99 11 03
Reviewed by CONSTRUCTOR	yyyy mm dd 99 11 03	Approved by VICE-PRESIDENT	yyyy mm dd 99 11 16

H2856/r Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Complex no. 268

Advance or deferral impact

Factors affecting timing or viability

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Glenboro > Harvey 230kV T/L				14,415	14,415	
TOTAL				14,415	14,415	

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
1999 10	15,980	New Complex

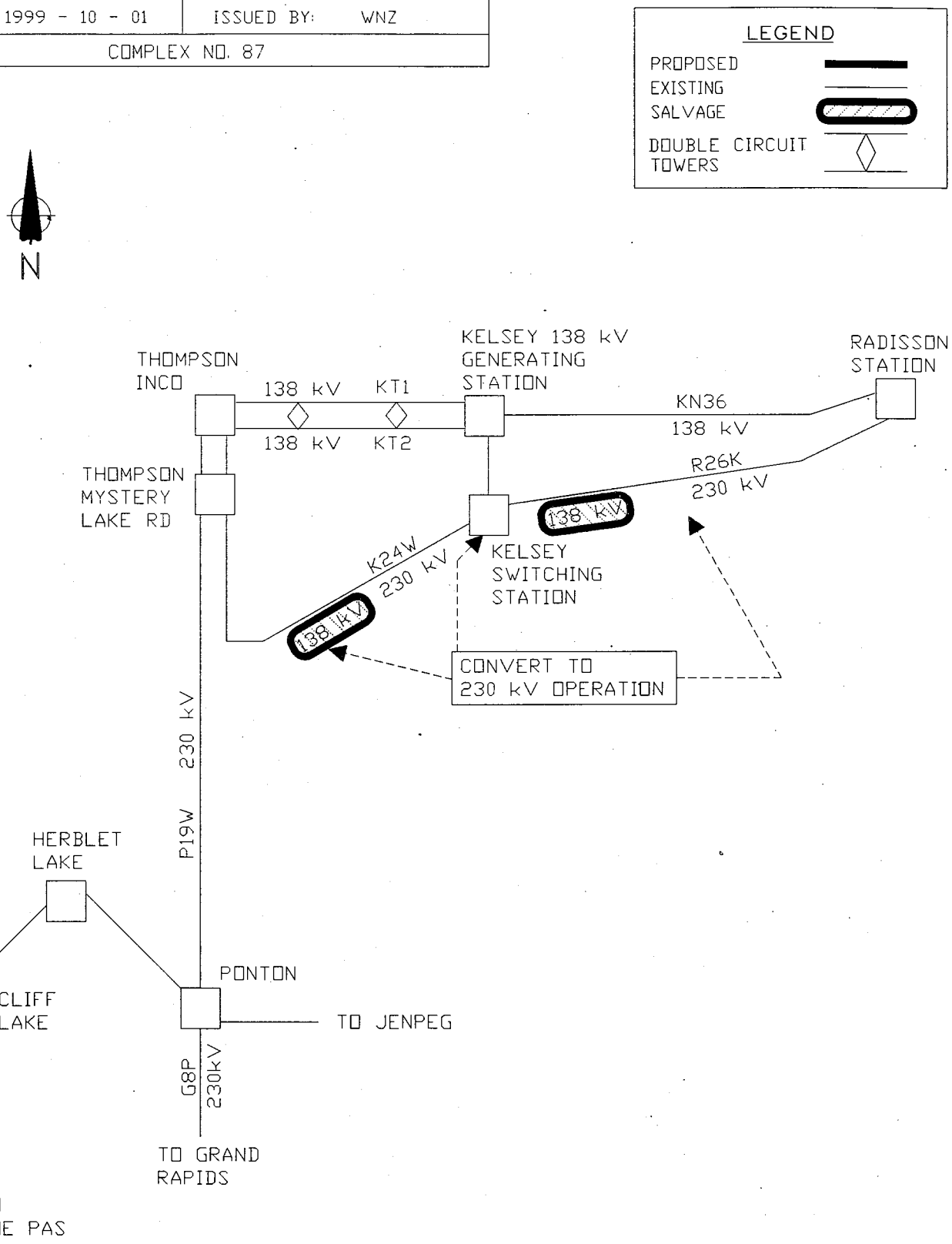
ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

CAPITAL BUDGET COMPLEX CONCEPTUAL DIAGRAM

KETTLE AC TRANSMISSION IMPROVEMENTS

REVISED: 1999 - 10 - 01	ISSUED BY: WNZ
COMPLEX NO. 87	



H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

COMPLEX STATUS: ☐ Planned ☒ In progress

Complex no. 87

REVISION STATUS: ☐ New complex ☒ In service change ☐ Concept change ☐ Estimate change only

COMPLEX: KETTLE AC TRANSMISSION IMPROVEMENTS

Proposal

Design and reconnect AC transmission facilities in Northern AC system to enhance transmission system reliability as follows:

Transmission & Terminations: Convert Radisson-Kelsey line R26K & Kelsey-Thompson line K24W and associated station facilities at Thompson Mystery Lake Road, Kelsey, and Radisson to 230 KV operation. Install new 230KV circuit breaker at Thompson Mystery Lake Road. Install 230-138 KV 250 MVA transformer at Kelsey.

JUSTIFICATION

☐ Load ☐ Service
☐ Safety ☐ Efficiency
☒ Reliability ☐ Other

Explanation

The addition of Limestone has loaded the HVDC system to capacity. With Bipole 3 deferred, transmission system capacity and reliability margins for firm export sales can be partially restored economically by providing facilities to off-load 2 Kettle units from the DC system to the AC system if required.

Estimate Level	COMPLEX START (yyyy mm)
L3	1995 04

IN SERVICE DATES AND AMOUNTS

2003 09	$1387	2004 09	$4679	2004 10	$5583

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	822		211		1,033	1,169	-136	-12
Year 99/00	-1		90		89	1,570	-1,481	-94
00/01	-49	1	95		47	2,400	-2,353	-98
01/02	71	5	104		180	2,437	-2,257	-93
02/03	775	73	153		1,001	2,766	-1,765	-64
03/04	3,623	421	290	55	4,279		4,279	
04/05	4,111	535	317	6	4,957		4,957	
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	9,352	1,035	1,260	61	11,586	10,342	1,244	12

REVISION: Transmission, termination and communication items deferred three years and Kelsey transformer deferred two years to 2004 due to capital constraint reasons.

Reviewed by ORIGINATOR	yyyy mm dd 99 11 08	Reviewed by COORDINATOR	yyyy mm dd 99 11 03
Reviewed by CONSTRUCTOR	yyyy mm dd 99 11 03	Approved by VICE-PRESIDENT	yyyy mm dd 99 11 14

H2856/r Rev 99 03

Complex no. 87

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Advance or deferral impact

Deferral of these facilities would result in inadequate reliability of the transmission system to support system firm loads and exports and could result in lower extra-provincial revenues.

Factors affecting timing or viability

System load growth forecasts.
Timely completion of Herblet Lake - Flin Flon Cliff Lake 230 KV Transmission to permit Kettle AC power transfer.
Completion of studies to confirm Kettle AC operation protection and control requirements.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Radisson Convert R26K to 230KV & Reterm. K4/K5	1,173	1,269	1,294	1,304	10	1
Kelsey Stn Convert T/L K24W & R26K to 230 KV	575	655	668	687	19	3
Thompson MLR Convert T/L K24W to 230 KV Oprtn.	957	1,238	1,263	1,269	6	0
Ponton, Herblet Lk. & Cliff Lk>Ket AC Prtcn Chng	477	560	571	594	23	4
Kelsey Install 230-138 KV Transformer	3,753	3,952	4,031	4,041	10	0
Telecommunications for Kettle AC Operation	1,025	1,199	1,223	1,457	234	19
TOTAL	7,960	8,873	9,050	9,352	302	3

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
1995 10	69,154	Equip cost increases. Breaker relocation, protection and telecom facil added. Valve cooling removed. Kettle AC facil defer'd, Dorsey cooling, reactors, & transf defer'd.
1996 10	9,085	HVDC spares, Radisson SST1 relocation transferred to complex 223. Kelsey trnsfmr added from Notigi Transmission complex. Communict'n cost incr. ISD defer 2 yr to 1999
1997 10	10,014	Ponton Herblet & Cliff Lake Kettle protection changes, Retermination of K4/K5, and Telecommunication deferred 1 year to 2000.
1998 10	10,342	Reflects 97/98 underexpenditure 0.8M. Transmission, termination and communication items deferred one year. Kelsey transformer deferred two years.
1999 10	11,586	Transmission, termination and communication items deferred three years and Kelsey transformer deferred two years to 2004 due to capital constraint reasons.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION
Complex 30	Thompson - Herblet Lake 230 KV Transmission

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

50.

COMPLEX STATUS	Complex no.	REVISION STATUS
☒ Planned ☐ In progress	30	☐ New complex ☒ In service change ☐ Concept change ☐ Estimate change only

COMPLEX	THOMPSON - HERBLET LAKE 230 KV TRANSMISSION

Proposal

Perform environmental assessments and route selection, design and construct transmission and terminal facilities to transmit power of up to 3 Kettle units to the Southern AC System as follows;
Transmission: 230 KV line 166km Thompson Birchtree - Herblet Lake. Sectionalize 230 KV line K24W into Thompson Birchtree station.
Terminations: Establish station at Thompson Birchtree, line termination at Herblet Lake, and modify line protection at Kelsey and Thompson Mystery Lake Road associated with line K24W.
Communications: Protection for Kelsey - Thompson - Herblet Lake T/Ls.

JUSTIFICATION	Explanation
☐ Load ☐ Service ☐ Safety ☐ Efficiency ☒ Reliability ☐ Other	Construction of the Thompson Birchtree - Herblet Lake 230 KV line and sectionalization of the Kelsey - Thompson Mystery Lake Road 230 KV line K24W into Thompson Birchtree station are required to transmit up to three units of Kettle generation to Southern Manitoba on the AC system under winter conditions for system reliability enhancement.

Estimate Level	COMPLEX START (yyyy mm)
L2	2000 04

IN SERVICE DATES AND AMOUNTS			
2007 10	$57148		

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend								
Year 99/00						246	-246	-100
00/01						274	-274	-100
01/02	213	14	12		239	405	-166	-41
02/03	186	16	33		235	429	-194	-45
03/04	641	72	76		789	5,127	-4,338	-85
04/05	4,534	618	285		5,437	21,011	-15,574	-74
05/06	17,256	2690	1,594		21,540	13,520	8,020	59
06/07	9,311	1724	3,019		14,054	14,272	-218	-2
07/08	10,958	1504	2,392		14,854		14,854	
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	43,099	6,638	7,411		57,148	55,284	1,864	3

REVISION	Deferred one year 2007 due to capital constraint reasons.

Reviewed by ORIGINATOR	yyyy mm dd 99 11 08	Reviewed by COORDINATOR	yyyy mm dd 99 11 03
Reviewed by CONSTRUCTOR	yyyy mm dd 99 11 03	Approved by VICE PRESIDENT	yyyy mm dd 99 11 14

H2856/r Rev 99 03

Complex no. 30

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Advance or deferral impact

Deferral of these facilities will limit the number of Kettle units that can be transferred to the northern AC system during DC contingency or maintenance outages and thereby reduce system reliability.

Factors affecting timing or viability

Environmental Licencing.
System load growth forecasts.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Thompson Birchtree-Herblet Lake 230KV T/L		28,663	29,236	28,764	-472	-2
Thompson Birchtree - Establish Station		7,812	7,968	8,130	162	2
Herblet Lake-Terminate Thmpsn Birchtree 230KV T/L		3,539	3,610	3,651	41	1
Thompson Mystry Lk-Prtctn. Chng for Birchtree T/L		216	220	236	16	7
Kelsey-Prtctn. Chng for Thmpsn Brchtree 230KV T/L		216	220	236	16	7
Communications for Thompson Birchtree 230KV T/L		1,859	1,996	2,081	85	4
TOTAL		42,305	43,250	43,098	-152	-0

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
9510	54,500	Reflects cost increases for line K24W sectionalization, protection modifications at line K24W termination stations, and added Thompson Birchtree station equipment.
9610	54,425	Revised escalation and interest rates. Complex name changed.
1997 10	54,174	Scope unchanged, estimate reflects revised costing methodology implemented with the new financial reporting system. Also reflects revised interest and escalation rates.
1998 10	55,284	Scope unchanged.
1999 10	57,148	Deferred one year to 2007 due to capital constraint reasons.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

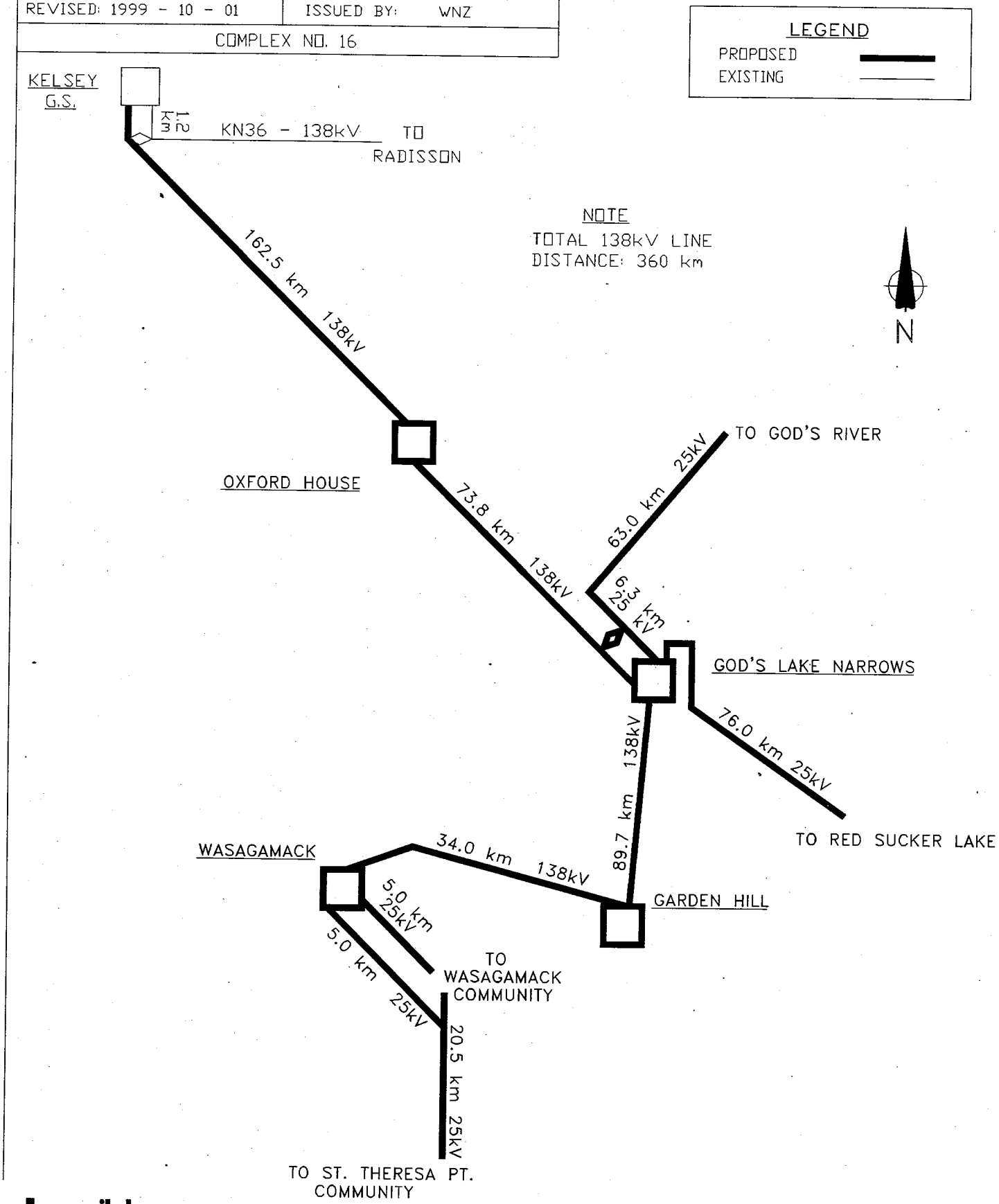
REFERENCE NUMBER	DESCRIPTION
Complex 87	Kettle AC Transmission Improvements
Complex 63	Henday and Radisson Spare Converter Transformers

CAPITAL BUDGET COMPLEX CONCEPTUAL DIAGRAM

NORTH CENTRAL MANITOBA TRANSMISSION

REVISED: 1999 - 10 - 01 | ISSUED BY: WNZ

COMPLEX NO. 16



manitoba hydro

PLANNING AND CONTROL DIVISION

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

51.

COMPLEX STATUS	Complex no.	REVISION STATUS
☐ Planned ☒ In progress	16	☐ New complex ☐ In service change ☐ Concept change ☒ Estimate change only

COMPLEX	NORTH CENTRAL MANITOBA PROJECT

Proposal

Perform environmental assessments and route selection, design and construct transmission and terminal facilities for central supply to Island Lake communities from Kelsey as follows:
Transmission: 138 KV line 360 KM Kelsey - Oxford House - God's Lake Narrows - Garden Hill - Wasagamack. 25 KV feeder lines 63.0 KM God's Lake Narrows - God's River, 76.0 KM God's Lake Narrows - Red Sucker Lake, 30.5 KM of single/double circuit between Wasagamack station and Wasagamack & St. Theresa communities.
Terminations: Extend 138 KV facilities at Kelsey. Construct 138-25 KV distribution stations and required feeders at Oxford House, God's Lake Narrows, Garden Hill, and Wasagamack. Communications: VHF Mobile coverage using VHF repeaters. Supervisory control at Oxford House, God's Lake Narrows and Garden Hill.

JUSTIFICATION		Explanation
☒ Load	☒ Service	The 138 KV line and associated distribution facilities will provide central supply to seven Island Lake communities, as per agreement between Manitoba Hydro, the aboriginal communities, the Manitoba Provincial government, and the Federal Government.
☐ Safety	☐ Efficiency	
☒ Reliability	☐ Other	

Estimate Level	COMPLEX START (yyyy mm)
L3	1990 01

IN SERVICE DATES AND AMOUNTS							
1997 10	$85381	1998 04	$19916	1998 09	$400	1999 03	$40652
1999 04	$9936	1999 05	$8544	1999 07	$182	1999 12	$2753
2000 02	$753	2000 11	$210	2000 12	$1511	2001 12	$2742

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	147,420		18,826	149,616	16,630	16,649	-19	-0
Year 99/00	5,454	145	205	5,763	41	784	-743	-95
00/01	1,710	97	52	1,511	348	334	14	4
01/02	2,439	190	84	2,275	438	518	-80	-15
02/03	10			10	0	1	-1	-100
03/04								
04/05								
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	157,033	432	19,167	159,175	17,457	18,286	-829	-5

REVISION	Relects actual costs to completion.

Reviewed by ORIGINATOR	yyyy mm dd 99 11 08	Reviewed by COORDINATOR	yyyy mm dd 99 11 03
Reviewed by CONSTRUCTOR	yyyy mm dd 99 11 10 3	Approved by VICE PRESIDENT	yyyy mm dd 99 11 16

H2856/r Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Complex no. 16

Advance or deferral impact

Delays in this project will extend the duration of limited supply of electricity to affected communities from diesel generation.

Factors affecting timing or viability

Environmental Licensing.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
North Central MB T/L ROW, Site Sel & Env Approval	1,542	6,243	6,368	7,107	739	12
North Central Manitoba 138 KV T/L	36,753	68,372	69,739	66,972	-2,767	-4
North Central Manitoba Community Involvement	1,252	5,088	5,190	5,054	-136	-3
Kelsey-Terminate 138 KV Line to Oxford House	2,114	1,558	1,589	1,559	-30	-2
Oxford House New 138-25 KV Station	3,476	8,335	8,502	8,379	-123	-1
God's Lake Narrows New 138-25 KV Station	6,481	9,058	9,239	9,048	-191	-2
Garden Hill New 138-25 KV Station	3,493	10,586	10,798	10,998	200	2
Wasagamack New 138-25 KV Station	3,289	7,479	7,629	7,153	-476	-6
Oxford House Community Central Supp (completed)	434	2,042	2,042	2,042	0	0
Gods River Community Central Supp (completed)	2,871	5,543	5,570	5,570	0	0
Red Sucker Lake Community - Central Supply	3,628	8,421	8,589	8,568	-21	-0
Island Lake Communities - Central Supply	1,292	8,777	8,953	9,445	492	5
God's Lake Narrows Community - Central Supply	575	1,793	1,829	1,770	-59	-3
Salvage of Diesel Sites-North Central Project	1,050	1,593	1,625	1,646	21	1
Soil Remediation of Diesel Sites-North Centrl Proj	8,176	7,955	8,114	8,066	-48	-1
North Central VHF Communications (completed)	430	365	365	365	0	0
St Theresa > Wasagamack Tie Feeder (completed)	3,291	3,291	3,291	3,291	0	0
TOTAL	80,147	156,499	159,432	157,033	-2,399	-2

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
9510	34,461	Design now replaces 15.1 km of river crossing line with steel towers. Stn site areas increased and costs for line & stn materials. Diesel site soil remediation added.
9610	19,582	Communctns advanced to 95 10 31. Cost incrs for site imprvmnts, oil spill containmnt, materials,overhead. Net cost reduced to reflect Provincial contribution.
1997 10	18,127	16 km dbl-cct line north of GLN changed to 6.3 km. RS feeder layout changed. ISD of OH-GLN 138 kV line & service to GLN & GR advanced 10 months to 97 09 30.
1998 10	18,286	ISD of line, Garden Hill station, and Wasagamack station deferred approx. 10 months due to poor winter road conditions.
1999 10	17,457	Reflects actual costs to completion.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

52.

COMPLEX STATUS	Complex no.	REVISION STATUS
☐ Planned ☒ In progress	40	☐ New complex ☒ In service change ☐ Concept change ☐ Estimate change only

COMPLEX	FLIN FLON CLIFF LAKE TRANSFORMER REPLACEMENT

Proposal

Replace one 230 KV breaker at The Pas Ralls Island.

Replace Flin Flon Cliff Lake 125 MVA Transformer Bank No. 1 with 230-115-13.8 KV 120/160/200 MVA autotransformer.

JUSTIFICATION

☒ Load ☐ Service
☐ Safety ☐ Efficiency
☒ Reliability ☐ Other

Explanation

The new transformer will match the rating of the existing bank no. 2 and will provide firm capacity for Flin Flon area loads. The Pas 230KV replacement breaker is required for switching of Flin Flon Cliff Lake tertiary capacitors by line P58C breakers at The Pas.

Estimate Level	COMPLEX START (yyyy mm)
L3	1993 11

IN SERVICE DATES AND AMOUNTS

1997 07	$510	1997 09	$13	1997 10	$45	1998 05	$28
1999 02	$12	1999 12	$101	2000 10	$4582		

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	2,858		274	29	3,103	3,825	-722	-19
Year 99/00	368	2	229		599	295	304	103
00/01	1,342	33	186	690	871		871	
01/02								
02/03								
03/04								
04/05								
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	4,568	35	689	719	4,573	4,120	453	11

REVISION	ISD of Cliff Lake transformer deferred one year to 2000 10 31 to address single contingency outages during bank replacement.

Reviewed by ORIGINATOR	yyyy mm dd 99 11 08	Reviewed by COORDINATOR	yyyy mm dd 99 11 03
Reviewed by CONSTRUCTOR	yyyy mm dd 99 11 03	Approved by VICE PRESIDENT	yyyy mm dd 99 11 16

H2856/r Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Complex no. 40

Advance or deferral impact

Deferral of the transformer will force curtailment of Flin Flon area town and HBM&S loads during outages of transformer bank no. 2. Deferral of the breaker replacement will require continued dependance on back-up protection systems to protect an existing breaker at The Pas from capacitive load interruption damage.

Factors affecting timing or viability

Flin Flon area load growth.
Sask Power requirement for Island Falls generation on the Sask Power northern system.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Flin Flon Cliff Lk.-Replace 230-115KV Trnsfmr No1	2,672	3,735	3,810	3,932	122	3
The Pas Ralls Island - Replace 230KV Breaker	476	634	647	636	-11	-2
TOTAL	3,148	4,369	4,457	4,568	111	2

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
9510	3,506	Reflects transformer price increases.
9610	2,679	The Pas 230KV breaker replacement transferred from Flin Flon-Cliff Lake Transformer Addition complex.Transformer cost estimate decreased based on latest costs.
1997 10	2,630	Scope unchanged, estimate reflects revised costing methodology implemented with the new financial reporting system. Also reflects revised interest and escalation rates.
1998 10	4,120	Reflects FP&P addition, increased engineering and const costs to fit larger transformer. ISD of Cliff Lake transformer deferred one year to 1999 10 31 due to damage during shipping.
1999 10	4,573	ISD of Cliff Lake transformer deferred one year to 2000 10 31 to address single contingency outages during bank replacement.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

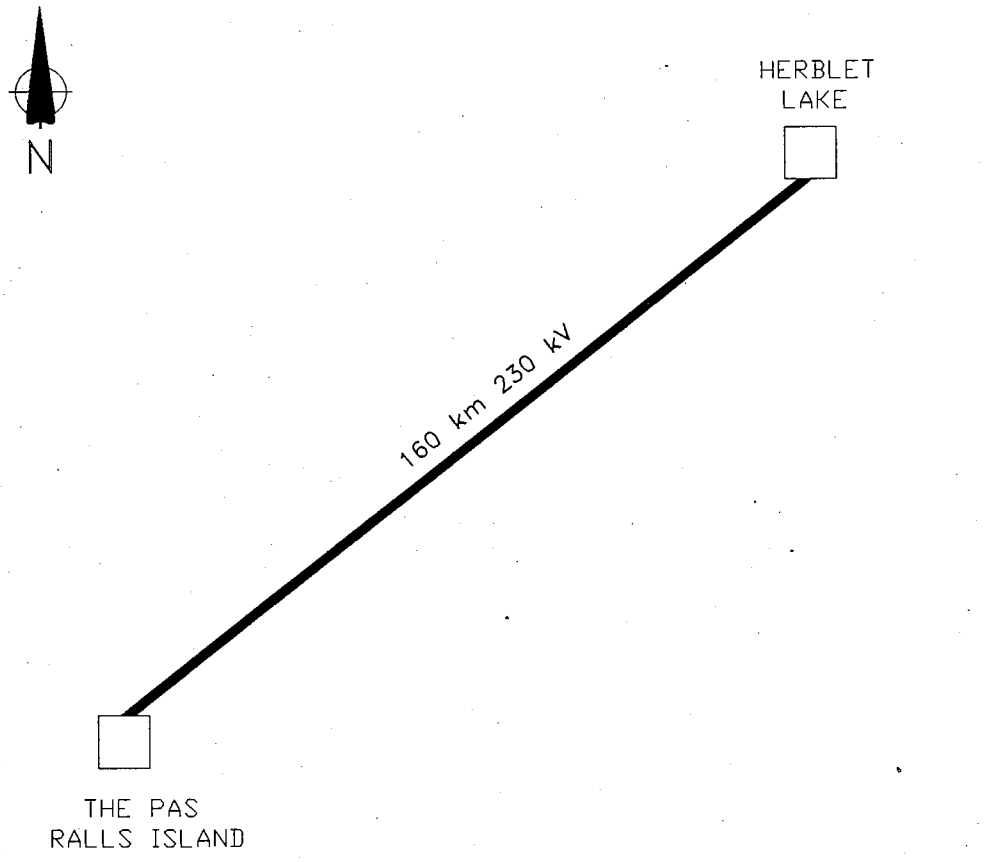
REFERENCE NUMBER	DESCRIPTION
Complex 76	Flin Flon Cliff Lake Transformer Addition
Complex 46	Herblet Lake - Flin Flon 230 Transmission

CAPITAL BUDGET COMPLEX CONCEPTUAL DIAGRAM

HERBLET LAKE – THE PAS 230KV TRANSMISSION

REVISED: 1999 - 10 - 01	ISSUED BY: WNZ

COMPLEX NO. 47



manitoba hydro

PLANNING AND CONTROL DIVISION

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

53.

COMPLEX STATUS: [X] Planned [ ] In progress

Complex no. 47

REVISION STATUS: [ ] New complex [ ] In service change [ ] Concept change [X] Estimate change only

COMPLEX: HERBLET LAKE - THE PAS 230 KV TRANSMISSION

Proposal

Perform environmental assessments and route selection, design and construct transmission and terminal facilities to provide firm supply to Flin Flon Cliff Lake and The Pas Ralls Island as follows:

Transmission: 230 KV line 160 KM Herblet Lake - The Pas Ralls Island.

Terminations: Extend 230 KV facilities at Herblet Lake and The Pas Ralls Island stations.

Communications: Upgrade and co-ordinate with existing Herblet Lake and The Pas facilities.

JUSTIFICATION

[X] Load [ ] Service
[ ] Safety [ ] Efficiency
[X] Reliability [ ] Other

Explanation

The line is required to provide firm supply and voltage support for increasing Flin Flon and The Pas area loads.

Estimate Level	COMPLEX START (yyyy mm)
L2	2002 04

IN SERVICE DATES AND AMOUNTS

2010 10	$48550			

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend								
Year 99/00								
00/01								
01/02								
02/03	140	14	6		160	155	5	3
03/04	384	47	31		462	440	22	5
04/05	779	113	91		983	932	51	5
05/06	91	15	149		255	244	11	5
06/07	785	154	189		1,128	1,052	76	7
07/08	2,484	544	356		3,384	3,235	149	5
08/09	12,383	3008	1,040		16,431	16,330	101	1
09/10	12,604	3294	3,140		19,038	18,742	296	2
10/11	3,285	942	2,480		6,707	6,459	248	4
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	32,935	8,131	7,482		48,548	47,589	959	2

REVISION: Scope unchanged.

Reviewed by ORIGINATOR	yyyy 99	mm 11	dd 08	Reviewed by COORDINATOR	yyyy 99 / mm 11 / dd 03
Reviewed by CONSTRUCTOR	yyyy 99	mm 11	dd 03	Approved by VICE-PRESIDENT	yyyy 99 / mm 11 / dd 16

H2856/r Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Complex no. 47

Advance or deferral impact

Deferral will force curtailment of Flin Flon and The Pas area loads during outages of 230 KV supply lines in the Flin Flon - The Pas - Herblet Lake area.

Factors affecting timing or viability

Flin Flon and The Pas area load growth.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE	
					Amount	%
Herblet Lake - The Pas Ralls Island 230 KV T/L		26,141	26,664	26,553	-111	-0
Herblet Lake Stn. - Terminate The Pas 230 KV T/L		3,524	3,594	3,626	32	1
The Pas Ralls Islnd-Terminate Herblet Lk 23KV T/L		1,989	2,029	2,107	78	4
Communicatn for Herblet Lake-The Pas RI 230KV T/L		605	617	647	30	5
TOTAL		32,259	32,904	32,933	29	0

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
9510	49,662	Revised escalation and interest rates.
9610	49,630	Revised escalation and interest rates.
1997 10	47,621	Scope unchanged, estimate reflects revised costing methodology implemented with the new financial reporting system. Also reflects revised interest and escalation rates.
1998 10	47,589	Scope unchanged.
1999 10	48,548	Scope unchanged.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

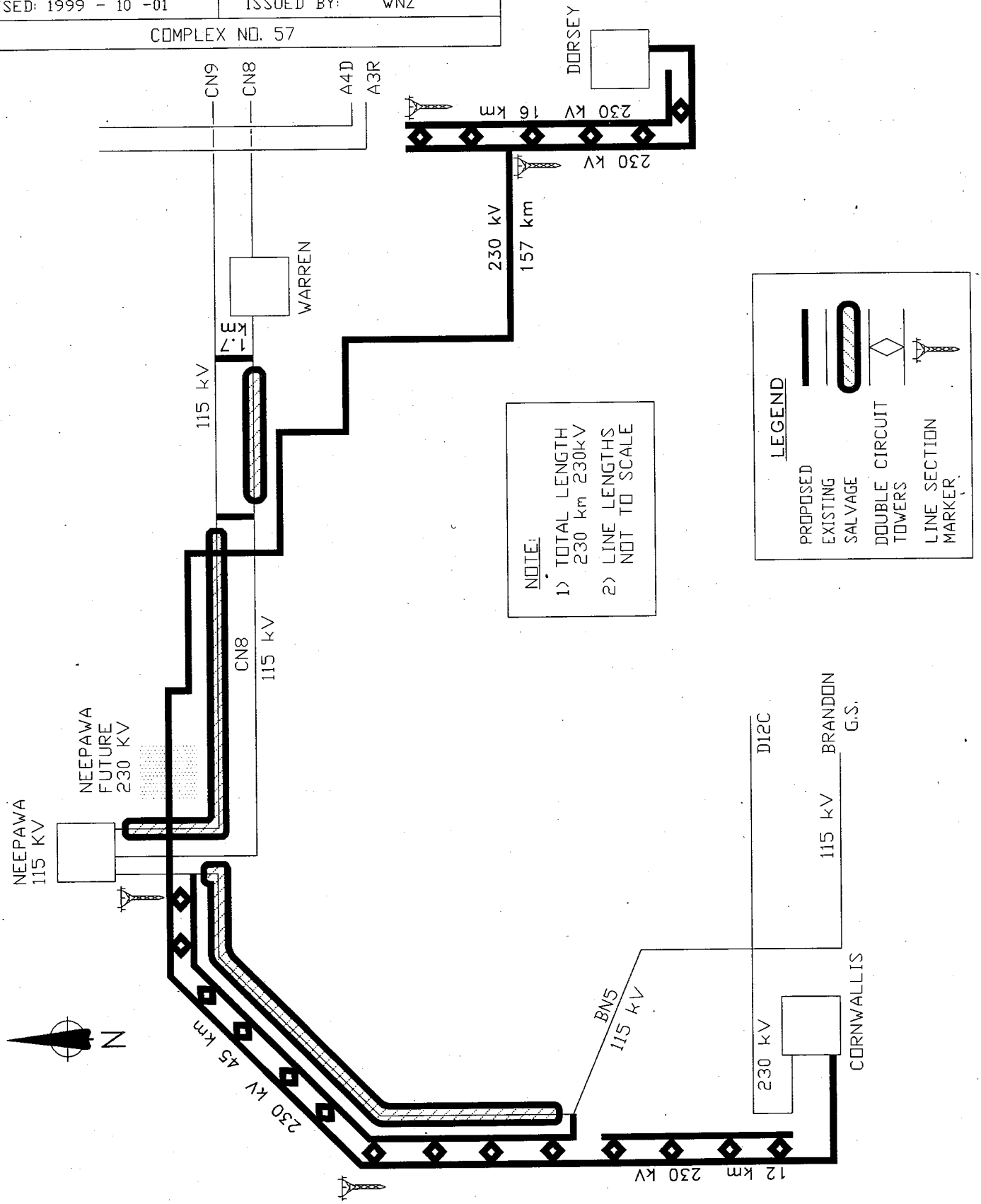
REFERENCE NUMBER	DESCRIPTION

CAPITAL BUDGET COMPLEX CONCEPTUAL DIAGRAM

DORSEY–NEEPAWA–CORNWALLIS 230KV LINE

REVISED: 1999 - 10 -01 | ISSUED BY: WNZ

COMPLEX NO. 57



manitoba hydro

PLANNING AND CONTROL DIVISION

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

54

(IN THOUSANDS OF DOLLARS)

COMPLEX STATUS: ☐ Planned ☒ In progress

Complex no. 57

REVISION STATUS: ☐ New complex ☒ In service change ☐ Concept change ☐ Estimate change only

COMPLEX: DORSEY - NEEPAWA - CORNWALLIS 230 KV LINE

Proposal

Perform environmental assessments and route selection, design and construct transmission and terminal facilities to provide firm supply to Brandon as follows: Transmission: 230 KV line Dorsey - Neepawa - Cornwallis (D-N-C), consisting of 73 KM on double circuit and 157 KM on single circuit towers. New 115 KV line of 1.7 KM Warren-Line CN9 Tap. Salvage 63 KM of 115 KV line CN8 from Warren towards Neepawa and 79 KM of 115 KV line CN9 from Neepawa towards Warren. Salvage 52 KM of 115 KV line BN5 from Neepawa to north of Brandon and replace with east side of 230 KV line operating at 115 KV as 2nd circuit on D-N-C towers. Terminations: Extend 230 KV facilities at Dorsey and Cornwallis stations. Salvage 15 MVAR transformer reactor & 1 reactor switching breaker. Install 2-20 MVAR 13.2 KV shunt reactors and 3 transformer reactor switching breakers. Purchase property for future Neepawa 230 KV station. Communications: Integrate with existing Dorsey and Cornwallis facilities.

JUSTIFICATION

☒ Load ☐ Service ☐ Safety ☐ Efficiency ☒ Reliability ☐ Other

Explanation

These facilities provide transmission improvements required by 1999 to supply Brandon area future load growth. They also defer the future Winnipeg - Brandon 230 KV transmission complex and provide for future Neepawa area support.
One new reactor will replace an existing reactor in deteriorated condition. Both reactors are required to control 230 KV voltage at Cornwallis under light load conditions.

Estimate Level	COMPLEX START (yyyy mm)
L2-3	1991 09

IN SERVICE DATES AND AMOUNTS

1998 03	$2100	1998 04	$440	1999 07	$624	2000 04	$46978

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	28,466		3,195	7	31,654	25,861	5,793	22
Year 99/00	13,483	51	3,258		16,792	15,703	1,089	7
00/01	1,357	12	319		1,688	6,605	-4,917	-74
01/02								
02/03								
03/04								
04/05								
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	43,306	63	6,772	7	50,134	48,169	1,965	4

REVISION: ISD deferred 6 months to 2000 04 30 by Transmission Line Construction.

Reviewed by ORIGINATOR	yyyy mm dd 99 11 08	Reviewed by COORDINATOR	yyyy mm dd 99 11 03
Reviewed by CONSTRUCTOR	yyyy mm dd 99 11 03	Approved by VICE-PRESIDENT	yyyy mm dd 99 11 16

H2856/r Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Complex no. 57

Advance or deferral impact

Deferral will reduce firm load support of the Brandon area. Delay in completing this line will impact on the retermination of Ashern - Dorsey 230KV line and subsequent Winnipeg area transmission improvements.

Factors affecting timing or viability

Manitoba Load.
Brandon thermal generation service life.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Dorsey-Neepawa-Cornwallis 230 KV T/L	39,924	37,388	38,136	37,597	-539	-1
Neepawa Station - Land Purchase	596	389	397	391	-6	-2
Cornwallis-Terminate Dorsey (Neepawa) 230KV T/L	2,855	2,766	2,821	2,643	-178	-6
Dorsey-Terminate Cornwallis (Neepawa) 230KV T/L	1,953	1,561	1,592	1,743	151	9
Cornwallis-Tertiary Reactor R12 and Bkr. Rplcmnt.	995	591	603	602	-1	-0
Dorsey-Neepawa-Cornwallis 230KV Line Commnctn.	183	293	299	331	32	11
TOTAL	46,506	42,988	43,848	43,307	-541	-1

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
9510	54,204	In-service date of 214 km of line from HVDC line ROW to Cornwallis deferred 1 year to 1998 10 31. Reflects cost decreases for station engineering, material, and labour.
9610	51,613	ISD for 214 km of line deferred 1 year to 1999 10 31. Cornwallis transformer reactor and switching breaker added. Cost decreases for line materials, station engineering
1997 10	47,344	Scope unchanged, reflects revised costing methodology implemented with the new financial reporting system, and revised interest and escalation rates.
1998 10	48,169	Scope unchanged.
1999 10	50,134	ISD deferred 6 months to 2000 04 30 by Transmission Line Construction.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

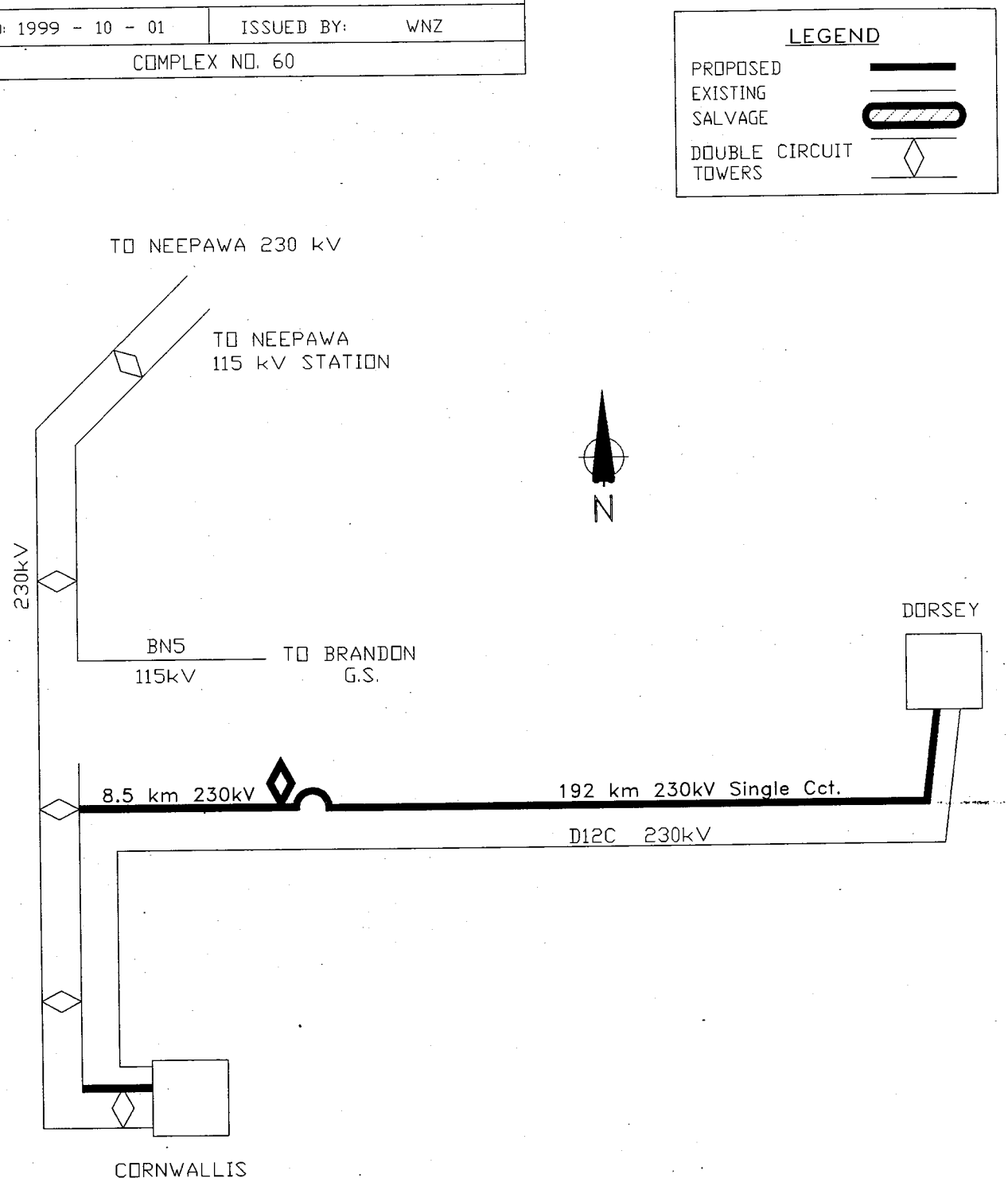
REFERENCE NUMBER	DESCRIPTION
Complex 60	Winnipeg - Brandon 230 KV Transmission
Complex 51	Ashern - Dorsey 230KV Line Changes

CAPITAL BUDGET COMPLEX CONCEPTUAL DIAGRAM

WINNIPEG – BRANDON 230KV TRANSMISSION

REVISED: 1999 - 10 - 01	ISSUED BY: WNZ

COMPLEX NO. 60



H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

55.

COMPLEX STATUS: ☐ Planned ☒ In progress

Complex no. 60

REVISION STATUS: ☐ New complex ☒ In service change ☐ Concept change ☐ Estimate change only

COMPLEX: WINNIPEG - BRANDON 230 KV TRANSMISSION

Proposal

Perform environmental assessments and route selection, design and construct transmission and terminal facilities to provide firm supply to Brandon as follows:
Transmission: 230 KV line 192 KM Dorsey - Brandon, 230 KV double circuit line with only one side strung 8.5 KM Brandon - location north of Cornwallis. Connect to unused 230 KV line north of Cornwallis to create Dorsey - Cornwallis 230 KV circuit.

Terminations: Extend 230 KV facilities at Dorsey and Cornwallis stations.

Communications: Integrate with existing facilities at Dorsey and Cornwallis stations.

JUSTIFICATION

☒ Load ☐ Service
☐ Safety ☐ Efficiency
☒ Reliability ☐ Other

Explanation

These facilities provide transmission improvements required by 2007 to supply Brandon area future load growth.

Estimate Level	COMPLEX START (yyyy mm)
L2	1989 04

IN SERVICE DATES AND AMOUNTS

2003 03	$159	2007 10	$8731	2008 10	$64119

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	-2		2		0		0	
Year 99/00								
00/01						67	-67	-100
01/02	62	4	3		69	237	-168	-71
02/03	2,657	211	119		2,987	6,145	-3,158	-51
03/04	3,933	399	429		4,761	6,432	-1,671	-26
04/05	5,749	729	943		7,421	12,517	-5,096	-41
05/06	10,355	1556	1,823		13,734	17,822	-4,088	-23
06/07	13,151	2286	3,245		18,682	15,944	2,738	17
07/08	9,474	1235	4,380		15,089	9,913	5,176	52
08/09	6,000	1305	2,961		10,266		10,266	
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	51,379	7,725	13,905		73,009	69,077	3,932	

REVISION: Deferred one year 2007 due to capital constraint reasons.

Reviewed by ORIGINATOR	yyyy mm dd 99 11 08	Reviewed by COORDINATOR	yyyy mm d 99 11 0
Reviewed by CONSTRUCTOR	yyyy mm dd 99 11 03	Approved by VICE-PRESIDENT	yyyy mm d 99 11 1

H2856/r Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Complex no. 60

Advance or deferral impact

Deferral will reduce firm supply to the Brandon area.

Factors affecting timing or viability

Manitoba Load.
Brandon thermal generation service life.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Dorsey West Property Requirements		134	137	136	-1	-1
Winnipeg - Brandon 230 KV T/L		44,105	44,987	44,528	-459	-1
Cornwallis - Terminate Dorsey 230 KV T/L		3,072	3,133	3,242	109	3
Dorsey - Terminate Brandon 230 KV T/L		3,117	3,179	3,286	107	3
Winnipeg - Brandon Communications		182	186	186	0	0
TOTAL		50,610	51,622	51,378	-244	-0

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
9510	150,317	230 KV line reactor deleted. Planning (EMTP) studies added. Reflects additional property costs for EHV station.
9610	75,389	Concept change to 230 KV from 500 KV operating at 230 KV. Brandon EHV land purchase trnsfr'd to another complex. Dorsey West prop. reqrmnt def 4 1/2 years to 02 09 30.
1997 10	77,330	Scope unchanged, estimate reflects revised costing methodology implemented with the new financial reporting system. Also reflects revised interest and escalation rates.
1998 10	69,078	Revised to reflect current transmission line costs (previously reflected historic costs) and to defer the transmission line ISD 1 year.
1999 10	73,009	Deferred one year 2007 due to capital constraint reasons.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION
Complex 57	Dorsey - Neepawa - Cornwallis 230 KV Line

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

56.

COMPLEX STATUS: [X] Planned [ ] In progress

Complex no. 45

REVISION STATUS: [ ] New complex [X] In service change [ ] Concept change [ ] Estimate change only

COMPLEX	FT. GARRY PERIMETER SOUTH BANK REPLACEMENTS

Proposal

Replace 2 - 7.5/10 mva, 3ph transformers with 2 - 15/20/25 mva 66-12.47y/7.2 kv 3ph transformers c/w LTC's at Ft. Garry-Perimeter South station.

JUSTIFICATION

[X] Load [ ] Service [ ] Safety [ ] Efficiency [ ] Reliability [ ] Other

Explanation

The non-firm capacity of the Ft. Garry- Perimeter South station will be exceeded in 1996/97. This station supplies south Ft. Garry and Lasalle area (both fast growing communities) and provides a back-up supply to St. Norbert single bank station.

Estimate Level	COMPLEX START (yyyy mm)
L2	2000 04

IN SERVICE DATES AND AMOUNTS				
2003 07	$4503			

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend								
Year 99/00								
00/01						367	-367	-100
01/02	349	27	14		390	218	172	79
02/03	2,163	223	94		2,480	3,840	-1,360	-35
03/04	1,419	120	93	149	1,483		1,483	
04/05								
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	3,931	370	201	149	4,353	4,425	-72	-2

REVISION	Deferred one year to 2003 07 31 due to capital constraint reasons.

Reviewed by ORIGINATOR	yyyy mm dd 99 11 08	Reviewed by COORDINATOR	yyyy mm dd 99 11 03
Reviewed by CONSTRUCTOR	yyyy mm dd 99 11 03	Approved by VICE-PRESIDENT	yyyy mm dd 99 11 16

H2856/r Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Complex no. 45

Advance or deferral impact

Thermal capacity of 2 - 7.5/10 mva banks will be exceeded.

Factors affecting timing or viability

Load growth.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
FT. GARRY PERIMETER SOUTH BANK REPLMNT		4,317	4,403	3,930	-473	-11
TOTAL		4,317	4,403	3,930	-473	-11

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
9510	3,494	Environmental approval costs included.
9610	3,661	ISD deferred 2 years to 2000 07 31.
9710	4,146	Increase due to scope change to rebuild 12KV bus, replace reclosers, replace 66KV structure, add 66KV breakers.
1998 10	4,425	ISD deferred 2 years to 2002 07 31.
1999 10	4,353	Deferred one year 2003 07 31 due to capital constraint reasons.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

57.

COMPLEX STATUS	Complex no.	REVISION STATUS
☒ Planned ☐ In progress	84	☐ New complex ☐ In service change ☐ Concept change ☒ Estimate change only

COMPLEX	RIDGEWAY TRANSFORMER ADDITION

Proposal

Design and construct terminal facilities at Ridgeway as follows:

Terminations: Extend 230 & 66 KV facilities at Ridgeway station, including 3rd 230-66 KV 125 MVA transformer and circuit breakers.

JUSTIFICATION		Explanation
☒ Load	☐ Service	This transformer is required in 2007 to supply increased Winnipeg load.
☐ Safety	☐ Efficiency	
☒ Reliability	☐ Other	

Estimate Level	COMPLEX START (yyyy mm)
L2	2003 09

IN SERVICE DATES AND AMOUNTS			
2007 10 31	$9179		

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend								
Year 99/00								
00/01								
01/02								
02/03								
03/04	261	33	6		300	262	38	15
04/05	448	65	47		560	492	68	14
05/06	633	108	99		840	764	76	10
06/07	3,201	613	310		4,124	4,063	61	2
07/08	2,475	524	355		3,354	3,320	34	1
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	7,018	1,343	817		9,178	8,901	277	3

REVISION	Scope unchanged.

Reviewed by ORIGINATOR	yyyy 99	mm 11	dd 08	Reviewed by COORDINATOR	yyyy 99 / mm 11 / dd 03
Reviewed by CONSTRUCTOR	yyyy 99	mm 11	dd 03	Approved by VICE PRESIDENT	yyyy 99 / mm 11 / dd 16

H2856/r Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Complex no. 84

Advance or deferral impact

Deferral will decrease supply reliability in Ridgeway area in the event of an outage of existing Ridgeway 230-66 KV transformer.

Factors affecting timing or viability

Manitoba Load.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE	
					Amount	%
Ridgeway 230 KV Switchyard - Transformer Addition		6,772	6,907	7,018	111	2
TOTAL		6,772	6,907	7,018	111	2

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
1995 10	8,936	Reflects transformer price increase.
1996 10	8,894	Revised interest rates and correction to calculated escalation.
1997 10	8,894	Reflects revised cost flows and methodology implemented with the new financial reporting system.
1998 10	8,901	Scope unchanged.
1999 10	9,178	Scope unchanged.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

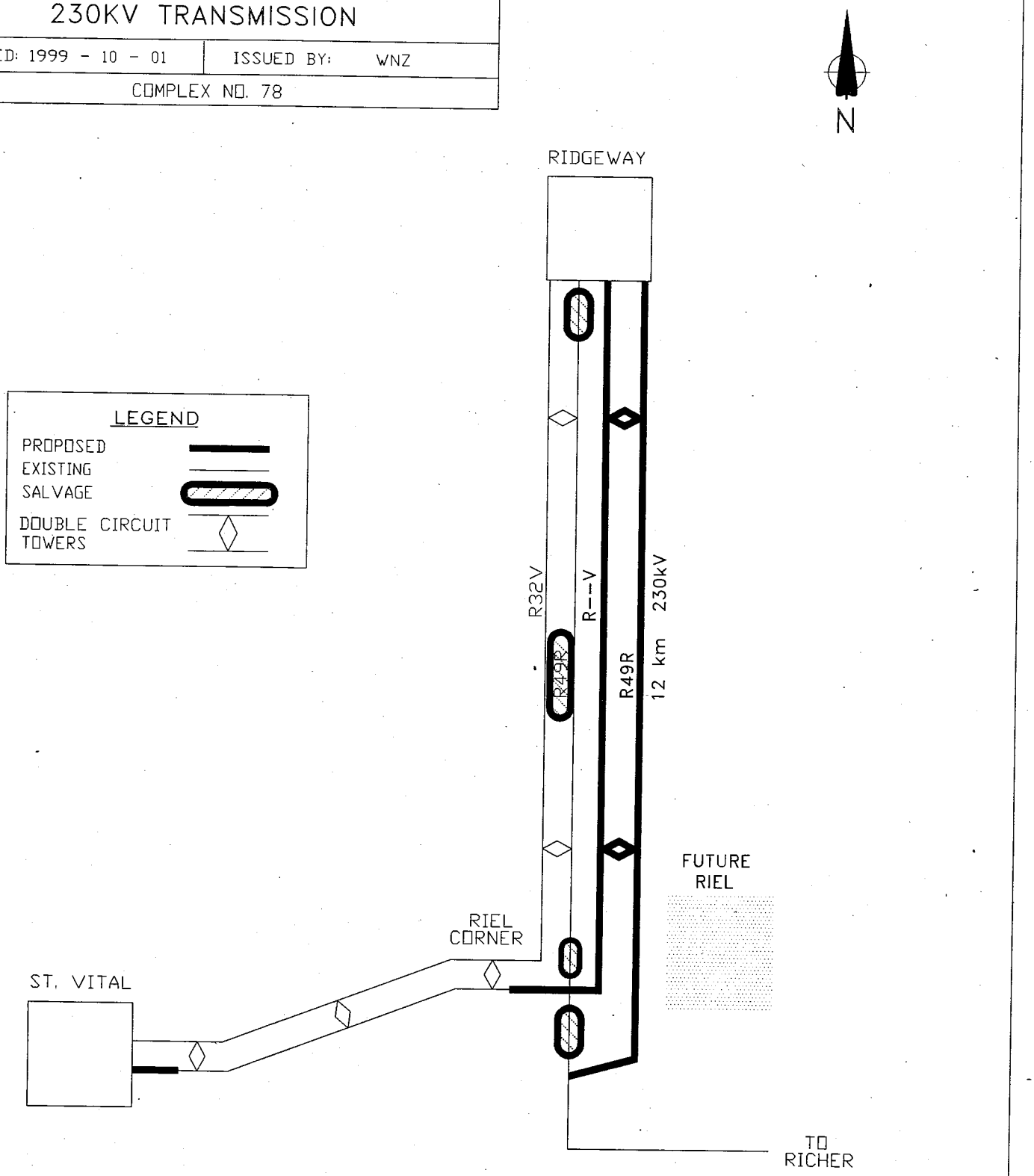
REFERENCE NUMBER	DESCRIPTION

CAPITAL BUDGET COMPLEX CONCEPTUAL DIAGRAM

RIDGEWAY – ST.VITAL 230KV TRANSMISSION

REVISED: 1999 - 10 - 01 | ISSUED BY: WNZ

COMPLEX NO. 78



manitoba hydro

PLANNING AND CONTROL DIVISION

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

58.

COMPLEX STATUS	Complex no.	REVISION STATUS
☐ Planned ☒ In progress	78	☐ New complex ☐ In service change ☐ Concept change ☒ Estimate change only

COMPLEX	RIDGEWAY - ST. VITAL 230 KV TRANSMISSION

Proposal

Perform environmental assessments and obtain licences, design and construct transmission and terminal facilities to provide firm supply to St. Vital station as follows:
Transmission: Construct 12.0 KM double circuit 230 KV line Ridgeway - Riel Future Station Site. Open 230 KV line R49R at Ridgeway and Riel site and reconnect south section at Riel site to Ridgeway using east side of new double circuit. Connect west side of new double circuit at Riel site to unused circuit extending to St. Vital. This results in 2nd Ridgeway-St. Vital 230 KV line, re-establishment of Ridgeway - Richer 230 KV line R49R , and one unenergized new Ridgeway-Riel Site line.
Terminations: Extend 230 & 115 KV facilities at St. Vital station, including a 2nd 230-115 KV 250 MVA transformer and 230 & 115 KV circuit breakers. Extend 230 KV facilities at Ridgeway. Communications: Integrate with existing east Winnipeg facilities.

JUSTIFICATION		Explanation
☒ Load	☐ Service	This complex provides transmission system improvements for firm supply to the St. Vital area.
☐ Safety	☐ Efficiency	
☒ Reliability	☐ Other	

Estimate Level	COMPLEX START (yyyy mm)
L2-3	1994 09

IN SERVICE DATES AND AMOUNTS							
1998 10	$3610	1998 11	$71	1999 02	$96	1999 03	$18662
1999 04	$419	1999 06	$470	1999 07	$299	1999 09	$810
1999 10	$92	1999 12	$194				

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	20,888		2,171	73	22,986	21,289	1,697	8
Year 99/00	1,612	22	29		1,663	903	760	84
00/01								
01/02								
02/03								
03/04								
04/05								
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	22,500	22	2,200	73	24,649	22,192	2,457	11

REVISION	Revised to reflect the inclusion of a FP&P deluge system for banks 7&8, and site improvements at St Vital; higher costs for termination, communications and compressed air system.

		yyyy mm dd			yyyy mm dd
Reviewed by	ORIGINATOR	99 11 08	Reviewed by	COORDINATOR	99 11 03
Reviewed by	CONSTRUCTOR	99 11 03	Approved by	VICE PRESIDENT	99 11 16

H2856/r Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Complex no. 78

Advance or deferral impact

Deferral will limit firm supply to the St Vital area and also effect firmness of Ontario Hydro 200 MW Sale and supply to TCPL.

Factors affecting timing or viability

Manitoba Load.
Ontario Hydro 200 MW Sale.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Ridgeway-St. Vital & Ridgeway-Richer 230 KV T/L	3,576	4,243	4,328	4,092	-236	-5
St. Vital Transformer Addition & Line Terminat'ns	11,798	12,156	12,399	13,700	1,301	10
Ridgeway - Terminate St. Vital & Richer 230KV T/L	3,121	3,436	3,505	3,562	57	2
Ridgeway Stn upgrade Compressed Air System	703	517	527	703	176	33
Ridgeway-St. Vital-Richer 230KV Telecontrol Rqmts	282	294	300	443	143	48
TOTAL	19,480	20,646	21,059	22,500	1,441	7

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
9510	25,145	Transformer price increase and concept chg- using both sides of new double circuit line, additional 230KV circuit breaker at St. Vital, and incr 230KV bay developments.
9610	19,697	Re-establish R49R advnc 2 months to 1998 04 30. Commnctns advnce 4 months to 1998 06 30. 115 KV line sections inside St. Vtl for tfr add. Cost dcrs. matrl, engnrng, labor.
1997 10	20,177	Scope unchanged, estimate reflects revised costing methodology implemented with the new financial reporting system. Also reflects revised interest and escalation rates.
1998 10	22,192	Revised to reflect 97/98 overexpenditure 1.9M, higher transmission line material costs and five months ISD delay of St Vital transformer.
1999 10	24,649	Revised to reflect the inclusion of a FP&P deluge system for banks 7&8, and site improvements at St Vital; higher costs for termination, communications and compressed air

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION
Complex 64	St. Vital Transformer Addition
Complex 27	Dorsey - St. Vital 230 KV Transmission
Complex 95	200 MW Ontario Hydro Sale - Transmission Upgrade

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

59.

COMPLEX STATUS	Complex no.	REVISION STATUS
☐ Planned ☒ In progress	64	☐ New complex ☒ In service change ☐ Concept change ☐ Estimate change only

COMPLEX	ST. VITAL TRANSFORMER ADDITION

Proposal

Design and construct terminal facilities at St. Vital as follows:

Terminations: Extend 230 and 115 KV facilities at St. Vital station, including a 3rd 230-115 KV 250 MVA transformer and associated 230 KV circuit breakers.

JUSTIFICATION		Explanation
☒ Load	☐ Service	The transformer is required in 2001 to supply increased Winnipeg load.
☐ Safety	☐ Efficiency	
☒ Reliability	☐ Other	

Estimate Level	COMPLEX START (yyyy mm)
L2	1997 10

IN SERVICE DATES AND AMOUNTS				
2002 04	$8990			

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	6				6	304	-298	-98
Year 99/00	306	12	6		324	3,270	-2,946	-90
00/01	3,304	198	134		3,636	2,777	859	31
01/02	3,252	253	479		3,984	349	3,635	NA
02/03	960	24	56		1,040	2,062	-1,022	-50
03/04								
04/05								
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	7,828	487	675		8,990	8,762	228	3

REVISION	Deferred one year 2002 04 30 due to capital constraint reasons.

Reviewed by ORIGINATOR	yyyy mm dd 99 11 08	Reviewed by COORDINATOR	yyyy mm dd 99 11 03
Reviewed by CONSTRUCTOR	yyyy mm dd 99 11 03	Approved by VICE PRESIDENT	yyyy mm dd 99 11 16

H2856/r Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Complex no. 64

Advance or deferral impact

Deferral will decrease supply reliability in the St. Vital area in case of outage of an existing St. Vital 230-115 KV transformer.

Factors affecting timing or viability

Manitoba Load.
Ontario Hydro 200 MW Sale.
Supply to TCPL.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
St. Vital 230 KV Transformer Addition		7,707	7,861	7,828	-33	-0
TOTAL		7,707	7,861	7,828	-33	-0

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
9510	9,520	Retermination of 230 KV line R32V deleted. Transformer price increase, 1-230KV circuit brkr add'd (from Dorsey-St. Vital 230KV Trnsmssn cmplx), and add'l stn facil adj.
9610	8,198	Retermination of 2 - 115 kV lines and installation of 1 - 115 kV circuit breaker deleted. Reduced material cost based on recent autotransformer quote.
1997 10	8,885	In service date deferred 6 months to 2001 04 30 to coincide with Dorsey - St. Vital line addition at St. Vital Station. Also reflects revised interest and escalation rates.
1998 10	8,762	Scope unchanged.
1999 10	8,989	Deferred one year 2002 04 30 due to capital constraint reasons.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

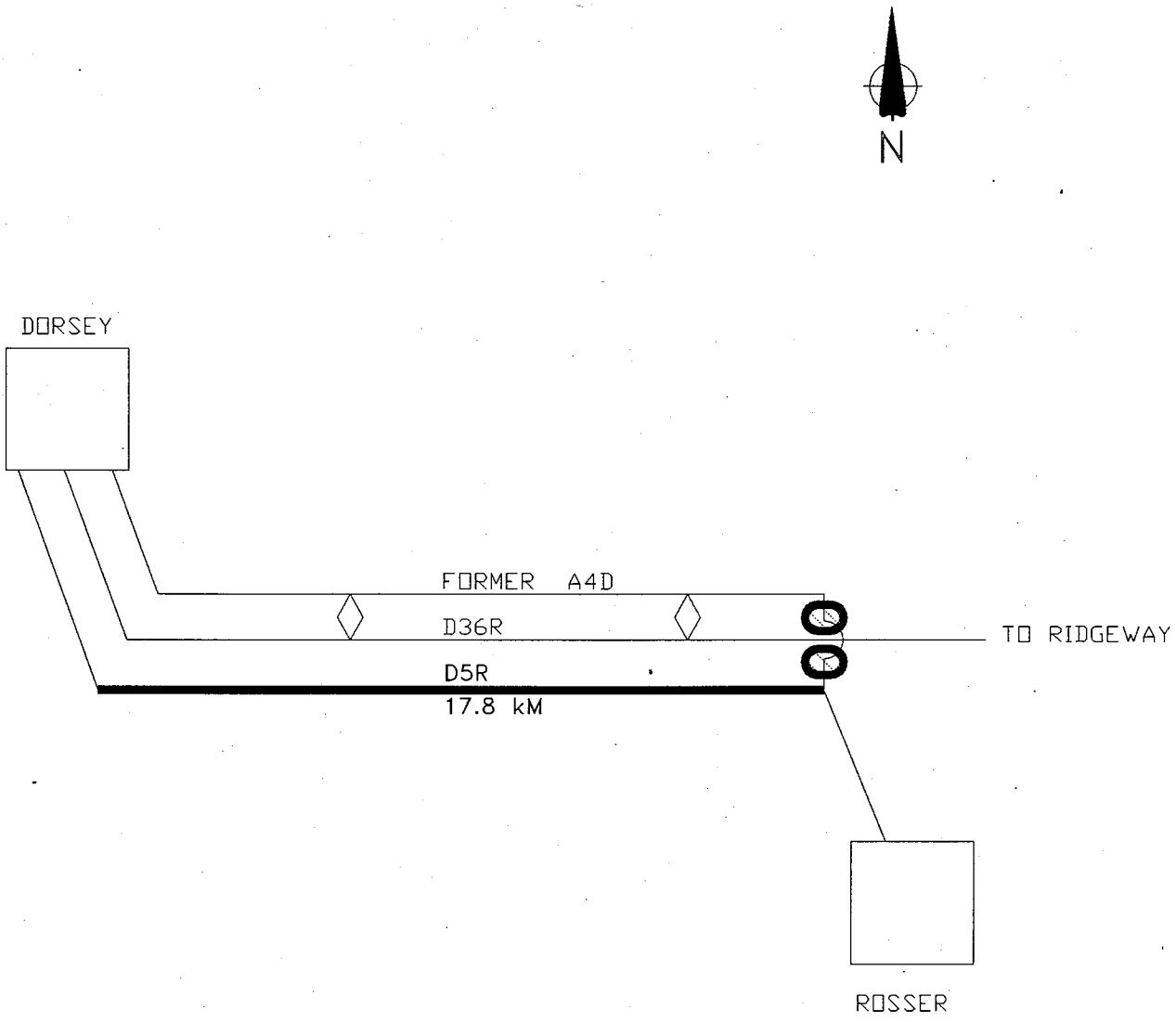
REFERENCE NUMBER	DESCRIPTION
Complex 78	Ridgeway-St. Vital 230 KV Transmission
Complex 27	Dorsey - St. Vital 230 KV Transmission

CAPITAL BUDGET COMPLEX CONCEPTUAL DIAGRAM

DORSEY – ROSSER 230KV TRANSMISSION IMPROVEMENTS

REVISED: 1999 - 10 - 01	ISSUED BY: WNZ

COMPLEX NO. 42



LEGEND

PROPOSED

EXISTING

SALVAGE

DOUBLE CIRCUIT TOWERS

manitoba hydro

PLANNING AND CONTROL DIVISION

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

60.

COMPLEX STATUS	Complex no.	REVISION STATUS
☐ Planned ☒ In progress	42	☐ New complex ☐ In service change ☐ Concept change ☒ Estimate change only

COMPLEX	DORSEY - ROSSER 230 KV TRANSMISSION IMPROVEMENTS

Proposal

Perform environmental assessments and obtain licences, design and construct transmission and terminal facilities to refurbish Dorsey - Rosser 230 KV line D5R as follows:

Transmission: Reconductor 17.8 km of line D5R. Open temporary bypass of Dorsey - Rosser line D5R (former A4D). Restore reconductored D5R line by reconnecting at Dorsey and at Rosser.

Terminations: Modify line protection equipment at Dorsey and Rosser.

JUSTIFICATION		Explanation
☒ Load	☐ Service	Reconductoring of line D5R is part of the development of Winnipeg area 230 KV transmission. It will upgrade the line to the same current carrying capacity as all other 230 KV network lines in the Winnipeg area and prevent D5R overloads during transmission contingency outages.
☐ Safety	☐ Efficiency	
☒ Reliability	☐ Other	

Estimate Level	COMPLEX START (yyyy mm)
L2	1998 04

IN SERVICE DATES AND AMOUNTS			
2001 04	$1816		

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	13		1		14	30	-16	-53
Year 99/00	46	1	2		49	33	16	48
00/01	1,290	42	38		1,370	1,310	60	5
01/02	355	18	10		383	349	34	10
02/03								
03/04								
04/05								
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	1,704	61	51		1,816	1,722	94	5

REVISION	Reflects addition of protection channels for transmission line D5R.

Reviewed by ORIGINATOR	yyyy mm dd 99 11 08	Reviewed by COORDINATOR	yyyy mm dd 99 11 03
Reviewed by CONSTRUCTOR	yyyy mm dd 99 11 03	Approved by VICE-PRESIDENT	yyyy mm dd 99 11 16

H2856/r Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Complex no. 42

Advance or deferral impact

Deferral will cause overloading of D5R (which has smaller conductors than parallel lines) during contingency outages. It will also delay construction of the Dorsey - St. Vital 230 KV line required for firm supply of east Winnipeg and Ontario Hydro 200 MW Sale.

Factors affecting timing or viability

Manitoba Load.
Ontario Hydro 200 MW Sale.
Ashern - Dorsey 230 KV Transmission Improvements.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Reconductor & Reconnect 230 KV T/L D5R		1,396	1,424	1,366	-58	-4
Dorsey - Line D5R Protection Changes		118	120	131	11	9
Rosser - Line D5R Protection Changes		64	65	70	5	8
D5R Protection Channels				136	136	
TOTAL		1,578	1,609	1,703	94	6

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
9510	1,498	Reflects cost increase for line tower modifications.
9610	1,499	Revised interest rates.
1997 10	1,583	In service date advanced 6 months to 2001 04 30 to accommodate TCPL load addition at Ile des Chenes. Also reflects revised interest and escalation rates.
1998 10	1,722	Contingency added.
1999 10	1,816	Reflects addition of protection channels for transmission line D5R.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

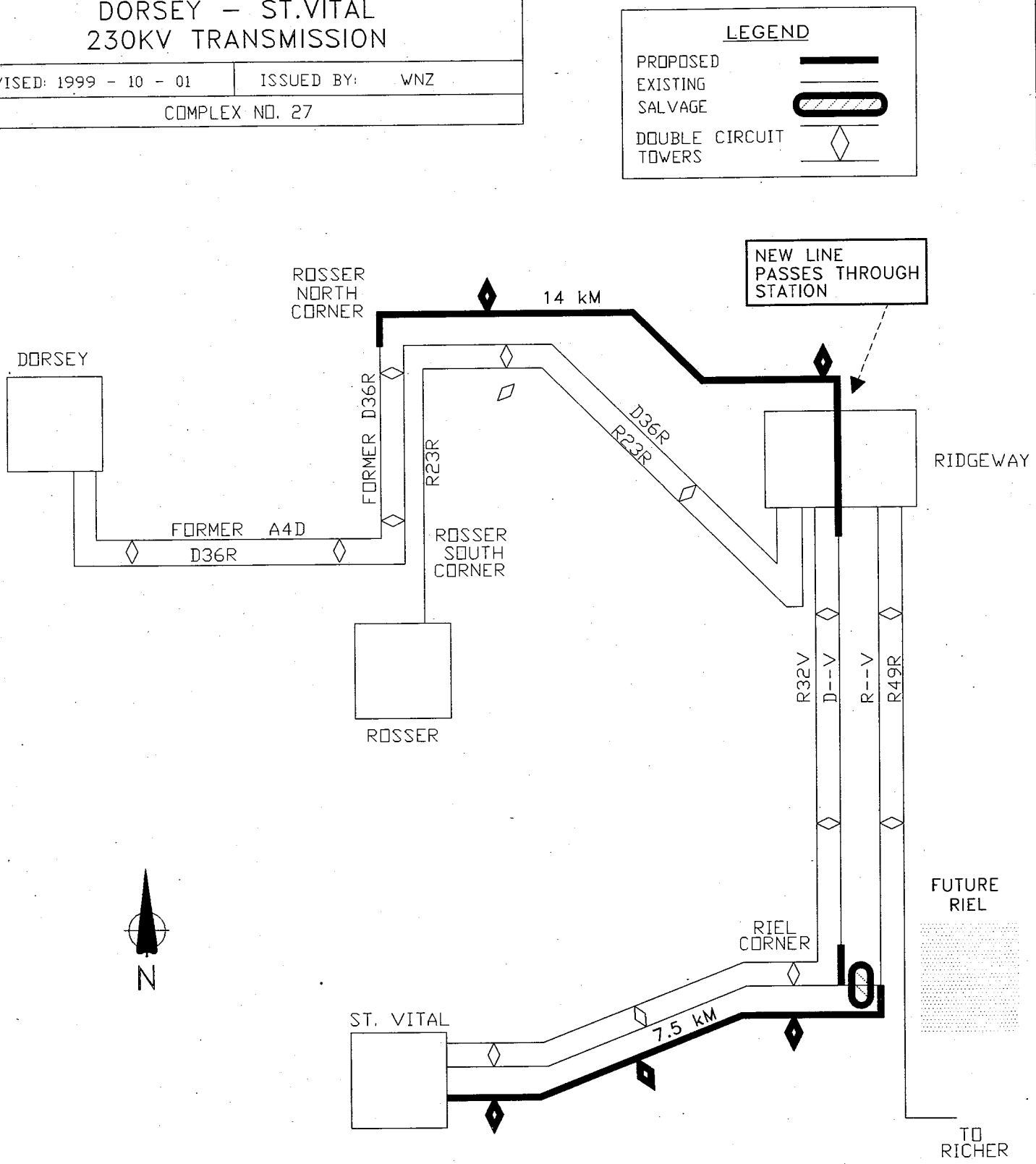
REFERENCE NUMBER	DESCRIPTION
Complex 51	Ashern - Dorsey 230 KV Line Changes
Complex 27	Dorsey - St. Vital 230 KV Transmission

CAPITAL BUDGET COMPLEX CONCEPTUAL DIAGRAM

DORSEY – ST.VITAL 230KV TRANSMISSION

REVISED: 1999 - 10 - 01	ISSUED BY: WNZ

COMPLEX NO. 27



manitoba hydro

PLANNING AND CONTROL DIVISION

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

61.

COMPLEX STATUS: ☐ Planned ☒ In progress

Complex no. 27

REVISION STATUS: ☐ New complex ☒ In service change ☐ Concept change ☐ Estimate change only

COMPLEX: DORSEY - ST. VITAL 230 KV TRANSMISSION

Proposal

Perform environmental assessments and route selection, design and construct transmission and terminal facilities to firm up supply to stations in east Winnipeg as follows: Transmission: 230 KV line double circuit strung one side only, 14 km from Ridgeway along D36R/R23R R.O.W towards Rosser, 7.5 km from St. Vital along R32V R.O.W to Riel Corner. Open 2nd Ridgeway-St. Vital 230KV line at Riel Corner and re-establish line by connecting Ridgeway section to new 7.5 km circuit to St. Vital. Connect remaining St. Vital section of previous Ridgeway- St. Vital 230KV line, unused Ridgeway-Riel Corner line, new 14 km line, and unused former lines D36R & A4D north of Rosser to create Dorsey - St. Vital 230 KV circuit (passing through Ridgeway station). Terminations: Extend 230 KV facilities at St. Vital station. Install line protection changes at Dorsey. Communications: Integrated with existing Dorsey & St. Vital facilities.

JUSTIFICATION

☒ Load ☐ Service
☐ Safety ☐ Efficiency
☒ Reliability ☐ Other

Explanation

This line is required to provide firm supply to east Winnipeg stations from Dorsey via St. Vital station.

Estimate Level	COMPLEX START (yyyy mm)
L2	1998 04

IN SERVICE DATES AND AMOUNTS

2002 04	$8136		

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	375		18		393	557	-164	-29
Year 99/00			34		34	5,143	-5,109	-99
00/01	1,136	56	72		1,264	1,489	-225	-15
01/02	4,665	344	325		5,334	457	4,877	NA
02/03	1,015	41	49		1,105		1,105	
03/04	5				5		5	
04/05								
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	7,196	441	498		8,135	7,646	489	6

REVISION: Deferred one year 2002 04 30 due to capital constraint reasons.

Reviewed by ORIGINATOR	yyyy mm dd 99 11 08	Reviewed by COORDINATOR	yyyy mm dd 99 11 03
Reviewed by CONSTRUCTOR	yyyy mm dd 99 11 03	Approved by VICE-PRESIDENT	yyyy mm dd 99 11 16

H2856/r Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Complex no. 27

Advance or deferral impact

This transmission is required for supply to stations in east Winnipeg . Deferral will result in overloads or curtailment of load or Ontario Hydro 200 MW export during outages of Winnipeg area AC lines.

Factors affecting timing or viability

Manitoba Load.
Ontario Hydro 200 MW Sale.
Ashern - Dorsey - Rosser 230 KV Transmission Improvements.
Supply to TCPL.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Dorsey - St. Vital 230 KV T/L		5,769	5,884	5,857	-27	-0
St. Vital - Termination of Dorsey 230 KV Line		791	807	837	30	4
Dorsey-Protection Changes for St. Vital Line Term		279	285	300	15	5
Telecontrol for Dorsey-St. Vital 230 KV T/L		199	203	202	-1	-0
TOTAL		7,038	7,179	7,196	17	0

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
9510	10,110	Concept chg to different unused Ridgeway-Riel Corner line section, passing line through Ridgeway Stn. New St. Vital 230KV circuit brkr trnsf'd to Complex 64.
9610	10,062	Reflects concept change using former line D36R to replace 1.4 km of 230 KV line construction.
1997 10	7,948	In service date advanced 6 months to 2001 04 30 to accommodate TCPL load addition at Ile des Chenes. Also reflects revised interest and escalation rates.
1998 10	7,646	ISD of transmission line advanced one year from 2001 to 2000.
1999 10	8,135	Deferred one year 2002 04 30 due to capital constraint reasons.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

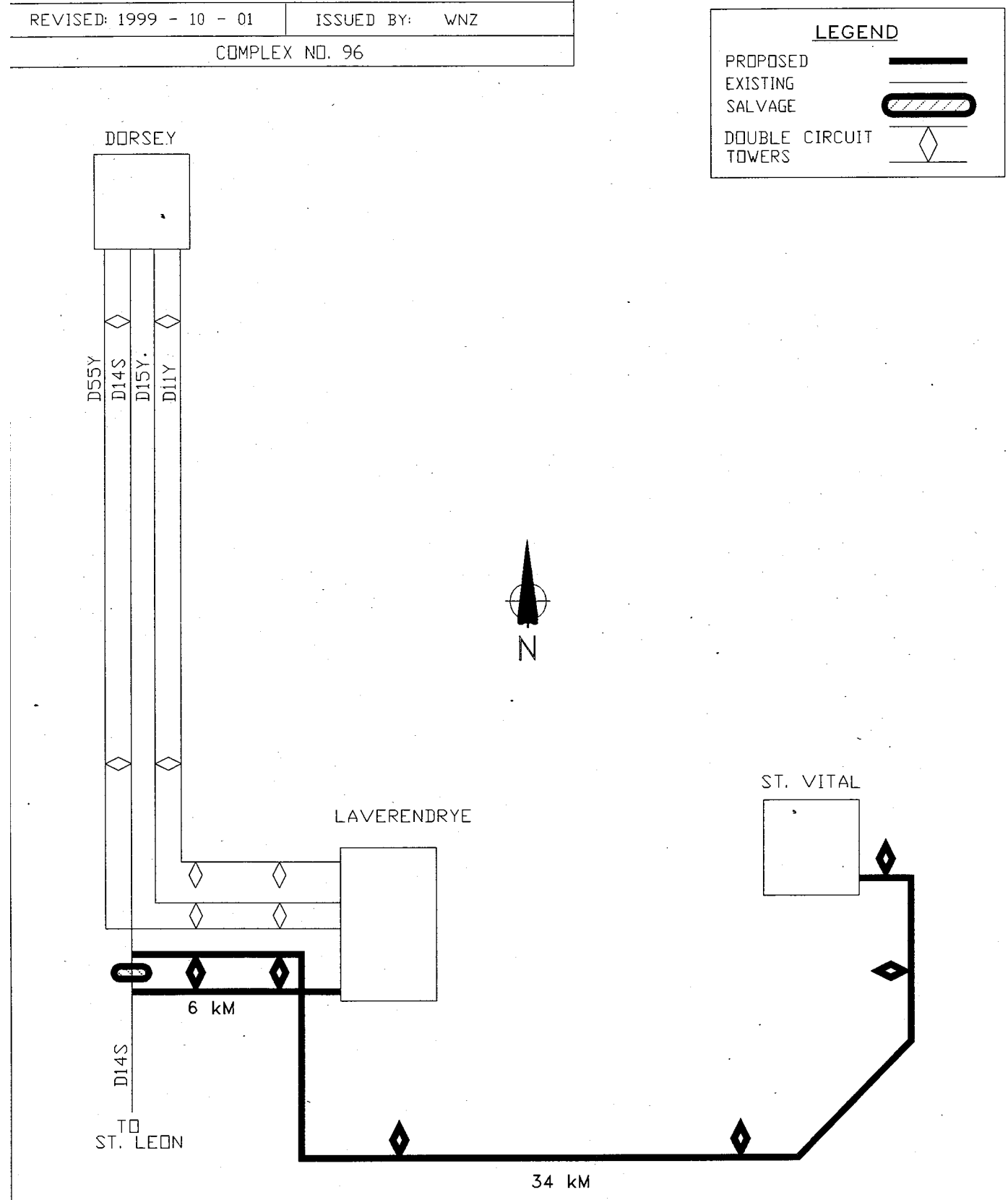
REFERENCE NUMBER	DESCRIPTION
Complex 78	Ridgeway - St. Vital 230 KV Transmission
Complex 64	St. Vital Transformer Addition
Complex 51	Ashern - Dorsey 230 KV Line Changes
Complex 42	Dorsey - Rosser 230 kV Transmission Improvements

CAPITAL BUDGET COMPLEX CONCEPTUAL DIAGRAM

DORSEY–LA VERENDRYE–ST.VITAL 230KV TRANSMISSION

REVISED: 1999 - 10 - 01	ISSUED BY: WNZ

COMPLEX NO. 96



manitoba hydro

PLANNING AND CONTROL DIVISION

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

62.

COMPLEX STATUS	Complex no.	REVISION STATUS
[X] Planned [ ] In progress	96	[ ] New complex [ ] In service change [ ] Concept change [X] Estimate change only

COMPLEX	DORSEY - LA VERENDRYE - ST. VITAL 230KV TRANSMISSION

Proposal

Perform environmental assessments, acquire property along south Winnipeg loop and obtain licences; design and construct transmission and terminal facilities to firm up supply to stations in east Winnipeg as follows:
Transmission: 230 KV line double circuit strung one side only, 34.0 km from La Verendrye to St. Vital; 230 KV line double circuit strung both sides 6.0 km La Verendrye to La Verendrye Corner. Open Dorsey-St. Leon 230 KV line D14S at La Verendyre corner and join St. Leon open end to south side of double circuit to create La Verendrye - St. Leon 230 KV line. Join north side to Dorsey open end and new St. Vital line to create Dorsey - St. Vital south loop circuit. Terminations: Extend 230 KV facilities at St. Vital and La Verendrye stations. Install line protection changes at Dorsey and St. Leon.
Communications: Integrated with existing facilities at Dorsey, St. Vital, La Verendrye and St. Leon.

JUSTIFICATION		Explanation
[X] Load	[ ] Service	The Dorsey - St. Vital line is required to provide firm supply to east Winnipeg stations from Dorsey via St. Vital station. Reterminating St. Leon line at La Verendrye permits use of high capacity line section from Dorsey to La Verendrye corner as part of Dorsey - St. Vital circuit.
[ ] Safety	[ ] Efficiency	
[X] Reliability	[ ] Other	

Estimate Level	COMPLEX START (yyyy mm)
L2	2012 04

IN SERVICE DATES AND AMOUNTS			
2015 10	$25859		

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend								
Year 99/00								
00/01								
01/02								
02/03								
03/04								
04/05								
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13	1,190	401	102		1,693	1,613	80	5
13/14	2,275	830	354		3,459	3,284	175	5
14/15	6,854	2652	1,220		10,726	10,690	36	0
15/16	6,277	2528	1,176		9,981	9,961	20	0
16/17								
17/18								
18/19								
Beyond								
TOTAL	16,596	6,411	2,852		25,859	25,548	311	1

REVISION	Scope unchanged.

Reviewed by	ORIGINATOR	yyyy mm dd 99 11 08	Reviewed by	COORDINATOR	yyyy mm dd 99 11 03
Reviewed by	CONSTRUCTOR	yyyy mm dd 99 11 03	Approved by	VICE-PRESIDENT	yyyy mm dd 99 11 16

H2856/r Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Complex no. 96

Advance or deferral impact

Deferral will cause overloading or curtailment of loads during outages of Winnipeg area AC lines.

Factors affecting timing or viability

Manitoba Load.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Dorsey-St. Vital & LaVerendrye-St. Leon 230KV T/L		10,884	11,102	10,884	-218	-2
Dorsey-Protctn Changes for Term of St. Vital T/L		179	183	193	10	5
St. Vital-Term. of Dorsey South Loop 230KV T/L		2,792	2,848	2,936	88	3
LaVerendrye-Termination of St. Leon 230KV T/L		2,097	2,139	2,228	89	4
St. Leon-Protctn Change for LaVerendrye 230KV T/L		71	72	79	7	10
Tlcntrl for Dorsey-St.Vtl & LaVrndrye-St. Ln T/L		262	267	274	7	3
TOTAL		16,285	16,611	16,594	-17	-0

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
9510	30,225	Reflects added completion of 230KV Bay 3 at St. Vital. Revised escalation and interest rates.
9610	30,192	Revised escalation and interest rates.
1997 10	27,945	Scope unchanged, estimate reflects revised costing methodology implemented with the new financial reporting system. Also reflects revised interest and escalation rates.
1998 10	25,548	Revised to reflect current transmission line costs.
1999 10	25,859	Scope unchanged.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

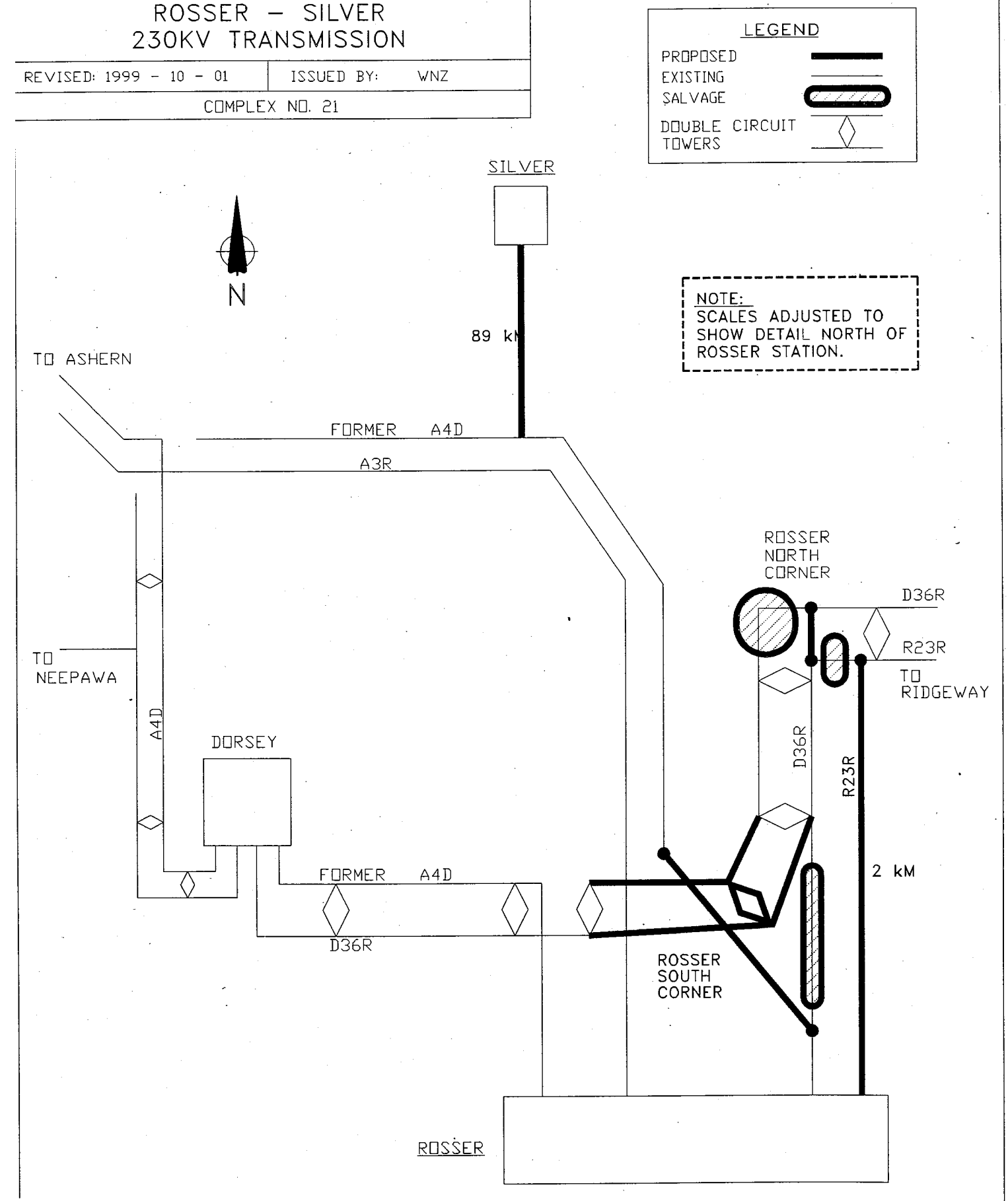
REFERENCE NUMBER	DESCRIPTION
Complex 41	Metro Winnipeg Loop
Complex 27	Dorsey - St. Vital 230 KV Transmission

CAPITAL BUDGET COMPLEX CONCEPTUAL DIAGRAM

ROSSER – SILVER 230KV TRANSMISSION

REVISED: 1999 - 10 - 01	ISSUED BY: WNZ

COMPLEX NO. 21



manitoba hydro

PLANNING AND CONTROL DIVISION

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

63.

COMPLEX STATUS	Complex no.	REVISION STATUS
☐ Planned ☒ In progress	21	☐ New complex ☒ In service change ☐ Concept change ☐ Estimate change only

COMPLEX	ROSSER - SILVER 230 KV TRANSMISSION

Proposal

Perform environmental assessments and route selection, design and construct transmission and terminal facilities to provide firm supply to Silver stn as follows: Transmission: Construct 230kV line 89 km Silver to Wpg. Connect to unused former line A4D 15 km north of Rosser. Open 230kV lines D36R & R23R at Rosser North & South Corners. Connect end of former A4D to Rosser end of former R23R at Rosser S Corner to create Rosser-Silver circuit. Construct 2.0 km 230kV line from Rosser and connect to Ridgeway end of R23R at Rosser N Corner to re-establish Rosser-Ridgeway line R23R. Connect open ends of D36R to former R23R at Rosser N & S Corners to re-establish Dorsey-Ridgeway line D36R. Terminations: Extend 230kV facilities at Rosser and Silver. Extend 66kVfacilities at Silver to terminate previously installed spare 230-66kV transformer #1 Replace line protection at Ashern. Communications: Integrate with existing facilities at Rosser and Silver.

JUSTIFICATION	Explanation
☒ Load ☐ Service ☐ Safety ☐ Efficiency ☒ Reliability ☐ Other	This complex provides transmission system improvements for firm supply to Silver station.

Estimate Level	COMPLEX START (yyyy mm)
L2	95 04 0

IN SERVICE DATES AND AMOUNTS					
1999 03	$1388	2000 10	$1964	2004 10	$27767

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	3,125		418	2	3,541	2,771	770	28
Year 99/00	3,158	52	359		3,569	2,979	590	20
00/01		0	433		433	4,008	-3,575	-89
01/02	92	6	364		1,462	11,120	-10,658	-96
02/03	2,658	91	510		3,259	7,436	-4,177	-56
03/04	8,210	806	863		9,879		9,879	
04/05	7,907	948	1,120		9,975		9,975	
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	25,150	1,903	4,067	2	31,118	28,314	2,804	10

REVISION	ISD deferred two years to October 2004 due to financial constraints.

Reviewed by ORIGINATOR	yyyy mm dd 99 11 08	Reviewed by COORDINATOR	yyyy mm dd 99 11 03
Reviewed by CONSTRUCTOR	yyyy mm dd 99 11 03	Approved by VICE PRESIDENT	yyyy mm dd 99 11 16

H2856/r Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Complex no. 21

Advance or deferral impact

Deferral will limit firm supply to the Silver area and affect timing of Dorsey - St. Vital 230 KV Transmission improvements.

Factors affecting timing or viability

Manitoba Load.
Ashern - Dorsey 230 KV Transmission Improvements.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Rosser - Silver 230 KV T/L	13,269	15,456	15,765	16,103	338	2
Silver-Terminate Rosser 230KV T/L & 230-66KV Tfr.	4,832	4,319	4,405	4,736	331	8
Rosser-Terminate Silver 230KV T/L & Reterm. R23R	2,206	2,285	2,331	2,465	134	6
Ashern - Line A3R Protection Changes	254	271	276	290	14	5
Rosser-Silver 230KV T/L Telecontrol Facilities	1,436	1,494	1,524	1,554	30	2
TOTAL	21,997	23,825	24,301	25,148	847	3

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
9510	25,500	Reflects increases for material, engineering, line construction unit costs and added contingency.
9610	25,490	T/L work ISD defer 1 yr to 2000. Line modifctn optimized. Rosser-Silver line incrs 9 km. Ln R23R construct'n incrs 1.2 km. Ashern line prtctn rplc. Silver stn costs dcrs
1997 10	25,338	Scope unchanged, estimate reflects revised costing methodology implemented with the new financial reporting system. Also reflects revised interest and escalation rates.
1998 10	28,314	ISD deferred two years to October 2002.
1999 10	31,118	ISD deferred two years to October 2004 due to financial constraints.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

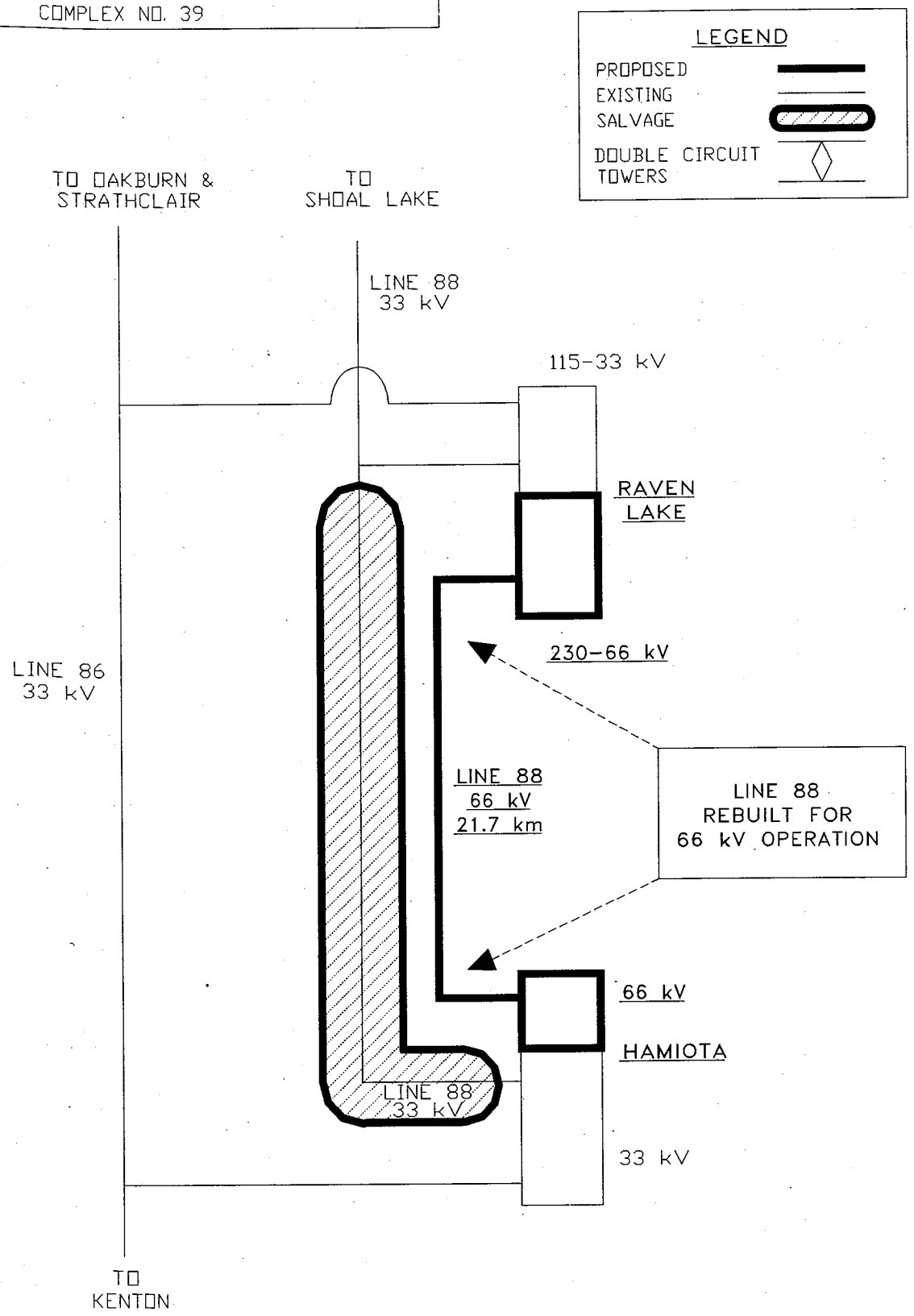
REFERENCE NUMBER	DESCRIPTION
Complex 51	Ashern - Dorsey 230 KV Line Changes

CAPITAL BUDGET COMPLEX CONCEPTUAL DIAGRAM

RAVEN LAKE STATION
230–66 KV TRANSFORMATION

REVISED: 1999 - 10 - 01	ISSUED BY: WNZ

COMPLEX NO. 39



H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

64.

COMPLEX STATUS	Complex no.	REVISION STATUS
☒ Planned ☐ In progress	39	☐ New complex ☐ In service change ☐ Concept change ☒ Estimate change only

COMPLEX	RAVEN LAKE 230-66 KV TRANSFORMATION

Proposal

Design and construct transmission and terminal facilities for supply at Raven Lake and Hamiota as follows:

Transmission: Rebuild 33 KV line 88 Raven Lake - Hamiota for 66 KV operation.

Terminations: Extend 230 and 66 KV facilities at Raven Lake station, including addition of a 230-66 KV 50 MVA transformer and associated 66 KV circuit breaker and 40 MVA grounding bank. Reconnect Hamiota 33-25 KV Bank 2 for 66-25 KV operation.

JUSTIFICATION		Explanation
☒ Load	☐ Service	This transformer is required to supply increased load at Raven Lake. Loading on the Raven Lake 115-33 KV system will be reduced by transferring part of the 33 KV load at Raven Lake and Hamiota to 66 KV supply.
☐ Safety	☐ Efficiency	
☒ Reliability	☐ Other	

Estimate Level	COMPLEX START (yyyy mm)
L2	2014 04

IN SERVICE DATES AND AMOUNTS				
2017 10	$8321			

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend								
Year 99/00								
00/01								
01/02								
02/03								
03/04								
04/05								
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15	396	156	24		576	505	71	14
15/16	956	408	97		1,461	1,388	73	5
16/17	1,837	828	327		2,992	2,927	65	2
17/18	1,972	940	369	20	3,261	3,231	30	1
18/19								
Beyond								
TOTAL	5,161	2,332	817	20	8,290	8,051	239	3

REVISION	Scope unchanged.

		yyyy mm dd			yyyy mm dd
Reviewed by	ORIGINATOR	99 11 08	Reviewed by	COORDINATOR	99 11 03
Reviewed by	CONSTRUCTOR	99 11 03	Approved by	VICE-PRESIDENT	99 VI 16

H2856/r Rev 99 03

Complex no. 39

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Advance or deferral impact

Deferral will decrease supply reliability in the Raven Lake area in case of an outage of an existing Raven Lake 115-33 KV transformer and will overload 33 KV facilities during peak load conditions.

Factors affecting timing or viability

Manitoba Load.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Raven Lake Station 230-66 KV Transformation		4,451	4,540	4,619	79	2
Hamiota Stn.-Reconnect Bank 2 for 66 KV Operation		60	61	61	0	0
Line 88 Conversion to 66 KV Operation		487	497	481	-16	-3
TOTAL		4,998	5,098	5,161	63	1

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy mm	TOTAL AMOUNT	AMENDMENT
1995 10	3,737	Reflects revised escalation and interest rates.
1996 10	8,061	In-service date deferred 19 years to 2017. Conversion of Hamiota 33 KV line and transformer to 66 KV operation added.
1997 10	7,993	Estimate reflects revised costing methodology implemented with the new financial reporting system. Also reflects revised insterest and escalation rates.
1998 10	8,051	Scope unchanged
1999 10	8,290	Scope unchanged.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

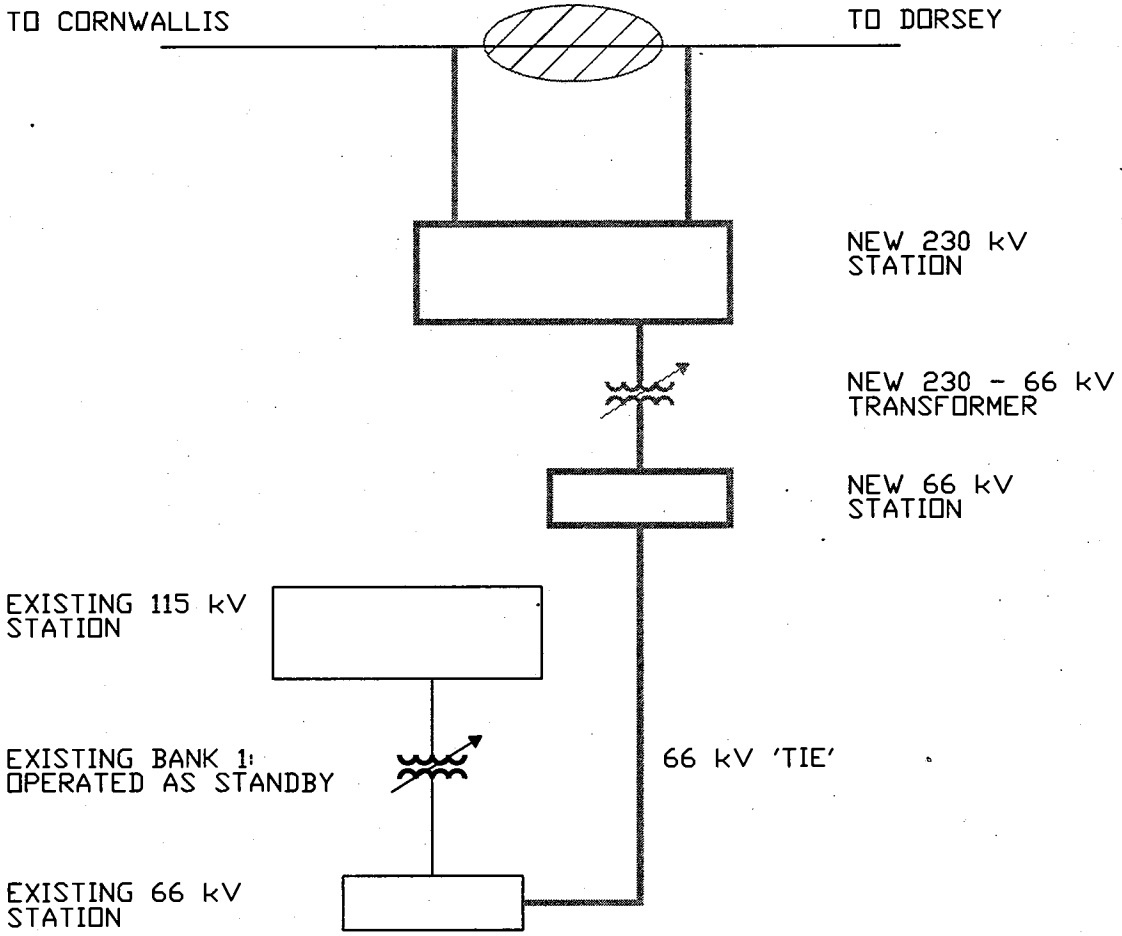
REFERENCE NUMBER	DESCRIPTION

CAPITAL BUDGET COMPLEX CONCEPTUAL DIAGRAM

NEEPAWA 230 - 66 kV STATION

REVISED: 1999 10 01	ISSUED BY: CS

COMPLEX NO. 18



LEGEND

PROPOSED

EXISTING

SALVAGE

manitoba hydro

PLANNING AND CONTROL DIVISION

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

65.

COMPLEX STATUS	Complex no.	REVISION STATUS
☒ Planned ☐ In progress	18	☐ New complex ☒ In service change ☒ Concept change ☐ Estimate change only

COMPLEX	NEEPAWA 230-66KV STATION

Proposal

Perform environmental assessments and route selection, design and construct terminal facilities to provide firm supply to Neepawa as follows:
Transmission: Sectionalize 230KV T/L D54C into Neepawa 230kV Stn, creating Dorsey-Neepawa and Neepawa -Cornwallis 230kV circuits. Build a 66KV tie line between the new 66KV terminal and the Existing 115/66/kV Station
Terminations: Establish Neepawa 230-66KV station, including three 230kV circuit breakers, a 50/66/83.3/93.3 MVA, 230-66KV LTC transformer, six 66KV circuit breakers and associated equipment. Adjust line protection equipment at Dorsey and Cornwallis 230KV stations. Terminate two 230kV transmission lines to Dorsey and Cornwallis.
Communications: Integrate with existing facilities at Neepawa , Dorsey, and Cornwallis 230KV stations.

JUSTIFICATION		Explanation
☒ Load	☐ Service	These facilities provide transmission improvements required by 2006 to supply Neepawa and related Western Region future load growth.
☐ Safety	☐ Efficiency	
☒ Reliability	☐ Other	

Estimate Level	COMPLEX START yyyy mm
L2	1999 04

IN SERVICE DATES AND AMOUNTS			
2006 10	$17689		

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend								
Year 99/00						325	-325	-100
00/01						416	-416	-100
01/02						1,007	-1,007	-100
02/03						10,109	-10,109	-100
03/04	54	7	1		62	10,513	-10,451	-99
04/05	872	118	33		1,023		1,023	
05/06	6,035	999	324		7,358		7,358	
06/07	7,325	1323	597	153	9,092		9,092	
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	14,286	2,447	955	153	17,535	22,370	-4,835	-22

REVISION	Concept changed from 230-115kV to 230-66kV project, eliminating 115kv improvements to existing stn. ISD deferred 3 years to 2006 10 31.

		yyyy mm dd			yyyy mm dd
Reviewed by	ORIGINATOR	99 11 08	Reviewed by	COORDINATOR	99 11 03
Reviewed by	CONSTRUCTOR	99 11 03	Approved by	VICE PRESIDENT	99 11 16

H2856/r Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Complex no. 18

Advance or deferral impact

Delays will reduce firm supply to Neepawa load.

Factors affecting timing or viability

Manitoba Load.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Neepawa Sectionalize 230kV T/L D54C		764	883	780	-103	-12
Neepawa - Establish 230-66kV Station		9,706	11,443	10,019	-1,424	-12
Neepawa 115 KV Station Upgrade (cancelled)		7,045	7,186	0	-7,186	-100
Dorsey - Protection Changes for Neepawa 230KV T/L		62	71	67	-4	-6
Cornwallis-Protectn Changes for Neepawa 230KV T/L		46	53	50	-3	-6
Telecontrol for Neepawa 230-115KV Station Addtn.		1,357	1,161	1,485	324	28
Neepawa Terminate 66kV from New 230/66kV Stn				1,414	1,414	
Neepawa 66kV Subtransmission				470	470	
TOTAL		18,980	20,797	14,285	-6,512	-31

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy mm	TOTAL AMOUNT	AMENDMENT
95 10	22,752	New complex.
96 10	22,689	Revised escalation and interest rates.
1997 10	22,245	Scope unchanged, estimate reflects revised costing methodology implemented with the new financial reporting system. Also reflects revised interest and escalation rates.
1998 10	22,370	ISD deferred one year to Octobr 2003.
1999 10	17,535	Concept changed from 230-115kV to 230-66kV project, eliminating 115kv improvements to existing stn. ISD deferred 3 years to 2006 10 31.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION
Complex 57	Dorsey-Neepawa-Cornwallis 230 KV Line

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

66.

COMPLEX STATUS	Complex no.	REVISION STATUS
☐ Planned ☒ In progress	201	☐ New complex ☐ In service change ☐ Concept change ☒ Estimate change only

COMPLEX	ASSINIBOINE WILKES AVE. 115-24 KV BANK 1 ADDITION

Proposal

Design and construct transmission and terminal facilities to firm supply to Assiniboine Wilkes Avenue as follows:

Transmission: 4.4 KM 115 KV line Assiniboine Wilkes - Line YV5 Tap.

Terminations: Extend 115-24.9 KV distribution station facilities at Assiniboine Wilkes, including new 115-24 KV 100 MVA transformer bank #1 and 3-24 KV additional feeder lines.

Communications: Expand and integrate with existing Assiniboine Wilkes facilities.

JUSTIFICATION		Explanation
☒ Load	☐ Service	The facilities are required to firm 115-24 KV supply at Assiniboine Wilkes and provide for future area load growth. Additional feeders are required to supply load and increase feeder tie capacities in the St. James and Kirkfield station areas.
☐ Safety	☐ Efficiency	
☒ Reliability	☐ Other	

Estimate Level	COMPLEX START (yyyy mm)
L2	1996 04

IN SERVICE DATES AND AMOUNTS							
1999 02	$26	1999 04	$418	1999 05	$4823	1999 10	$2315
1999 12	$5341	2000 09	$571				

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	5,831		392	4	6,219	7,625	-1,406	-18
Year 99/00	6,775	71	368	74	7,140	5,866	1,274	22
00/01	33	1	24		58	1,258	-1,200	-95
01/02								
02/03								
03/04								
04/05								
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	12,639	72	784	78	13,417	14,749	-1,332	-9

REVISION	Labour costs were lower than estimated.

Reviewed by ORIGINATOR	yyyy mm dd 99 11 08	Reviewed by COORDINATOR	yyyy mm dd 99 11 03
Reviewed by CONSTRUCTOR	yyyy mm dd 99 11 03	Approved by VICE PRESIDENT	yyyy mm dd 99 11 04

H2856/r Rev 99 03

Complex no. 201

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Advance or deferral impact

Deferral will decrease supply reliability in the Assiniboine Wilkes, St James and Kirkfield areas in case of outage of the existing 115-24 KV transformer or 115 KV tap supply line.

Factors affecting timing or viability

Assiniboine-Wilkes area load growth.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Assiniboine Wilkes Ave-YV5 115KV T/L Tap	490	447	456	490	34	7
Assiniboine Wilkes Ave-W65 24KV Breaker Addtn.	213	245	250	205	-45	-18
Assiniboine Wilkes Ave-W62 24KV Breaker Addtn.	219	219	223	219	-4	-2
Assiniboine Wilkes Ave- 115-24KV Trnsfmr. Addtn.	5,565	5,367	5,474	5,565	91	2
Assiniboine Wilkes Ave-W71 24KV Breaker Addtn.	216	250	255	168	-87	-34
Assiniboine Wilkes Ave-W65 24KV Feeder Addtn.	4,759	4,421	4,509	3,169	-1,340	-30
Assiniboine Wilkes Ave-W62 24KV Feeder Addtn.		559	570	1,114	544	95
Assiniboine Wilkes Ave-W71 24KV Feeder Addtn.	2,285	2,186	2,230	1,293	-937	-42
Assiniboine Wilkes Ave-Bank 1 Addtn.-Communictn.	417	287	293	417	124	42
TOTAL	14,164	13,981	14,260	12,640	-1,620	-11

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
96 10	12,265	New complex.
1997 10	14,445	W65 & W7 breakers deferred 4 months, W65 feeder deferred 5 months, W71 feeder deferred 8 months and W62 feeder and breaker advanced 1 year to 1998 06 30
1998 10	14,749	Reflects 97/98 underexpend 0.8M,W62 feeder and breaker deferred one year to Oct 1999, to coincide with voltage conversion in Wilkes station area by Distribution Planning Wpg.
1999 10	13,417	Labour costs were lower than estimated.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

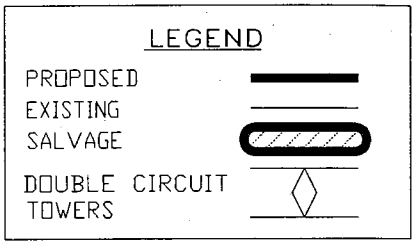
REFERENCE NUMBER	DESCRIPTION

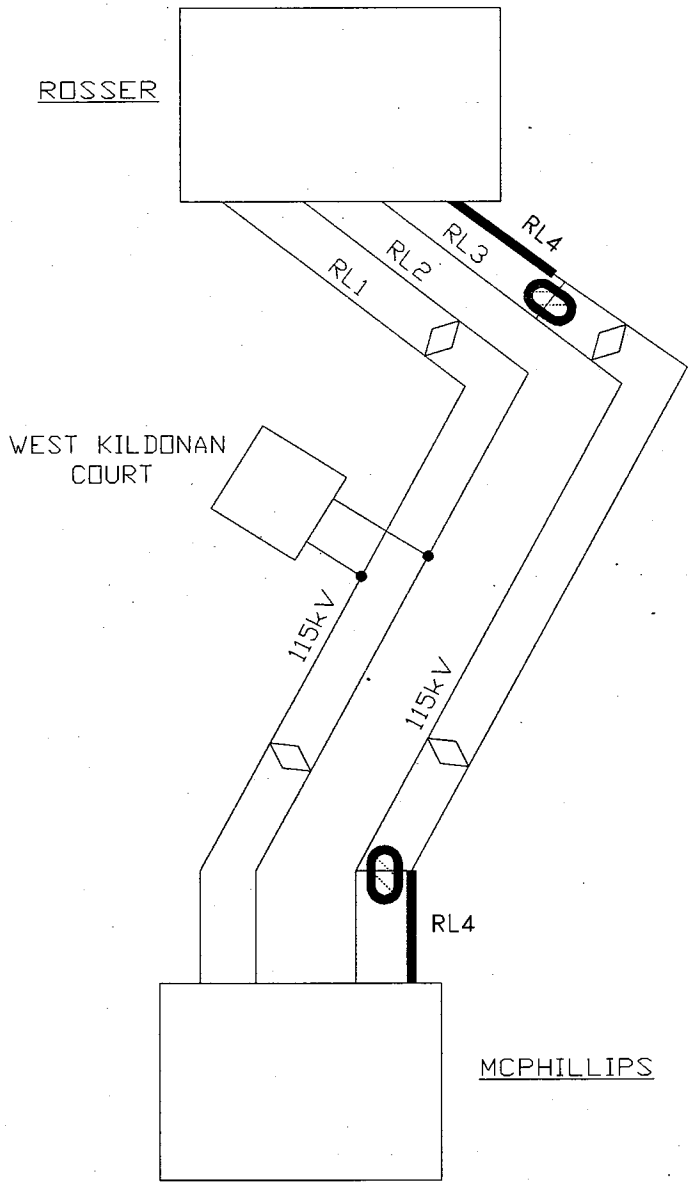
CAPITAL BUDGET COMPLEX CONCEPTUAL DIAGRAM

ROSSER – MCPHILLIPS 115KV TRANSMISSION IMPROVEMENTS

REVISED: 1999 - 10 - 01	ISSUED BY: WNZ

COMPLEX NO. 202





manitoba hydro

PLANNING AND CONTROL DIVISION

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

67.

COMPLEX STATUS	Complex no.	REVISION STATUS
[X] Planned [ ] In progress	202	[ ] New complex [X] In service change [ ] Concept change [ ] Estimate change only

COMPLEX	ROSSER - MCPHILLIPS 115 KV TRANSMISSION IMPROVEMENTS

Proposal

Design and construct transmission and terminal facilities for supply to McPhillips station as follows:

Transmission: Remove jumpers at both ends of paralleled double circuit 115 KV line RL3 and extend open line ends into Rosser and McPhillips to create 115 KV line RL4.

Terminations: Extend 115 KV facilities at Rosser and McPhillips stations.

Communications: Integrated with existing facilities at Rosser and McPhillips.

JUSTIFICATION	Explanation
[X] Load [ ] Service [ ] Safety [ ] Efficiency [X] Reliability [ ] Other	Addition of a second transformer bank at West Kildonan Court station and upgrade of Winnipeg Hydro phase shifters at McPhillips station requires a transmission capacity increase between Rosser and McPhillips for load support.

Estimate Level	COMPLEX START (yyyy mm)
L2	1998 10

IN SERVICE DATES AND AMOUNTS			
2002 10	$2367		

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	4				4	32	-28	-88
Year 99/00	7	0	1		8	72	-64	-89
00/01	82	5	4		91	372	-281	-76
01/02	374	30	22		426	1,744	-1,318	-76
02/03	1,623	155	60		1,838		1,838	
03/04								
04/05								
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	2,090	190	87		2,367	2,220	147	7

REVISION	ISD deferred one year to October 2002 due to financial constraints.

Reviewed by ORIGINATOR		yyyy mm dd 99 11 08	Reviewed by COORDINATOR		yyyy mm dd 99 11 03
Reviewed by CONSTRUCTOR		yyyy mm dd 99 11 03	Approved by VICE PRESIDENT		yyyy mm dd 99 11 16

H2856/r Rev 99 03

Complex no. 202

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Advance or deferral impact

Deferral will cause overloading of two remaining Rosser - McPhillips 115 KV lines during an outage of double circuit line RL3.

Factors affecting timing or viability

Winnipeg Hydro Phase Shifter Upgrade.
West Kildonan Court 2nd transformer installation.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Rosser - McPhillips 115 KV T/L		53	54	54	0	0
Rosser - Terminate New McPhillips 115 KV Line		849	866	884	18	2
McPhillips - Terminate New Rosser 115 KV Line		853	870	910	40	5
Rosser - McPhillips 115 KV T/L Telecontrol		227	232	242	10	4
TOTAL		1,982	2,022	2,090	68	3

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
96 10	2,255	New complex.
1997 10	2,267	Scope unchanged, estimate reflects revised costing methodology implemented with the new financial reporting system. Also reflects revised interest and escalation rates.
1998 10	2,220	Scope unchanged.
1999 10	2,367	ISD deferred one year to October 2002 due to financial constraints.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

68.

COMPLEX STATUS	Complex no.	REVISION STATUS
☒ Planned ☐ In progress	204	☐ New complex ☐ In service change ☐ Concept change ☒ Estimate change only

COMPLEX	RICHER SOUTH 230-66 KV TRANSFORMER ADDITION

Proposal

Design and construct terminal facilities at Richer South as follows:

Terminations: Extend 230 and 66 KV facilities at Richer station, including a 2nd 230-66 KV 93.3 MVA OLTC transformer and associated 66 KV circuit breaker and 40 MVA grounding bank.

JUSTIFICATION	Explanation
☒ Load ☐ Service ☐ Safety ☐ Efficiency ☒ Reliability ☐ Other	The second 230-66 KV transformer is required to provide firm supply to distribution station load in the Richer area.

Estimate Level	COMPLEX START (yyyy mm)
L2	2002 04

IN SERVICE DATES AND AMOUNTS				
2005 10	$4938			

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend								
Year 99/00								
00/01								
01/02								
02/03	328	33	14		375	328	47	14
03/04	328	40	48		416	364	52	14
04/05	1,892	275	157		2,324	2,300	24	1
05/06	1,454	180	188		1,822	1,807	15	1
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	4,002	528	407		4,937	4,799	138	3

REVISION	Scope unchanged.

Reviewed by ORIGINATOR		yyyy mm dd 99 11 08	Reviewed by COORDINATOR		yyyy mm dd 99 11 03
Reviewed by CONSTRUCTOR		yyyy mm dd 99 11 03	Approved by MANAGER/SUPT		yyyy mm dd 99 11 16

H2856/r Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Complex no. 204

Advance or deferral impact

Deferral will decrease supply reliability in the Richer area during an outage of the existing Richer 230-66 KV transformer.

Factors affecting timing or viability

Richer area load.
Transmission improvements from St. Vital to Randolph / Hanover.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Richer South 230-66 KV Transformer Addition		3,872	3,949	4,002	53	1
TOTAL		3,872	3,949	4,002	53	1

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
96 10	4,832	New complex.
1997 10	4,788	Scope unchanged, estimate reflects revised costing methodology implemented with the new financial reporting system. Also reflects revised interest and escalation rates.
1998 10	4,799	Scope unchanged.
1999 10	4,937	Scope unchanged.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

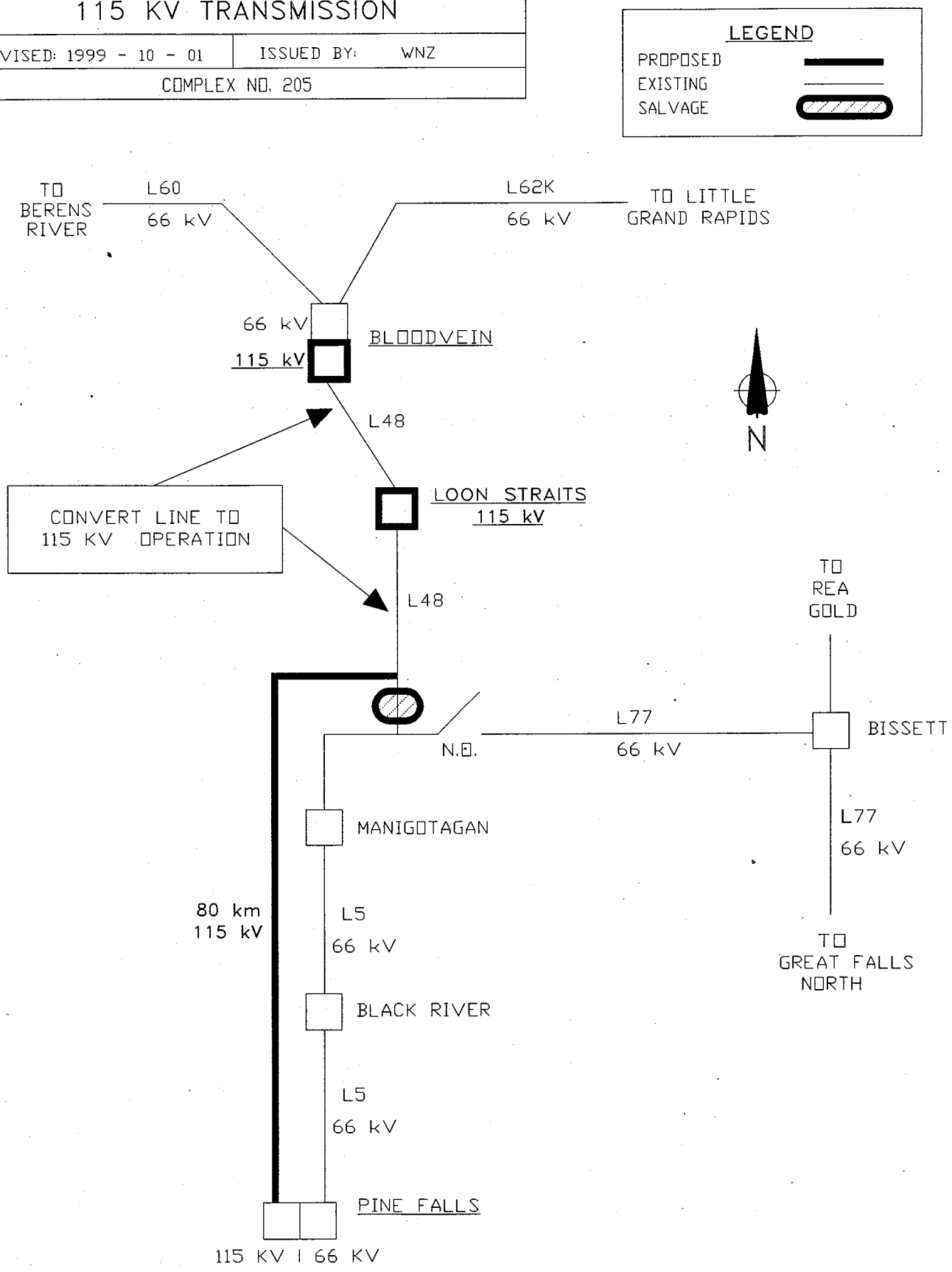
REFERENCE NUMBER	DESCRIPTION

CAPITAL BUDGET COMPLEX CONCEPTUAL DIAGRAM

PINE FALLS – BLOODVEIN 115 KV TRANSMISSION

REVISED: 1999 - 10 - 01 | ISSUED BY: WNZ

COMPLEX NO. 205



manitoba hydro

PLANNING AND CONTROL DIVISION

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

COMPLEX STATUS: [X] Planned [ ] In progress

Complex no. 205

REVISION STATUS: [ ] New complex [X] In service change [ ] Concept change [ ] Estimate change only

COMPLEX: PINE FALLS - BLOODVEIN 115 KV TRANSMISSION

Proposal

Perform environmental assessments and route selection, design and construct transmission and terminal facilities to provide 115 KV supply to Bloodvein station as follows:
Transmission: Construct 115 KV line 80 km Pine Falls-L48 to L5 Tap near Manigotagan. Disconnect L48 from L5 at tap location and connect L48 to new line, converting L48 from 66 KV to 115 KV operation up to Bloodvein.
Terminations: Extend 115 KV facilities at Pine Falls. Replace 66 KV transformers at Loon Straits with 2 - 115-7.2 KV 500 KVA transformers and modify station for 115 KV supply. Construct 115-66 KV station at Bloodvein, including 2 - 115-66 KV 28 MVA transformers.

JUSTIFICATION: [X] Load [ ] Service [ ] Safety [ ] Efficiency [X] Reliability [ ] Other

Explanation: This complex provides increased transmission capacity required to supply Lake Winnipeg East area load increases.

Estimate Level	COMPLEX START (yyyy mm)
L2	1999 04

IN SERVICE DATES AND AMOUNTS

2011 10	$29100		

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend								
Year 99/00						131	-131	-100
00/01						145	-145	-100
01/02						775	-775	-100
02/03						1,417	-1,417	-100
03/04						5,312	-5,312	-100
04/05						13,878	-13,878	-100
05/06						29	-29	-100
06/07	126	23	6		155		155	
07/08	126	26	20		172		172	
08/09	734	169	66		969		969	
09/10	1,218	315	201		1,734		1,734	
10/11	5,005	1440	585		7,030		7,030	
11/12	12,153	2768	696	4	15,613		15,613	
12/13	2,585	836			3,421		3,421	
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	21,947	5,577	1,574	4	29,094	21,687	7,407	34

REVISION: ISD deferred seven years to 2011 10 31

Reviewed by ORIGINATOR	yyyy mm dd 99 11 08	Reviewed by COORDINATOR	yyyy mm dd 99 11 03
Reviewed by CONSTRUCTOR	yyyy mm dd 99 11 03	Approved by VICE-PRESIDENT	yyyy mm dd 99 11 16

H2856/r Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Complex no. 205

Advance or deferral impact

Deferral will reduce reliability of supply and require load curtailments in the Lake Winnipeg East area during peak load periods.

Factors affecting timing or viability

Lake Winnipeg East load growth.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Pine Falls - Bloodvein 115 KV Line		14,083	14,365	14,156	-209	-1
Pine Falls Stn. Termination of Bloodvein 115 KV Line		278	284	286	2	1
Bloodvein 115-66 KV Transformer Additions		6,452	6,581	7,173	592	9
Loon Straits Station Transformer Replacement		322	328	330	2	1
TOTAL		21,135	21,558	21,945	387	2

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
96 10	19,123	New complex.
1997 10	18,190	Scope unchanged, estimate reflects revised costing methodology implemented with the new financial reporting system. Also reflects revised interest and escalation rates.
1998 10	24,646	Revised design concept - a sub standard wishbone type of transmission line was used in the previous estimate. Cursory review of the terrain also indicated that it is rougher than assumed.
1999 10	29,094	ISD deferred seven years to 2011 10 31

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

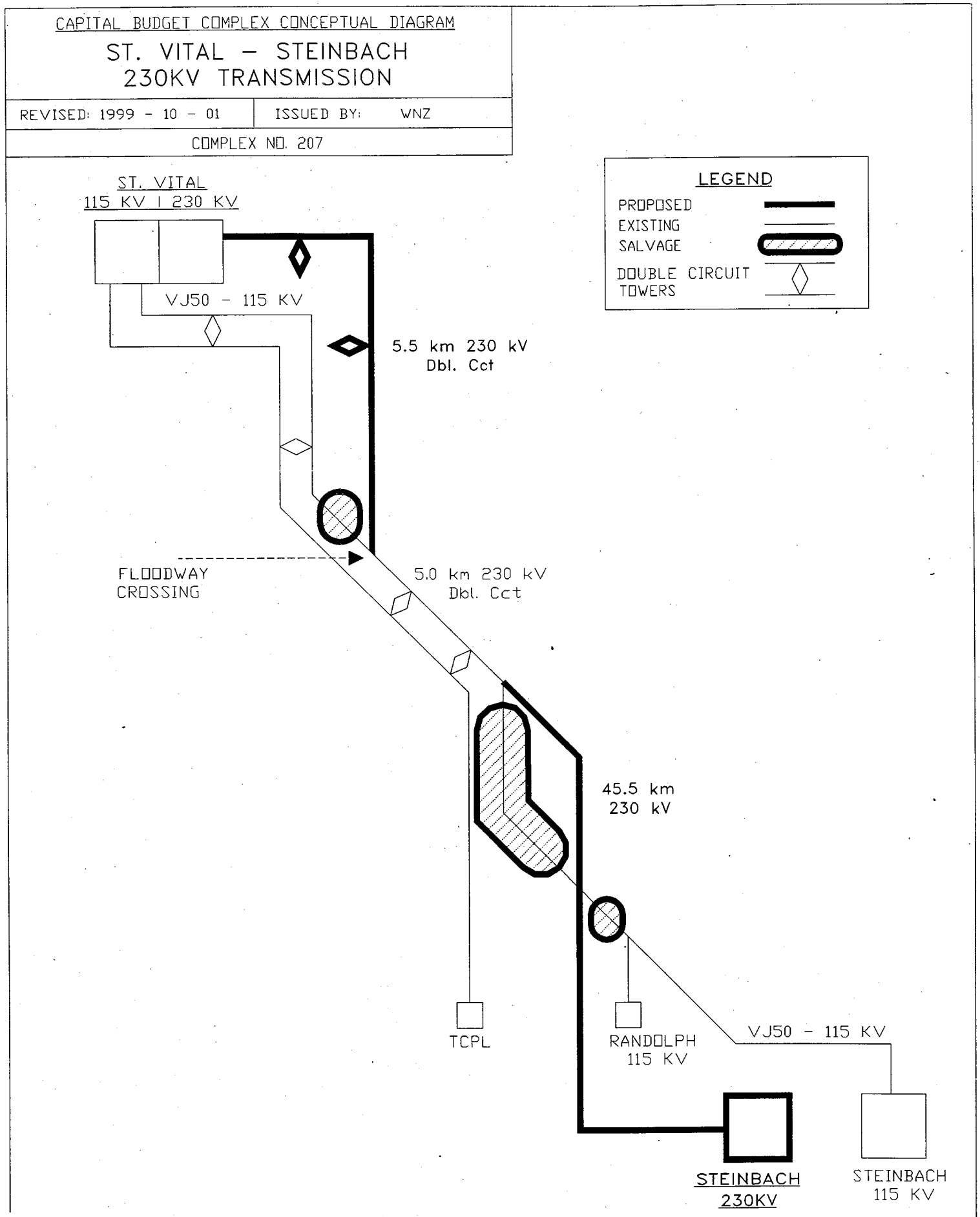
REFERENCE NUMBER	DESCRIPTION

CAPITAL BUDGET COMPLEX CONCEPTUAL DIAGRAM

ST. VITAL – STEINBACH 230KV TRANSMISSION

REVISED: 1999 - 10 - 01	ISSUED BY: WNZ

COMPLEX NO. 207



manitoba hydro

PLANNING AND CONTROL DIVISION

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

70.

COMPLEX STATUS	Complex no.	REVISION STATUS
[X] Planned [ ] In progress	207	[ ] New complex [ ] In service change [ ] Concept change [X] Estimate change only

COMPLEX: ST. VITAL - STEINBACH 230 KV TRANSMISSION

Proposal

Perform environmental assessments and route selection, acquire property and obtain licences, design and construct transmission and terminal facilities to provide support to Steinbach as follows:
Transmission: Construct 230 KV double cct. line strung one side only along 115 KV line VJ50 r.o.w. to location 5.5 km south of St.Vital. Construct 230 KV single cct. line 45.5 km north from Steinbach and connect to south end of double cct. line. Salvage 26.5 km of 115 KV line VJ50 from Ile des Chenes tap to Randolph station tap.
Terminations: Construct 230-66 KV station at Steinbach, including 230-66 KV 83 MVA transformer and associated 230 KV and 66 KV circuit breakers. Extend 230 KV facilities at St. Vital.
Communications: Integrate with existing facilities at St. Vital.

JUSTIFICATION		Explanation
[X] Load	[ ] Service	This complex provides a 230 KV supply into the Steinbach area for support of load growth in south eastern Manitoba.
[ ] Safety	[ ] Efficiency	
[X] Reliability	[ ] Other	

Estimate Level	COMPLEX START (yyyy mm)
L2	2004 04

IN SERVICE DATES AND AMOUNTS			
2009 10	$22259		

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend								
Year 99/00								
00/01								
01/02								
02/03								
03/04								
04/05	237	34	11		282	246	36	15
05/06	260	44	37		341	296	45	15
06/07	465	89	79		633	551	82	15
07/08	2,489	536	239		3,264	3,143	121	4
08/09	2,898	694	570		4,162	3,991	171	4
09/10	10,165	2628	784		13,577	13,441	136	1
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	16,514	4,025	1,720		22,259	21,668	591	

REVISION: Scope unchanged.

Reviewed by ORIGINATOR	yyyy mm dd 99 11 08	Reviewed by COORDINATOR	yyyy mm dd 99 11 10
Reviewed by CONSTRUCTOR	yyyy mm dd 99 11 03	Approved by MANAGER/DIRECTOR	yyyy mm dd 99 11 16

H2856/r Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Complex no. 207

Advance or deferral impact

Deferral will reduce reliability of supply to the Steinbach /Randolph area 66 KV and 115 KV systems.

Factors affecting timing or viability

Steinbach / Randolph area load growth.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
St. Vital - Steinbach 230 KV T/L		7,731	7,886	7,882	-4	-0
Steinbach - New 230-66 KV Station		5,566	5,677	5,769	92	2
St. Vital - Terminate Steinbach 230 KV T/L		2,058	2,099	2,179	80	4
St. Vital - Steinbach Communications Complex		654	667	684	17	3
TOTAL		16,009	16,329	16,514	185	1

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
96 10	26,352	New complex.
1997 10	21,593	5.0 km dbl cct line section btwn the floodway & Ile des Chenes tap, & VJ50 line salvage cmpltd on 97 07 24 under complex #212. Also reflects revised interest and escalation rates.
1998 10	21,668	Scope unchanged.
1999 10	22,259	Scope unchanged.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

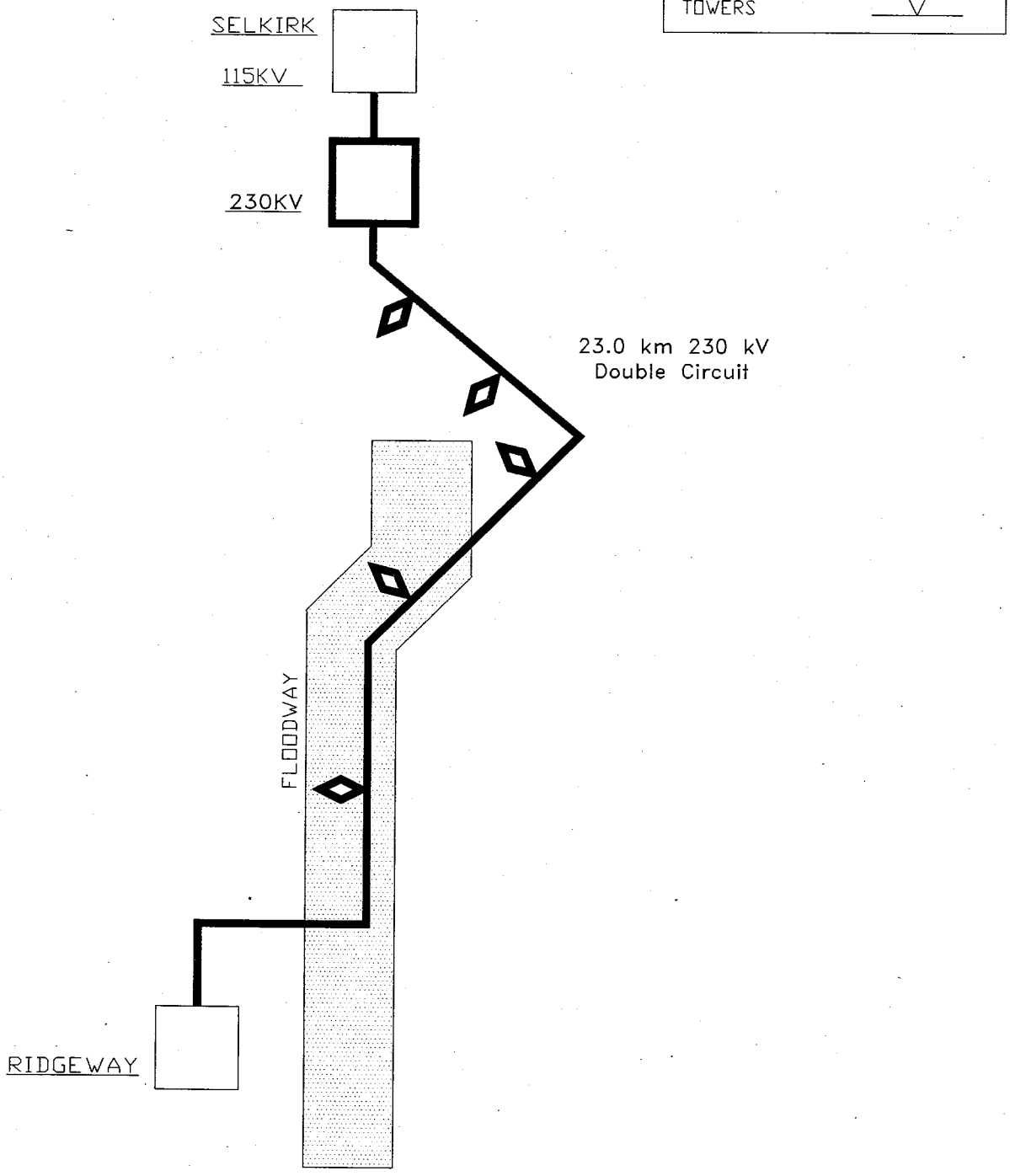
REFERENCE NUMBER	DESCRIPTION

CAPITAL BUDGET COMPLEX CONCEPTUAL DIAGRAM

RIDGEWAY – SELKRIK 230KV TRANSMISSION

REVISED: 1999 – 10 – 01	ISSUED BY: WNZ

COMPLEX NO. 208



manitoba hydro

PLANNING AND CONTROL DIVISION

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

71.

COMPLEX STATUS	Complex no.	REVISION STATUS
☒ Planned ☐ In progress	208	☐ New complex ☐ In service change ☐ Concept change ☒ Estimate change only

COMPLEX	RIDGEWAY - SELKIRK 230 KV TRANSMISSION

Proposal

Perform environmental assessments and route selection, acquire property and obtain licences, design and construct transmission and terminal facilities to provide support to Selkirk station as follows:
Transmission: 230 KV double cct. line strung one side only 23 km Ridgeway to Selkirk.

Terminations: Construct 230 KV station at Selkirk G.S. 115 KV station site, including 230-115 KV 250 MVA OLTC transformer and associated 230 KV and 115 KV circuit breakers. Extend 230 KV facilities at Ridgeway.

Communications: Integrate with existing facilities at Ridgeway and Selkirk.

JUSTIFICATION	Explanation
☒ Load ☒ Service ☐ Safety ☐ Efficiency ☒ Reliability ☐ Other	This complex provides a 230 KV supply into the Selkirk area to alleviate customer voltage flicker problems and increase system support to the Rosser - Parkdale - Selkirk area.

Estimate Level	COMPLEX START (yyyy mm)
L2	2002 04

IN SERVICE DATES AND AMOUNTS			
2007 10	$25099		

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend								
Year 99/00								
00/01								
01/02								
02/03	553	55	24		632	571	61	11
03/04	1,693	207	128		2,028	1,969	59	3
04/05	2,609	375	360		3,344	3,204	140	4
05/06	3,236	546	670		4,452	4,303	149	3
06/07	4,869	924	1,215		7,008	6,871	137	2
07/08	5,461	1156	1,018		7,635	7,554	81	1
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	18,421	3,263	3,415		25,099	24,472	627	3

REVISION	Scope unchanged.

Reviewed by ORIGINATOR	yyyy mm dd 99 11 08	Reviewed by COORDINATOR	yyyy mm dd 99 11 03
Reviewed by CONSTRUCTOR	yyyy mm dd 99 11 03	Approved by VICE PRESIDENT	yyyy mm dd 99 11 16

H2856/r Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Complex no. 208

Advance or deferral impact

Deferral will cause continuation of Selkirk area industrial load customer voltage flicker difficulties and reduce reliability of supply to Selkirk - Parkdale area load.

Factors affecting timing or viability

Selkirk - Parkdale area load growth.
Winnipeg area transmission improvements.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Ridgeway - Selkirk 230 KV T/L		6,156	6,279	6,156	-123	-2
Selkirk - Establish 230-115 KV Station		9,131	9,314	9,514	200	2
Ridgeway - Terminate Selkirk 230 KV T/L		2,064	2,105	2,199	94	4
Ridgeway - Selkirk - Communications Complex		524	534	553	19	4
TOTAL		17,875	18,232	18,422	190	1

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy mm	TOTAL AMOUNT	AMENDMENT
96 10	26,899	New complex.
1997 10	26,560	Scope unchanged, estimate reflects revised costing methodology implemented with the new financial reporting system. Also reflects revised interest and escalation rates.
1998 10	24,472	Revised to reflect current transmission line cost and advancement of start date to 2002 04 01.
1999 10	25,099	Scope unchanged.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

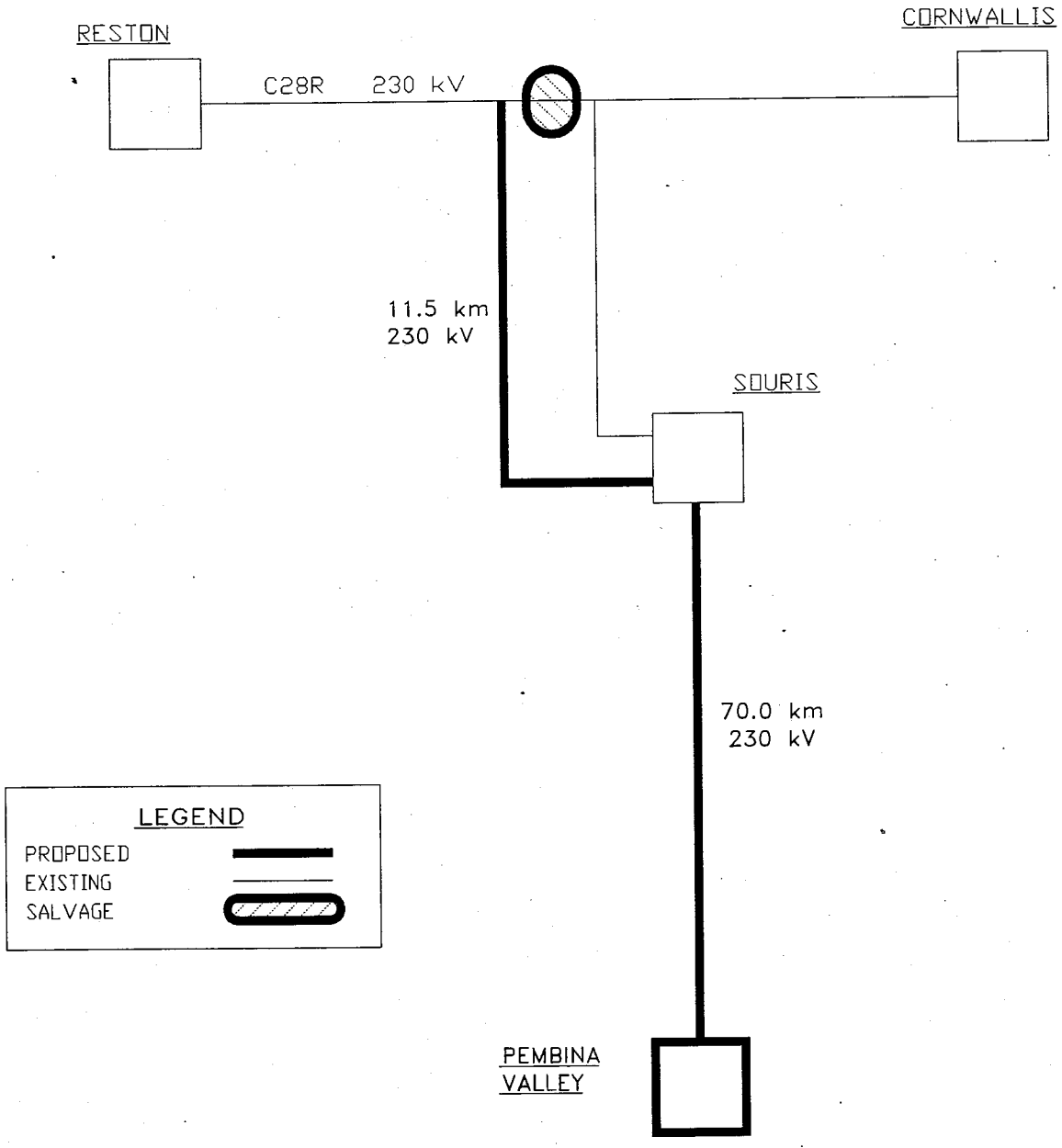
REFERENCE NUMBER	DESCRIPTION

CAPITAL BUDGET COMPLEX CONCEPTUAL DIAGRAM

SOURIS – PEMBINA VALLEY 230KV TRANSMISSION

REVISED: 1999 - 10 - 01 | ISSUED BY: WNZ

COMPLEX NO. 210



manitoba hydro

PLANNING AND CONTROL DIVISION

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

72

COMPLEX STATUS	Complex no.	REVISION STATUS
☒ Planned ☐ In progress	210	☐ New complex ☐ In service change ☐ Concept change ☒ Estimate change only

COMPLEX	SOURIS - PEMBINA VALLEY 230 KV TRANSMISSION

Proposal

Perform environmental assessments and route selection, acquire property and obtain licences, design and construct transmission and terminal facilities to provide supply to Pembina Valley and firm supply to Souris as follows:
Transmission: 230 KV line 11.5 km Souris-line C28R Tap, 230 KV line 70.0 km Souris-Pembina Valley. Open line C28R west of Souris Tap to create Cornwallis-Souris 230 KV line. Connect open end of C28R to 11.5 km line to create Reston-Souris 230 KV line.
Terminations: Establish Pembina Valley 230-66 KV station, including 230-66 KV 83 MVA transformer and associated 230 KV & 66 KV circuit breakers. Extend 230 KV facilities at Souris. Modify line protection at Cornwallis and Reston.
Communications: Integrate with existing facilities at Souris, Cornwallis and Reston.

JUSTIFICATION		Explanation
☒ Load	☐ Service	This complex provides a 230 KV supply into the Killarney/Boissevain area around Pembina Valley to support load growth in south-western Manitoba.
☐ Safety	☐ Efficiency	
☒ Reliability	☐ Other	

Estimate Level	COMPLEX START yyyy mm
L2	2006 04

IN SERVICE DATES AND AMOUNTS			
2011 10	$32570		

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend								
Year 99/00								
00/01								
01/02								
02/03								
03/04								
04/05								
05/06								
06/07	468	87	32		587	579	8	1
07/08	649	133	117		899	898	1	0
08/09	966	225	217		1,408	1,355	53	4
09/10	966	252	357		1,575	1,446	129	9
10/11	8,403	2385	1,192		11,980	11,759	221	2
11/12	11,476	3280	1,365		16,121	15,843	278	2
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	22,928	6,362	3,280		32,570	31,880	690	2

REVISION	Scope unchanged.

Reviewed by	yyyy mm dd	Reviewed by	yyyy mm dd
ORIGINATOR	99 11 08	COORDINATOR	99 11 03
Reviewed by	yyyy mm dd	Approved by	yyyy mm dd
CONSTRUCTOR	99 11 03	VICE PRESIDENT	99 11 16

H2856/r Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Complex no. 210

Advance or deferral impact

Deferral will reduce reliability of supply to the Killarney / Boissevain area, and to the Souris area for an outage of 230 KV line C28R.

Factors affecting timing or viability

Load growth in south-west Manitoba.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Souris-Pembina Valley 230 KV T/L		11,317	11,543	11,317	-226	-2
Pembina Valley - New 230-66 KV Station		5,649	5,762	5,926	164	3
Souris - Terminate Pembina Valley 230KV T/L		3,689	3,763	3,884	121	3
Cornwallis - Protection Changes for C28R		213	217	228	11	5
Reston - Protection Changes for C28R		212	216	228	12	6
Souris-Pembina Valley Communications Complex		1,297	1,323	1,345	22	2
TOTAL		22,377	22,824	22,928	104	0

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
96 10	33,012	New complex.
1997 10	30,474	Pembina Valley line termination changed to new bay.
1998 10	31,880	Estimate revised to reflect current transmission line costs.
1999 10	32,570	Scope unchanged.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

COMPLEX STATUS: ☐ Planned ☒ In progress

Complex no. 4

REVISION STATUS: ☐ New complex ☐ In service change ☐ Concept change ☒ Estimate change only

COMPLEX	WINNIPEG AREA TRANSMISSION REFURBISHMENT

Proposal

Refurbish 292.6 KM of double circuit and 120.7 KM of single circuit 230 and 110 KV transmission lines in the Winnipeg area. Refurbish 16.9 KM of double circuit and 49.2 KM of single circuit 63.5 KV subtransmission lines in the Winnipeg area. The refurbishment will correct insufficient ground clearances of line conductors. Using resagging, reconductoring, and tower extensions where required, the lines are to be upgraded to maintain safe ground clearances under thermal conductor loading.

JUSTIFICATION

☒ Load ☐ Service
☒ Safety ☐ Efficiency
☐ Reliability ☐ Other

Explanation

Lines in the Winnipeg area built pre-1970 cannot accommodate thermal conductor loading without violating required ground clearances. The refurbishment program will increase line to ground clearances to allow higher conductor temperatures under all potential heavy current line loads.

Estimate Level	COMPLEX START (yyyy mm)
L2-3	1991 03

IN SERVICE DATES AND AMOUNTS

To 1997 12	$474	1998 01	$490	1998 12	$408	1999 01	$118
1999 07	$766	1999 09	$297	1999 10	$351	2000 03	$568
2000 09	$297	2001 03	$587	2001 09	$297	2002 on	$2212

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	2,254		299	9	2,544	3,031	-487	-16
Year 99/00	957	18	101		1,076	630	446	71
00/01	485	13	52		550	721	-171	-24
01/02	396	19	18		433	722	-289	-40
02/03	756	51	10		817	736	81	11
03/04	1,038	25	21		1,084	882	202	23
04/05	5	1			6		6	
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	5,891	127	501	9	6,510	6,722	-212	-3

REVISION	Reduced cost resulted from less than expected upgrade work on several lines.

Reviewed by ORIGINATOR		yyyy mm dd 99 11 08	Reviewed by COORDINATOR		yyyy mm dd 99 11 03
Reviewed by CONSTRUCTOR		yyyy mm dd 99 11 03	Approved VICE PRESIDENT		yyyy mm dd 99 11 16

H2856/r Rev 99 03

Complex no. 4

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Advance or deferral impact

Deferral would result in a continued safety hazard due to insufficient line to ground clearances under operation with high conductor temperatures.

Factors affecting timing or viability

Time required for line measurement and testing.
Evaluation and design for refurbishment of individual circuits.
Actual (undetermined) capacities of lines.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE	
					Amount	%
Winipeg 230 & 115 KV Network T/L Refurbishment	4,856	5,951	6,070	5,791	-279	-5
Winnipeg 63.5 KV Network T/L Refurbishment	477	102	104	100	-4	-4
TOTAL	5,333	6,053	6,174	5,891	-283	-5

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
9510	5,875	In-service dates for all 230 & 110KV lines deferred 4.5 years to 2003 09 30 and for 63.5KV lines to 1996 09 30 to accommodate other work priorities.
9610	6,209	In-service dates for 63.5 KV lines deferred 6 months to 1997 03 31 to accommodate other work priorities. Work schedule for 1998/99 deferred.
1997 10	6,596	Scope unchanged, estimate reflects revised costing methodology implemented with the new financial reporting system. Also reflects revised interest and escalation rates.
1998 10	6,722	Reflects 97/98 underexpenditure 0.7M, and revised estimate based on last four years cost data.
1999 10	6,510	Reduced cost resulted from less than expected upgrade work on several lines.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

74.

COMPLEX STATUS	Complex no.	REVISION STATUS
☐ Planned ☒ In progress	28	☐ New complex ☐ In service change ☐ Concept change ☒ Estimate change only

COMPLEX	DORSEY STATION 230 KV BREAKER REPLACEMENT

Proposal

Replace 25 - 230 KV Dorsey breakers with gas insulated units of 63.5 KAMP fault current interrupting capacity.
Upgrade 5 - 230 KV breakers to 63.5 KAMP fault capacity. Replace 23 sets of underrated breaker current transformers (CT's).
Purchase 3 - 1 phase spare breaker heads and a gas cart for new breaker maintenance. Install resistors on 4KV secondary windings of station service transformers SST1 & SST2. Replacements are to be installed over a three year period.

JUSTIFICATION	Explanation
☐ Load ☐ Service ☒ Safety ☐ Efficiency ☒ Reliability ☐ Other	The specified Dorsey 230 KV breakers are underrated for the increasing short circuit levels in the Winnipeg area. The new breakers are rated to accommodate the increased fault levels.

Estimate Level	COMPLEX START (yyyy mm)
L4	1992 01

IN SERVICE DATES AND AMOUNTS							
1994 03	$7360	1996 06	$10045	1999 03	($538)	1999 12	$2279

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	15,666		1,915	344	17,237	19,097	-1,860	-10
Year 99/00	1,479	7	80		1,566	1,008	558	55
00/01								
01/02								
02/03								
03/04								
04/05								
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	17,145	7	1,995	344	18,803	20,105	-1,302	-6

REVISION	Decrease reflects settlement received from Square D.

Reviewed by ORIGINATOR		yyyy mm dd 99 11 08		Reviewed by COORDINATOR		yyyy mm dd 99 11 03	
Reviewed by CONSTRUCTOR		yyyy mm dd 99 11 03		Approved by MANAGER/DIRECTOR		yyyy mm dd 99 11 16	

H2856/r Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Complex no. 28

Advance or deferral impact

Deferral would result in continued risk of equipment damage and personnel hazard due to insufficient circuit breaker fault clearing capacity.

Factors affecting timing or viability

Supply delays.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Dorsey Station Replacement of 230 KV Breakers	17,884	18,436	18,805	17,145	-1,660	-9
TOTAL	17,884	18,436	18,805	17,145	-1,660	-9

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
9510	16,912	Reflects contingency adj, CT retrofit and addition of SST resistors. Cost decrease due to application of experience from initial stages of breaker repl to later stages.
9610	18,216	Replacement of 2 breakers deferred 8 months to 1996 06 30. Completion of CT replacement defer 2 years to 1997 10 31. Cost increases for engineering, labour and material.
1997 10	18,627	Completion of CT replacement deferred from 97 10 30 to 98 11 30.
1998 10	20,105	Reflects 97/98 underexpenditure 0.5M. Contingency increased to allow for purchase of current transformers to replace existing faulty Square D CTS.
1999 10	18,803	Decrease reflects settlement received from Square D.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

75.

COMPLEX STATUS	Complex no.	REVISION STATUS
☐ Planned ☒ In progress	43	☐ New complex ☒ In service change ☐ Concept change ☒ Estimate change only

COMPLEX	DORSEY - US BORDER 500 KV T/L INSULATOR REPLACEMENT

Proposal

Purchase and install new 36-kip suspension insulators on the 500kv transmission line between Dorsey and the US border to replace the existing defective ones. The scope of the work includes a total of 475 suspension, and possibly 15 dead end, towers..

JUSTIFICATION		Explanation
☒ Load	☐ Service	A 1994/95 test program indicated that the existing 36-kip suspension insulators in this line are defective. This item provides for their replacement and full restoration of the lines integrity.
☐ Safety	☐ Efficiency	
☒ Reliability	☐ Other	

Estimate Level	COMPLEX START (yyyy mm)
L2	1995 12

IN SERVICE DATES AND AMOUNTS							
1999 01	$3881	1999 12	$1897	2000 12	$607	2001 12	$607
2002 12	$683						

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	4,369		587		4,956	4,261	695	16
Year 99/00	1,103	9	109		1,221	792	429	54
00/01	401	10	43		454	763	-309	-40
01/02	402	17	29		448	928	-480	-52
02/03	551	26	18		595	1,195	-600	-50
03/04								
04/05								
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	6,826	62	786		7,674	7,939	-265	-3

REVISION	Reflects a schedule change to 120 towers in 99/00 (prev 60), and 40 towers per yr to 02/03 (prev 60).

Reviewed by ORIGINATOR	yyyy mm dd 1999 11 09	Reviewed by COORDINATOR	yyyy mm dd 99 11 09
Reviewed by CONSTRUCTOR	yyyy mm dd 99 11 03	Approved by VICE PRESIDENT	yyyy mm dd 99 11 16

H2856/r Rev 99 03

Complex no. 43

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Advance or deferral impact

Deferral increases chance of insulator failure.

Factors affecting timing or viability

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Dorsey - US border D602F 500kv T/L insulator repl	5,308	6,907	7,045	6,827	-218	-3
TOTAL	5,308	6,907	7,045	6,827	-218	-3

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
95 10	7,104	New Complex
96 10	6,899	COB insulator replacement at 60 towers at major crossings moved foreward to the fall of 1996 and 1997.
1997 10	7,395	Revised estimate based on all insulator replacement work being carried out by MH's work crews instead of contractors.
1998 10	7,939	In service deferred 1 year due to Oct 97 accident. Labour cost increase due to new safety procedures for equip mtce, replacing insulator strings and local weather checks.
1999 10	7,674	Reflects a schedule change to 120 towers in 99/00 (prev 60), and 40 towers per yr to 02/03 (prev 60).

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

76.

COMPLEX STATUS: ☐ Planned ☒ In progress

Complex no. 7

REVISION STATUS: ☐ New complex ☐ In service change ☐ Concept change ☒ Estimate change only

COMPLEX: BIPOLE 1 & 2 LINE SPACER DAMPERS REPLACEMENT

Proposal

Design and install a new damping system for the 2 DC transmission lines Radisson/Dorsey (896 KM each) and the DC transmission line Henday/Radisson (42 KM) to restore their capacity to suppress aeolian vibration to the origional design level. The new damping system will either reuse the existing refurbished spacer dampers or use new dampers of the existing design.

JUSTIFICATION

☒ Load ☐ Service
☐ Safety ☐ Efficiency
☒ Reliability ☐ Other

Explanation

These transmission lines are experiencing fatigue failures in the cross arms of the suspension towers. The origin of these failures has been traced to deterioration and some failures of the spacer dampers after approximately 25 years of service. A rehabilitation program is necessary to prevent further failures and escalating consequential failures of conductores.

Estimate Level	COMPLEX START yyyy mm
L1	1995 12

IN SERVICE DATES AND AMOUNTS					
1999 01	$4400	2000 12	$5590	2001 12	$324

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	4,690		514		5,204	6,100	-896	-15
Year 99/00	601	1	84		686	3,674	-2,988	-81
00/01	2,381	11	140		2,532	3,710	-1,178	-32
01/02	1,915	4	-27		1,892	3,458	-1,566	-45
02/03	1	0			1		1	
03/04								
04/05								
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	9,588	16	711		10,315	16,942	-6,627	-39

REVISION: Reflects favourable actual damper costs, 1 yr deferral of damper refurbishment prog, and unfavourable cost of retro-fitting dampers refurbished in 1998.

Reviewed by ORIGINATOR		yyyy mm dd 99 11 09	Reviewed by COORDINATOR		yyyy mm dd 99 11 09
Reviewed by CONSTRUCTOR		yyyy mm dd 99 11 03	Approved by VICE PRESIDENT		yyyy mm dd 99 11 16

H2856/r Rev 99 03

Complex no. 7

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Advance or deferral impact

Escalating failures of conductors.

Factors affecting timing or viability

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Radisson/Dorsey & Henday/Radisson DC lines spacer dampers	16,656	15,403	15,711	9,588	-6,123	-39
TOTAL	16,656	15,403	15,711	9,588	-6,123	-39

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
95 10	19,825	NEW ITEM.
96 10	22,248	Scope change to include: end span stock bridge dampers, repl rubber bushing performance tests, as built span length measurement, const schedule moved forward to 1997.
1997 10	19,121	Project recalculated using activity rates as per the new accounting system. Further studies indicated that end-spand stockbridge dampers and span length surveys not required.
1998 10	16,942	Revised to reflect the 97/98 underexpenditure 1.6M , and that labour costs, and contingency have been moved from 97/98 to 01/02.
1999 10	10,315	Reflects favourable actual damper costs, 1 yr deferral of damper refurbishment prog, and unfavourable cost of retro-fitting dampers refurbished in 1998.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

77.

COMPLEX STATUS	Complex no.	REVISION STATUS
[X] Planned [ ] In progress	247	[ ] New complex [ ] In service change [ ] Concept change [X] Estimate change only

COMPLEX	DORSEY BUS ENHANCEMENT

Proposal
Sectionalize Dorsey A and B busses with breaker and interconnecting bus. Installation will include 4 - 230kV breakers, an interconnecting bus, plus associated equipment.

JUSTIFICATION	Explanation
[ ] Load [ ] Service [X] Safety [X] Efficiency [X] Reliability [ ] Other	Sectionalizing Dorsey bus will minimize the chances of a complete Dorsey shutdown , and allow ent bus maintenance.

Estimate Level	COMPLEX START (yyyy mm)
L2	1999 04

IN SERVICE DATES AND AMOUNTS							
2002 05	$4009	2002 09	$4009	2003 05	$4009	2003 09	$4009

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend								
Year 99/00	377	9	18		404	371	33	9
00/01	764	34	64		862	750	112	15
01/02	2,839	182	222		3,243	2,658	585	22
02/03	6,239	528	200		6,967	6,412	555	9
03/04	4,056	416	88		4,560	4,393	167	4
04/05								
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	14,275	1,169	592		16,036	14,584	1,452	10

REVISION	Scope Unchanged

Reviewed by ORIGINATOR	yyyy mm dd 99 11 08	Reviewed by COORDINATOR	yyyy mm dd 99 11 03
Reviewed by CONSTRUCTOR	yyyy mm dd 99 11 03	Approved by VICE PRESIDENT	yyyy mm dd 99 11 16

H2856/r Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Complex no. 247

Advance or deferral impact

System Planning report 98/2 recommended that bus enhancement be done A.S.A.P. due to the secutity risk. Deferral increases the risk of system collapse.

Factors affecting timing or viability

A detailed design study will be done due to the complexity of protection changes.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Dorsey bus enhancement		12,952	13,211	14,275	1,064	8
TOTAL		12,952	13,211	14,275	1,064	8

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
1998 06	14,584	NEW ITEM
1999 10	16,037	Scope Unchanged.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

78.

COMPLEX STATUS	Complex no.	REVISION STATUS
☒ Planned ☐ In progress	251	☒ New complex ☐ In service change ☐ Concept change ☐ Estimate change only

COMPLEX	FLIN FLON AREA TRANSMISSION IMPROVEMENTS

Proposal

Perform environmental assessments and route selection, design and construct transmission and terminal facilities, and reconnect T/L in Flin Flon area to salvage Switch Tower #3, Mile 13 Stn, and Mile 13 - Sherridon section of HS15 and to enhance system reliability. Transmission: Construct115 kV line 6.0 km Herblet L Stn - Chisel L tap, 115 kV line 1.5 km Ross L Stn - Switch Tower #3 line 1. Upgrade 115 kV line 73 km HS15 Herblet L Stn - Sherridon Stn. Termination: Establish single line termination into Ross L Stn for lines I1F & I2F, terminate HBM&S line 1 & re-terminate HBM&S line 3 and re-terminate line RC56 into Ross L Stn, install former Ponton's 30/40/45 MVA transformer bank at Herblet L Stn, terminate the new line to Chisel L tap into Herblet L Stn, install a single phase station service power VT at Ponton Stn. Modify, upgrade and coordinate protection at Ross L, Herblet L, Sherridon and Ponton . Communications: Modify to accommodate 2-line supply to HBM&S and changes at Ross L and Herblet L.

JUSTIFICATION	Explanation
☒ Load ☐ Service ☒ Safety ☒ Efficiency ☒ Reliability ☐ Other	Facilities are required to decommission crumbling Mile 13 Station and Switch Tower #3, to enhance reliability of transmission to HBM&S, to firm transformation at Herblet Lake Station, and to firm supply to Snow Lake area loads.

Estimate Level	COMPLEX START (yyyy mm)
L1-2	1998 06

IN SERVICE DATES AND AMOUNTS					
2001 08	$7793	2004 10	$9738		

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	19		1		20		20	
Year 99/00	299	10	3		312		312	
00/01	2,002	86	70	192	1,966		1,966	
01/02	4,850	257	145	4	5,248		5,248	
02/03	1,472	128	47		1,647		1,647	
03/04	4,392	470	334		5,196		5,196	
04/05	2,333	219	385	37	2,900		2,900	
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	15,367	1,170	985	233	17,289		17,289	

REVISION	NEW ITEM

Reviewed by ORIGINATOR	yyyy mm dd 99 11 08	Reviewed by COORDINATOR	yyyy mm dd 99 11 03
Reviewed by CONSTRUCTOR	yyyy mm dd 99 11 03	Approved by VICE-PRESIDENT	yyyy mm dd 99 11 16

H2856/r Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Complex no. 251

Advance or deferral impact

Delay of this complex will delay customer satisfaction in the HBM&S and Snow Lake area and will jeopardize personel safety due to an aging system with inadequate grounding and structures.

Factors affecting timing or viability

Environmental Licencing for new 6KM line from Herblet to Chisel L.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Dedicated Lines > HBM&S & Paralleling R1F/R2F				3,043	3,043	
Transmission Line HS15 Salvage & Upgrade				6,321	6,321	
Herblet Lake>Chisel Lake Tap 115kV line				1,375	1,375	
Flin Flon-Ross L Salvage Switch Tower #3 & Reconfig				1,063	1,063	
Mile 13 Salvage 115kV Stn				205	205	
Herblet L Add Spare 230-115kVBank and 115kVT/L				2,983	2,983	
Ponton Convert Stn Service & Salvage Auto Transf				378	378	
TOTAL				15,368	15,368	

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
1999 10	17,289	NEW ITEM

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

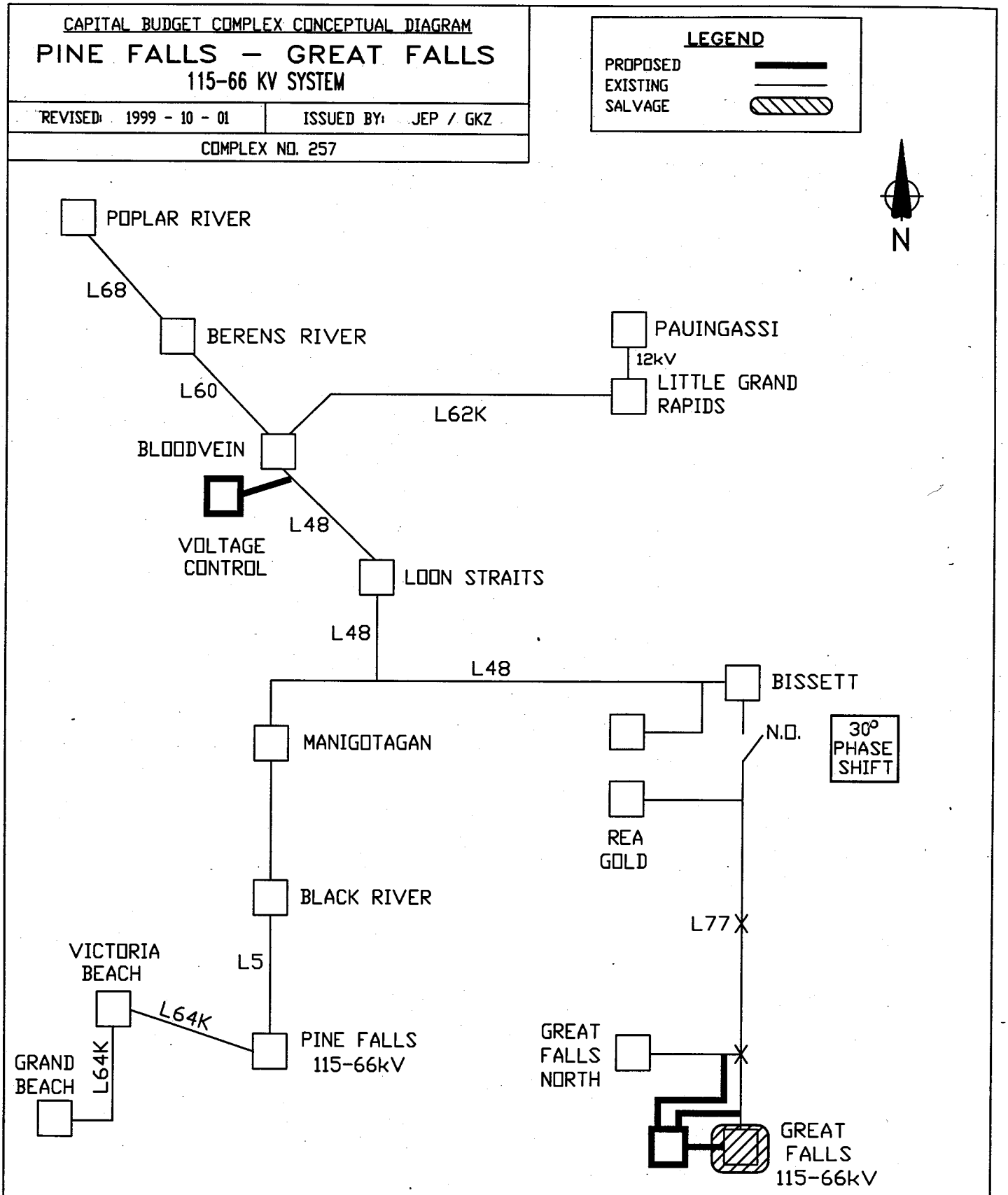
REFERENCE NUMBER	DESCRIPTION

CAPITAL BUDGET COMPLEX CONCEPTUAL DIAGRAM

PINE FALLS – GREAT FALLS
115-66 KV SYSTEM

REVISED: 1999 - 10 - 01 | ISSUED BY: JEP / GKZ

COMPLEX NO. 257



H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

79.

COMPLEX STATUS	Complex no.	REVISION STATUS
☒ Planned ☐ In progress	257	☒ New complex ☐ In service change ☐ Concept change ☐ Estimate change only

COMPLEX	PINE FALLS > GREAT FALLS 115-66KV SUPPLY

Proposal

Establish a new 115-66kV Station at Great Falls, with a 115kV circuit to the Great Falls G.S. Install a new voltage regulation device at Bloodvein. Construct a new 66kV 266.8 MCM line from Great Falls 115-66kV station to Great Falls -North 66-12kVstation and re-route line #77 to the new Great Falls 115-66kV station. Salvage the existing Great Falls 115-66kV, 5/6.67 MVA autotransformer station.

JUSTIFICATION		Explanation
☒ Load	☐ Service	THE ADDITION OF 115-66KV CAPACITY AT GREAT FALLS WILL PROVIDE CONTINGENCY CAPACITY FOR THE PINE FALLS 66KV SYSTEM WHICH WILL RUN SHORT BY 2008/09. THE EARLIER 2003 ISD IS RECOMMENDED TO SEPARATE GREAT FALLS -N STN AND BISSETT AREA ONTO SEPARATE BREAKERS. OUTAGES HAVE BEEN A CUSTOMER CONCERN AND THIS SERVICE DOES NOT MEET BASIC RELIABILITY INTENT OF THE TRANSMISSION PLANNING CRITERIA FOR FIRM LOAD.
☐ Safety	☐ Efficiency	
☒ Reliability	☐ Other	

Estimate Level	COMPLEX START (yyyy mm)
L1	2003 04

IN SERVICE DATES AND AMOUNTS							
2002 04	$6473	2003 10	$112	2004 10	$2884		

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend								
Year 99/00								
00/01	899		36		935		935	
01/02	2,447	107	180		2,734		2,734	
02/03	3,188	207	57		3,452		3,452	
03/04	1,024	86	107		1,217		1,217	
04/05	953	72	104	21	1,108		1,108	
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	8,511	472	484	21	9,446		9,446	

REVISION	New Complex

Reviewed by ORIGINATOR	yyyy mm dd 99 11 08	Reviewed by COORDINATOR	yyyy mm dd 99 11 03
Reviewed by CONSTRUCTOR	yyyy mm dd 99 11 03	Approved by VICE-PRESIDENT	yyyy mm dd 99 11 16

H2856/r Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Complex no. 257

Advance or deferral impact

Customer satisfaction level.
Reliability level.

Factors affecting timing or viability

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
GREAT FALLS 115KV LINE				352	352	
BLOODVEIN VOLTAGE CONTROL DEVICE				5,950	5,950	
GREAT FALLS NEW 115-66KV STATION				1,982	1,982	
GREAT FALLS 115KV STATION SALVAGE				120	120	
GREAT FALLS 66KV LINES				106	106	
TOTAL				8,510	8,510	

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
1999 10	9,446	New Complex

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

80.

(IN THOUSANDS OF DOLLARS)

COMPLEX STATUS: ☐ Planned ☒ In progress

Complex no. 55

REVISION STATUS: ☐ New complex ☒ In service change ☐ Concept change ☐ Estimate change only

COMPLEX: JENPEG-NORWAY HOUSE 66KV SUBTRANSMISSION LINE

Proposal

Perform environmental assessments and route selection, design and construct transmission and terminal facilities to provide firm supply to Norway House as follows:

Transmission: 66 KV line 85 KM Jenpeg - Norway House.

Terminations: Extend 66 KV facilities at Jenpeg station, including 3 - 66 KV breakers and 2 - 66 KV grounding transformers.

JUSTIFICATION

☒ Load ☐ Service
☐ Safety ☐ Efficiency
☒ Reliability ☐ Other

Explanation

The 66 KV line is required for reliability of supply to Norway House and voltage control.

Estimate Level	COMPLEX START (yyyy mm)
L2	1994 04

IN SERVICE DATES AND AMOUNTS			
2004 10	$12675		

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	135		49		184	249	-65	-26
Year 99/00			16		16	176	-160	-91
00/01			18		18	1,696	-1,678	-99
01/02	306	6	24		336	2,311	-1,975	-85
02/03	815	28	70		913	7,247	-6,334	-87
03/04	4,413	186	303		4,902		4,902	
04/05	5,384	465	456		6,305		6,305	
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	11,053	685	936		12,674	11,679	995	9

REVISION: ISD deferred 2 years to 2004 due to financial constraints.

Reviewed by ORIGINATOR	yyyy mm dd 99 11 08	Reviewed by COORDINATOR	yyyy mm dd 99 11 03
Reviewed by CONSTRUCTOR	yyyy mm dd 99 11 03	Approved by VICE PRESIDENT	yyyy mm dd 99 11 16

H2856/r Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Complex no. 55

Advance or deferral impact

Deferral will continue low reliability of Norway House supply over existing 66 KV line from William River.

Factors affecting timing or viability

Environmental Licencing.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Jenpeg to Norway House 66 KV Line	5,850	8,232	8,397	8,488	91	1
Jenpeg Terminal 66 KV Changes	2,230	2,399	2,447	2,566	119	5
TOTAL	8,080	10,631	10,844	11,054	210	2

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
9510	8,479	In-service date deferred 2 years to 1999 10 31. Reflects grounding transfomer price increases.
9610	9,726	Project in-service date deferred 2 years to 2001 10 31.
1997 10	11,683	Reflects revised costing methodology with the new financial reporting system.
1998 10	11,679	Revised to reflect one year deferral of transmission line from 2001 to 2002.
1999 10	12,674	ISD deferred 2 years to 2004 due to financial constraints.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

81.

(IN THOUSANDS OF DOLLARS)

COMPLEX STATUS	Complex no.	REVISION STATUS
☐ Planned ☒ In progress	53	☐ New complex ☒ In service change ☐ Concept change ☐ Estimate change only

COMPLEX	RUTTAN - SOUTH INDIAN LAKE 66KV LINE

Proposal

1. Construct 75.6 km of 66kv 2/0 acsr line from Ruttan Lake to South Indian Lake. Salvage 75.6 km of 33kv line between Ruttan Lake-South Bay-South Indian Lake.
2. Salvage Southbay 33-12kv station, complete with 3 - 100kva 33 - 7.2kV transformers
3. Ruttan Lake station "a" - salvage existing 3 -1 000kva 12-33kv transformers re-locate 1 - 15/20/25mva 138-12kv transformer from Ruttan Lake station "b". Install 2 - 7.5/10mva LTC 12-66kv transformers.
4. Construct a 66-12kv station at South Indian Lake c/w 3 - 7.5/10mva LTC transformers. Salvage existing 33-12kv station.

JUSTIFICATION	Explanation
☒ Load ☐ Service ☐ Safety ☐ Efficiency ☐ Reliability ☐ Other	The existing Ruttan Lake - South Indian Lake power supply is limited to 300 kva. Based on current load forecast, the voltage regulation on the existing system will result in inadequate customer voltages. The proposed 12-66kv Ruttan Lake station, Ruttan - South Indian Lake 66kv line and South Indian Lake 66-12kv station will provide additional capacity and adequate voltage regulation.

Estimate Level	COMPLEX START (yyyy mm)
L1-3	1994 10

IN SERVICE DATES AND AMOUNTS							
1997 08	$8697	1997 09	$430	1997 10	($41)	1997 11	$112
1997 12	$17	1998 04	$107	1998 06	$68	1998 12	($131)
1999 04	$95	2001 09	$251	2002 08	($7)	2003 08	$6579

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	9,361		249	502	9,108	9,312	-204	-2
Year 99/00	255	7	14		276	121	155	128
00/01	242	11	38		291	671	-380	-57
01/02	312	15	65	126	266	2,096	-1,830	-87
02/03	1,333	116	143		1,592	2,277	-685	-30
03/04	3,536	371	110	989	3,028		3,028	
04/05								
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	15,039	520	619	1,617	14,561	14,477	84	1

REVISION	Ruttan Lake Station ISD deferred one year 2003 due to financial constraints.

Reviewed by ORIGINATOR	yyyy mm dd 99 11 08	Reviewed by COORDINATOR	yyyy mm dd 99 11 03
Reviewed by CONSTRUCTOR	yyyy mm dd 99 11 03	Approved by VICE-PRESIDENT	yyyy mm dd 99 11 16

H2856/r Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Complex no. 53

Advance or deferral impact

Forecast loads at South Indian Lake will exceed capacity in 1996/97 winter.

Factors affecting timing or viability

Load growth.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
SOUTH BAY STATION	77	30	31	25	-6	-19
RUTTAN LAKE STATION	4,118	8,261	8,426	8,136	-290	-3
SOUTH INDIAN LAKE STATION	843	1,724	1,758	1,785	27	2
RUTTAN L - SOUTH INDIAN L. 66KV SUPPLY	3,905	5,002	5,102	5,094	-8	-0
TOTAL	8,943	15,017	15,317	15,040	-277	-2

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
9510	7,289	Estimates revised to more detailed level.
9610	9,234	Scope incr: move & inst 2 transf banks from Ruttan "B" stn to "A". Incr cap of new 138/12kV transf, repl cntrl bldg, serv & prot.Conductor upgrade for SIL supply.
1997 10	14,066	Customer load increase required equipment to be replaced at Ruttan Lake before winter loading. A third transformer added at South Indian Lake Station. Cost of 66kV line
1998 10	14,477	Reflects 97/98 overexpenditure 0.5M and Ruttan Lake Station ISD deferred three years from 1999 to 2002.
1999 10	14,561	Ruttan Lake Station ISD deferred one year 2003 due to financial constraints.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

82.

COMPLEX STATUS	Complex no.	REVISION STATUS
☐ Planned ☒ In progress	17	☐ New complex ☒ In service change ☐ Concept change ☒ Estimate change only

COMPLEX	CENTRAL SUPPLY TO PIKWITONEI AND THICKET PORTAGE

Proposal

1. Construct 5km-66kV line (operating 12kV) from Mystery L. Stn. Fdr.TM9 to jctn of PTH#6 and Jonas Rd.
2. Construct a 12-25kV interchange bank c/w 4-1000kVA single phase 7.2-14.4kV units (one spare).
3. Construct 44.3km-66kV line (operating 25kV) from jctn PTH#6 & Jonas Rd. to Sipiwesk.
4. Construct 21.5km-25kV line from Sipiwesk to Pikwitonei. Rebuild and convert Pikwitonei distribution to 25kV.
5. Construct 24.7km-25kV line from Sipiwesk to Thicket Portage. Rebuild and convert distribution to 25kV.
6. Salvage diesel units at Pikwitonei and Thicket Portage and remediate sites.

JUSTIFICATION		Explanation
☒ Load	☒ Service	The communities of Pikwitonei and Thicket Portage were scheduled for conversion to enhanced diesel supply in 1997. Due to the proximity of central station supply at Thompson and the associated benefits to our customers and Manitoba Hydro, central supply is the preferred option, provided that a contribution can be negotiated.
☐ Safety	☐ Efficiency	
☐ Reliability	☐ Other	

Estimate Level	COMPLEX START (yyyy mm)
L3	1992 01

IN SERVICE DATES AND AMOUNTS							
1997 03	$577	1997 04	$1582	1997 05	$99	1998 06	$2
1999 04	$3610	1999 12	$135	2000 09	$330	2000 12	$331

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	5,818		152	3,498	2,472	2,011	461	23
Year 99/00	31	0	9		40		40	
00/01	608	32	16		656	641	15	2
01/02								
02/03								
03/04								
04/05								
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	6,457	32	177	3,498	3,168	2,652	516	19

REVISION	Revised to remove estimated salvage which has not materialized .

		yyyy mm dd			yyyy mm dd
Reviewed by	ORIGINATOR	99 11 09	Reviewed by	COORDINATOR	99 11 03
Reviewed by	CONSTRUCTOR	99 11 03	Approved by	VICE PRESIDENT	99 11 16

H2856/r Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Complex no. 17

Advance or deferral impact

Factors affecting timing or viability

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Central Supply to Pikwitonei & Thicket Portage	5,368	5,456	5,565	5,453	-112	-2
Thicket Portage D.G.S. - Site Clean-up	446	508	518	520	2	0
Pikwitonei D.G.S. - Site Clean-up	446	468	477	484	7	1
TOTAL	6,260	6,432	6,560	6,457	-103	-2

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
9510	1,519	Enhanced diesel operation costs inadvertently applied to the line land cost in the 1994 estimate.
9610	1,516	Work deferred two years at Thicket & Pikwitone. Net amount adjusted to 577,000 per agreement, and interest and escalation revised.
1997 10	2,169	Cost of central supply increase due to increases inconstruction costs and reduced capital contibutions. ISD of D.D.S. site clean up advanced two years.
1998 10	2,652	Reflects 97/98 overexpenditure 0.8M, final costs for central supply item, increases to site investigation estimates and one year deferral to Thicket Portage and Pikwitonei items.
1999 10	3,168	Revised to remove estimated salvage which has not materialized .

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

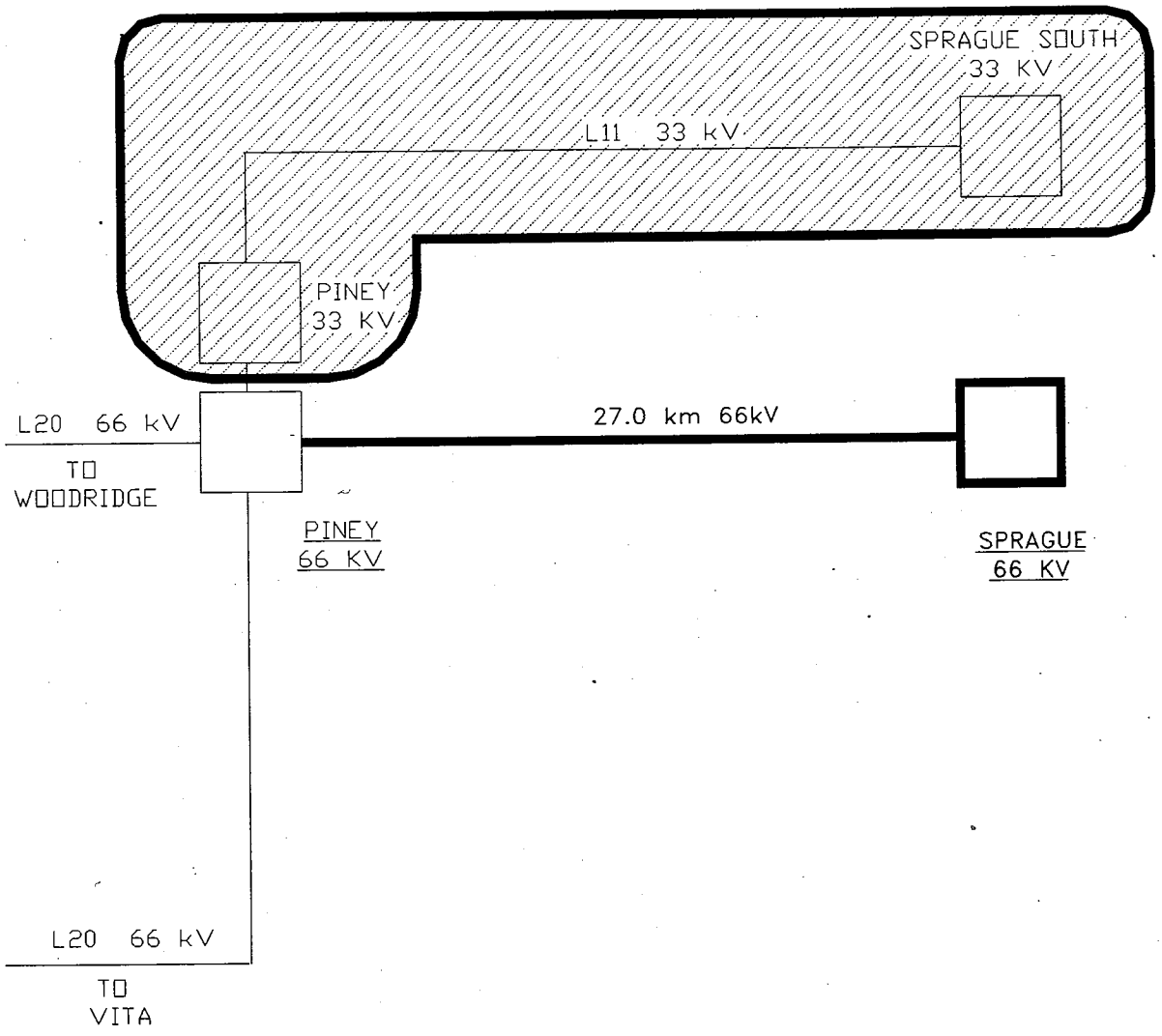
REFERENCE NUMBER	DESCRIPTION

CAPITAL BUDGET COMPLEX CONCEPTUAL DIAGRAM

PINEY – SPRAGUE 66KV LINE

REVISED: 1999 - 10 - 01	ISSUED BY: WNZ

COMPLEX NO. 206



LEGEND

PROPOSED

EXISTING

SALVAGE

manitoba hydro

PLANNING AND CONTROL DIVISION

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Complex no. 206

COMPLEX STATUS: ☐ Planned ☒ In progress

REVISION STATUS: ☐ New complex ☐ In service change ☐ Concept change ☒ Estimate change only

COMPLEX: PINEY - SPRAGUE 66 KV LINE

Proposal

Perform route selection, design and construct transmission and terminal facilities for the supply of Sprague as follows:

Transmission: 66 KV line 27 km Piney - Sprague. Salvage 33 KV line L11 Piney - Sprague.

Terminations: Construct 66-12 KV station at Sprague, including 66-12 KV 10 MVA transfomer and 2 - 66 KV bays. Salvage Sprague 33-12 KV station and Piney 66-33 KV station.

JUSTIFICATION

☒ Load ☐ Service
☐ Safety ☐ Efficiency
☒ Reliability ☐ Other

Explanation

This complex provides support for load increases and eliminates requirement for extensive 33 KV system rebuilding in Sprague area.

Estimate Level	COMPLEX START (yyyy mm)
L2	1996 08

IN SERVICE DATES AND AMOUNTS

1999 07	$3753	2000 07	$288		

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	1,944		145	1	2,088	2,459	-371	-15
Year 99/00	1,737	19	77	117	1,716	1,237	479	39
00/01	108	4	5	83	34	31	3	10
01/02								
02/03								
03/04								
04/05								
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	3,789	23	227	201	3,838	3,727	111	

REVISION: Scope Unchanged

Reviewed by ORIGINATOR	yyyy mm dd 99 11 08	Reviewed by COORDINATOR	yyyy mm dd 99 11 0
Reviewed by CONSTRUCTOR	yyyy mm dd 99 11 03	Approved by VICE PRESIDENT	yyyy mm dd 99 11 1

H2856/r Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Complex no. 206

Advance or deferral impact

Deferral will limit load supply at Sprague or cause overloading of existing 33 KV transformers.

Factors affecting timing or viability

Sprague area load.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Sprague 66-12 KV Station	1,453	1,430	1,459	1,453	-6	-0
Piney Station 33 KV Equipment Salvage		117	119	121	2	2
Sprague Station 33-12 KV Salvage		142	145	146	1	1
Piney-Sprague 66 KV T/L	2,069	1,955	1,994	2,069	75	4
TOTAL	3,522	3,644	3,717	3,789	72	2

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
96 10	3,039	New complex.
1997 10	4,247	ISD of line deferred 1 year to 1999 and DC project cancelled
1998 10	3,727	Reflects 97/98 underexpenditure 1.2M, and current transmission line costs.
1999 10	3,838	Scope Unchanged

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

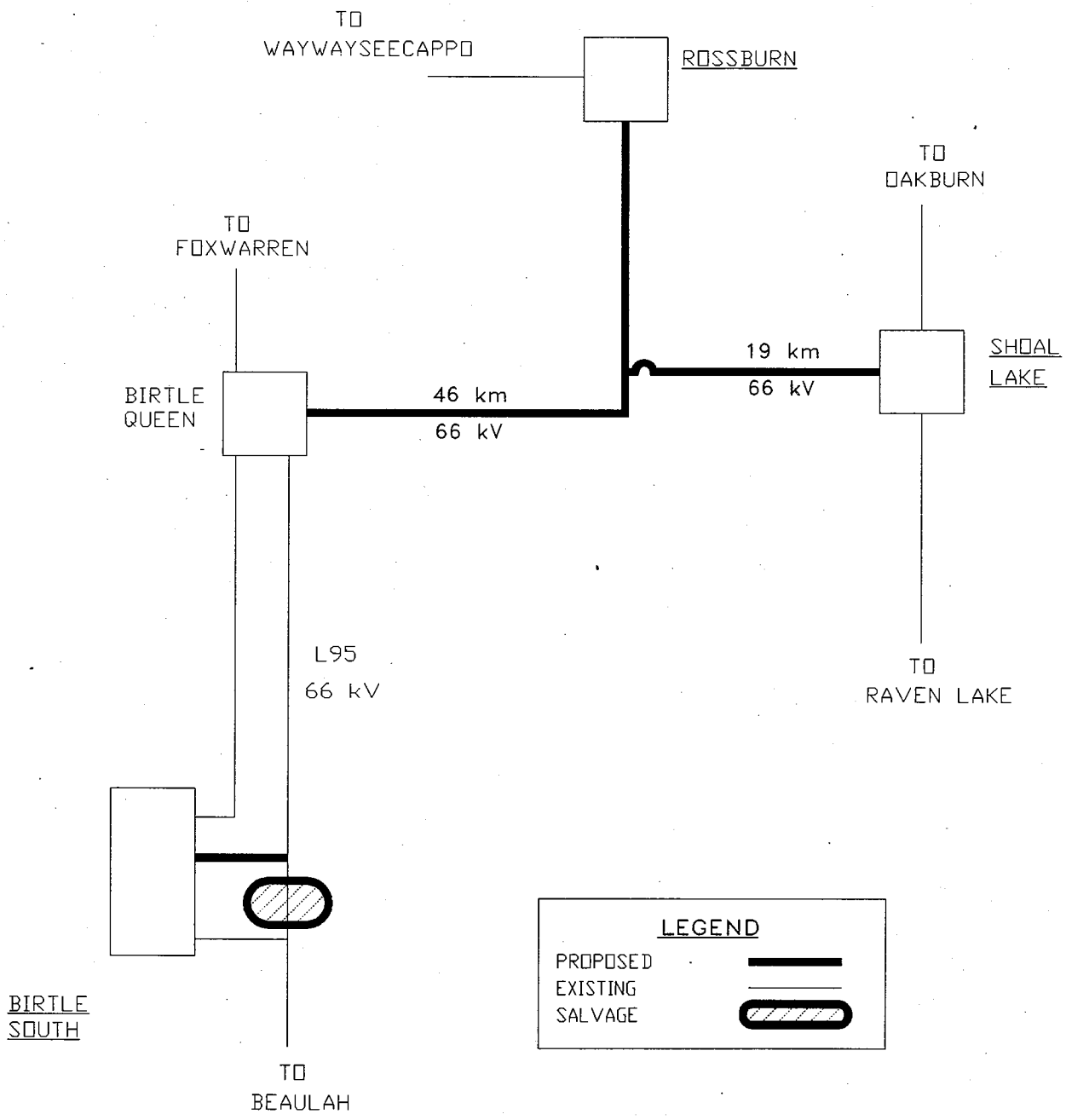
REFERENCE NUMBER	DESCRIPTION

CAPITAL BUDGET COMPLEX CONCEPTUAL DIAGRAM

BIRTLE – ROSSBURN 66KV LINE

REVISED: 1999 - 10 - 01	ISSUED BY: WNZ

COMPLEX NO. 209



manitoba hydro

PLANNING AND CONTROL DIVISION

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

84.

COMPLEX STATUS	Complex no.	REVISION STATUS
[X] Planned [ ] In progress	209	[ ] New complex [ ] In service change [ ] Concept change [X] Estimate change only

COMPLEX: BIRTLE - ROSSBURN 66 KV LINE

Proposal

Perform route selection, design and construct transmission and terminal facilities for supply to Rossburn and Shoal Lake as follows:

Transmission: 66 KV line 46 km Birtle Queen - Rossburn, 66 KV line 19 km Shoal Lake - Tap on Birtle Queen to Rossburn line. Open 66 KV line L95 at Birtle South north of Beaulah tap and extend open end into Birtle South.

Terminations: Extend 66 KV facilities at Birtle South.

JUSTIFICATION		Explanation
[X] Load	[ ] Service	This complex provides voltage support for distribution loads in the Rossburn area, maintains firm supply to increased load at Shoal Lake, and extends the service life of the Raven Lake 33 KV system.
[ ] Safety	[ ] Efficiency	
[X] Reliability	[ ] Other	

Estimate Level	COMPLEX START (yyyy mm)
L2	2002 04

IN SERVICE DATES AND AMOUNTS					
2004 10	$3997	2005 10	$1559		

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend								
Year 99/00								
00/01								
01/02								
02/03	73	7	3		83	73	10	14
03/04	196	24	13		233	233	0	0
04/05	3,221	328	136	48	3,637	3,783	-146	-4
05/06	1,329	158	56	48	1,495	1,568	-73	-5
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	4,819	517	208	96	5,448	5,657	-209	-4

REVISION: Scope unchanged.

Reviewed by ORIGINATOR	yyyy mm dd 99 11 08	Reviewed by COORDINATOR	yyyy mm dd 99 11 09
Reviewed by CONSTRUCTOR	yyyy mm dd 99 11 03	Approved by VICE PRESIDENT	yyyy mm dd 99 11 16

H2856/r Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Complex no. 209

Advance or deferral impact

Deferral will result in inadequate Rossburn area voltage support under peak conditions and reduce firm load support capability to Shoal Lake.

Factors affecting timing or viability

Rossburn and Shoal Lake area load growth.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE	
					Amount	%
Birtle South Stn- Rossburn 66 KV Line Termination		481	491	508	17	3
Birtle South - Rossburn 66 KV Line		2,997	3,057	2,974	-83	-3
Shoal Lake Station 66 KV Supply		1,352	1,379	1,337	-42	-3
TOTAL		4,830	4,927	4,819	-108	-2

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
96 10	5,104	New complex.
1997 10	5,577	Estimate reflects revised costing methodology implemented with the new financial reporting system.
1998 10	5,657	Revised to include interest.
1999 10	5,448	Scope unchanged.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

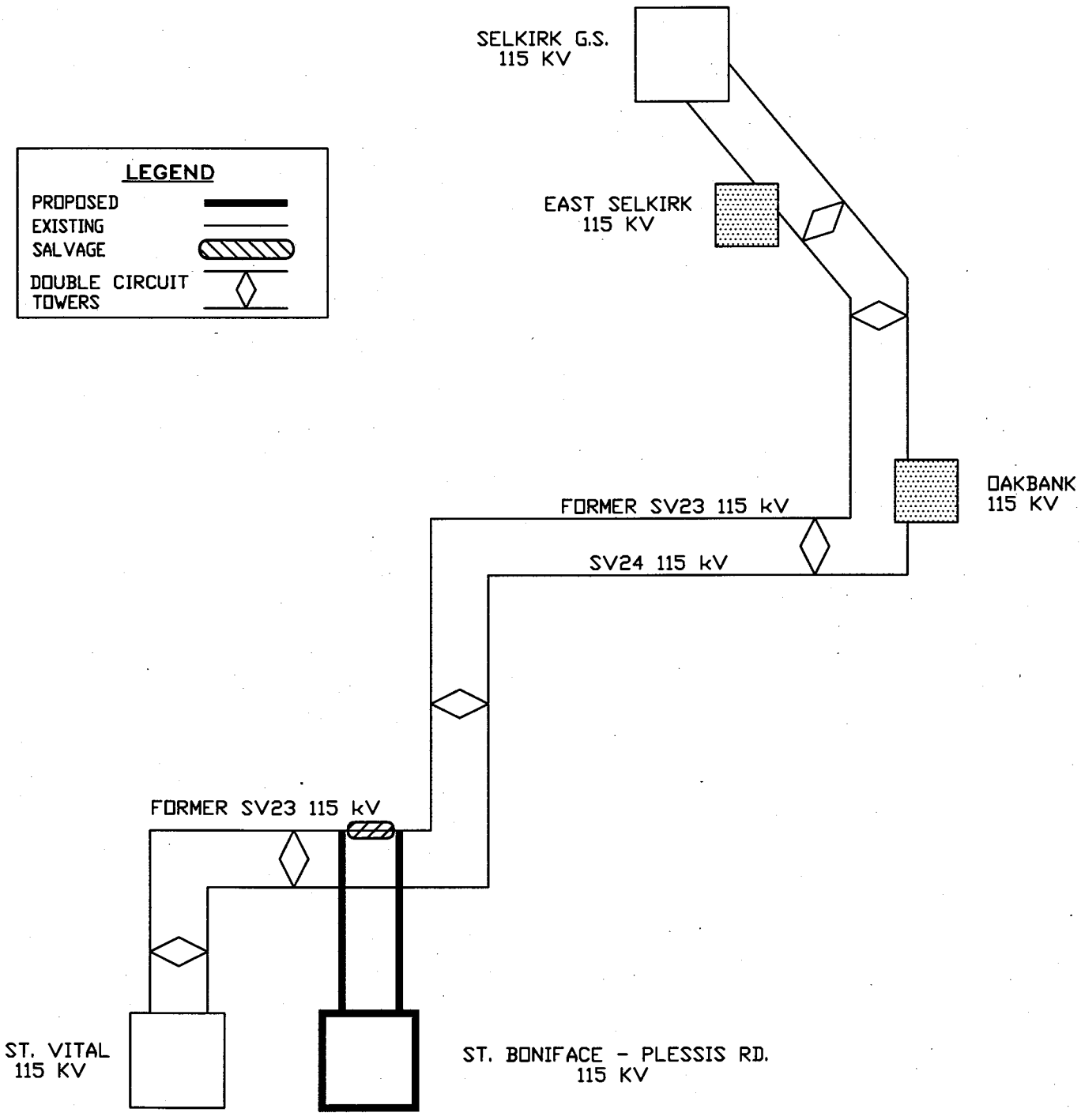
REFERENCE NUMBER	DESCRIPTION

CAPITAL BUDGET COMPLEX CONCEPTUAL DIAGRAM

ST BONIFACE – PLESSIS ROAD
115-24 KV STATION

REVISED: 1999 - 10 - 01	ISSUED BY: CS

COMPLEX NO. 237



H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

COMPLEX STATUS: ☐ Planned ☒ In progress

Complex no. 237

REVISION STATUS: ☐ New complex ☐ In service change ☐ Concept change ☒ Estimate change only

COMPLEX: ST BONIFACE - PLESSIS RD 115-24KV STATION

Proposal

DESIGN AND CONSTRUCT A NEW STEEL 115/24 KV STN ALONG PLESSIS ROAD TO ACCOMMODATE 2- 60/80/100/112 MVA, 114.3-24/13.8 KV LTC TRANSF'S WITH NEUTRAL REACTORS, A 115KV BRKR AND 12 - 24KV FDR LINES. INTIALLY, INSTALL 1- 60/80/100/112 MVA, 114.3-24/13.8 KV +/- 10% LTC TRANSF AND NEUTRAL REACTOR, 8-24KV CIRCUIT BREAKERS, 6-24 KV CIRCUIT LINE REACTORS, 2-24 KV CIRCUIT SWITCHERS, AND 2-14.4 MVAR 24 KV CAPACITOR BANKS. PROTECTION FOR THE TRANSF AND THE SECTIONALIZED 115 KV SV23 LINE TERMINATIONS INTO THE STATION IS PROVIDED BY OPENING BRKRS ON LINES AT ST BONIFACE RD AND SELKIRK GENERATING STATION, (TRANSCONA-FUTURE) OR ST. VITAL TERMINAL VIA TELECOMMUNICATIONS. TRANSIENT VOLTAGE STUDIES MAY BE REQUIRED TO DEFINE THE TRANSIENT RECOVERY VOLTAGE MITIGATING EQUIPMENT.

JUSTIFICATION

☒ Load ☐ Service
☐ Safety ☐ Efficiency
☒ Reliability ☐ Other

Explanation

THIS NEW STATION IS REQUIRED TO SUPPORT THE LOAD GROWTH IN THE AREA AND TO PROVIDE BACKUP TO OTHER 24 KV STATIONS NEARBY.

Estimate Level	COMPLEX START (yyyy mm)
L2	1997 08

IN SERVICE DATES AND AMOUNTS

2000 09	$17315	2001 04	$487		

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	1,329		78		1,407	1,603	-196	-12
Year 99/00	7,237	198	352		7,787	5,032	2,755	55
00/01	7,457	279	549	2	8,283	3,242	5,041	155
01/02	309	13	1		323	7,053	-6,730	-95
02/03								
03/04								
04/05								
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	16,332	490	980	2	17,800	16,930	870	5

REVISION: Reflects revised activity and overhead rates.

Reviewed by ORIGINATOR	yyyy mm dd 99 11 08	Reviewed by COORDINATOR	yyyy mm dd 99 11 03
Reviewed by CONSTRUCTOR	yyyy mm dd 99 11 03	Approved by VICE PRESIDENT	yyyy mm dd 99 11 16

H2856/r Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Complex no. 237

Advance or deferral impact

Delay in components of this complex will reduce service reliability and quality in the St. Boniface, and St.Vital areas.

Factors affecting timing or viability.

Load Growth

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
St Boniface-Plessis Road Stn 115kv T/L Improvements		946	965	969	4	0
St Boniface Plessis Road New Station	11,204	11,867	12,104	11,681	-423	-3
St Vital Terminal 115kv Line SV23 Protection Repl		221	225	236	11	5
Selkirk GS 115kV Line SV23 Protection Replacement		221	225	236	11	5
St Boniface - Plessis Road Stn 4 -24kV Feeder Lines		1,957	1,996	2,820	824	41
St Boniface-Plessis Road Stn Communication Req		381	389	389	0	0
TOTAL	11,204	15,593	15,904	16,331	427	3

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
1997 10	15,140	New Complex
1998 10	16,930	ISD of complex advanced nine months to September 2000. Scope changed from SV23 tap to sectionallization and reconductoring of 2.7 Km of 115 kV lines GT1/ST2.
1999 10	17,800	Reflects revised activity and overhead rates.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

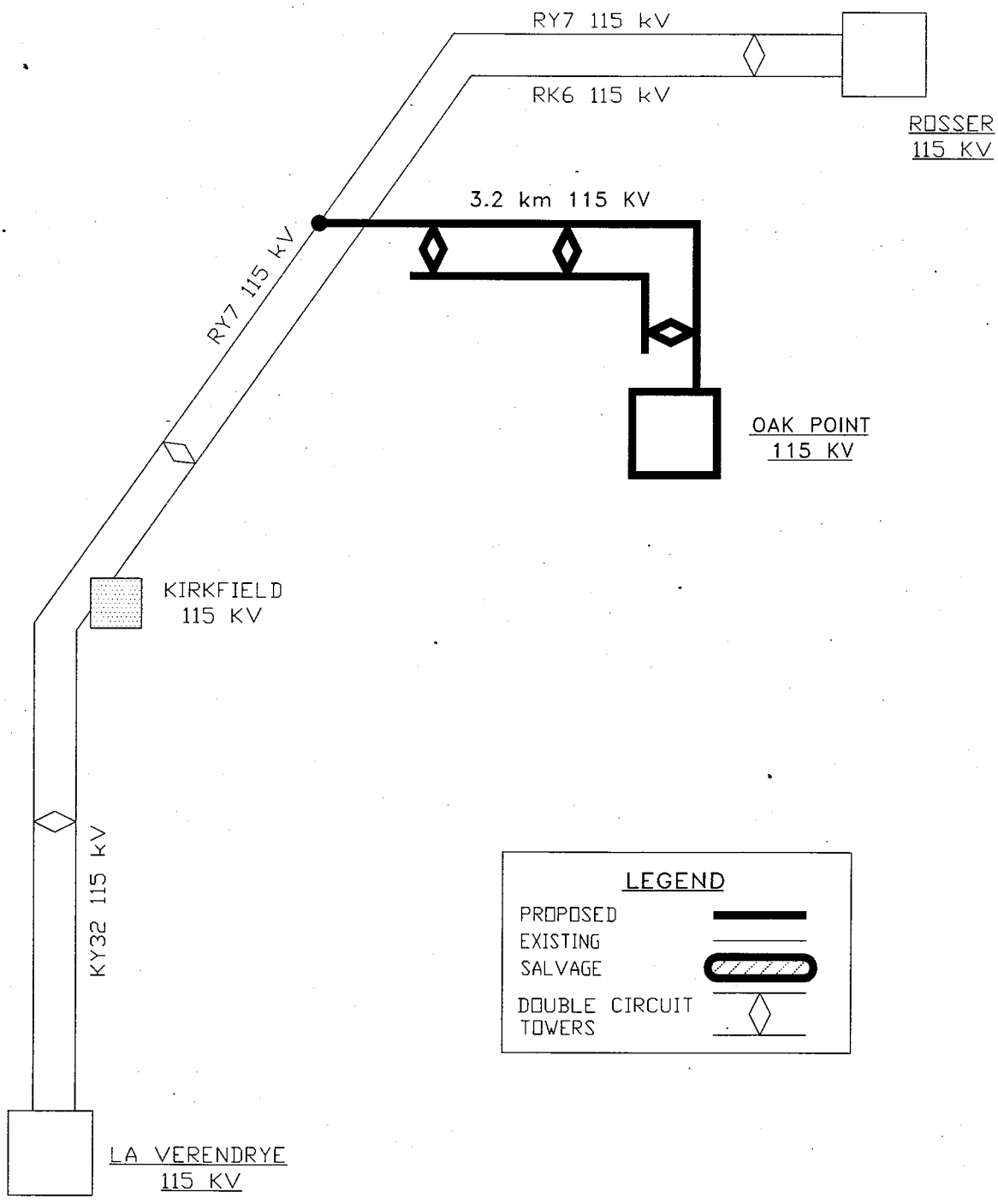
REFERENCE NUMBER	DESCRIPTION

CAPITAL BUDGET COMPLEX CONCEPTUAL DIAGRAM

OAK POINT
115–24 KV STATION

REVISED: 1999 - 10 - 01	ISSUED BY: WNZ

COMPLEX NO. 238



manitoba hydro

PLANNING AND CONTROL DIVISION

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

86.

COMPLEX STATUS	Complex no.	REVISION STATUS
[X] Planned [ ] In progress	238	[ ] New complex [X] In service change [ ] Concept change [ ] Estimate change only

COMPLEX	ROSSER-OAK POINT 115-24KV STATION

Proposal
Design and construct a new low profile 115/24 kV steel station in the Rosser area to accommodate 2-60/80/100//112 MVA transformers and 12-24 kV feeder lines. Use 115 kV lines RK6 and RY7 as the primary supply. Complete site selection and environmental requirements. Design and construct the subtransmission, protection, communication, and terminal facilities for the first transformer. In addition, design and construct 4-24 kV feeder lines to supply customer load

JUSTIFICATION		Explanation
[X] Load	[ ] Service	Existing 24 kV stations in the area are at firm capacity. Additional transformer capacity is required to accommodate future voltage conversions, load growth and to provide surplus firm capacity for the area.
[ ] Safety	[ ] Efficiency	
[X] Reliability	[ ] Other	

Estimate Level	COMPLEX START (yyyy mm)
12	2000 04

IN SERVICE DATES AND AMOUNTS					
2004 06	$2984	2005 06	$15514		

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend								
Year 99/00								
00/01						27	-27	-100
01/02	25	2	1		28	578	-550	-95
02/03	582	57	27		666	847	-181	-21
03/04	1,696	206	123		2,025	10,538	-8,513	-81
04/05	8,393	1208	470		10,071	5,920	4,151	70
05/06	4,733	733	241	4	5,703		5,703	
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	15,429	2,206	862	4	18,493	17,910	583	3

REVISION	ISD deferred one year 2003 due to financial constraints.

Reviewed by ORIGINATOR	yyyy mm dd 99 11 08	Reviewed by COORDINATOR	yyyy mm dd 99 11 03
Reviewed by CONSTRUCTOR	yyyy mm dd 99 11 03	Approved by VICE PRESIDENT	yyyy mm dd 99 11 16

H2856/r Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Complex no. 238

Advance or deferral impact

Delay in components of this complex will reduce service reliability and quality in the St. James area.

Factors affecting timing or viability

The I.S.D. of this complex is in part, contingent upon the development of the Winport Industrial Park, west of the Winnipeg International Airport

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	%
Rosser-Oak Point Station - RY7 115kV T/L Tap		651	664	706	42	6
Rosser-Oak Point New Station		10,192	10,396	10,466	70	1
LaVerendrye Station 115kV Line Protection		415	423	446	23	5
Rosser Station 115kV Line Protection Repl		415	423	446	23	5
Rosser-Oak Point Station 4-24kV Feeder Lines		2,618	2,670	2,570	-100	-4
Rosser-Oak Point Station Communication Req't		758	773	795	22	3
TOTAL		15,049	15,349	15,429	80	1

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
1997 10	18,435	New Complex
1998 10	17,910	Scope unchanged. Start date advanced one year.
1999 10	18,493	ISD deferred one year 2003 due to financial constraints.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

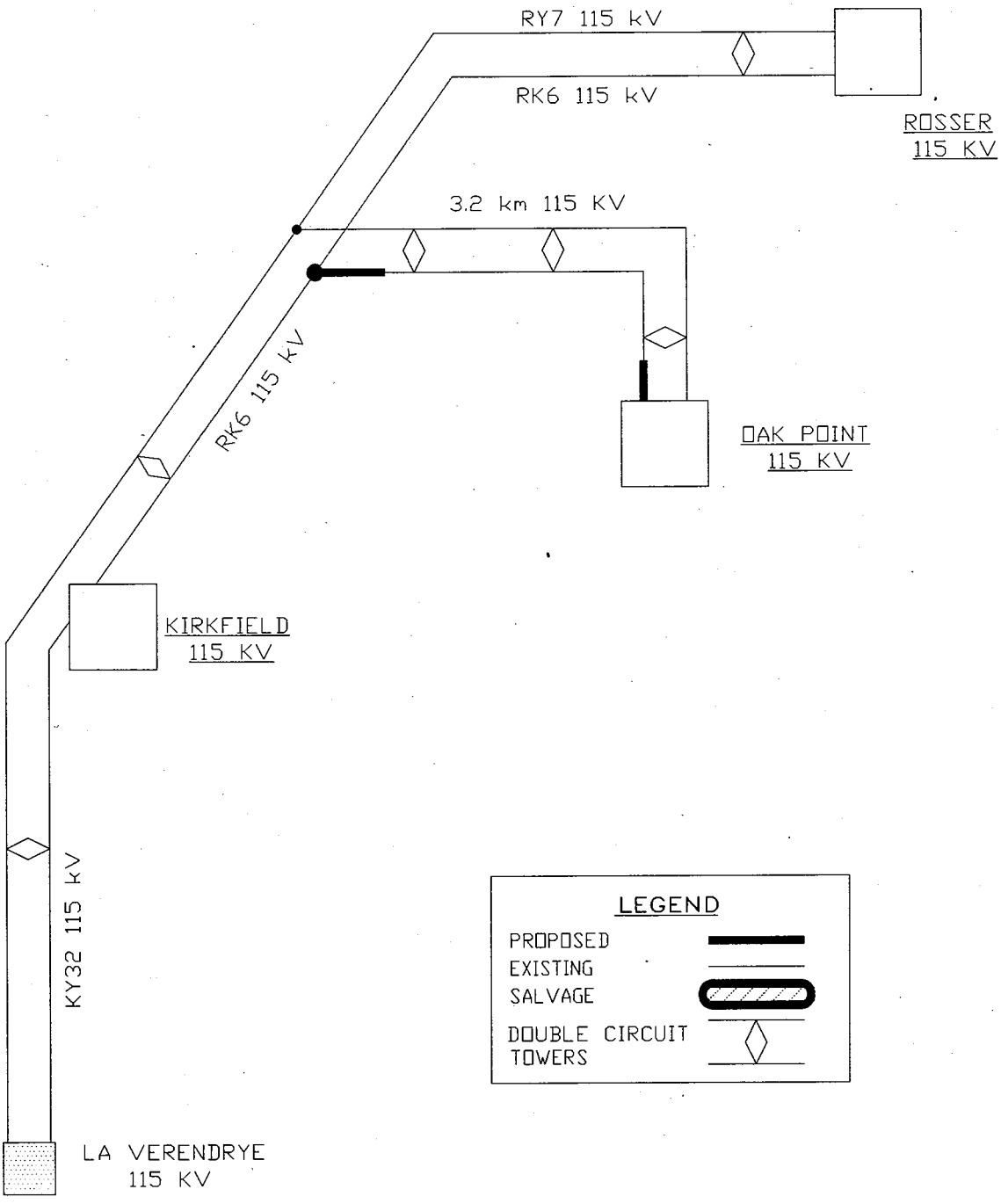
REFERENCE NUMBER	DESCRIPTION

CAPITAL BUDGET COMPLEX CONCEPTUAL DIAGRAM

OAK POINT
115–24 KV BANK 2 ADDITION

REVISED: 1999 - 10 - 01	ISSUED BY: WNZ

COMPLEX NO. 239



manitoba hydro

PLANNING AND CONTROL DIVISION

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

87.

(IN THOUSANDS OF DOLLARS)

COMPLEX STATUS	Complex no.	REVISION STATUS
☒ Planned ☐ In progress	239	☐ New complex ☐ In service change ☐ Concept change ☒ Estimate change only

COMPLEX	ROSSER-OAK POINT BANK 2 ADDITION

Proposal

Install a second 60/80/100//112 MVA transformer, 2-24 kV 1500 MVA circuit breakers with associated equipment and 2-24 kV feeder lines. Use 115 kV line RK6 and RY7 as the primary supply. Complete environmental requirements for the second bank and the 115 kV RK6 tap. Design and construct the subtransmission, protection, communication, and terminal facilities for the second transformer.

JUSTIFICATION	Explanation
☒ Load ☐ Service ☐ Safety ☐ Efficiency ☒ Reliability ☐ Other	Additional transformer capacity is required to accomodate future voltage conversions, load growth and to provide surplus firm capacity for the area.

Estimate Level	COMPLEX START (yyyy mm)
L2	2008 04

IN SERVICE DATES AND AMOUNTS			
2010 06	$9753		

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend								
Year 99/00								
00/01								
01/02								
02/03								
03/04								
04/05								
05/06								
06/07								
07/08								
08/09	630	151	27		808	722	86	12
09/10	4,685	1236	294		6,215	6,254	-39	-1
10/11	1,998	546	185	2	2,727	2,744	-17	-1
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	7,313	1,933	506	2	9,750	9,720	30	0

REVISION	Scope unchanged.

Reviewed by ORIGINATOR	yyyy 99 mm 11 dd 08	Reviewed by COORDINATOR	yyyy 99 mm 11 dd 07
Reviewed by CONSTRUCTOR	yyyy 99 mm 11 dd 03	Approved by VICE PRESIDENT	yyyy 99 mm 11 dd 16

H2856/r Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Complex no. 239

Advance or deferral impact

Delay in components of this complex will reduce service reliability and quality in the St. James area.

Factors affecting timing or viability

The I.S.D. of this complex is in part, contingent upon the development of the Winport Industrial Park, west of the Winnipeg International Airport.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	%
Rosser-Oak Point Station - RK6 115kV T/L Tap		60	61	63	2	3
Rosser-Oak Point 115-24kV Transformer Addition		4,857	4,954	4,985	31	1
Kirkfield Station 115kV Line RK6 Protection Repl		151	154	162	8	5
Rosser Station 115kV Line RK6 Protection Repl		151	154	162	8	5
Rosser-Oak Point 2-24kV feeder Lines		2,038	2,079	1,944	-135	-6
TOTAL		7,257	7,402	7,316	-86	-1

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
1997 10	10,283	New Complex
1998 10	9,720	Scope unchanged
1999 10	9,750	Scope unchanged.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

88.

COMPLEX STATUS	Complex no.	REVISION STATUS
☒ Planned ☐ In progress	240	☐ New complex ☐ In service change ☐ Concept change ☒ Estimate change only

COMPLEX	ST BONIFACE - PLESSIS RD BANK 2 ADDITION

Proposal
Install a second 60/80/100//112 MVA transformer, 2-24 kV 1500 MVA circuit breakers with associated equipment and 2-24 kV feeder lines. Use sectionalized 115 kV line SV23 as the primary supply. Complete environmental requirements for the second bank Design and construct the subtransmission, protection, communication, and terminal facilities for the second transformer.

JUSTIFICATION		Explanation
☒ Load	☐ Service	Additional transformer capacity is required to accomodate future voltage conversions, load growth and to provide surplus firm capacity for the area.
☐ Safety	☐ Efficiency	
☒ Reliability	☐ Other	

Estimate Level	COMPLEX START (yyyy mm)
L2	1999 06

IN SERVICE DATES AND AMOUNTS					
2001 07	$4768	2001 12	$158		

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend								
Year 99/00	99	4	2		105	84	21	25
00/01	1,447	76	77		1,600	1,638	-38	-2
01/02	2,955	186	79		3,220	2,710	510	19
02/03								
03/04								
04/05								
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	4,501	266	158		4,925	4,432	493	11

REVISION	Reflects revised activity and overhead rates.

Reviewed by ORIGINATOR	yyyy mm dd 99 11 05	Reviewed by COORDINATOR	yyyy mm dd 99 11 03
Reviewed by CONSTRUCTOR	yyyy mm dd 99 11 03	Approved by VICE-PRESIDENT	yyyy mm dd 99 11 16

H2856/r Rev 99 03

Complex no. 240

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Advance or deferral impact

Delay in components of this complex will reduce service reliability and quality in the St. Boniface, and St.Vital areas

Factors affecting timing or viability

Load Growth

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	%
St Boniface-Plessis Rd SV24 115kV T/L Tap		0	0	0	0	
St Boniface-Plessis Rd Stn 115-24kV Transformer Add		2,045	2,086	2,058	-28	-1
St Vital Terminal 115kV Line SV24 Protection Repl		0	0	0	0	
Selkirk GS 115kV Line SV24 Protection Repl		0	0	0	0	
Transcona Stn SV23 T/L Retermination & Prot chg		193	197	204	7	4
St Boniface - Plessis Rd Stn add'n 2-24kV Circuits		1,671	1,704	2,103	399	23
St Boniface-Plessis Rd Bk 2 Addition Communication		115	117	137	20	17
TOTAL		4,024	4,104	4,502	398	10

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
1997 10	9,003	New Complex
1998 10	4,432	ISD of complex advanced four years to July 2001 to add firm tranformer capacity in the area. Scope changed from SV24 tap to sectionallization of SV23.
1999 10	4,925	Reflects revised activity and overhead rates.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

89.

COMPLEX STATUS: [X] Planned [ ] In progress

Complex no. 241

REVISION STATUS: [ ] New complex [ ] In service change [ ] Concept change [X] Estimate change only

COMPLEX: NEEPAWA 66 KV SYSTEM

Proposal

Perform route selection, design and construct transmission and terminal facilities to off load 66kV Line 85.

Transmission: 23.3 km, 66kV from Neepawa to Plumas tap.

Terminations: A 66kV breaker and termination at Neepawa.

JUSTIFICATION

[X] Load [ ] Service
[ ] Safety [ ] Efficiency
[X] Reliability [ ] Other

Explanation

This complex provides support to the Gladstone, Langruth, Plumas, Amaranth area which is required due to the load limit on Line 85 which supplies this area.

Estimate Level	COMPLEX START yyyy mm
L2	2000 03

IN SERVICE DATES AND AMOUNTS

2002 10	$3443		

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend								
Year 99/00								
00/01								
01/02	139	10	5		154	188	-34	-18
02/03	2,979	189	120		3,288	3,364	-76	-2
03/04								
04/05								
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	3,118	199	125		3,442	3,552	-110	-3

REVISION: Scope unchanged.

Reviewed by ORIGINATOR	yyyy mm dd 99 11 08	Reviewed by COORDINATOR	yyyy mm dd 99 11 03
Reviewed by CONSTRUCTOR	yyyy mm dd 99 11 03	Approved by VICE PRESIDENT	yyyy mm dd 99 11 16

H2856/r Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Complex no. 241

Advance or deferral impact

Deferral will cause Line 85 to become overloaded.

Factors affecting timing or viability

Load Growth.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Neepawa 66kV Breaker Addition		493	503	517	14	3
Neepawa - Plumas Tap 66kV Line		2,620	2,672	2,601	-71	-3
TOTAL		3,113	3,175	3,118	-57	-2

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
1997 10	3,460	New Complex
1998 10	3,552	Revised to include interest.
1999 10	3,442	Scope unchanged.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

90.

COMPLEX STATUS	Complex no.	REVISION STATUS
☒ Planned ☐ In progress	242	☐ New complex ☐ In service change ☐ Concept change ☒ Estimate change only

COMPLEX	RESTON - GLENBORO CAPACIY INCREASE

Proposal

Design and construct facilities at Reston and Glenboro as Follows:

Replace the 56.3 MVA 230-66kV Bank 1 at Reston with a 93.7 MVA unit and install the 56.3 unit at Glenboro in a new Bank 3 position.

JUSTIFICATION		Explanation
☒ Load	☐ Service	Capacity increases at Reston and Glenboro are required to provide firm supply to distribution stations in their respective areas and for load increases at Cromer and Glenboro IPL stations.
☐ Safety	☐ Efficiency	
☒ Reliability	☐ Other	

Estimate Level	COMPLEX START (yyyy mm)
L2	1999 04

IN SERVICE DATES AND AMOUNTS					
2001 07	$2611	2001 10	$2480		

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend								
Year 99/00	454	19	18		491	430	61	14
00/01	2,526	146	149		2,821	2,774	47	2
01/02	1,526	110	143	195	1,584	1,570	14	1
02/03								
03/04								
04/05								
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	4,506	275	310	195	4,896	4,774	122	3

REVISION	Scope unchanged.

Reviewed by ORIGINATOR	yyyy mm dd 99 11 03	Reviewed by COORDINATOR	yyyy mm dd 99 11 03
Reviewed by CONSTRUCTOR	yyyy mm dd 99 11 03	Approved by VICE PRESIDENT	yyyy mm dd 99 11 16

H2856/r Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Complex no. 242

Advance or deferral impact

Deferral will reduce reliability of support for IPL and Reston - Glenboro South areas.

Factors affecting timing or viability

Load Growth.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Reston Station - Bank 1 Replacement		2,265	2,310	2,335	25	1
Glenboro South Station - Bank 3 Addition		2,102	2,144	2,171	27	1
TOTAL		4,367	4,454	4,506	52	1

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
1997 10	4,788	New Complex
1998 10	4,774	Scope unchanged.
1999 10	4,896	Scope unchanged.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

91.

COMPLEX STATUS: ☐ Planned ☒ In progress

Complex no. 80

REVISION STATUS: ☐ New complex ☐ In service change ☐ Concept change ☒ Estimate change only

COMPLEX: ST LEON 230-66KV TRANSFORMER ADD'N & IPL EXPANSION

Proposal

Design and construct facilities at St Leon , Virden West, Cromer North, Letellier, Gretna IPL, Souris IPL East, Souris IPL West and Manitou IPL Stations to provide supplies to meet IPL operational requirements.

JUSTIFICATION

☒ Load ☐ Service
☐ Safety ☐ Efficiency
☒ Reliability ☐ Other

Explanation

IPL is implementing a major system expansion and require full voltage motor starting capability for motors sized up to 3500 HP and the ability to continue operation with failure of customer owned motor drives and PF correction.

Estimate Level	COMPLEX START (yyyy mm)
L2	1995 09

IN SERVICE DATES AND AMOUNTS

1999 04	$2357	1999 08	$1363	1999 09	$433	2001 09	$6494
2001 10	$1024	2004 09	$2696	2004 10	$617		

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	357		-5	350	2	-18	20	-111
Year 99/00	1,435	7	11	1,279	174	-39	213	-546
00/01	688	201	29		918	700	218	31
01/02	1,319	183	99		1,601	1,300	301	23
02/03	5,004	0	1		5,005	5,004	1	0
03/04	1,028	110	20	450	708	655	53	8
04/05	1,862	236	40	1,635	503	1,063	-560	-53
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	11,693	737	195	3,714	8,911	8,665	246	3

REVISION: Scope unchanged.

Reviewed by ORIGINATOR	yyyy mm dd 99 11 08	Reviewed by COORDINATOR	yyyy mm dd 99 11 03
Reviewed by CONSTRUCTOR	yyyy mm dd 99 11 03	Approved by VICE PRESIDENT	yyyy mm dd 99 11 16

H2856/r Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Complex no. 80

Advance or deferral impact

Deferral will decrease supply reliability in the St. Leon area in case of an outage of the existing St. Leon 230-66 KV transformer.

Factors affecting timing or viability

Manitoba Load.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
St. Leon Station 230-66 KV Transformer Addition		5,785	5,901	6,084	183	3
Virden West Station 66kV Breaker Addition		534	545	533	-12	-2
Cromer North Station 66kV Breaker Addition	821	828	845	821	-24	-3
Letellier Station 66kV Breaker Addition		0	0	0	0	
Souris IPL East Station 66kV Breaker Additions		777	793	812	19	2
St Leon Station 66kV Breaker Addition		502	512	529	17	3
Souris IPL West Station Bank Addition		0	0	0	0	
Souris IPL East - Souris IPL West 66kV Line		539	550	550	0	0
St Leon - Manitou IPL 66kV Line		924	942	1,011	69	7
Letellier - Gretna IPL 66kV Line e		0	0	0	0	
Virden West - Cromer IPL 66kV Line	426	304	310	426	116	37
IPL Capital Contributions		0	0	0	0	
Richer South Add 230-66kV Spare Power Transformer		712	726	924	198	27
TOTAL	1,247	10,905	11,124	11,690	566	5

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
9510	6,357	Reflects transformer price increase.
9610	6,634	In-service date deferred 2 years to 2001 10 31.
1997 10	6,588	The St Leon 230-66kV transformer addition requires advancement to 1998 10 31 and additional new facilities are required to provide IPL supplies.
1998 10	8,665	Based on IPL's reduced electric requirement, St Leon 230-66kV transformer deferred 3 years to September 2001, dedicated supply to Manitou and Souris West IPL deferred to 2004.
1999 10	8,911	Scope unchanged.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

92.

(IN THOUSANDS OF DOLLARS)

COMPLEX STATUS: ☐ Planned ☒ In progress

Complex no. 253

REVISION STATUS: ☒ New complex ☐ In service change ☐ Concept change ☐ Estimate change only

COMPLEX	BRANDON EAST 115KV IMPROVEMENTS

Proposal

Conduct environmental assessment,acquire prorerty,and obtain licencing for construction of 2.63km of 795 MCM ACSR double circuit tubular steel transmission line between Brandon GS and structure 9A. Terminate the new 115kV, 795 MCM ACSR transmission lines replacing BD52 and BK41 at tower 9A and connect to existing transmission lines BD52 to crocus plains and BK41 to CXY Chemicals and Maple Leaf. Construct a new 115-25kV steel stn with 1x10/13.3/16.6MVA,3PH LTC transformers and two feeders at the proposed Maple Leaf hog processing plant site in Brandon and a supply line tap at 115kV line BK41.

JUSTIFICATION

☒ Load ☒ Service
☐ Safety ☒ Efficiency
☐ Reliability ☐ Other

Explanation

New steel station and system changes required to transmit power from Brandon GS to the proposed Maple Leaf hog processing plant, to upgrade existing 115kV facilities for supplying additional load at CXY Chemicals and to accommodate Brandon area load growth.

Estimate Level	COMPLEX START (yyyy mm)
L2-3	1998 03

IN SERVICE DATES AND AMOUNTS					
1999 04	$1527	1999 05	$2225		

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	2,679		62		2,741	2,541	200	8
Year 99/00	965	15	31	3	1,008	900	108	12
00/01								
01/02								
02/03								
03/04								
04/05								
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	3,644	15	93	3	3,749	3,441	308	9

REVISION	Increased to reflect a design concept change in foundation type, and costs to completion.

Reviewed by ORIGINATOR	yyyy mm dd 99 11 08	Reviewed by COORDINATOR	yyyy mm dd 99 11 03
Reviewed by CONSTRUCTOR	yyyy mm dd 99 11 03	Approved by VICE-PRESIDENT	yyyy mm dd 99 11 16

H2856/r Rev 99 03

Complex no. 253

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Advance or deferral impact

Ability to supply power requirements at the planned Maple Leaf hog processing plant, and load growth in the Brandon area, and at CXY Chemicals.

Factors affecting timing or viability

Rate of current load growth, and progress on develpoment of the Maple Leaf hog processing plant.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Brandon East 115kV Improvements	1,314	1,316	1,342	1,499	157	12
Brandon 65th St East New 115-25kV Stn	1,776	1,773	1,808	1,926	118	7
Brandon GS Term of Tower 9A 115kV T/L	220	196	200	220	20	10
TOTAL	3,310	3,285	3,350	3,645	295	9

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
1998 06	3,441	NEW ITEM
1999 10	3,749	Increased to reflect a design concept change in foundation type, and costs to completion

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

93.

COMPLEX STATUS: [X] Planned [ ] In progress

Complex no. 250

REVISION STATUS: [ ] New complex [ ] In service change [ ] Concept change [X] Estimate change only

COMPLEX: BRANDON CROCUS PLAINS 115-25KV STN ADDITION

Proposal
Install two 15/20/25 MVA 115-25KV transformers with OLTC. Install one 115KV breaker to connect the transformers to line BF52. Install 7x25KV breakers and associated equipment to connect the transformers and to provide four additional 25KV feeders into the industrial park. Salvage a bypass jumper.

JUSTIFICATION
[X] Load [X] Service
[ ] Safety [X] Efficiency
[X] Reliability [ ] Other

Explanation
To supply the load growth and the industrial loads in the south Brandon area.

Estimate Level	COMPLEX START (yyyy mm)
L2	2001 01

IN SERVICE DATES AND AMOUNTS

2003 10	$7159			

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend								
Year 99/00								
00/01	82	4	1		87	85	2	2
01/02	546	37	23		606	588	18	3
02/03	3,377	293	183		3,853	3,585	268	7
03/04	1,791	181	289		2,261	2,206	55	2
04/05	314	38			352	354	-2	-1
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	6,110	553	496		7,159	6,818	341	5

REVISION: Scope unchanged.

Reviewed by ORIGINATOR	yyyy mm dd 99 11 08	Reviewed by COORDINATOR	yyyy mm dd 99 11 03
Reviewed by CONSTRUCTOR	yyyy mm dd 99 11 03	Approved by VICE-PRESIDENT	yyyy mm dd 99 11 16

H2856/r Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Complex no. 250

Advance or deferral impact

Ability to supply load growth and the industrial loads in the south Brandon area.

Factors affecting timing or viability

Rate of current load growth.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Brandon Crocus Plains 115-25KV Stn addition		5,803	5,919	6,110	191	3
TOTAL		5,803	5,919	6,110	191	3

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
1998 10	6,818	NEW ITEM
1999 10	7,159	Scope unchanged.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

94.

COMPLEX STATUS	Complex no.	REVISION STATUS
☐ Planned ☒ In progress	86	☐ New complex ☒ In service change ☒ Concept change ☐ Estimate change only

COMPLEX	DIESEL UPGRADING ENHANCEMENT

Proposal

Increase capacity to provide 60 amp service at 4 diesel sites:
1) Brochet - Larger units, additional units, tanks and plant expansion.
2) Lac Brochet - Larger units, additional units, tanks and plant expansion.
3) Tadoule - Site improvements, additional units and plant expansion.
4) Shamattawa - Additional tanks, two mobiles and new plant.
5) Distribution - Pik/Thicket- 25kv tie line; other sites- rebuild distribution system to deliver enhanced.

JUSTIFICATION	Explanation
☒ Load ☒ Service ☐ Safety ☐ Efficiency ☐ Reliability ☐ Other	The provision of service to isolated diesel served customers has not been equivalent to that enjoyed by southern rural customers. Expansion of service to accommodate 60 amp residential supply is a priority.

Estimate Level	COMPLEX START (yyyy mm)
L3	1990 04

IN SERVICE DATES AND AMOUNTS							
1997 03	$9886	1998 01	$2181	1998 07	$875	1998 08	$112
1999 02	$186	1999 08	$1952	1999 10	$7830	2000 03	$241
2002 10	$8297	2003 03	$220				

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	19,870		1,342	1,078	20,134	18,651	1,483	8
Year 99/00	1,860	29	408	183	2,114	3,000	-886	-30
00/01	1,598	101	47	8	1,738	1,129	609	54
01/02	3,828	306	317	27	4,424	253	4,171	NA
02/03	1,558	145	356	76	1,983	5,500	-3,517	-64
03/04								
04/05								
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	28,714	581	2,470	1,372	30,393	28,533	1,860	7

REVISION	Reflects additional costs for:CT & PT metering (Brochet), Eng & Consult'g (Brochet & Lac Brochet), welding & commissioning (Lac Brochet), & 1 YR deferral of Shamattawa Mods

		yyyy	mm	dd			yyyy	mm	dd
Reviewed by	ORIGINATOR	99	11	09	Reviewed by	COORDINATOR	99	11	09
Reviewed by	CONSTRUCTOR	99	11	03	Approved by	VICE PRESIDENT	99	11	16

H2856/r Rev 99 03

Complex no. 86

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Advance or deferral impact

The provision of electrical service equivalent to that enjoyed by southern rural customers is a priority.

Factors affecting timing or viability

Decision/ agreement to connect community(s) to the central system supply.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE	
					Amount	%
Diesel Generation - Enhanced Requirements	10,377	3,740	3,815	3,740	-75	-2
Brochet Powerhouse - Tank Farm	1,752	7,212	7,356	8,307	951	13
Lac Brochet Modifications	1,722	3,804	3,880	3,904	24	1
St. Theresa Modifications	344	341	348	343	-5	-1
Shamatawa Modifications	1,717	7,092	7,013	7,362	349	5
Tadoule Lake New Powerhouse	2,314	4,891	4,989	4,891	-98	-2
Lac Brochet Distribution upgrade to 25kV	241	151	154	166	12	8
TOTAL	18,467	27,231	27,555	28,713	1,158	4

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
9510	23,929	Reflects 1995 base and adds requirements to complete Tadoule Lake powerhouse.
9610	24,913	Lac Brochet advanced & Shamatawa deferred 1 year, Brochet powerhoust tank farm deferred 2 years, shamatawa mods estimate updated & ISD deferred to 2000 11 30.
9710	27,252	The est. reflects the relocation extension and expansion of the existing Brochet powerhouse and final design estimates associated with the distribution and upgrades at Lac Brochet
1998 10	28,533	Reflects additional fire protection, scope increase for consultant, and higher distribution and interest costs for Brochet tank farm. Shamattawa Mods have been deferred one year.
1999 10	30,393	Reflects additional costs for:CT & PT metering (Brochet), Eng & Consult'g (Brochet & Lac Brochet), welding & commissioning (Lac Brochet), & 1 YR deferral of Shamattawa Mods

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

95.

(IN THOUSANDS OF DOLLARS)

COMPLEX STATUS: ☐ Planned ☒ In progress

Complex no. 221

REVISION STATUS: ☐ New complex ☒ In service change ☐ Concept change ☒ Estimate change only

COMPLEX	VIRDEN AREA DISTRIBUTION CHANGES

Proposal

Rebuild 136 KM (85%) of primary distribution served by Virden-Seventh, Virden-North, Hargrave & Kenton Stns, and convert 438 transformers from 4.8/8.32kV to 14.4/24.9kV. Salvage & rebuild 33kV L66 Virden to Kenton.

Rebuild 95 KM of 66kV lines #95 & 97 and 24 KM of primary distribution Elkhorn to Manson.

Build a new 66-25kV station 1 mile west of the town of Virden.

JUSTIFICATION

☒ Load ☐ Service
☒ Safety ☒ Efficiency
☒ Reliability ☐ Other

Explanation

136 km line is old (rural electrification-30 ft poles) & does not meet CSA clearance criteria. Transformer upgrades will correct high voltage fluctuations, & losses, and reduce monitoring requirements. Line 95/97 is over 40 years old, deteriorated and does not comply with CSA standards, posing a safety hazard. The new Virden-Wallace Stn is required to meet 1998 projected load requirements..

Estimate Level	COMPLEX START (yyyy mm)
L2-3	1995 10

IN SERVICE DATES AND AMOUNTS

1997 09	$1966	1998 07	$868	1999 03	$41	1999 04	$1388
1999 10	$4299	2000 10	$1795	2001 10	$1907	2002 10	$925
2003 10	$1055	2004 10	$1073				

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	4,434		200	264	4,370	4,200	170	4
Year 99/00	4,234	66	119	190	4,229	3,351	878	26
00/01	1,351	59	40	182	1,268	1,292	-24	-2
01/02	1,477	80	49		1,606	1,514	92	6
02/03	920	69	9	138	860	775	85	11
03/04	990	96	10	72	1,024	947	77	8
04/05	980	116	20	73	1,043	966	77	8
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	14,386	486	447	919	14,400	13,045	1,355	10

REVISION	Increased to reflect the addition of larger conductor (Birtle > Foxwarren), installation of ground rods (Virden-Wallace Stn), and revised activity and overhead rates.

		yyyy mm dd			yyyy mm dd
Reviewed by	ORIGINATOR	99 11 08	Reviewed by	COORDINATOR	99 11 03
Reviewed by	CONSTRUCTOR	99 11 03	Approved by	VICE PRESIDENT	99 11 16

H2856/r Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Complex no. 221

Advance or deferral impact

Factors affecting timing or viability

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Virden - Wallace new 66-25kV Stn	2,097	2,113	2,155	2,376	221	10
Kenton Distribution Rebuild	5,419	5,912	6,030	6,824	794	13
Line 95 & Line 97 Rebuild	5,851	4,766	4,861	5,188	327	7
TOTAL	13,367	12,791	13,046	14,388	1,342	10

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
96 10	13,394	NEW COMPLEX
9710	13,786	REFLECTS FULL COSTING METHODOLOGY IMPLEMENTED WITH THE NEW FINANCIAL REPORTING SYSTEM.
1998 10	13,045	Reflects 97/98 underexpenditure 0.5M, a new estimate for Kenton distribution rbld and in-service dates revised to align with the Dept of Highways schedule for Lines 95 & 97 rbld.
1999 10	14,400	Increased to reflect the addition of larger conductor (Birtle > Foxwarren), installation of ground rods (Virden-Wallace Stn), and revised activity and overhead rates.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

96.

COMPLEX STATUS	Complex no.	REVISION STATUS
☐ Planned ☒ In progress	217	☐ New complex ☒ In service change ☐ Concept change ☒ Estimate change only

COMPLEX	DEFECTIVE RINJ CABLE REPLACEMENT

Proposal

Replace approximately 62,500 metres of rinj (red Jacket) cable within the city of Winnipeg.

JUSTIFICATION	Explanation
☐ Load ☒ Service ☐ Safety ☐ Efficiency ☒ Reliability ☐ Other	The failure rate of rinj underground cable installed in the City of Winnipeg during the 1960's is three times the rate at which CSA recommends cable replacement.

Estimate Level	COMPLEX START (yyyy mm)
L2	1996 11

IN SERVICE DATES AND AMOUNTS							
1999 06	$399	1999 09	$399	1999 12	$399	2000 03	$399
2000 06	$399	2000 09	$399	2000 12	$399	2001 03	$399
2001 06	$399	2001 09	$399	2001 12	$399	2002 on	$3587

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	152		8		160	147	13	9
Year 99/00	779	27	2		808	896	-88	-10
00/01	1,146	45	-37		1,154	1,248	-94	-8
01/02	1,780	107	-43		1,844	2,041	-197	-10
02/03	1,756	138	-24		1,870	2,045	-175	-9
03/04	1,922	200	13		2,135	2,401	-266	-11
04/05								
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	7,535	517	-81		7,971	8,778	-807	-9

REVISION	Reduced to reflect the effect of placing sections in service as completed, rather than annually.

Reviewed by ORIGINATOR	yyyy mm dd 94 11 03	Reviewed by COORDINATOR	yyyy mm dd 99 11 03
Reviewed by CONSTRUCTOR	yyyy mm dd 94 11 03	Approved by VICE-PRESIDENT	yyyy mm dd 99 11 16

H2856/r Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Complex no. 217

Advance or deferral impact

Factors affecting timing or viability

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	%
Defective Rinj Cable Replacement	7,534	7,661	7,814	7,534	-280	-4
TOTAL	7,534	7,661	7,814	7,534	-280	-4

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
96 10	8,613	NEW COMPLEX
9710	9,506	Reflects revised costing methodology implemented with the new financial reporting system, revised interest and escalation, and staged in-service dates.
1998 10	8,778	Deferred one year due to budget constraints.
1999 10	7,971	Reduced to reflect the effect of placing sections in service as completed, rather than annually.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

97.

COMPLEX STATUS	Complex no.	REVISION STATUS
☒ Planned ☐ In progress	261	☒ New complex ☐ In service change ☐ Concept change ☐ Estimate change only

COMPLEX	BRERETON LAKE STATION AREA

Proposal
Construct a new 124-12/25kV steel station c/w 2-7.5/10MVA 124-12/25kV LTC transformers and 2-560A WVE 12kV OCRs.

JUSTIFICATION		Explanation
☐ Load	☒ Service	The existing 33kV line from SW 293 to White Lake Stn, Rennie Stn and SW 1810 is at the end of its life expectancy. There are deficiencies associated with White Lake and Rennie stations, as well. A new station complete with a rebuilt distribution system will provide more acceptable customer service reliability.
☐ Safety	☒ Efficiency	
☒ Reliability	☐ Other	

Estimate Level	COMPLEX START (yyyy mm)
L2	2000 04

IN SERVICE DATES AND AMOUNTS							
2002 03	$3534	2002 04	$1037	2003 04	$985	2004 03	$322
2004 04	$156	2005 04	$529				

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend								
Year 99/00								
00/01	2,485	44	102		2,631		2,631	
01/02	1,792	72	299		2,163		2,163	
02/03	550	49	71		670		670	
03/04	470	37	23		530		530	
04/05	400	40	15		455		455	
05/06	100	11	3		114		114	
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	5,797	253	513		6,563		6,563	

REVISION	New Complex

Reviewed by ORIGINATOR		yyyy mm dd 99 11 08	Reviewed by COORDINATOR		yyyy mm dd 99 11 03
Reviewed by CONSTRUCTOR		yyyy mm dd 99 11 03	Approved by VICE-PRESIDENT		yyyy mm dd 99 11 16

H2856/r Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Complex no. 261

Advance or deferral impact

Will have an affect on maintenance costs, and customer service.

Factors affecting timing or viability

Construction season.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Brereton Lake Station				5,797	5,797	
TOTAL				5,797	5,797	

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
1999 10	6,563	New Complex

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

98.

COMPLEX STATUS	Complex no.	REVISION STATUS
[X] Planned [ ] In progress	267	[X] New complex [ ] In service change [ ] Concept change [ ] Estimate change only

COMPLEX	PAINT LAKE NEW FEEDER

Proposal
Construct 24 KM Z-2/0 AASC 25kV feeder from Jonas Road, Thompson to Paint Lake.Rebuild and convert Paint Lake 12 kV distribution system to 25 kV, and salvage Pipe Lake 1500KVA 4-12kV interchange transformer bank and associated 4kV and 12kV feeder sections.

JUSTIFICATION	Explanation
[ ] Load [X] Service [ ] Safety [X] Efficiency [X] Reliability [ ] Other	Power supply to Paint Lake is provided from Pipe Lake 230-4kV station owned by Inco. Contract with Inco will expire in March 2001. Based on a cost analysis it is recommended to construct a new Jonas Road-Paint Lake 25kV feeder. Purchasing and upgrading Pipe Lake station would be more costly.

Estimate Level	COMPLEX START yyyy mm
L1	1999 04

IN SERVICE DATES AND AMOUNTS				
2002 03	$1774			

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend								
Year 99/00								
00/01								
01/02	1,662	51	37		1,750		1,750	
02/03	23			180	-157		-157	
03/04								
04/05								
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	1,685	51	37	180	1,593		1,593	

REVISION	New Complex

Reviewed by ORIGINATOR	yyyy mm dd	Reviewed by COORDINATOR	yyyy mm dd
99 11 05			99 11 03
Reviewed by CONSTRUCTOR	yyyy mm dd	Approved by VICE PRESIDENT	yyyy mm dd
99 11 03			99 11 16

H2856/r Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Complex no. 267

Advance or deferral impact

Customers will continue to be served by a 12kV system.

Factors affecting timing or viability

Present contract expires in 2001may have to be renewed.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Paint Lake New Feeder				1,685	1,685	
TOTAL				1,685	1,685	

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
1999 10	1,593	New Complex

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

99.

(IN THOUSANDS OF DOLLARS)

COMPLEX STATUS	Complex no.	REVISION STATUS
☐ Planned ☒ In progress	10	☐ New complex ☒ In service change ☐ Concept change ☒ Estimate change only

COMPLEX	E M S SCADA

Proposal

Establish site, define, procure and install an EMS SCADA to replace the existing AGC SCADA. Provide any additional renovations or plant additions required to house the new EMS SCADA and salvage the old.

JUSTIFICATION		Explanation
☐ Load	☒ Service	The existing AGC SCADA has reached its maximum capability and can not be expanded without high risk to the Corporation. The applications of the existing AGC SCADA are limited and are not able to run the new generation of applications that are required. The reliability of the existing AGC SCADA may also become a concern as supply of new and used parts diminish.
☐ Safety	☒ Efficiency	
☒ Reliability	☐ Other	

Estimate Level	COMPLEX START (yyyy mm)
L2	1996 02

IN SERVICE DATES AND AMOUNTS							
1998 02	$3244	1998 03	$2576	1998 04	$698	1998 06	$456
1998 09	($314)	1998 10	$51969	1998 11	$1224	1998 12	$763
1999 02	$893	1999 03	$2046	1999 06	$1582	1999 09	$743

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	59,815		3,984	73	63,726	63,957	-231	-0
Year 99/00	2,075	6			2,081	461	1,620	351
00/01								
01/02								
02/03								
03/04								
04/05								
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	61,890	6	3,984	73	65,807	64,418	1,389	2

REVISION	Reflects additional costs to salvage and renovate existing system control ctr (cc), and clean up Brandon and Dorsey emergency cc's.

Reviewed by ORIGINATOR	yyyy mm dd 99 11 08	Reviewed by COORDINATOR	yyyy mm dd		
Reviewed by CONSTRUCTOR	yyyy mm dd 99 11 03	Approved by VICE PRESIDENT	yyyy mm dd 99 4 16		

H2856/r Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Complex no. 10

Advance or deferral impact

Increasingly unstable operating control system.

Factors affecting timing or viability

Degree of dependence on the new generation of applications.
Availability of new and used parts for the AGC SCADA system.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
EMS SCADA	54,048	60,391	61,599	61,890	291	0
TOTAL	54,048	60,391	61,599	61,890	291	0

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
95 10	30,194	NEW COMPLEX
96 10	60,847	Revised to include a new building facility and communications.
1997 10	60,717	In Service date advanced from 1999 01 01 to 1998 10 31. Previous estimate was based on an even cashflow whereas this revision reflects a detailed schedule.
1998 10	64,418	Reflects 97/98 undexp 4.1M,purch of video proj, + more work than orig est on 48V battery sys, MTS serv, SCC bkup facil, Multiplex, WLFOS, WAFOS, Alarms, and SCC/BUCC facil.
1999 10	65,807	Reflects additional costs to salvage and renovate existing system control ctr (cc), and clean up Brandon and Dorsey emergency cc's.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

100

COMPLEX STATUS: ☐ Planned ☒ In progress

Complex no. 12

REVISION STATUS: ☐ New complex ☒ In service change ☒ Concept change ☐ Estimate change only

COMPLEX: MICROWAVE RADIO REPLACEMENTS

Proposal

Upgrade and refurbish the Lake Winnipeg Microwave System.
Replace the Winnipeg River Microwave System.
Replace Thompson/Kelsey/Radisson Communications.
Provide a Fiber Optic cable system from Winnipeg Area to Brandon Area.
Provide replacement microwave equipment required to access Industry Canada re-allocated frequencies.
Replace the Interlake Digital Microwave System.

JUSTIFICATION

☐ Load ☒ Service
☐ Safety ☐ Efficiency
☒ Reliability ☐ Other

Explanation

The joint MH/MTS Dorsey-Radisson link is nearing end of life. Details will be determined in future studies. The Wpg R MW System is less reliable due to age, and unavailability of parts. Thompson, Kelsey, Radisson comm channels will replace those which MTS is removing. Wpg/Bdn fibre optics will provide more channels and digital capacity to meet forecast requirements. Various microwave equipment must be replaced as it is dedicated to frequencies which have been re-allocated from our licence. Interlake syst repl required for all of the above reasons.

Estimate Level	COMPLEX START (yyyy mm)
L2	1997 04

IN SERVICE DATES AND AMOUNTS

1999 03	($150)	1999 04	$6911	1999 08	$109	1999 12	$448
2000 03	$9618	2001 12	$1483	2002 01	$1987	2002 03	$6897
2002 12	$12437	2005 10	$18124				

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	8,576		677	142	9,111	9,486	-375	-4
Year 99/00	8,690	81	701	505	8,967	5,760	3,207	56
00/01	2,927	108	249		3,284	2,524	760	30
01/02	8,524	388	718		9,630	12,947	-3,317	-26
02/03	7,109	484	509		8,102	3,427	4,675	136
03/04								
04/05	1,384	184	63		1,631	1,495	136	9
05/06	14,252	1974	266		16,492	15,910	582	4
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	51,462	3,219	3,183	647	57,217	51,549	5,668	11

REVISION: Add'n of: 1)site,upgrades,reloc of comm rm on Wpg R syst.2)Grd Rpds > Tyrell Mw Repl.3) Thompson cable repl.4)Wpg > Bdn upgr & equip,&5) scope chg in Minn & Thomp areas.

Reviewed by ORIGINATOR	yyyy mm dd 99 11 08	Reviewed by COORDINATOR	yyyy mm dd
Reviewed by CONSTRUCTOR	yyyy mm dd 99 11 03	Approved by MANAGER/VP	yyyy mm dd 99 11 16

H2856/r Rev 99 03

Complex no. 12

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Advance or deferral impact

Factors affecting timing or viability

n/a

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Lake Winnipeg Microwave Upgrade		10,719	10,933	11,032	99	1
Wpg River Microwave System Replacement	7,152	6,641	6,774	8,544	1,770	26
Microwave Frequency Displacement (2GH)	5,561	5,771	5,886	5,852	-34	-1
Thompson/Kelsey/Radisson Communications Repl		250	255	108	-147	-58
Wpg/Bdn Fibre Optic Communications	8,403	5,962	6,081	6,750	669	11
Minnedosa area 71E3 microwave replacement		1,657	1,690	1,742	52	3
Jenpeg-Whiskey Jack-Wabowden M/W replacement	425	392	400	425	25	6
Interlake Digital Microwave Replacement		14,970	15,269	15,636	367	2
Thompson Communications Cables Repl				650	650	
Grand rapids > Tyrell RCA 9202 Microwave Repl				723	723	
TOTAL	21,541	46,362	47,288	51,462	4,174	9

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
9510	36,047	Complex increased to include Wpg R MW repl, Thompson/Kelsey/Radisson comm repl, frequency change equip, and Wpg/Bdn fibre optic cable system.
9610	39,349	Increase due to 1) deferrals, Lake Wpg, MW frequency displacement, Thompson-Kelsey-Rad, and Wpg/Bdn fibre optic. 2)addition of Minnedosa, & Jenpeg-Whiskeyjack-Wabowden.
1997 10	40,798	Winnipeg River Microwave system replacement deferred 15 mo to 1999 03 31. Estimate reflects revised costing methodology implemented with the new financial reporting system.
1998 10	51,549	Reflects 97/98 underexpenditure 9.5M, and addition of the Interlake Digital Microwave Replacement item.
1999 10	57,217	Add'n of: 1)site,upgrades,reloc of comm rm on Wpg R syst.2)Grd Rpds > Tyrell Mw Repl.3) Thompson cable repl.4)Wpg > Bdn upgr & equip,&5) scope chg in Minn & Thomp areas.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION
94 - T2	Telecontrol Communications Option Winnipeg Area to Brandon Area

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

101.

COMPLEX STATUS	Complex no.	REVISION STATUS
☐ Planned ☒ In progress	219	☐ New complex ☒ In service change ☐ Concept change ☒ Estimate change only

COMPLEX	MAPINFO IMPLEMENTATION

Proposal

Design, implement and provide training and data conversion for a geographic information system.

JUSTIFICATION		Explanation
☐ Load	☐ Service	Based on a favourable benefit/cost analysis completed in 1990, the decision was made to proceed with the development of a geographical information system for Manitoba Hydro.
☐ Safety	☒ Efficiency	
☐ Reliability	☐ Other	

Estimate Level	COMPLEX START (yyyy mm)
L3	1995 04

IN SERVICE DATES AND AMOUNTS							
To 1997 12	$5864	1998 01	$1491	1999 02	$4728	1999 07	$3780
2000 01	$3780	2000 07	$3780	2001 12	$3780		

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	16,525		947		17,472	17,023	449	3
Year 99/00	4,107	42	281		4,430	4,692	-262	-6
00/01	4,128	109	68		4,305	2,795	1,510	54
01/02	1,753	75	166		1,994	2,346	-352	-15
02/03								
03/04								
04/05								
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	26,513	226	1,462		28,201	26,856	1,345	5

REVISION	Reflects addition of transmission line maintenance, revision of cashflow, and 9 Mo. deferral of final ISD

		yyyy mm dd			yyyy mm dd
Reviewed by	ORIGINATOR	99 11 03	Reviewed by	COORDINATOR	99 11 03
Reviewed by	INSTRUCTOR	99 11 03	Approved by	VICE PRESIDENT	99 11 16

H2856/r Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Complex no. 219

Advance or deferral impact

Factors affecting timing or viability

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Mapinfo Implementation Part II	23,169	25,281	25,787	26,513	726	3
TOTAL	23,169	25,281	25,787	26,513	726	3

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
96 10	25,079	New complex transferred from domestic.
9710	25,252	SCOPE UNCHANGED, ESTIMATE REFLECTS REVISED COSTING METHODOLOGY IMPLEMENTED WITH THE NEW FINANCIAL REPORTING SYSTEM.
1998 10	26,856	Reflects 97/98 underexpenditure 0.8M, in service deferred 8 months, and cash flow revised.
1999 10	28,201	Reflects addition of transmission line maintenance, revision of cashflow, and 9 Mo. deferral of final ISD

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

102

COMPLEX STATUS: ☐ Planned ☒ In progress

Complex no. 2

REVISION STATUS: ☐ New complex ☐ In service change ☐ Concept change ☒ Estimate change only

COMPLEX	SITE REMEDIATION

Proposal

Implement programs designed to minimize or ameliorate the impact of the Corporation's operations on the environment, such as;

Conduct geotechnical investigations and remediate any hydrocarbon contaminated sites at 26 former isolated diesel generating stations in; Dauphin River, Bloodvien, Berens River, Jackhead, Little Grand Rapids, Manigotogan, Matheson Island, Pauingassi, Pine Dock, Poplar River, Pukatawagan, Gods Lake Narrows, Tadoule, The Pas, Moose Lake, Norway House, Cross Lake, Ilford, Nelson House, Split Lake, Wanless, Granville Lake, Bakers Narrows, Cormorant and Cranberry Portage.

Conduct geotechnical investigation for the various contaminated Corporate facilities, prepare a report with cleanup recommendations, remediate any contaminated areas identified and issue a final report confirming the facility and surrounding area were remediated and all areas of the work were left in accordance with applicable environmental regulations.

JUSTIFICATION

☐ Load ☐ Service
☒ Safety ☐ Efficiency
☐ Reliability ☒ Other

Explanation

Due to concerns and in compliance with current environmental regulations and standards applicable to unrestricted use of abandoned former diesel sites, the sites must be investigated, remediated and restored to equivalency of the surrounding area.

Various existing Corporate contaminated facilities should be brought into compliance with current environmental regulations and standards.

Estimate Level	COMPLEX START (yyyy mm)
L1-3	1991 10

IN SERVICE DATES AND AMOUNTS

Up To 96/97	$3278	1999 04	$93	1999 08	$611	1999 10	$1574
1999 12	$99	2000 08	$373	2000 09	$299	2000 11	$992
2000 12	$1239	2001 10	$209	2001 11	$1186	2002 ON	$1736

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	4,728		283	2,032	2,979	5,332	-2,353	-44
Year 99/00	1,514	35	7	245	1,311	1,003	308	31
00/01	2,331	129	27	251	2,236	1,439	797	55
01/02	835	66	16	51	866	861	5	1
02/03	1,574	144		649	1,069	1,051	18	2
03/04								
04/05								
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	10,982	374	333	3,228	8,461	9,686	-1,225	-13

REVISION	Reflects increases for Nelson House remediation , trailors and advancement at First Nation request, and Cormorant as req'd by MB Environmen t. Four sites deferred, & 5 completed.

Reviewed by COORDINATOR		yyyy mm dd 99 11 09	Reviewed by COORDINATOR		yyyy mm dd 99 11 09
Reviewed by CONSTRUCTOR		yyyy mm dd 99 11 03	Approved by VICE PRESIDENT		yyyy mm dd 99 11 16

H2856/r Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Complex no. 2

Advance or deferral impact

POTENTIAL FOR LEGAL ACTIONS.

Factors affecting timing or viability

SUBJECT TO ENVIRONMENTAL REGULATIONS

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Diesel Site Clean-ups (19 abandoned sites)	24,030	12,143	12,386	10,982	-1,404	-11
TOTAL	24,030	12,143	12,386	10,982	-1,404	-11

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
9510	37,841	Oil containment items transferred to complex 81. Site remediation items do not reflect Federal Contribution.
9610	13,783	Estimates revised to reflect new overall work plan for remediation of diesel sites, with contributions based on 35 - 50% of all costs.
9710	12,016	Reflects receipt of federal contributions, results of latest comprehensive investigations, and adjustment of spent to date for closed out sites.
1998 10	9,686	Reflects cancellation of soil remediation work at Churchill DGS.
1999 10	8,461	Reflects increases for Nelson House remediation , trailors and advancement at First Nation request, and Cormorant as req'd by MB Environmen t. Four sites deferred, & 5 completed.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

103.

COMPLEX STATUS: ☐ Planned ☒ In progress

Complex no. 81

REVISION STATUS: ☐ New complex ☐ In service change ☐ Concept change ☒ Estimate change only

COMPLEX: OIL CONTAINMENT

Proposal

Implement programs designed to minimize or ameliorate the impact of the Corporation's operations on the environment, such as;

Design and construct oil containment systems to collect and recover any oil spilled within the system.

JUSTIFICATION: ☐ Load ☐ Service ☒ Safety ☐ Efficiency ☐ Reliability ☒ Other

Explanation

Previous experience with oil spills requires the Corporation to demonstrate "due diligence" with respect to containing and minimizing the potential for any further occurances.

Estimate Level	COMPLEX START (yyyy mm)
L1	1995 02

IN SERVICE DATES AND AMOUNTS							
1997 03	$70	1999 05	$192	2002 03	$266	2002 10	$3341

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	421		63		484	474	10	2
Year 99/00	54		24		78	33	45	136
00/01	722	32	51		805	694	111	16
01/02	1,020	70	138		1,228	1,085	143	13
02/03	825	67	115		1,007	857	150	18
03/04	244	23			267	233	34	15
04/05								
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	3,286	192	391		3,869	3,376	493	15

REVISION: Scope unchanged.

Reviewed by ORIGINATOR	yyyy mm dd 99 11 09	Reviewed by COORDINATOR	yyyy mm dd 99 11 03
Reviewed by CONSTRUCTOR	yyyy mm dd 99 11 03	Approved by VICE-PRESIDENT	yyyy mm dd 99 11 16

H2856/r Rev 99 03

Complex no. 81

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Advance or deferral impact

POTENTIAL FOR LEGAL ACTIONS.

Factors affecting timing or viability

SUBJECT TO ENVIRONMENTAL REGULATIONS

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE	
					Amount	%
AC Sub- Station Oil Containment - Central Area	747	637	650	747	97	15
AC Sub- Station Oil Containment - Western Area	879	749	764	879	115	15
AC Sub- Station Oil Containment - Eastern Area	901	772	787	901	114	14
AC Sub- Station Oil Containment - Northern Area	280	241	246	280	34	14
Microwave & VHF Sites Oil Spill Containment		230	235	230	-5	-2
Thompson Service Ctr Oil Spill Containment	70	70	71	70	-1	-1
Operations & Maintenance spill response equipment	150	155	158	179	21	13
TOTAL	3,027	2,854	2,911	3,286	375	13

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
95 10	19,780	NewComplex. (previously part of ENVIRONMENTAL INITIATIVES complex) .
96 10	3,363	Reflects Transmission & Distribution portion of previous oil containment item and addition of a spill response equipment purchase item, base year 1996.
9710	3,409	ESTIMATE REFLECTS REVISED COSTING METHODOLOGY IMPLEMENTED WITH THE NEW FINANCIAL REPORTING SYSTEM.
1998 10	3,376	Estimates revised to reflect actual site assessments completed, and balance of deferred equipment purchase requirements.
1999 10	3,869	Scope unchanged.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION
95 - M5	Oil spill containment in Corporate Facilities.

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

104.

COMPLEX STATUS	Complex no.	REVISION STATUS
☐ Planned ☒ In progress	131 - 139	☐ New complex ☐ In service change ☒ Concept change ☐ Estimate change only

COMPLEX	DOMESTIC ITEM - TRANSMISSION & DISTRIBUTION

Proposal

This complex consists of several hundred projects which are not identified as Major Items and whose individual cost is of a relatively small amount. The majority of projects are required to extend sub-transmission, distribution and transformation facilities to supply service to residential, farm, commercial and industrial customers and to replace plant facilities whose useful life has been exceeded.

JUSTIFICATION	
☒ Load	☒ Service
☒ Safety	☒ Efficiency
☒ Reliability	☒ Other

Explanation

The system has incurred consistant expenditures in the past which are required to meet the load growth into the foredeeable future. The residential, farm, commercial and industrial loads are expected to grow at an 20 year average rate of 1.5% per annum and will require a program of additions to the System to accommodate these anticipated loads.

Estimate Level	COMPLEX START (yyyy mm)
L2	1996 04

IN SERVICE DATES AND AMOUNTS							
1999 03 31	$74482	2000 03 31	$77560	2001 03 31	$78856	2002 03 31	$81652
2003 03 31	$83726	2004 03 31	$86027	2005 03 31	$88303	2006 03 31	$90580
2007 03 31	$92885	2008 03 31	$95198	2009 03 31	$97603	2010 03 31	$100092

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend						74,482	-74,482	-100
Year 99/00	89,187	310	3,043	14,984	77,556	77,560	-4	-0
00/01	89,966	1076	3,077	18,363	75,756	78,856	-3,100	-4
01/02	91,900	2321	3,134	18,803	78,552	81,652	-3,100	-4
02/03	93,110	3554	3,134	19,172	80,626	83,726	-3,100	-4
03/04	89,133	7055	1,713	14,175	83,726	86,027	-2,301	-3
04/05	89,837	8759	1,761	14,330	86,027	88,303	-2,276	-3
05/06	90,424	10508	1,829	14,458	88,303	90,580	-2,277	-3
06/07	90,953	12304	1,897	14,574	90,580	92,885	-2,305	-2
07/08	91,476	14153	1,946	14,690	92,885	95,198	-2,313	-2
08/09	91,925	16045	2,016	14,788	95,198	97,603	-2,405	-2
09/10	92,389	17992	2,112	14,890	97,603	100,092	-2,489	-2
10/11	92,901	20005	2,189	15,003	100,092	102,746	-2,654	-3
11/12	93,493	22093	2,293	15,133	102,746	105,352	-2,606	-2
12/13	93,996	24223	2,376	15,243	105,352	108,078	-2,726	-3
13/14	94,531	26422	2,486	15,361	108,078	110,760	-2,682	-2
14/15	95,009	28668	2,549	15,466	110,760	113,572	-2,812	-2
15/16	95,570	31002	2,589	15,589	113,572	116,517	-2,945	-3
16/17	96,165	33414	2,658	15,720	116,517	119,574	-3,057	-3
17/18	96,771	35901	2,755	15,853	119,574	122,718	-3,144	-3
18/19	97,409	38473	2,829	15,993	122,718		122,718	
Beyond								
TOTAL	1,856,145	354,278	48,386	312,588	1,946,221	1,946,281	-60	-0

REVISION	Reflects forecast costs for the Transmission & Distribution Group.

Reviewed by ORIGINATOR	yyyy mm dd 99 11 08	Reviewed by COORDINATOR	yyyy mm dd 99 11 03
Reviewed by CONSTRUCTOR	yyyy mm dd 99 11 03	Approved by VICE-PRESIDENT	yyyy mm dd 99 11 16

H2856/r Rev 99 03

Complex no.
131 - 139

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Advance or deferral impact

Requirements are necessary to meet capacity and energy demands, in accordance with our system design criteria and/or commitments.

Factors affecting timing or viability

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
TOTAL						

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
9510	2,681,204	Reflects reduced load growth.
9610	1,721,964	This item reflects forecast costs attributable to the Transmission & Distribution Group.
1997 10	1,635,878	REFLECTS TRANSMISSION AND DISTRIBUTION'S REVISED SHARE OF THE DOMESTIC FORECAST BASED ON CURRENT RATES.
1998 10	1,946,281	Annual forecast adjusted to reflect the revised costing methodology impacts based on experience to date.
1999 10	1,946,221	Reflects forecast costs for the Transmission & Distribution Group.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

CAPITAL EXPENDITURE FORECAST (CEF99-1)
(IN MILLIONS OF DOLLARS)
FOR THE YEARS 1999/00 TO 2018/19

		Total	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	20 year Forecast
CUSTOMER SERVICE																							
991	DEMAND SIDE MANAGEMENT CAPITAL COSTS		8.2	10.1	10.4	9.2	9.3	7.2	7.3	7.2	7.4	7.5	5.3	5.4	5.5	5.6	5.7	5.8	5.7	5.8	5.9	6.0	140.7
97	AUTOMATIC METER READING IMPLEMENTATION	30.5		0.1	2.1	3.2	3.3	3.1	3.4	3.5	3.5	6.2	2.3										30.5
	DOMESTIC ITEMS - CUSTOMER SERVICE		33.7	30.3	31.3	32.5	35.0	36.1	37.1	38.1	39.1	40.2	41.3	42.5	43.7	44.9	46.1	47.4	48.8	50.2	51.6	52.9	823.0
	SUB-TOTAL CUSTOMER SERVICE		41.9	40.5	43.8	44.9	47.6	46.3	47.8	48.8	50.1	54.0	49.0	47.9	49.2	50.5	51.8	53.2	54.4	56.0	57.5	58.9	994.2

CAPITAL EXPENDITURE FORECAST REVISIONS (CEF99-1)
(IN MILLIONS OF DOLLARS)
FOR THE YEARS 1999/00 TO 2018/19

		2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	20 year Forecast
CUSTOMER SERVICE																						
991	DEMAND SIDE MANAGEMENT CAPITAL COSTS	(0.0)	2.1	2.2	1.0	2.0	1.6	1.8	1.7	1.8	2.0	0.8	0.6	0.8	0.8	0.8	0.9	1.0	1.0	1.0	1.1	25.0
97	AUTOMATIC METER READING IMPLEMENTATION		(1.5)	(0.9)	(0.1)	(0.0)	(0.0)	(0.1)	(0.0)	(0.1)	(0.1)	2.3										(0.6)
	DOMESTIC ITEMS - CUSTOMER SERVICE	0.1	(1.4)	(1.5)	(1.5)																	(4.4)
	SUB-TOTAL CUSTOMER SERVICE	**0.1**	**(0.8)**	**(0.2)**	**(0.6)**	**1.9**	**1.6**	**1.7**	**1.6**	**1.6**	**1.9**	**3.1**	**0.6**	**0.8**	**0.8**	**0.8**	**0.9**	**1.0**	**1.0**	**1.0**	**1.1**	**20.0**

MANITOBA HYDRO
IFF99 - DSM BUDGET

	ACTUAL TO 1998/99	1999/00	2000/01	2001/02	2002/03	2003/04	2004/05	IFF99 1999$ to 2004/05	IFF98 1998$ to 2004/05	Variance
RESIDENTIAL										
82019 Residential Comprehensive	1,732	445	666	719	773	835	894	6,064	2,302	3,762
82010 New Homes - Insulation/Air Seal	565	315	220	226	231	232	232	2,021	3,468	(1,447)
82003 Heat Recovery Ventilators	2	25	25	25	25	25	25	152	257	(105)
82011 Appliances	207	25	25	25	25	25	25	357	417	(60)
Water Heater Program	957	77	77	77	77	77	77	1,419	2,371	(952)
Hot Water Tank Rental Program	100	-	-	-	-	-	-	100	100	(0)
82035 Power Saver Cords	-	5	5	5	5	5	5	30	2,034	(2,004)
82020 Outdoor Timers	752	13	13	13	13	13	-	817	929	(112)
Subtotal	**4,314**	**905**	**1,031**	**1,090**	**1,149**	**1,212**	**1,258**	**10,959**	**11,878**	**(919)**
COMMERCIAL										
82016 Lighting	10,102	1,328	1,693	1,897	170	120	120	15,430	15,353	77
82005 Commercial Construction	2,814	896	1,338	1,066	1,322	1,549	144	9,129	6,880	2,249
Heat Lamps/Demand Cont	618	-	-	-	-	-	-	618	618	-
82004 Livestock Waterer	301	-	-	-	-	-	-	301	339	(38)
82018 Agricultural Heat Pads	154	208	233	234	234	15	6	1,084	824	260
82015 Internal Retrofit	1,043	179	186	186	188	188	188	2,158	2,760	(602)
Subtotal	**15,032**	**2,611**	**3,450**	**3,383**	**1,914**	**1,872**	**458**	**28,720**	**26,774**	**1,946**
INDUSTRIAL										
82014 Performance Optimization	2,192	803	860	862	808	694	196	6,415	7,961	(1,546)
82017 High Efficiency Motors	2,672	270	257	281	313	325	321	4,439	4,655	(216)
82013 Industrial Retrofit	1,336	473	600	743	982	982	982	6,098	7,014	(916)
82008 Quality Motor Repair	70	-	-	-	-	-	-	70	1,354	(1,284)
Subtotal	**6,270**	**1,546**	**1,717**	**1,886**	**2,103**	**2,001**	**1,499**	**17,022**	**20,984**	**(3,962)**
CONSERVATION SUBTOTAL	25,616	5,062	6,198	6,359	5,166	5,085	3,215	56,701	59,636	(2,935)
RATES										
82007 Curtailable Rates	5,836	1,423	1,401	1,380	1,367	1,345	1,324	14,076	6,136	7,940
82083 Time of Use Rates	-	253	51	52	52	52	52	512	583	(71)
Subtotal	**5,836**	**1,676**	**1,452**	**1,432**	**1,419**	**1,397**	**1,376**	**14,588**	**6,719**	**7,869**
Subtotal of Programs	**31,452**	**6,738**	**7,650**	**7,791**	**6,585**	**6,482**	**4,591**	**71,289**	**66,355**	**4,934**
Support Activity & Contingency										
82002 Program Audits	202	145	145	146	146	146	146	1,076	1,005	71
82021 Commercial Baseline	185	125	125	125	125	125	125	935	308	627
82023 P. S. Communications	6,176	748	699	701	701	701	701	10,427	9,920	507
82022 DSM Tracking System	343	40	40	40	40	40	40	583	630	(47)
Residential Baseline	344	-	-	-	-	-	-	344	344	-
Load Research	1,748	-	-	-	-	-	-	1,748	1,748	-
82024 Integrated Plan/Targets	1,532	138	138	140	140	140	140	2,368	3,076	(708)
82009 Retrofit Demos	1,585	57	57	57	57	57	57	1,927	1,856	71
82025 DSM Administration	1,230	84	84	85	85	85	85	1,738	2,211	(473)
Technology Database	-	-	-	-	-	-	-	-	-	-
Contingency	-	67	933	908	788	778	589	4,063	2,033	2,030
Subtotal	**13,344**	**1,404**	**2,221**	**2,202**	**2,082**	**2,072**	**1,883**	**25,208**	**23,131**	**2,077**
TRC OPTION UTILITY COST SUBTOTAL	**44,796**	**8,142**	**9,871**	**9,993**	**8,667**	**8,554**	**6,474**	**96,497**	**89,486**	**7,011**
HPS CONVERSIONS - DEFERRED ASSET										
Street Lighting	2,785	-	-	-	-	-	-	2,785	2,785	-
Sentinel Lighting	1,178	-	-	-	-	-	-	1,178	1,178	-
HPS CONVERSIONS - PLANT IN SERVICE										
Street Lighting	5,564	-	-	-	-	-	-	5,564	5,564	-
Sentinel Lighting	1,332	-	-	-	-	-	-	1,332	1,332	-
TRC OPTION UTILITY COST - GROSS	**55,655**	**8,142**	**9,871**	**9,993**	**8,667**	**8,554**	**6,474**	**107,356**	**100,345**	**7,011**
CUSTOMER CONTRIBUTIONS	(3,356)	-	-	-	-	-	-	(3,356)	(3,356)	-
TOTAL UTILITY COST - NET	**52,299**	**8,142**	**9,871**	**9,993**	**8,667**	**8,554**	**6,474**	**104,000**	**96,989**	**7,011**
ESCALATION		55	229	426	550	725	689	2,674	2,514	160
TOTAL		8,197	10,100	10,419	9,217	9,279	7,163			
CUMULATIVE	52,299	60,496	70,596	81,015	90,232	99,511	106,674	106,674	99,503	7,171
				1998/99 Actual/Budget				(4,521)	(6,187)	1,666
				Actuals to 1997/98				(47,778)	(47,778)	-
				CER totals to 2003/04				54,375	45,538	8,837

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

105.

COMPLEX STATUS	Complex no.	REVISION STATUS
☐ Planned ☒ In progress	991	☐ New complex ☐ In service change ☒ Concept change ☐ Estimate change only

COMPLEX	DEMAND SIDE MANAGEMENT COSTS - 221

Proposal

To promote conservation of electricity when it can be acheived more economically than supply and to conduct all corporate activities to minimize adverse environmental impacts.

JUSTIFICATION

☐ Load ☐ Service
☐ Safety ☒ Efficiency
☐ Reliability ☐ Other

Explanation

Energy conservation can be economically efficient and environmentally beneficial. Manitoba Hydro is committed to promoting conservation of electricity when it can be acheived more economically than supply. The strategic objective is a reduction in Manitoba Hydro's peak load of 316 MW and firm annual energy requirement of 1249 GW.h by the year 2011/12.

Estimate Level	COMPLEX START (yyyy mm)
L3	1993 04

IN SERVICE DATES AND AMOUNTS							
1999 03	$4521	2000 03	$8197	2001 03	$10100	2002 03	$10419
2003 03	$9217	2004 03	$9279	2005 03	$7163	2006 03	$7308
2007 03	$7243	2008 03	$7443	2009 03	$7548	09/10 on	$206194

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	4,521				4,521	12,137	-7,616	-63
Year 99/00	8,142	55			8,197	8,209	-12	-0
00/01	9,871	229			10,100	8,012	2,088	26
01/02	9,993	426			10,419	8,220	2,199	27
02/03	8,667	550			9,217	8,219	998	12
03/04	8,554	725			9,279	7,303	1,976	27
04/05	6,474	689			7,163	5,573	1,590	29
05/06	6,476	833			7,309	5,484	1,825	33
06/07	6,292	951			7,243	5,565	1,678	30
07/08	6,339	1104			7,443	5,676	1,767	31
08/09	6,302	1246			7,548	5,511	2,037	37
09/10	4,374	969			5,343	4,526	817	18
10/11	4,341	1068			5,409	4,833	576	12
11/12	4,341	1176			5,517	4,674	843	18
12/13	4,302	1275			5,577	4,762	815	17
13/14	4,302	1386			5,688	4,851	837	17
14/15	4,302	1500			5,802	4,942	860	17
15/16	4,130	1552			5,682	4,698	984	21
16/17	4,130	1665			5,795	4,786	1,009	21
17/18	4,130	1781			5,911	4,876	1,035	21
18/19	4,130	1900			6,030		6,030	
Beyond	82,603	66835			149,438	85,186	64,252	75
TOTAL	206,716	87,915			294,631	208,043	86,588	42

REVISION Based on saving 334 MW/1229 GW.H by the year 2011/12 (approved option 4). Additional funds are required beyond the 2012 period to promote the DSM program.

Reviewed by ORIGINATOR	yyyy mm dd 99 11 12	Reviewed by COORDINATOR	yyyy mm dd
Reviewed by CONSTRUCTOR	yyyy mm dd	Approved by VICE-PRESIDENT	yyyy mm dd 99 11 18

H2856/r Rev 99 03

Complex no. 991

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Advance or deferral impact

Delays in the DSM implementation schedule could influence future generation sequence timing.

Factors affecting timing or viability

Avoided utility cost of supplying customers; Economic tests used to measure cost effectiveness; technological change; Customer needs and expectations; Government Legislation - Codes.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE	
					Amount	%
TOTAL						

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
9510	240,682	Reflects the all Economic Lost Opportunities Option as recommended in the 1995 Power Resource Plan Report.
9610	174,425	Reflects the all Economic Lost Opportunities Option as recommended in the 1996 Power Resource Plan Report.
9710	298,393	THIS REVISION IS BASED ON THE ALL ECONOMIC LOST OPPORTUNITIES OPTION AS RECOMMENDED IN THE 1997 POWER RESOURCE PLAN.
1998 10	208,039	Based on saving 316 MW/1249 GW.H by the year 2011/12. Additional funds are required beyond the 2012 period to promote the DSM program.
1999 10	294,631	Based on saving 334 MW/1229 GW.H by the year 2011/12 (approved option 4). Additional funds are required beyond the 2012 period to promote the DSM program.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

106.

COMPLEX STATUS	Complex no.	REVISION STATUS
☒ Planned ☐ In progress	97	☐ New complex ☒ In service change ☐ Concept change ☐ Estimate change only

COMPLEX	AUTOMATIC METER READING IMPLEMENTATION

Proposal

PURCHASE AND INSTALLATION OF AN AUTOMATIC METER READING (AMR) COMMUNICATION NETWORK TO REMOTELY READ AND ELECTRONICALLY DISSEMINATE READINGS AND OTHER RELEVANT CUSTOMER INFORMATION TO THE APPROPRIATE DEPARTMENT OR DIVISION.

JUSTIFICATION	Explanation
☐ Load ☒ Service ☐ Safety ☒ Efficiency ☐ Reliability ☐ Other	AMR WILL SATISFY THE ON-GOING NEED FOR METER READINGS IN SUPPORT OF BILLINGS AS WELL AS PROVIDING " ON DEMAND" READINGS TO RESPOND TO CUSTOMER INQUIRIES. OTHER BENEFITS INCLUDE; POWER OUTAGE ALARMS, DEFECTIVE METER/ THEFT OF SERVICE, FLEXIBLE TIMING AND CONSOLIDATION OF BILLINGS.

Estimate Level	COMPLEX START (yyyy mm)
L1	2001 01

IN SERVICE DATES AND AMOUNTS					
2001 03	$99	2002 03	$2078	2003 03	$3167	2004 03	$3266
2005 03	$3068	2006 03	$3365	2007 03	$3464	2008 03	$3464
2009 03	$6265	2010 03	$2276				

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend								
Year 99/00								
00/01	97	2			99	1,550	-1,451	-94
01/02	1,994	84			2,078	3,011	-933	-31
02/03	2,978	189			3,167	3,244	-77	-2
03/04	3,011	255			3,266	3,309	-43	-1
04/05	2,773	295			3,068	3,092	-24	-1
05/06	2,982	383			3,365	3,442	-77	-2
06/07	3,009	455			3,464	3,511	-47	-1
07/08	2,950	514			3,464	3,581	-117	-3
08/09	5,206	1029			6,235	6,381	-146	-2
09/10	1,863	413			2,276		2,276	
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	26,863	3,619			30,482	31,121	-639	-2

REVISION	Reflects cashflow adjusted for revised schedule.

Reviewed by ORIGINATOR	yyyy mm dd 99 11 17	Reviewed by COORDINATOR	yyyy mm dd		
Reviewed by CONSTRUCTOR	yyyy mm dd	Approved by VICE-PRESIDENT	yyyy mm dd 99 11 18		

H2856/r Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Complex no. 97

Advance or deferral impact

Factors affecting timing or viability

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
AUTOMATIC METER READING (AMR)		26,265	26,790	26,863	73	0
TOTAL		26,265	26,790	26,863	73	0

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
9510	32,047	Base year adjusted to 1995
9610	31,706	Schedule, cash flow, and base year revised.
9710	30,099	Schedule, cash flow, and base year revised.
1998 10	31,121	Deferred two years.
1999 10	30,482	Reflects cashflow adjusted for revised schedule.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

107.

COMPLEX STATUS: ☐ Planned ☒ In progress

Complex no. 141 - 149

REVISION STATUS: ☐ New complex ☐ In service change ☒ Concept change ☐ Estimate change only

COMPLEX: DOMESTIC ITEM - CUSTOMER SERVICE

Proposal
This complex consists of minor projects which are not identified as Major Items and whose individual cost is of a relatively small amount. The majority of projects are required to supply service to residential, farm, commercial and industrial customers and to replace plant facilities whose useful life has been exceeded.

JUSTIFICATION: ☒ Load ☒ Service ☒ Safety ☒ Efficiency ☒ Reliability ☒ Other

Explanation
The Corporation has incurred consistant expenditures in the past to meet customer service requirements. The residential, farm, commercial and industrial loads are expected to grow at an 20 year average rate of 1.5% per annum and will require a program of additions and replacements at the customer service point to accommodate these anticipated changes.

Estimate Level	COMPLEX START (yyyy mm)
L2	1996 04

IN SERVICE DATES AND AMOUNTS

1999 03 31	$29702	2000 03 31	$33665	2001 03 31	$31718	2002 03 31	$32840
2003 03 31	$33998	2004 03 31	$35045	2005 03 31	$36069	2006 03 31	$37087
2007 03 31	$38120	2008 03 31	$39145	2009 03 31	$40214	2010 03 31	$41332

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend						29,702	-29,702	-100
Year 99/00	40,054	235	249	6,801	33,737	33,665	72	0
00/01	37,603	742	229	8,300	30,274	31,718	-1,444	-5
01/02	38,285	1123	232	8,300	31,340	32,840	-1,500	-5
02/03	39,200	1740	232	8,674	32,498	33,998	-1,500	-4
03/04	39,558	2859	760	9,179	33,998	35,045	-1,047	-3
04/05	39,983	3561	784	9,283	35,045	36,069	-1,024	-3
05/06	40,338	4284	816	9,369	36,069	37,087	-1,018	-3
06/07	40,658	5028	848	9,447	37,087	38,120	-1,033	-3
07/08	40,975	5797	872	9,524	38,120	39,145	-1,025	-3
08/09	41,246	6584	905	9,590	39,145	40,214	-1,069	-3
09/10	41,526	7398	949	9,659	40,214	41,332	-1,118	-3
10/11	41,836	8244	986	9,734	41,332	42,535	-1,203	-3
11/12	42,194	9127	1,035	9,821	42,535	43,705	-1,170	-3
12/13	42,498	10028	1,074	9,895	43,705	44,936	-1,231	-3
13/14	42,822	10962	1,126	9,974	44,936	46,041	-1,105	-2
14/15	43,111	11917	1,157	10,144	46,041	47,416	-1,375	-3
15/16	43,450	12916	1,177	10,127	47,416	48,759	-1,343	-3
16/17	43,809	13954	1,211	10,215	48,759	50,158	-1,399	-3
17/18	44,176	15028	1,258	10,304	50,158	51,602	-1,444	-3
18/19	44,562	16144	1,294	10,398	51,602		51,602	
Beyond								
TOTAL	827,884	147,671	17,194	188,738	804,011	804,087	-76	-

REVISION: Reflects current forecast costs for Customer Service and Marketing.

Reviewed by ORIGINATOR	yyyy mm dd 99 11 17	Reviewed by COORDINATOR	yyyy mm dd		
Reviewed by CONSTRUCTOR	yyyy mm dd	Approved by VICE PRESIDENT	yyyy mm dd 99 11 18		

H2856/r Rev 99 03

Complex no.
141 - 149

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Advance or deferral impact

Requirements are necessary to meet capacity and energy demands, in accordance with our system design criteria and/or commitments.

Factors affecting timing or viability

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE	
					Amount	%
TOTAL						

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
9510	2,681,204	Reflects reduced load growth.
9610	461,809	This item reflects current forecast costs attributable to Customer Service and Marketing.
1997 10	519,305	Reflects re-apportionment of DWO between T&D and Customer Service.
1998 10	804,087	Annual forecast adjusted to reflect the revised costing methodology impacts based on experience to date.
1999 10	804,011	Reflects current forecast costs for Customer Service and Marketing.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

CAPITAL EXPENDITURE FORECAST (CEF99-1)
(IN MILLIONS OF DOLLARS)
FOR THE YEARS 1999/00 TO 2018/19

		Total	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	20 year Forecast
CORPORATE GROUP																							
230	FIRE PROTECTION PROJECTS	1.0	0.7	0.3																			1.0
231	CORPORATE BUILDING PROGRAM	17.2	0.0				15.1	2.1															17.2
244	YEAR 2000 CONVERSION	8.8	6.8	2.0																			8.8
245	NEW CUSTOMER SERVICE SYSTEM	8.0			0.3	2.6	5.1																7.9
	DOMESTIC ITEMS - CORPORATE GROUP		23.0	23.6	22.2	24.8	25.7	26.2	26.8	27.3	27.9	28.4	29.0	29.6	30.2	30.8	31.5	32.1	32.8	33.4	34.1	35.0	574.4
	SUB-TOTAL CORPORATE GROUP		**30.5**	**25.9**	**22.6**	**27.3**	**45.9**	**28.3**	**26.8**	**27.3**	**27.9**	**28.4**	**29.0**	**29.6**	**30.2**	**30.8**	**31.5**	**32.1**	**32.8**	**33.4**	**34.1**	**35.0**	**609.3**
	TOTAL CAPITAL EXPENDITURES		**301.3**	**270.0**	**272.7**	**274.3**	**315.4**	**312.0**	**311.3**	**252.6**	**252.7**	**252.5**	**279.8**	**297.1**	**392.6**	**424.3**	**597.5**	**956.7**	**1,247.2**	**1,334.4**	**1,045.1**	**784.9**	**10,174.4**

CAPITAL EXPENDITURE FORECAST REVISIONS (CEF99-1)
(IN MILLIONS OF DOLLARS)
FOR THE YEARS 1999/00 TO 2018/19

		2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	20 year Forecast
CORPORATE GROUP																						
230	FIRE PROTECTION PROJECTS	(0.0)	(0.0)																			(0.0)
231	CORPORATE BUILDING PROGRAM	0.0				(0.1)	(0.0)															(0.1)
244	YEAR 2000 CONVERSION	0.0	(0.7)																			(0.7)
245	NEW CUSTOMER SERVICE SYSTEM			(0.0)	(0.0)	(0.0)																(0.1)
	DOMESTIC ITEMS - CORPORATE GROUP	5.1	(0.4)	(0.4)	(0.4)																	3.9
	SUB-TOTAL CORPORATE GROUP	5.1	(1.1)	(0.4)	(0.4)	(0.2)	(0.0)															3.0
	TOTAL CAPITAL EXPENDITURES	(12.7)	(5.0)	(5.1)	(9.3)	6.5	(3.5)	18.1	16.2	25.7	24.2	32.5	50.0	117.4	37.6	168.7	516.3	999.7	1,089.5	819.9	454.3	4,341.1

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

108.

COMPLEX STATUS	Complex no.	REVISION STATUS
☐ Planned ☒ In progress	230	☐ New complex ☒ In service change ☐ Concept change ☒ Estimate change only

COMPLEX	FIRE PROTECTION PROJECTS - CORPORATE GROUP

Proposal

Design and install passive and/or active fire prevention and protection systems at all generating stations, key transmission terminating stations and strategic buildings (Head Office/ Operating Centre) as outlined by The Fire Prevention and Protection Committee and defined in the Fire Manual Part II.

Locations covered by this capital item complex are; Head Office and Waverley SC.

JUSTIFICATION	Explanation
☐ Load ☐ Service ☒ Safety ☐ Efficiency ☐ Reliability ☐ Other	In accordance with the rules and guidelines established by The Fire Prevention and Protection Committee, implementation of this program will reduce the risk of fire to an acceptable level and mitigate the effects of any such occurance.

Estimate Level	COMPLEX START (yyyy mm)
L3	1996 04

IN SERVICE DATES AND AMOUNTS					
1999 10	$751	2000 10	$347		

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	135		10		145	100	45	45
Year 99/00	631	25	17		673	683	-10	-1
00/01	258	15	7		280	293	-13	-4
01/02								
02/03								
03/04								
04/05								
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	1,024	40	34		1,098	1,076	22	2

REVISION	Reflects current activity rates.

Reviewed by ORIGINATOR	yyyy mm dd	Reviewed by COORDINATOR	yyyy mm dd
Reviewed by CONSTRUCTOR	yyyy mm dd	Approved by VICE-PRESIDENT	yyyy mm dd 99 11 12

H2856/r Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Complex no. 230

Advance or deferral impact

Work well advanced, deferrals not possible.

Factors affecting timing or viability

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE	
					Amount	%
Fire Prevention & Protection - H.O.	751	746	761	751	-10	-1
Fire Prevention & Protection - WSC		271	276	273	-3	-1
TOTAL	751	1,017	1,037	1,024	-13	-1

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
96 10	671	New complex (previously part of FP&P cx 92) which covers the Corporate Group portion of FP&P.
9710	740	PROJECT STARTS DELAYED ONE YEAR.
1998 10	1,076	Reflects deferral of Waverley Service Centre one year, Head Office two years, and rescheduled work at HO.
1999 10	1,098	Reflects current activity rates.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

109.

COMPLEX STATUS	Complex no.	REVISION STATUS
☐ Planned ☒ In progress	231	☐ New complex ☒ In service change ☐ Concept change ☒ Estimate change only

COMPLEX	BUILDINGS - CORPORATE GROUP

Proposal

Refurbish existing 205000sq.ft. Head Office (HO) mech/elec, HVAC, fire protection and curtain walls. (2003/04-2004/05)

JUSTIFICATION	Explanation
☐ Load ☐ Service ☒ Safety ☒ Efficiency ☐ Reliability ☐ Other	Refurbishing HO will provide improved security & fire protection, modern communication, power & HVAC control systems and reduced energy consumption.

Estimate Level	COMPLEX START (yyyy mm)
L3	2003 04

IN SERVICE DATES AND AMOUNTS			
2004 04 $17170			

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend								
Year 99/00								
00/01								
01/02								
02/03								
03/04	12,584	1400	1,130		15,114	15,223	-109	-1
04/05	1,718	229	108		2,055	2,071	-16	-1
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	14,302	1,629	1,238		17,169	17,294	-125	-1

REVISION	Updated escalation and interest

Reviewed by ORIGINATOR	yyyy mm dd	Reviewed by COORDINATOR	yyyy mm dd
Reviewed by CONSTRUCTOR	yyyy mm dd	Approved by VICE-PRESIDENT	yyyy mm dd 99 11 12

H2856/r Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Complex no. 231

Advance or deferral impact

Continuation of existing inefficiencies.

Factors affecting timing or viability

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Refurbish 820 Taylor Ave Bldg.		14,302	14,588	14,302	-286	-2
TOTAL		14,302	14,588	14,302	-286	-2

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
96 10	20,409	New complex (previously part of complex 13) which covers the Corporate Group building program, base year 1996. Training centre ISD deferred to 97 08 03.
9710	20,036	Revised scope of work to include office furnishings in 1997/98 and site improvements in 1998/99. Base estiment for H.O. refurbishment.
1998 10	20,666	Reflects funds required to complete Training Ctr minor deficien cies, and two year deferral of Taylor Ave refurbishment.
1999 10	17,169	Updated escalation and interest on the Head Office refurbishment. Training Center complete and deleted from complex.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

110.

COMPLEX STATUS	Complex no.	REVISION STATUS
☐ Planned ☒ In progress	244	☐ New complex ☒ In service change ☒ Concept change ☐ Estimate change only

COMPLEX	YEAR 2000 CONVERSION

Proposal

Convert existing computer application programs (ie Customer Service System, Human Resources System, Plant Maintenance System, CADD and computational) NETWORK and PC HARDWARE / SOFTWARE systems to year 2000 compatability. To provide replacements, repair,consulting, or contracting for the year 2000 embedded system failures or performance issues for power system equipment in all business units.

JUSTIFICATION	Explanation
☐ Load ☒ Service ☐ Safety ☒ Efficiency ☒ Reliability ☐ Other	Current software / hardware systems have not been programmed to recognize the year 2000. This will result in all systems failing to operate as programmed. In addition funding is required to replace or repair candidatres for year 2000 failures or loss of performance such as power system equip used in energy mgmt,process control, monitoring, metering , data acquisition, communication, and protection equipment.

Estimate Level	COMPLEX START (yyyy mm)
L2	1997 09

IN SERVICE DATES AND AMOUNTS					
2000 03	$10933	2001 03	$2027		

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	4,137		34		4,171	4,183	-12	-0
Year 99/00	6,763				6,763	6,751	12	0
00/01	2,027				2,027	2,762	-735	-27
01/02								
02/03								
03/04								
04/05								
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	12,927		34		12,961	13,696	-735	-5

REVISION	Revised to reflect a reduction in interest. Components are placed in service as soon as they are received.

Reviewed by ORIGINATOR	yyyy mm dd 1999 11 10	Reviewed by COORDINATOR	yyyy mm dd
Reviewed by CONSTRUCTOR	yyyy mm dd	Approved by VICE-PRESIDENT	yyyy mm dd 99 11 12

H2856/r Rev 99 03

Complex no. 244

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Advance or deferral impact

Systems will fail to operate as programmed.

Factors affecting timing or viability

Arrival of Jan 1, 2000.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE	
					Amount	%
Year 2000 conversion.	12,927	12,075	12,317	12,927	610	5
TOTAL	12,927	12,075	12,317	12,927	610	5

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
1997 10	5,977	New complex, transferred from the Domestic Budget.
1998 10	13,696	Reflects 97/98 underexpenditure 1.3M, and addition of a new item to provide funding for repair or replacement of year 2000 affected embedded systems.
1999 10	12,961	Revised to reflect a reduction in interest. Components are placed in service as soon as they are received.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

111.

COMPLEX STATUS	Complex no.	REVISION STATUS
[X] Planned [ ] In progress	245	[ ] New complex [X] In service change [ ] Concept change [ ] Estimate change only

COMPLEX	NEW CUSTOMER SERVICE SYSTEM

Proposal
To replace the existing mainframe Customer Service System, Meter Records System,Miscellaneous Billing System, and Street Light System with a modern customer system.

JUSTIFICATION		Explanation
[ ] Load	[X] Service	These existing systems require extensive modifications, as well as various current and upcoming business functions.
[ ] Safety	[X] Efficiency	
[X] Reliability	[ ] Other	

Estimate Level	COMPLEX START (yyyy mm)
L3	2001 04

IN SERVICE DATES AND AMOUNTS			
2004 03	$7943		

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend								
Year 99/00								
00/01								
01/02	298	24	13		335	339	-4	-1
02/03	2,202	227	125		2,554	2,578	-24	-1
03/04	4,100	514	439		5,053	5,095	-42	-1
04/05								
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	6,600	765	577		7,942	8,012	-70	-1

REVISION	Revised to reflect current escalation and interest rates.

Reviewed by ORIGINATOR	yyyy mm dd 1999 11 10	Reviewed by COORDINATOR	yyyy mm dd		
Reviewed by CONSTRUCTOR	yyyy mm dd	Approved by VICE-PRESIDENT	yyyy mm dd 99 11 12		

H2856/r Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Complex no. 245

Advance or deferral impact

Current information indicates that these systems will become totally non functional as of Jan 1, 2000.

Factors affecting timing or viability

Unavailability of an economical upgrade to current software, making it year 2000 compatible, and more powerful.
Various current and upcoming business functions.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Customer Service System		6,600	6,732	6,600	-132	-2
TOTAL		6,600	6,732	6,600	-132	-2

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
1997 10	6,851	New item.
1998 10	8,012	Deferred spending until 2000/01. ISD deferred 2 years.
1999 10	7,942	Revised to reflect current escalation and interest rates.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

1/2.

COMPLEX STATUS	Complex no.	REVISION STATUS
☐ Planned ☒ In progress	111 - 119	☐ New complex ☐ In service change ☐ Concept change ☒ Estimate change only

COMPLEX	DOMESTIC ITEM - CORPORATE

Proposal
TO PROVIDE INFORMATION TECHNOLOGY HARDWARE, SOFTWARE, APPLICATION DEVELOPMENT AND OTHER RELATED SERVICES TO THE CORPORATION.

JUSTIFICATION	Explanation
☒ Load ☒ Service ☒ Safety ☒ Efficiency ☒ Reliability ☒ Other	COMPUTER SYSTEM ENHANCEMENTS ARE REQUIRED THROUGHOUT THE CORPORATION TO ACHIEVE ONGOING IMPROVEMENTS IN RESOURCE PRODUCTIVITY AND RELIABILITY.

Estimate Level	COMPLEX START (yyyy mm)
L2	1996 04

IN SERVICE DATES AND AMOUNTS							
1999 03 31	$18592	2000 03 31	$17960	2001 03 31	$24183	2002 03 31	$22623
2003 03 31	$25179	2004 03 31	$25692	2005 03 31	$26219	2006 03 31	$26757
2007 03 31	$27300	2008 03 31	$27858	2009 03 31	$28434	2010 03 31	$29016

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend						18,592	-18,592	-100
Year 99/00	22,697	125	178		23,000	17,960	5,040	28
00/01	23,157	455	170		23,782	24,183	-401	-2
01/02	21,398	655	170		22,223	22,623	-400	-2
02/03	23,667	915	197		24,779	25,179	-400	-2
03/04	22,615	2129	435		25,179	25,692	-513	-2
04/05	22,624	2624	444		25,692	26,219	-527	-2
05/06	22,631	3130	458		26,219	26,757	-538	-2
06/07	22,638	3647	472		26,757	27,300	-543	-2
07/08	22,644	4174	482		27,300	27,858	-558	-2
08/09	22,650	4711	497		27,858	28,434	-576	-2
09/10	22,656	5260	518		28,434	29,016	-582	-2
10/11	22,662	5820	534		29,016	29,616	-600	-2
11/12	22,669	6391	556		29,616	30,224	-608	-2
12/13	22,676	6975	573		30,224	30,850	-626	-2
13/14	22,683	7570	597		30,850	31,475	-625	-2
14/15	22,689	8177	609		31,475	32,108	-633	-2
15/16	22,696	8797	615		32,108	32,760	-652	-2
16/17	22,703	9430	627		32,760	33,434	-674	-2
17/18	22,711	10076	647		33,434	34,115	-681	-2
18/19	22,719	10736	660		34,115		34,115	
Beyond								
TOTAL	453,585	101,797	9,439		564,821	554,395	10,426	2

REVISION	Reflects current forecast costs for information technology and related system additions and enhancements throughout the Corporation.

Reviewed by ORIGINATOR	yyyy mm dd	Reviewed by COORDINATOR	yyyy mm dd
Reviewed by CONSTRUCTOR	yyyy mm dd	Approved by VICE-PRESIDENT	yyyy mm dd 99 11 17

CORP GROUP DOMESTIC CAPITAL FORECAST (CEF99-1)

CAPITAL REQUIREMENTS	1999/00	2000/01	2001/02
INFO TECH HARDWARE			
NETWORK	2.2	2.5	2.5
INFRASTRUCTURE	1.2	1.3	1.3
PCs	3.4	3.5	3.6
INFO TECH SOFTWARE			
SOFTWARE	0.6	0.6	0.6
PS /CAD HRDWR/SOFTWR	0.5	0.5	0.5
ENG HW/WRKSTNS/SOFTWR	0.6	0.6	0.6
APPLICATION DEVELOPMENT			
PROJ & CAP MGMT (SAP)	4.3	1.6	0.0
NT NETWRK OP SYSTEM	1.4	0.4	0.0
PAYPERS	0.5	3.6	5.9
ELECTRONIC OFFICE	0.6	0.0	0.0
ENTERPRISE MGMT SYST	0.9	0.7	0.0
BUSINESS CONT PLNG	0.5	0.2	0.0
SAP ARCHIVING	0.5	1.0	1.0
SAP REPORTING	0.0	1.0	0.0
SAP 4.5 UPGRADE	0.0	1.0	0.0
FINFOR REPLCMT	0.0	0.7	0.0
MS OFFICE	0.0	0.0	2.0
MISC OTHERS	0.3	0.5	1.6
OTHER(UNSPECIFIED)	5.5	4.5	3.0
TOTAL CG DOMESTIC	23.0	24.2	22.6

Manitoba Hydro

Capital Forecast

Volume 2 of 2
Transmission & Distribution

CEF 99-1
1999/00 – 2018/19

October 1999

CAPITAL EXPENDITU... ...ECAST (CEF99-1)
(IN MILLIONS OF DOLLARS)
FOR THE YEARS 1999/00 TO 2018/19

		Total	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	20 year Forecast
TRANSMISSION AND DISTRIBUTION																							
	TRANSMISSION FOR GENERATION																						
58	WUSKWATIM TRANSMISSION	66.5												1.1	1.2	2.7	2.6	8.2	25.8	25.1			66.5
263	HVDC CONVERSION BIPOLE 3/CONAWAPA TRANSMISSION	1,896.2										2.6	9.2	15.3	15.8	41.5	55.3	215.8	412.4	509.3	372.7	186.7	1,836.6
	INTERCONNECTIONS																						
79	MANITOBA > MINNESOTA 500kV TRANSMISSION UPGRADE (MMTU)																						
95	200MW ONTARIO HYDRO SALE - T/L UPGRADE	0.8	0.8																				0.8
268	HARVEY-GLENBORO 230KV LINE	16.0		1.6	6.4	8.0																	16.0
	TRANSMISSION																						
87	KETTLE AC TRANSMISSION IMPROVEMENTS	10.6	0.1	0.0	0.2	1.0	4.3	5.0															10.6
16	NORTH CENTRAL MANITOBA PROJECT	0.8	0.0	0.3	0.4																		0.8
30	THOMPSON>HERBLET LAKE 230kV TRANSMISSION	57.1			0.2	0.2	0.8	5.4	21.5	14.1	14.9												57.1
40	FLIN FLON - CLIFF LAKE TRANSFORMER REPLACEMENT	1.5	0.6	0.9																			1.5
47	HERBLET LAKE > THE PAS 230kV TRANSMISSION	55.3				0.2	0.5	1.0	0.3	1.1	3.4	16.4	19.0	6.7									48.5
57	DORSEY > NEEPAWA > CORNWALLIS 230kV LINE	18.5	16.8	1.7																			18.5
60	WINNIPEG > BRANDON 230kV TRANSMISSION	73.0			0.1	3.0	4.8	7.4	13.7	18.7	15.1	10.3											73.0
45	FT GARRY - PERIMETER SOUTH BANK REPLACEMENT	4.4			0.4	2.5	1.5																4.4
84	RIDGEWAY TRANSFORMER ADDITION	9.2					0.3	0.6	0.8	4.1	3.4												9.2
78	RIDGEWAY > ST. VITAL 230kV TRANSMISSION	1.7	1.7																				1.7
64	ST. VITAL TRANSFORMER ADDITION	9.0	0.3	3.6	4.0	1.0																	9.0
42	DORSEY-ROSSER 230kV TRANSMISSION IMPROVEMENTS	1.8	0.0	1.4	0.4																		1.8
27	DORSEY > ST. VITAL 230kV AC TRANSMISSION	7.7	0.0	1.3	5.3	1.1	0.0																7.7
96	DORSEY > LAVERENDRYE > ST. VITAL 230kV TRANSMISSION	25.9														1.7	3.5	10.7	10.0				25.9
21	ROSSER > SILVER 230kV TRANSMISSION	27.6	3.6	0.4	0.5	3.3	9.9	10.0															27.6
9	RAVEN LAKE > BIRTLE 230kV TRANSMISSION																						
94	BRANDON 115kV LOOP																						
39	RAVEN LAKE STATION 230-66kV TRANSFORMATION	8.3																0.6	1.5	3.0	3.3		8.3
98	VERMILION STATION STATIC VAR GENERATOR																						
18	NEEPAWA 230 -115kV STN	17.5					0.1	1.0	7.4	9.1													17.5
201	ASSINIBOINE - WILKES AVE 115-24 KV BANK 1 ADDITION	7.2	7.1	0.1																			7.2
202	ROSSER > MCPHILLIPS 115kV TRANSMISSION IMPROVEMENTS	2.4	0.0	0.1	0.4	1.8																	2.4
204	RICHER SOUTH 230-66kV TRANSFORMER ADDITION	4.9				0.4	0.4	2.3	1.8														4.9
205	PINE FALLS > BLOODVEIN 115kV TRANSMISSION LINE	29.1								0.2	0.2	1.0	1.7	7.0	15.6	3.4							29.1
207	ST. VITAL > STEINBACH 230kV TRANSMISSION	22.3						0.3	0.3	0.6	3.3	4.2	13.6										22.3
208	RIDGEWAY > SELKIRK 230kV TRANSMISSION	25.1				0.6	2.0	3.3	4.5	7.0	7.6												25.1
210	SOURIS > PEMBINA VALLEY 230kV TRANSMISSION	32.6								0.6	0.9	1.4	1.6	12.0	16.1								32.6
4	WINNIPEG AREA TRANSMISSION REFURBISHMENT	4.0	1.1	0.6	0.4	0.8	1.1	0.0															4.0
28	DORSEY STATION 230kV BREAKER REPLACEMENT	1.6	1.6																				1.6
43	DORSEY > US BORDER D602F 500KV AC T/L INSULATOR REPL.	2.7	1.2	0.5	0.4	0.6																	2.7
7	BIPOLE 1 & 2 LINE SPACER DAMPERS REPLACEMENT	5.1	0.7	2.5	1.9	0.0																	5.1
247	DORSEY 230kV BUS ENHANCEMENTS	16.0	0.4	0.9	3.2	7.0	4.6																16.0
251	FLIN FLON AREA TRANSMISSION IMPROVEMENTS	17.3	0.3	2.0	5.2	1.6	5.2	2.9															17.3
257	PINE FALLS-GREAT FALLS 115-66kV SUPPLY	9.4		0.9	2.7	3.4	1.2	1.1															9.4
	SUBTRANSMISSION																						
55	JENPEG > NORWAY HOUSE 66 kV SUB TRANSMISSION LINE	12.5	0.0	0.0	0.3	0.9	4.9	6.3															12.5
53	RUTTAN > SOUTH INDIAN LAKE 66 kV LINE	5.5	0.3	0.3	0.3	1.6	3.0																5.5
17	CENTRAL SUPPLY > PIKWITONEI & THICKET PORTAGE	0.7	0.0	0.7																			0.7
206	PINEY > SPRAGUE 66kV LINE	1.7	1.7	0.0																			1.7
209	BIRTLE SOUTH > ROSSBURN 66kV LINE	5.4				0.1	0.2	3.6	1.5														5.4
237	ST. BONIFACE-PLESSIS ROAD 115-25KV STATION	16.4	7.8	8.3	0.3																		16.4
238	ROSSER - OAK POINT 115-24KV STATION	18.5			0.0	0.7	2.0	10.1	5.7														18.5
239	ROSSER - OAK POINT BANK 2 ADDITION	9.8										0.8	6.2	2.7									9.8
240	ST. BONIFACE - PLESSIS ROAD BANK 2 ADDITION	4.9	0.1	1.6	3.2																		4.9
241	NEEPAWA 66KV SYSTEM	3.4			0.2	3.3																	3.4
242	RESTON/GLENBORO CAPACITY INCREASE	4.9	0.5	2.8	1.6																		4.9
80	ST. LEON 230-66KV TRANSF. ADD'N AND IPL EXPANSION	8.9	0.2	0.9	1.6	5.0	0.7	0.5															8.9
253	BRANDON EAST 115kV IMPROVEMENTS	1.0	1.0																				1.0
250	BRANDON CROCUS PLAINS 115-24kV BANK ADDITION	7.2		0.1	0.6	3.9	2.3	0.4															7.2
	DISTRIBUTION																						
86	DIESEL UPGRADING ENHANCEMENT	10.3	2.1	1.7	4.4	2.0																	10.3
221	VIRDEN AREA DISTRIBUTION CHANGES	10.0	4.2	1.3	1.6	0.9	1.0	1.0															10.0
217	DEFECTIVE RINJ CABLE REPLACEMENT	7.8	0.8	1.2	1.8	1.9	2.1																7.8
261	BRERETON LAKE STATION AREA	6.6		2.6	2.2	0.7	0.5	0.5	0.1														6.6
267	PAINT LAKE NEW FEEDER	1.6			1.8	(0.2)																	1.6
	COMMUNICATIONS, CONTROLS AND INFO TECHNOLOGY																						
10	EMS SCADA	2.1	2.1																				2.1
12	MICROWAVE RADIO REPLACEMENTS	48.1	9.0	3.3	9.6	8.1		1.6	16.5														48.1
218	LAN NETWORK EXPANSION																						
219	MAPINFO IMPLEMENTATION	10.7	4.4	4.3	2.0																		10.7
	OTHER																						
2	SITE REMEDIATION	5.5	1.3	2.2	0.9	1.1																	5.5
81	OIL CONTAINMENT	3.4	0.1	0.8	1.2	1.0	0.3																3.4
92	FIRE PROTECTION PROJECTS																						

CAPITAL EXPENDITU[illegible]AST (CEF99-1)
(IN MILLIONS OF [illegible]LLARS)
FOR THE YEARS 1999/00 TO 2018/19

	Total	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	20 year Forecast
DOMESTIC ITEMS - TRANMISSION AND DISTRIBUTION		77.6	75.8	78.6	80.6	86.0	88.3	90.6	92.9	95.2	97.6	100.1	102.7	105.4	108.1	110.8	113.6	116.5	119.6	122.7	125.8	1,988.3
SUB-TOTAL TRANSMISSION AND DISTRIBUTION		149.5	126.6	144.5	148.0	139.7	152.6	164.7	148.3	143.8	134.2	151.4	147.5	154.1	157.4	172.1	348.8	566.1	657.0	498.7	312.5	4,617.7

CAPITAL EXPENDITURE FORECAST (CEF99-1)
(IN MILLIONS OF DOLLARS)
FOR THE YEARS 1999/00 TO 2018/19

		Total	Prev	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	20 year Forecast
POWER SUPPLY																								
	FUTURE ENERGY SUPPLY																							
24	WUSKWATIM GENERATING STATION	632.5														24.1	11.7	76.0	158.3	182.5	179.9			632.5
264	CONAWAPA GENERATING STATION	2,695.6												45.1	49.9	131.1	151.7	246.4	346.2	393.8	390.1	436.4	359.5	2,550.3
	HVDC FACILITIES																							
223	HVDC BIPOLE RELIABILITY ENHANCEMENTS	32.3	16.4	10.9	5.0																			15.9
88	BIPOLE 1 CONVERTER TRANSFORMERS	4.9	4.9																					
11	BIPOLE 1 MERCURY ARC VALVES STAGE 3	151.0				1.0	3.8	43.5	60.5	41.6	0.7													151.0
5	HVDC BIPOLE 2 THYRISTOR POLY PIPE REPLACEMENTS	5.5	3.4	1.4	0.8																			2.2
54	CONVERTER TRANSFORMER BUSHING REPLACEMENT	6.4	4.0	0.4	1.3	0.6	0.1																	2.4
203	DORSEY BIPOLE 1 SYNCH CONDENSER BREAKER REPLACEMENT	7.0	0.6	1.5	0.4	2.3	2.2																	6.4
216	BIPOLE 1 DC FILTER CAPACITOR REPLACEMENT	5.0	0.2	0.8	1.7	2.0	0.3																	4.7
213	S.E.R. REPLACEMENT	2.0	1.3	0.7																				0.7
214	BIPOLE 1 VALVE HALL WALL BUSHING REPLACEMENT	9.1	2.0	4.9	2.0	0.2																		7.1
249	DORSEY BRINE EFFLUENT DISPOSAL STUDY AND IMPROVEMENT	0.8	0.8																					
258	BIPOLE 1 &2 ELECTRODE LINE MONITORING	1.4				0.2	1.2																	1.4
259	HVDC SWITCHGEAR ARCPROOF/SAFETY UPGRADES (PHASE 1)	1.1			0.4	0.5	0.1																	1.1
260	HVDC AUXILIARY POWER SUPPLY UPGRADES	1.8			0.5	0.5	0.4	0.4																1.8
272	DORSEY SYNCHRONOUS CONDENSER REFURBISHMENT	7.3			1.1	1.3	1.3	1.3	1.2	1.2														7.3
	HYDRAULIC REHABILITATION																							
3	GREAT FALLS G.S. REHABILITATION	23.6	0.1	0.3	2.7	10.6	7.4	2.5																23.5
52	SEVEN SISTERS G.S. REHABILITATION	19.5	18.0	1.5																				1.5
32	PINE FALLS G.S. REHABILITATION	18.1	2.8	0.8	0.8	1.5	7.1	5.0	0.1															15.3
33	McARTHUR G.S. REHABILITATION	11.9	11.1	0.8																				0.8
1	LAURIE RIVER PLANT 1 AND 2 REHABILITATION	16.1	9.3	0.5	2.2		0.1	0.5	0.5						1.2	0.9	0.9							6.9
48	GRAND RAPIDS G.S. REHABILITATION	100.7	75.7	5.4	13.8	5.8																		25.0
25	JENPEG G.S. UNIT OVERHAULS (UNITS 1 - 6)	29.0	6.7	2.2	0.7	3.7	3.7	3.6	0.3	3.8	0.3	3.9												22.3
22	KETTLE & LONG SPRUCE G.S. STATOR REWEDGING	7.1	5.8	1.0	0.3																			1.3
82	PRODUCTION NORTH DAM SAFETY UPGRADES	14.8	3.3	2.1	1.7	2.2	2.2	2.3	1.1															11.6
26	WINNIPEG RIVER CONTROL SYSTEM	13.5	2.4	2.6	2.0	5.6	0.9																	11.1
234	LIMESTONE OUTSTANDING WORK	17.9	11.5	1.7	2.8	0.6	0.6	0.6																6.4
243	WINNIPEG RIVER RIVERBANK PROTECTION PROGRAM	8.3	2.0	0.8	0.7	0.7	0.8	0.8	0.8	0.8	0.8													6.2
246	KETTLE GS - STATOR REWIND	33.8			0.2	0.9	2.5	2.5	2.6	2.6	2.6	2.7	2.7	2.8	2.8	2.9	2.9	3.0						33.8
252	KELSEY G.S. GATE REHABILITATION	3.5				0.6		0.7		0.7		0.7		0.8										3.5
256	KETTLE ANNUNCIATION SYSTEM RENEWAL	1.5			1.0	0.5																		1.5
	THERMAL REHABILITATION																							
38	THERMAL G.S. ASSURANCE	134.1	129.2	4.0	0.9																			4.9
226	BRANDON G.S. UNIT 5 LCENSE RENEWAL	23.3						2.1	0.9	5.8	0.9	1.7	1.0	2.7	1.5	0.9	2.1	0.5	1.2	0.5	0.5	0.5	0.7	23.3
220	BRANDON G.S. SWITCHYARD JETAIRE BREAKER REPLACEMENT	3.6	2.2	1.4																				1.4
	OTHER																							
224	200MW ONTARIO HYDRO SALE - SYNC COND CONVERSION	7.7	4.2	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.5													3.5
227	SITE REMEDIATION OF CONTAMINATED CORPORATE FACILITIES	12.9	0.9	0.8	0.8	0.8	0.8	0.9	0.9	0.9	0.9	0.9	1.0	1.0	1.0	1.0	0.3							12.0
225	OIL CONTAINMENT	15.6	8.2	0.3	0.6	2.3	1.0	1.6	1.6															7.4
228	FIRE PROTECTION PROJECTS	6.7	2.6	0.5	3.1	0.6																		4.1
13	POWER SUPPLY BUILDINGS	35.4	19.1	5.7	2.3	2.8	3.6	1.8																16.2
990	PLANNING STUDY COSTS			16.1	16.5	3.1	2.7	0.9	2.8	2.8	9.7	9.1	18.9	(14.4)	2.8	(15.0)	2.6	2.6	2.8	2.8	2.9	3.0	3.0	75.7
	DOMESTIC ITEMS - POWER SUPPLY			10.0	10.2	10.5	10.7	11.0	11.2	11.5	11.7	12.0	12.2	12.5	12.8	13.1	13.4	13.7	14.0	14.3	14.6	14.9	15.3	249.5
	SUB-TOTAL POWER SUPPLY			79.4	77.1	61.8	54.0	82.3	84.9	72.1	28.1	30.9	35.8	50.4	72.0	159.0	185.6	342.2	522.5	593.9	588.1	454.8	378.5	3,953.2

CAPITAL EXPENDITURE FORECAST (CEF99-1)
(IN MILLIONS OF DOLLARS)
FOR THE YEARS 1999/00 TO 2018/19

		Total	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	20 year Forecast
CUSTOMER SERVICE																							
991	DEMAND SIDE MANAGEMENT CAPITAL COSTS		8.2	10.1	10.4	9.2	9.3	7.2	7.3	7.2	7.4	7.5	5.3	5.4	5.5	5.6	5.7	5.8	5.7	5.8	5.9	6.0	140.7
97	AUTOMATIC METER READING IMPLEMENTATION	30.5		0.1	2.1	3.2	3.3	3.1	3.4	3.5	3.5	6.2	2.3										30.5
	DOMESTIC ITEMS - CUSTOMER SERVICE		33.7	30.3	31.3	32.5	35.0	36.1	37.1	38.1	39.1	40.2	41.3	42.5	43.7	44.9	46.1	47.4	48.8	50.2	51.6	52.9	823.0
	SUB-TOTAL CUSTOMER SERVICE		**41.9**	**40.5**	**43.8**	**44.9**	**47.6**	**46.3**	**47.8**	**48.8**	**50.1**	**54.0**	**49.0**	**47.9**	**49.2**	**50.5**	**51.8**	**53.2**	**54.4**	**56.0**	**57.5**	**58.9**	**994.2**

CAPITAL EXPENDITURE ...CAST (CEF99-1)
(IN MILLIONS OF DOLLARS)
FOR THE YEARS 1999/00 TO 2018/19

		Total	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	20 year Forecast
CORPORATE GROUP																							
230	FIRE PROTECTION PROJECTS	1.0	0.7	0.3																			1.0
231	CORPORATE BUILDING PROGRAM	17.2	0.0				15.1	2.1															17.2
244	YEAR 2000 CONVERSION	8.8	6.8	2.0																			8.8
245	NEW CUSTOMER SERVICE SYSTEM	8.0			0.3	2.6	5.1																7.9
	DOMESTIC ITEMS - CORPORATE GROUP		23.0	23.6	22.2	24.8	25.7	26.2	26.8	27.3	27.9	28.4	29.0	29.6	30.2	30.8	31.5	32.1	32.8	33.4	34.1	35.0	574.4
	SUB-TOTAL CORPORATE GROUP		30.5	25.9	22.6	27.3	45.9	28.3	26.8	27.3	27.9	28.4	29.0	29.6	30.2	30.8	31.5	32.1	32.8	33.4	34.1	35.0	609.3
	TOTAL CAPITAL EXPENDITURES		**301.3**	**270.0**	**272.7**	**274.3**	**315.4**	**312.0**	**311.3**	**252.6**	**252.7**	**252.5**	**279.8**	**297.1**	**392.6**	**424.3**	**597.5**	**956.7**	**1,247.2**	**1,334.4**	**1,045.1**	**784.9**	**10,174.4**

CAPITAL EXPENDITURE F[illegible] REVISIONS (CEF99-1[illegible]
(IN MILLION[illegible] ARS)
FOR THE YEARS [illegible] TO 2018/19

		2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	20 year Forecast
TRANSMISSION AND DISTRIBUTION																						
	TRANSMISSION FOR GENERATION																					
58	WUSKWATIM TRANSMISSION										(0.8)	(0.9)	(2.1)	(2.1)	(7.2)	(24.2)	(23.5)					(60.8)
263	HVDC CONVERSION BIPOLE 3/CONAWAPA TRANSMISSION										2.6	9.2	15.3	15.8	41.5	55.3	215.8	412.4	509.3	372.7	186.7	1,836.6
	INTERCONNECTIONS																					
79	MANITOBA > MINNESOTA 500kV TRANSMISSION UPGRADE (MMTU)																					
95	200MW ONTARIO HYDRO SALE - T/L UPGRADE	0.8																				0.8
268	HARVEY-GLENBORO 230KV LINE		1.6	6.4	8.0																	16.0
	TRANSMISSION																					
87	KETTLE AC TRANSMISSION IMPROVEMENTS	(1.5)	(2.4)	(2.3)	(1.8)	4.3	5.0															1.4
16	NORTH CENTRAL MANITOBA PROJECT	(0.7)	0.0	(0.1)	(0.0)																	(0.8)
30	THOMPSON>HERBLET LAKE 230kV TRANSMISSION	(0.2)	(0.3)	(0.2)	(0.2)	(4.3)	(15.6)	8.0	(0.2)	14.9												1.9
40	FLIN FLON - CLIFF LAKE TRANSFORMER REPLACEMENT	0.3	0.9																			1.2
47	HERBLET LAKE > THE PAS 230kV TRANSMISSION				0.0	0.0	0.1	0.0	0.1	0.1	0.1	0.3	0.2									1.0
57	DORSEY > NEEPAWA > CORNWALLIS 230kV LINE	1.1	(4.9)																			(3.8)
60	WINNIPEG > BRANDON 230kV TRANSMISSION		(0.1)	(0.2)	(3.2)	(1.7)	(5.1)	(4.1)	2.7	5.2	10.3											3.9
45	FT GARRY - PERIMETER SOUTH BANK REPLACEMENT		(0.4)	0.2	(1.4)	1.5																(0.1)
84	RIDGEWAY TRANSFORMER ADDITION					0.0	0.1	0.1	0.1	0.0												0.3
78	RIDGEWAY > ST. VITAL 230kV TRANSMISSION	0.8																				0.8
64	ST. VITAL TRANSFORMER ADDITION	(2.9)	0.9	3.6	(1.0)																	0.5
42	DORSEY-ROSSER 230kV TRANSMISSION IMPROVEMENTS	0.0	(0.1)	0.0																		(0.0)
27	DORSEY > ST. VITAL 230kV AC TRANSMISSION	(5.1)	(0.2)	4.9	1.1	0.0																0.7
96	DORSEY > LAVERENDRYE > ST. VITAL 230kV TRANSMISSION														0.1	0.2	0.0	0.0				0.3
21	ROSSER > SILVER 230kV TRANSMISSION	0.6	(3.6)	(10.7)	(4.2)	9.9	10.0															2.0
9	RAVEN LAKE > BIRTLE 230kV TRANSMISSION																					
94	BRANDON 115kV LOOP																					
39	RAVEN LAKE STATION 230-66kV TRANSFORMATION																0.1	0.1	0.1	0.0		0.2
98	VERMILION STATION STATIC VAR GENERATOR	(0.0)	(0.1)	(0.5)	(8.5)	(8.6)	(3.9)															(21.7)
18	NEEPAWA 230 -115kV STN	(0.3)	(0.4)	(1.0)	(10.1)	(10.5)	1.0	7.4	9.1													(4.8)
201	ASSINIBOINE - WILKES AVE 115-24 KV BANK 1 ADDITION	1.3	(1.2)																			0.1
202	ROSSER > MCPHILLIPS 115kV TRANSMISSION IMPROVEMENTS	(0.1)	(0.3)	(1.3)	1.8																	0.2
204	RICHER SOUTH 230-66kV TRANSFORMER ADDITION				0.0	0.1	0.0	0.0														0.1
205	PINE FALLS > BLOODVEIN 115kV TRANSMISSION LINE	(0.1)	(0.1)	(0.8)	(1.4)	(5.3)	(13.9)	(3.0)	0.2	0.2	1.0	1.7	7.0	15.6	3.4							4.4
207	ST. VITAL > STEINBACH 230kV TRANSMISSION						0.0	0.0	0.1	0.1	0.2	0.1										0.6
208	RIDGEWAY > SELKIRK 230kV TRANSMISSION				0.1	0.1	0.1	0.2	0.1	0.1												0.6
210	SOURIS > PEMBINA VALLEY 230kV TRANSMISSION								0.0	0.0	0.1	0.1	0.2	0.3								0.7
4	WINNIPEG AREA TRANSMISSION REFURBISHMENT	0.4	(0.2)	(0.3)	0.1	0.2	0.0															0.3
28	DORSEY STATION 230kV BREAKER REPLACEMENT	0.6																				0.6
43	DORSEY > US BORDER D602F 500KV AC T/L INSULATOR REPLACEMENT	0.4	(0.3)	(0.5)	(0.6)																	(1.0)
7	BIPOLE 1 & 2 LINE SPACER DAMPERS REPLACEMENT	(3.0)	(1.2)	(1.6)	0.0																	(5.7)
247	DORSEY 230kV BUS ENHANCEMENTS	0.0	0.1	0.6	0.6	0.2																1.5
251	FLIN FLON AREA TRANSMISSION IMPROVEMENTS	0.3	2.0	5.2	1.6	5.2	2.9															17.3
257	PINE FALLS-GREAT FALLS 115-66kV SUPPLY		0.9	2.7	3.4	1.2	1.1															9.4
	SUBTRANSMISSION																					
55	JENPEG > NORWAY HOUSE 66 kV SUB TRANSMISSION LINE	(0.2)	(1.7)	(2.0)	(6.3)	4.9	6.3															1.1
53	RUTTAN > SOUTH INDIAN LAKE 66 kV LINE	0.2	(0.4)	(1.8)	(0.7)	3.0																0.3
17	CENTRAL SUPPLY > PIKWITONEI & THICKET PORTAGE	0.0	0.0																			0.1
206	PINEY > SPRAGUE 66kV LINE	0.5	0.0																			0.5
209	BIRTLE SOUTH > ROSSBURN 66kV LINE				0.0	0.0	(0.1)	(0.1)														(0.2)
237	SPRINGFIELD-ST. BONIFACE 115-25KV STATION	2.8	5.0	(6.7)																		1.1
238	ROSSER - OAK POINT 115-24KV STATION		(0.0)	(0.5)	(0.2)	(8.5)	4.2	5.7														0.6
239	ROSSER - OAK POINT BANK 2 ADDITION										0.1	(0.0)	(0.0)									0.0
240	SPRINGFIELD-ST. BONIFACE BANK 2 ADDITION	0.0	(0.0)	0.5																		0.5
241	NEEPAWA 66KV SYSTEM			(0.0)	(0.1)																	(0.1)
242	RESTON/GLENBORO CAPACITY INCREASE	0.1	0.0	0.0																		0.1
80	ST. LEON 230-66KV TRANSFORMER ADD'N AND IPL EXPANSION	0.3	0.2	0.3	0.0	0.1	(0.6)															0.3
253	BRANDON EAST 115kV IMPROVEMENTS	0.1																				0.1
250	BRANDON CROCUS PLAINS 115-24kV BANK ADDITION		0.0	0.0	0.3	0.1	(0.0)															0.3
	DISTRIBUTION																					
86	DIESEL UPGRADING ENHANCEMENT	(0.9)	0.6	4.2	(3.5)																	0.4
221	VIRDEN AREA DISTRIBUTION CHANGES	0.9	(0.0)	0.1	0.1	0.1	0.1															1.2
217	DEFECTIVE RINJ CABLE REPLACEMENT	(0.1)	(0.1)	(0.2)	(0.2)	(0.3)																(0.8)
261	BRERETON LAKE STATION AREA STUDY		2.6	2.2	0.7	0.5	0.5	0.1														6.6
267	PAINT LAKE NEW FEEDER			1.8	(0.2)																	1.6
	COMMUNICATIONS, CONTROLS AND INFO TECHNOLOGY																					
10	EMS SCADA	1.6																				1.6
12	MICROWAVE RADIO REPLACEMENTS	3.2	0.8	(3.3)	4.7		0.1	0.6														6.0
218	LAN NETWORK EXPANSION																					
219	MAPINFO IMPLEMENTATION	(0.3)	1.5	(0.4)																		0.9

CAPITAL EXPENDITURE FO[illegible]EVISIONS (CER99-1)
(IN MILLION[illegible]ARS)
FOR THE YEARS [illegible]O 2018/19

		2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	20 year Forecast
	OTHER																					
2	SITE REMEDIATION	0.3	0.8	0.0	0.0																	1.1
81	OIL CONTAINMENT	0.0	0.1	0.1	0.2	0.0																0.5
92	FIRE PROTECTION PROJECTS											1.0	2.0	3.0	4.0	5.0	6.0	7.0	8.0	9.0	10.0	55.0
	DOMESTIC ITEMS - TRANMISSION AND DISTRIBUTION	(0.0)	(3.2)	(3.1)	(3.1)								(0.0)						(0.0)			(9.4)
	SUB-TOTAL TRANSMISSION AND DISTRIBUTION	1.0	(3.0)	(4.5)	(23.9)	(7.8)	(7.8)	14.9	12.1	20.6	13.4	11.6	22.7	32.6	41.7	36.3	198.4	419.5	517.4	381.7	196.7	1,873.7

CAPITAL EXPENDITURE FORECAST REVISIONS (CEF99-1)
(IN MILLIONS OF DOLLARS)
FOR THE YEARS 1999/00 TO 2018/19

		2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	20 year Forecast
POWER SUPPLY																						
	FUTURE ENERGY SUPPLY																					
24	WUSKWATIM GENERATING STATION											(31.0)	(24.8)	(30.4)	(159.9)	(118.2)	(30.2)	182.5	179.9			(32.1)
264	CONAWAPA GENERATING STATION											45.1	49.9	131.1	151.7	246.4	346.2	393.8	390.1	436.4	359.5	2,550.3
	HVDC FACILITIES																					
223	HVDC BIPOLE RELIABILITY ENHANCEMENTS	(4.2)	(4.1)	(2.1)																		(10.4)
88	BIPOLE 1 CONVERTER TRANSFORMERS	(1.6)																				(1.6)
11	BIPOLE 1 MERCURY ARC VALVES STAGE 3			0.0	0.1	0.7	1.0	0.7	0.0													2.5
5	HVDC BIPOLE 2 THYRISTOR POLY PIPE REPLACEMENTS	(0.8)	0.1																			(0.7)
54	CONVERTER TRANSFORMER BUSHING REPLACEMENT	(0.9)	0.7	0.4	0.1																	0.3
203	DORSEY BIPOLE 1 SYNCH CONDENSER BREAKER REPLACEMENT	0.2	(1.0)	(0.2)	(0.4)																	(1.3)
216	BIPOLE 1 DC FILTER CAPACITOR REPLACEMENT	0.1	0.7	1.0	0.3																	2.1
213	S.E.R. REPLACEMENT	0.7																				0.7
214	BIPOLE 1 VALVE HALL WALL BUSHING REPLACEMENT	1.8	(2.0)	0.2																		0.1
249	DORSEY BRINE EFFLUENT DISPOSAL STUDY AND IMPROVEMENT																					
258	BIPOLE 1 &2 ELECTRODE LINE MONITORING			0.2	1.2																	1.4
259	HVDC SWITCHGEAR ARCPROOF/SAFETY UPGRADES (PHASE 1 & 2)		0.4	0.5	0.1																	1.1
260	HVDC AUXILIARY POWER SUPPLY UPGRADES		0.5	0.5	0.4	0.4																1.8
272	DORSEY SYNCHRONOUS CONDENSER REFURBISHMENT		1.1	1.3	1.3	1.3	1.2	1.2														7.3
	HYDRAULIC REHABILITATION																					
3	GREAT FALLS G.S. REHABILITATION	(0.6)	(6.7)	(0.5)	5.1	2.5																(0.1)
52	SEVEN SISTERS G.S. REHABILITATION	0.8																				0.8
32	PINE FALLS G.S. REHABILITATION	(2.3)	(6.2)	(3.5)	6.9	5.0	0.1															0.1
33	McARTHUR G.S. REHABILITATION	0.1																				0.1
1	LAURIE RIVER PLANT 1 AND 2 REHABILITATION	(0.0)	0.1		(0.0)	(0.0)	(0.0)						(0.0)	(0.0)	(0.0)							0.0
48	GRAND RAPIDS G.S. REHABILITATION	(10.9)	8.8	1.3	(4.6)	(3.6)	(2.4)															(11.5)
25	JENPEG G.S. UNIT OVERHAULS (UNITS 1 - 6)	(1.7)	(3.2)	0.6	3.7	0.3	0.3	0.3	0.3	0.3												0.9
22	KETTLE & LONG SPRUCE G.S. STATOR REWEDGING	0.1	0.0																			0.1
82	PRODUCTION NORTH DAM SAFETY UPGRADES	0.8	1.6	2.2	2.2	2.3	1.1															10.2
26	WINNIPEG RIVER CONTROL SYSTEM	0.7	(4.7)	4.0	0.5																	0.6
234	LIMESTONE OUTSTANDING WORK	(2.2)	2.4	0.0	0.0	0.0																0.2
243	WINNIPEG RIVER RIVERBANK PROTECTION PROGRAM	0.4	0.1	0.1	0.2	0.2	0.2	0.2	0.2													1.5
246	KETTLE GS - STATOR REWIND	(0.9)	(1.2)	(1.3)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.3)	(0.3)	(0.3)	1.0	3.0						(1.6)
252	KELSEY G.S. GATE REHABILITATION		(0.6)	0.6	(0.7)	0.7	(0.7)	0.7	(0.7)	0.7	(0.7)	0.8										0.1
256	KETTLE ANNUNCIATION SYSTEM RENEWAL		1.0	0.5																		1.5
	THERMAL REHABILITATION																					
38	THERMAL G.S. ASSURANCE	3.2	0.9																			4.2
226	BRANDON G.S. UNIT 5 LICENSE RENEWAL		(1.1)	(3.6)	(2.5)	0.9	(0.4)	(1.7)	(1.3)	(0.3)	(0.8)	2.7	1.5	0.9	2.1	0.5	1.2	0.5	0.5	0.5	0.7	0.1
220	BRANDON G.S. SWITCHYARD JETAIRE BREAKER REPLACEMENT	(0.6)																				(0.6)
	OTHER																					
224	200MW ONTARIO HYDRO SALE - SYNC COND CONVERSION	(0.7)	(0.1)	(0.1)	(0.1)	0.1	0.4	0.4	0.5													0.6
227	SITE REMEDIATION OF CONTAMINATED CORPORATE FACILITIES	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0							0.4
225	OIL CONTAINMENT	(0.3)	(1.6)	(2.6)	0.1	1.6	1.6															(1.1)
228	FIRE PROTECTION PROJECTS	0.1	0.7	0.6																		1.3
13	POWER SUPPLY BUILDINGS	(0.2)	(1.6)	(1.1)	1.4	1.8																0.3
990	PLANNING STUDY COSTS	0.0	14.5	0.8	0.4	(1.4)	0.5	(0.2)	3.7	3.0	10.7	0.5	0.5	(17.4)	0.1	(0.2)	(0.1)	2.5	0.5	0.3	0.3	19.0
	DOMESTIC ITEMS - POWER SUPPLY	(0.0)	0.0	0.0																		(0.0)
	SUB-TOTAL POWER SUPPLY	**(19.0)**	**(0.1)**	**0.0**	**15.6**	**12.6**	**2.7**	**1.4**	**2.5**	**3.5**	**8.9**	**17.8**	**26.8**	**84.0**	**(5.0)**	**131.6**	**317.1**	**579.2**	**571.1**	**437.2**	**360.5**	**2,548.4**

CAPITAL EXPENDITURE FOR[illegible]VISIONS (CEP99-1)
(IN MILLIONS [illegible]S)
FOR THE YEARS [illegible]2018/19

		2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	20 year Forecast
CUSTOMER SERVICE																						
991	DEMAND SIDE MANAGEMENT CAPITAL COSTS	(0.0)	2.1	2.2	1.0	2.0	1.6	1.8	1.7	1.8	2.0	0.8	0.6	0.8	0.8	0.8	0.9	1.0	1.0	1.0	1.1	25.0
97	AUTOMATIC METER READING IMPLEMENTATION		(1.5)	(0.9)	(0.1)	(0.0)	(0.0)	(0.1)	(0.0)	(0.1)	(0.1)	2.3										(0.6)
	DOMESTIC ITEMS - CUSTOMER SERVICE	0.1	(1.4)	(1.5)	(1.5)																	(4.4)
	SUB-TOTAL CUSTOMER SERVICE	0.1	(0.8)	(0.2)	(0.6)	1.9	1.6	1.7	1.6	1.6	1.9	3.1	0.6	0.8	0.8	0.8	0.9	1.0	1.0	1.0	1.1	20.0

CAPITAL EXPENDITURE FO[illegible]VISIONS (CEF99-1)
(IN MILLIONS[illegible]RS)
FOR THE YEARS [illegible]2018/19

		2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	20 year Forecast
CORPORATE GROUP																						
230	FIRE PROTECTION PROJECTS	(0.0)	(0.0)																			(0.0)
231	CORPORATE BUILDING PROGRAM	0.0				(0.1)	(0.0)															(0.1)
244	YEAR 2000 CONVERSION	0.0	(0.7)																			(0.7)
245	NEW CUSTOMER SERVICE SYSTEM			(0.0)	(0.0)	(0.0)																(0.1)
	DOMESTIC ITEMS - CORPORATE GROUP	5.1	(0.4)	(0.4)	(0.4)																	3.9
	SUB-TOTAL CORPORATE GROUP	5.1	(1.1)	(0.4)	(0.4)	(0.2)	(0.0)															3.0
	TOTAL CAPITAL EXPENDITURES	(12.7)	(5.0)	(5.1)	(9.3)	6.5	(3.5)	18.1	16.2	25.7	24.2	32.5	50.0	117.4	37.6	168.7	516.3	999.7	1,089.5	819.9	454.3	4,341.1

FALL 1999 FORECAST

SECTIONS

SUMMARY

POWER SUPPLY

FUTURE ENERGY SUPPLY

HVDC FACILITIES

HYDRAULIC REHABILITATION

THERMAL REHABILITATION

OTHER

DOMESTIC ITEM - POWER SUPPLY

CUSTOMER SERVICE

MAJOR ITEMS

DOMESTIC ITEM - CUSTOMER SERVICE

CORPORATE GROUP

MAJOR ITEMS

DOMESTIC ITEM - CORPORATE GROUP

TRANSMISSION & DISTRIBUTION

TRANSMISSION FOR GENERATION

INTERCONNECTIONS - T & D

TRANSMISSION

SUBTRANSMISSION

DISTRIBUTION

COMMUNICATIONS, CONTROLS AND INFO TECHNOLOGY

OTHER

DOMESTIC ITEM - T & D

Volume 2

TRANSMISSION & DISTRIBUTION

COMPLEX	BUDGET REFERENCE DESCRIPTION	BRN #	PAGE
	TRANSMISSION FOR GENERATION		
58	WUSKWATIM TRANSMISSION		
	WUSKWATIM G.S. > WUSKWATIM SWITCHING STN 230kV LINES	02-00-6152	111
	WUSKWATIM > HERBLET LAKE 230 kVT/L	02-00-7005	112
	WUSKWATIM - SWITCHING STATION 230kV TERMINATIONS	03-00-7080	113
	GRAND RAPIDS LINE REACTOR CIRCUIT SWITCHERS	03-00-8111	114
	HERBLET LAKE TERMINATE WUSKWATIM 230 kV T/L	03-00-5301	115
	COMMUNICATIONS FOR WUSKWATIM 230kV T/L	05-00-5131	116
262	CONAWAPA TRANSMISSION		
263	HVDC CONVERSION BIPOLE 3		
265	RIEL > WINNIPEG AC TRANSMISSION		
266	DORSEY > RIEL 500KV AC T/L		
	INTERCONNECTIONS - T & D		
95	200MW ONTARIO HYDRO SALE - T/L UPGRADE		
	WHITESHELL > TRANSCONA 110kV RECONDUCTOR WT34 END SECTIONS	02-00-5959	117
	WINNIPEG RIVER & WINNIPEG 110kV T/L REFURBISHMENT	02-00-5960	118
	WHITESHELL REPL BANK 8 115KV PHASE SHIFTING TRANSFORMER	03-00-8295	119
268	GLENBORO > HARVEY 230KV LINE	02-00-8026	120
	TRANSMISSION		
87	KETTLE AC TRANSMISSION IMPROVEMENTS		
	RADISSON STATION CONVERT R26K TO 230kV & RETERMINATE K4/K5	03-00-3343	121
	KELSEY STATION CONVERT T/L K24W & R26K TO 230kV OPERATION	03-00-4820	122
	THOMPSON>MYSTERY LAKE ROAD STATION CONVERT T/L K24W TO 230kV	03-00-3342	123
	PONTON,HERBLET LK & CLIFF LK>KETTLE AC PROTECTION CHANGES	03-00-6122	124
	KELSEY INSTALL 230-130kV TRANSFORMER	03-00-6115	125
	TELECOMMUNICATION FOR KETTLE AC OPERATION	05-00-6556	126
30	THOMPSON > HERBLET LAKE 230kV TRANSMISSION		
	THOMPSON BIRCHTREE > HERBLET LAKE 230kV T/L	02-00-7006	127
	THOMPSON BIRCHTREE ESTABLISH STATION	03-00-8103	128
	HERBLET LAKE TERMINATE THOMPSON BIRCHTREE 230kV T/L	03-00-3344	129
	THOMPSON > MYSTERY LAKE PROTECTION CHANGES FOR BIRCHTREE T/L	03-00-6116	130
	KELSEY PROTECTION CHANGES FOR THOMPSON BIRCHTREE 230kV T/L	03-00-6117	131
	COMMUNICATIONS FOR THOMPSON > BIRCHTREE 230kV T/L	05-00-3219	132
16	NORTH CENTRAL MANITOBA PROJECT		
	NORTH CENTRAL MANITOBA T/L R.O.W. SITE SEL & ENV APPL	02-00-0229	133
	NORTH CENTRAL MANITOBA 138kV T/L	02-00-0230	134
	NORTH CENTRAL FEDERAL CAPITAL CONTRIBUTIONS - ELECTRIFICATION	02-00-0231	135

COMPLEX	BUDGET REFERENCE DESCRIPTION	BRN #	PAGE
	NORTH CENTRAL COMMUNITY INVOLVEMENT	02-00-0232	136
	NORTH CENTRAL PROVINCIAL CAPITAL CONTRIBUTIONS	02-00-7993	137
	OXFORD HOUSE NEW 138-25kV STATION	03-00-0617	138
	KELSEY TERMINATE OXFORD HOUSE 138kV LINE	03-00-0618	139
	GOD'S LAKE NARROWS NEW 138-25kV STATION	03-00-0615	140
	GARDEN HILL NEW 138-25kV STATION	03-00-0616	141
	WASAGAMACK NEW 138-25 kV STATION	03-00-1648	142
	RED SUCKER LAKE COMMUNITY > CENTRAL SUPPLY	04-00-0363	143
	ISLAND LAKE COMMUNITIES > CENTRAL SUPPLY	04-00-0364	144
	GOD'S LAKE NARROWS COMMUNITY > CENTRAL SUPPLY	04-00-0365	145
	NORTH CENTRAL SALVAGE OF DIESEL GENERATING STNS	04-00-0369	146
	NORTH CENTRAL SOIL REMEDIATION OF DIESEL SITES	04-00-6517	147
	NORTH CENTRAL FEDERAL CAPITAL CONTRIBUTIONS - SOIL REMEDIATION	04-00-6509	148
40	FLIN FLON - CLIFF LAKE TRANSFORMER REPLACEMENT		
	FLIN FLON - CLIFF LAKE REPLACE 230-115kV TRANSFORMER BANK #1	03-00-4818	149
	THE PAS - RALLS ISLAND REPLACE 230kV BREAKER	03-00-7226	150
47	HERBLET LAKE > THE PAS 230kV TRANSMISSION		
	HERBLET LAKE > THE PAS - RALLS ISLAND 230kV T/L	02-00-1243	151
	HERBLET LAKE STN TERMINATE THE PAS 230kV T/L	03-00-1694	152
	THE PAS - RALLS ISLAND TERMINATE HERBLET LAKE 230kV T/L	03-00-1695	153
	COMMUNICATIONS FOR HERBLET LAKE > THE PAS - RALLS ISLAND 230kV T/L	05-00-4509	154
57	DORSEY > NEEPAWA > CORNWALLIS 230kV LINE		
	DORSEY > NEEPAWA > CORNWALLIS 230kV T/L	02-00-1235	155
	NEEPAWA STATION LAND PURCHASE	03-00-1661	156
	CORNWALLIS STN TERMINATE DORSEY (NEEPAWA) 230kV T/L	03-00-1662	157
	DORSEY STN TERMINATE CORNWALLIS (NEEPAWA) 230kV T/L	03-00-1663	158
	CORNWALLIS TERTIARY REACTOR R12 AND BREAKER REPLACEMENT	03-00-6190	159
	DORSEY > NEEPAWA > CORNWALLIS 230kV LINE COMM. COMPLEX	05-00-1252	160
60	WINNIPEG > BRANDON 230kV TRANSMISSION		
	DORSEY WEST PROPERTY REQUIREMENTS	02-00-5137	161
	WINNIPEG > BRANDON 230kV T/L	02-00-7994	162
	CORNWALLIS TERMINATE DORSEY 230kV T/L	03-00-7078	163
	DORSEY TERMINATE BRANDON 230kV T/L	03-00-7079	164
	WINNIPEG > BRANDON COMMUNICATIONS FOR 230kV LINE	05-00-1260	165
45	FT GARRY - PERIMETER SOUTH BANK REPLACEMENT	03-00-5936	166
84	RIDGEWAY 230kV TRANSFORMER ADDITION	03-00-1673	167
78	RIDGEWAY > ST. VITAL 230kV TRANSMISSION		
	RIDGEWAY > ST. VITAL & RIDGEWAY > RICHER 230kV T/L	02-00-3201	168
	ST. VITAL TRANSFORMER ADDITION & LINE TERMINATIONS	03-00-6361	169
	RIDGEWAY TERMINATE ST VITAL & RICHER 230kV T/L	03-00-8493	170
	RIDGEWAY UPGRADE COMPRESSED AIR SYSTEM	03-00-8330	171
	RIDGEWAY > ST. VITAL > RICHER 230kV TELECONTROL REQUIREMENT	05-00-3205	172
64	ST. VITAL 230kV TRANSFORMER ADDITION	03-00-1672	173

COMPLEX	BUDGET REFERENCE DESCRIPTION	BRN #	PAGE
42	DORSEY > ROSSER 230kV TRANSMISSION IMPROVEMENTS		
	RECONDUCTOR & RECONNECT 230kV T/L D5R	02-00-5962	174
	DORSEY LINE D5R PROTECTION CHANGES	03-00-5916	175
	ROSSER LINE D5R PROTECTION CHANGES	03-00-5917	176
	D5R PROTECTION CHANNELS	05-00-8595	177
27	DORSEY > ST. VITAL 230kV TRANSMISSION		
	DORSEY > ST. VITAL 230kV T/L	02-00-5963	178
	DORSEY PROTECTION CHANGES FOR ST. VITAL LINE TERMINATION	03-00-3314	179
	ST. VITAL TERMINATION OF DORSEY 230kV LINE	03-00-3311	180
	TELECONTROL FOR DORSEY > ST. VITAL 230kV T/L	05-00-5532	181
96	DORSEY > LAVERENDRYE > ST. VITAL 230kV TRANSMISSION		
	DORSEY > ST. VITAL & LAVERENDRYE > ST.LEON 230kV T/L	02-00-5964	182
	DORSEY PROTECTION CHANGES FOR TERMINATION OF ST. VITAL T/L	03-00-5918	183
	ST. VITAL TERMINATION OF DORSEY SOUTH LOOP 230kV T/L	03-00-5919	184
	LAVERENDRYE TERMINATION OF ST.LEON 230kV T/L	03-00-5920	185
	ST.LEON PROTECTION CHANGE FOR LAVERENDRYE 230kV T/L	03-00-5921	186
	TELECONTROL FOR DORSEY > ST.VITAL & LAVERENDRYE > ST.LEON T/L	05-00-5533	187
21	ROSSER > SILVER 230kV TRANSMISSION		
	ROSSER > SILVER 230kV T/L	02-00-5961	188
	SILVER TERMINATE ROSSER 230kV T/L & 230-66kV TRANSFORMER	03-00-5912	189
	ROSSER TERMINATE SILVER 230kV T/L & RETERMINATE R23R	03-00-5914	190
	ASHERN LINE A3R PROTECTION CHANGES	03-00-5915	191
	ROSSER > SILVER 230kV T/L TELECONTROL FACILITIES	05-00-5531	192
39	RAVEN LAKE STATION 230-66kV TRANSFORMATION		
	RAVEN LAKE STATION 230-66kV TRANSFORMATION	03-00-5898	193
	HAMIOTA STATION RECONNECT BANK 2 FOR 66kV OPERATION	03-00-6187	194
	LINE 88 CONVERSION TO 66kV OPERATION	04-00-6543	195
18	NEEPAWA 230 - 66kV STN		
	NEEPAWA SECTIONALIZE 230kV TRANSMISSION LINE D54C	02-00-6970	196
	NEEPAWA ESTABLISH 230 - 66kV TERMINAL STATION	03-00-6990	197
	NEEPAWA 115kV STATION UPGRADE	03-00-6991	198
	DORSEY PROTECTION CHANGES FOR NEEPAWA 230kV T/L	03-00-6992	199
	CORNWALLIS PROTECTION CHANGES FOR NEEPAWA 230kV T/L	03-00-6993	200
	NEEPAWA TERMINATE 66KV FROM NEW 230/66KV STN	03-00-8406	201
	NEEPAWA 66KV SUBTRANSMISSION	04-00-8621	202
	TELECONTROL FOR NEEPAWA 230 - 66kV STATION ADDITION	05-00-6553	203
201	ASSINIBIONE WILKES AVE 115-24 KV BANK 1 ADDITION		
	ASSINIBOINE WILKES YV5 115kV TRANSMISSION LINE TAP	02-00-6985	204
	ASSINIBOINE WILKES W65 24kV BREAKER ADDITION	03-00-6154	205
	ASSINIBOINE WILKES W62 24kV BREAKER ADDITION	03-00-6155	206
	ASSINIBOINE WILKES W71 24kV BREAKER ADDITION	03-00-6158	207
	ASSINIBOINE WILKES 115-24kV TRANSFORMER ADDITION	03-00-6157	208
	ASSINIBOINE WILKES W65 24kV FEEDER ADDITION	04-00-6532	209
	ASSINIBOINE WILKES W62 24kV FEEDER ADDITION	04-00-6533	210
	ASSINIBOINE WILKES W71 24kV FEEDER ADDITION	04-00-6534	211
	ASSINIBOINE WILKES BANK 1 ADDITION COMMUNICATION	05-00-6571	212

COMPLEX	BUDGET REFERENCE DESCRIPTION	BRN #	PAGE
202	ROSSER > MCPHILLIPS 115kV TRANSMISSION IMPROVEMENTS		
	ROSSER > MCPHILLIPS 115kV T/L	02-00-6986	213
	MCPHILLIPS TERMINATE NEW ROSSER 115kV LINE	03-00-6176	214
	ROSSER TERMINATION OF MCPHILLIPS 115kV LINE	03-00-6177	215
	ROSSER > MCPHILLIPS 115kV T/L TELECONTROL	05-00-6576	216
204	RICHER - SOUTH 230-66kV TRANSFORMER ADDITION	03-00-6164	217
205	PINE FALLS > BLOODVEIN 115kV LINE TRANSMISSION		
	PINE FALLS > BLOODVEIN 115kV T/L	02-00-6984	218
	PINE FALLS TERMINATION OF BLOODVEIN 115kV LINE	03-00-6168	219
	BLOODVEIN 115-66kV TRANSFORMER ADDITIONS	03-00-6169	220
	LOON STRAITS TRANSFORMER REPLACEMENT	03-00-6170	221
207	ST. VITAL > STEINBACH 230kV TRANSMISSION		
	ST. VITAL > STEINBACH 230kV T/L	02-00-6987	222
	STEINBACH - NEW 230-66kV STATION	03-00-6178	223
	ST. VITAL TERMINATE STEINBACH 230kV T/L	03-00-6179	224
	ST. VITAL > STEINBACH COMMUNCATION COMPLEX	05-00-6572	225
208	RIDGEWAY > SELKIRK 230kV TRANSMISSION		
	RIDGEWAY > SELKIRK 230kV T/L	02-00-6988	226
	SELKIRK ESTABLISH 230-115kV STATION	03-00-6180	227
	RIDGEWAY TERMINATE SELKIRK 230kV LINE	03-00-6181	228
	RIDGEWAY > SELKIRK COMMUNICATION COMPLEX	05-00-6573	229
210	SOURIS > PEMBINA VALLEY 230kV TRANSMISSION		
	SOURIS > PEMBINA VALLEY 230kV T/L	02-00-6983	230
	PEMBINA VALLEY NEW 230-66kV STATION	03-00-6166	231
	SOURIS TERMINATE PEMBINA VALLEY 230kV T/L	03-00-6188	232
	CORNWALLIS PROTECTION CHANGES FOR LINE C28R	03-00-6167	233
	RESTON PROTECTION CHANGES FOR LINE C28R	03-00-6189	234
	SOURIS > PEMBINA VALLEY COMMMUNCATION COMPLEX	05-00-6574	235
4	WINNIPEG AREA TRANSMISSION REFURBISHMENT		
	WINNIPEG 230 & 110kV NETWORK T/L REFURBISHMENT	02-00-1259	236
	WINNIPEG 63.5kV NETWORK T/L REFURBISHMENT	04-00-1414	237
28	DORSEY STATION 230kV BREAKER REPLACEMENT	03-00-2338	238
43	DORSEY > US BORDER D602F 500KV AC T/L INSULATOR REPLACEMENT	02-00-6978	239
7	BIPOLE 1 & 2 LINE SPACER DAMPERS REPLACEMENT		
	RADISSON > DORSEY & HENDAY > RADISSON DC LINES SPACER DAMPERS	02-00-6977	240
247	DORSEY 230KV BUS ENHANCEMENTS	03-00-8339	241
251	FLIN FLON AREA TRANSMISSION IMPROVEMENTS		
	DEDICATED LINES TO HBM&S AND PARALLELING R1F / R2F	02-00-8004	242
	TRANSMISSION LINE HS15 SALVAGE AND UPGRADE	02-00-8005	243

COMPLEX	BUDGET REFERENCE DESCRIPTION	BRN #	PAGE
	HERBLET LAKE > CHISEL LAKE TAP 115kV LINE	02-00-8006	244
	FLIN FLON - ROSS LAKE SALVAGE SWITCHTOWER #3 AND RECONFIGURE	03-00-8352	245
	MILE 13 SALVAGE 115kV STATION	03-00-8353	246
	HERBLETT LAKE ADD SPARE 230-115kV BANK AND 115kV T/L	03-00-8354	247
	PONTON CONVERT STATION SERVICE AND SALVAGE AUTO TRANSFORMER	03-00-8355	248
257	PINE FALLS > GREAT FALLS 115-66KV SUPPLY		
	GREAT FALLS 115KV LINE	02-00-8010	249
	BLOODVEIN VOLTAGE CONTROL DEVICE	03-00-8403	250
	GREAT FALLS NEW 115-66KV STATION	03-00-8404	251
	GREAT FALLS 115-66KV STATION SALVAGE	03-00-8405	252
	GREAT FALLS 66KV LINES	04-00-8623	253
	SUBTRANSMISSION		
55	JENPEG > NORWAY HOUSE 66 kV SUB TRANSMISSION LINE		
	JENPEG TERMINAL 66 kV CHANGES	03-00-3350	254
	JENPEG > NORWAY HOUSE 66 kV LINE	04-00-3029	255
53	RUTTAN > SOUTH INDIAN LAKE 66 kV LINE		
	SOUTH BAY STATION SALVAGE	03-00-4857	256
	RUTTAN LAKE STATION (A)	03-00-4858	257
	SOUTH INDIAN LAKE STATION	03-00-4859	258
	RUTTAN LAKE > SOUTH INDIAN LAKE 66kV SUPPLY	04-00-5486	259
17	CENTRAL SUPPLY > PIKWITONEI & THICKET PORTAGE		
	CENTRAL SUPPLY > PIKWITONEI & THICKET PORTAGE	04-00-5498	260
	THICKET PORTAGE D.G.S. SITE CLEAN-UP	04-00-5499	261
	PIKWITONEI D.G.S. SITE CLEAN-UP	04-00-5500	262
206	PINEY > SPRAGUE 66kV LINE		
	SPRAGUE 66-12kV STATION	03-00-6161	263
	PINEY STATION 33kV EQUIPMENT SALVAGE	03-00-6162	264
	SPRAGUE STATION 33-12kV SALVAGE	03-00-6163	265
	PINEY > SPRAGUE 66kV T/L	04-00-6537	266
209	BIRTLE > ROSSBURN 66kV LINE		
	BIRTLE SOUTH > ROSSBURN 66kV LINE TERMINATION	03-00-6165	267
	BIRTLE SOUTH > ROSSBURN 66kV T/L	04-00-6538	268
	SHOAL LAKE 66kV SUPPLY	04-00-6539	269
237	ST BONIFACE - PLESSIS RD 115-25kV STATION		
	ST BONIFACE - PLESSIS RD STN 115kV T/L IMPROVEMENTS	02-00-7998	270
	ST BONIFACE - PLESSIS RD NEW STATION	03-00-7260	271
	ST VITAL TERMINAL 115kV LINE SV23 PROTECTION REPL	03-00-7261	272
	SELKIRK G.S. 115kV LINE SV23 PROTECTION REPL	03-00-7262	273
	ST BONIFACE - PLESSIS RD STN 4-24kV FEEDER LINES	04-00-7564	274
	ST BONIFACE - PLESSIS RD STN COMMUNICATION REQUIREMENT	05-00-7584	275
238	ROSSER - OAK POINT 115-24kV STN		
	ROSSER - OAK POINT STN RY7 115kV T/L TAP	02-00-7000	276

COMPLEX	BUDGET REFERENCE DESCRIPTION	BRN #	PAGE
	ROSSER - OAK POINT NEW STATION	03-00-7268	277
	LAVERENDRYE STN 115kV LINE PROTECTION REPL	03-00-7269	278
	ROSSER STN 115kV LINE PROTECTION	03-00-7270	279
	ROSSER - OAK POINT STN 2-24kV FEEDERS	04-00-7566	280
	ROSSER - OAK POINT STN COMMUNICATION REQUIREMENTS	05-00-7585	281
239	ROSSER - OAK POINT BANK 2 ADDITION		
	ROSSER - OAK POINT STN RK6 115kV T/L TAP	02-00-7001	282
	ROSSER - OAK POINT 115-24kV TRANSFORMER ADDITION	03-00-7272	283
	KIRKFIELD STN 115kV LINE RK6 PROTECTION REPL	03-00-7273	284
	ROSSER STN 115kV LINE RK6 PROTECTION REPL	03-00-7274	285
	ROSSER - OAK POINT STN 2-24kV FEEDERS	04-00-7567	286
240	ST BONIFACE - PLESSIS RD BANK 2 ADDITION		
	ST BONIFACE - PLESSIS RD STN SV24 115kV T/L TAP	02-00-7999	287
	ST BONIFACE - PLESSIS RD 115-24kV TRANSFORMER ADDITION	03-00-7264	288
	ST VITAL TERMINAL 115kV LINE SV24 PROTECTION REPL	03-00-7265	289
	SELKIRK G.S. 115kV LINE SV24 PROTECTION	03-00-7266	290
	TRANSCONA STN SV23 T/L RETERMINATION & PROTECTION CHG	03-00-8347	291
	ST BONIFACE - PLESSIS RD STN ADDITION OF 2-24kV CIRCUITS	04-00-7565	292
	SPRINGFIELD - PLESSIS RD BANK 2 COMMUNICATION REQUIREMENTS	05-00-8587	293
241	NEEPAWA 66kV SYSTEM		
	NEEPAWA STN 66kV BREAKER ADDITION	03-00-7277	294
	NEEPAWA PLUMAS TAP 66kV LINE	04-00-7568	295
242	RESTON / GLENBORO CAPACITY INCREASE		
	RESTON STN BANK 1 REPLACEMENT	03-00-7275	296
	GLENBORO - SOUTH STN BANK 3 ADDITION	03-00-7276	297
80	ST LEON 230-66KV TRANSFORMER ADD'N AND IPL EXPANSION		
	ST.LEON STATION 230-66kV TRANSFORMER ADDITION	03-00-5899	298
	VIRDEN - WEST STN 66kV BREAKER ADDITION	03-00-8286	299
	CROMER - NORTH STN 66kV BREAKER ADDITION	03-00-8287	300
	LETELLIER STN 66kV BREAKER ADDITION	03-00-8288	301
	SOURIS I.P.L. - EAST STN 66KV BREAKER ADDITION	03-00-8290	302
	SOURIS I.P.L. - WEST STN 66kV BREAKER ADDITION	03-00-8291	303
	ST LEON STN 66kV BREAKER ADDITION	03-00-8292	304
	I.P.L. CAPITAL CONTRIBUTIONS	03-00-8308	305
	RICHER - SOUTH ADD 230-66KV SPARE POWER TRANSFORMER	03-00-8345	306
	SOURIS I.P.L. - EAST > SOURIS I.P.L. - WEST 66KV LINE	04-00-8577	307
	ST LEON > MANITOU I.P.L. 66kV LINE	04-00-8578	308
	LETELLIER > GRETNA I.P.L. 66kV LINE	04-00-8579	309
	VIRDEN - WEST > CROMER I.P.L. 66kV LINE	04-00-8580	310
253	BRANDON - EAST 115KV IMPROVEMENTS		
	BRANDON - EAST 115KV IMPROVEMENTS	02-00-8002	311
	BRANDON - 65TH ST EAST NEW 115-25 KV STN	03-00-8332	312
	BRANDON GS TERMINATION OF TOWER 9A 115KV T/L	03-00-8343	313
250	BRANDON - CROCUS PLAINS 115-25KV BANK ADDITION	03-00-8350	314

COMPLEX	BUDGET REFERENCE DESCRIPTION	BRN #	PAGE
	DISTRIBUTION		
86	DIESEL UPGRADING ENHANCEMENT		
	TADOULE LAKE NEW POWERHOUSE	04-00-9304	315
	DIESEL GENERATION ENHANCED REQUIREMENTS	04-00-1413	316
	BROCHET POWERHOUSE TANK FARM	04-00-1385	317
	LAC BROCHET MODIFICATIONS	04-00-1395	318
	LAC BROCHET DISTRIBUTION UPGRADE TO 25kV	04-00-8594	319
	ST. THERESA MODIFICATIONS	04-00-1405	320
	SHAMATTAWA MODIFICATIONS	04-00-9303	321
221	VIRDEN AREA DISTRIBUTION CHANGES		
	VIRDEN - WALLACE NEW 66-12kV STATION	03-00-7227	322
	KENTON DISTRIBUTION REBUILD	04-00-7551	323
	LINE 95 & LINE 97 REBUILD	04-00-7552	324
217	DEFECTIVE RINJ CABLE REPLACEMENT	04-00-7550	325
261	BRERETON LAKE STATION AREA	03-00-8397	326
267	PAINT LAKE NEW FEEDER	04-00-7546	327
	COMMUNICATIONS, CONTROLS AND INFO TECHNOLOGY		
10	EMS SCADA	05-00-5542	328
12	MICROWAVE RADIO REPLACEMENTS		
	LAKE WINNIPEG MICROWAVE UPGRADE	05-00-4500	329
	WINNIPEG RIVER MICROWAVE SYSTEM REPLACEMENT	05-00-6550	330
	MICROWAVE FREQUENCY DISPLACEMENT (2GHZ)	05-00-6561	331
	THOMPSON > KELSEY > RADISSON COMMUNICATIONS REPLACEMENT	05-00-6562	332
	WINNIPEG AREA > BRANDON AREA FIBRE OPTIC COMMUNICATIONS	05-00-6567	333
	MINNEDOSA AREA 71E3 MICROWAVE REPLACEMENT	05-00-3207	334
	JENPEG > WHISKEY JACK > WABOWDEN MICROWAVE REPLACEMENT	05-00-7577	335
	INTERLAKE DIGITAL MICROWAVE REPLACEMENT	05-00-8589	336
	THOMPSON COMMUNICATIONS CABLES REPLACEMENT	05-00-8598	337
	GRAND RAPIDS > TYRELL MICROWAVE REPLACEMENT	05-00-8599	338
219	MAPINFO IMPLEMENTATION PART II	09-00-7807	339
	OTHER		
2	SITE REMEDIATION		
	LITTLE GRAND RAPIDS D.G.S. SITE INVESTIGATION & CLEANUP	04-00-5462	340
	MANIGOTOGAN D.G.S. SITE INVESTIGATION & CLEANUP	04-00-5463	341
	PAUINGASSI D.G.S. SITE INVESTIGATION & CLEANUP	04-00-5465	342
	POPLAR RIVER D.G.S. SITE INVESTIGATION & CLEANUP	04-00-5467	343
	PUKATAWAGAN D.G.S. SITE INVESTIGATION & CLEANUP	04-00-5468	344
	THE PAS D.G.S. SITE INVESTIGATION & CLEANUP	04-00-5471	345
	MOOSE LAKE D.G.S. SITE INVESTIGATION & CLEANUP	04-00-5472	346
	NORWAY HOUSE D.G.S. SITE INVESTIGATION & CLEANUP	04-00-5473	347
	NELSON HOUSE D.G.S. SITE INVESTIGATION & CLEANUP	04-00-5476	348
	WANLESS D.G.S. SITE INVESTIGATION & CLEANUP	04-00-5478	349
	CHURCHILL D.G.S. SITE CLEAN-UP	04-00-5479	350

COMPLEX	BUDGET REFERENCE DESCRIPTION	BRN #	PAGE
	GRANDVILLE LAKE D.G.S. SITE INVESTIGATION & CLEANUP	04-00-5480	351
	CORMORANT D.G.S. SITE INVESTIGATION & CLEANUP	04-00-5482	352
	CRANBERRY PORTAGE D.G.S. SITE INVESTIGATION & CLEANUP	04-00-5483	353
81	OIL CONTAINMENT		
	AC SUBSTATION OIL CONTAINMENT - CENTRAL AREA	03-00-6110	354
	AC SUBSTATION OIL CONTAINMENT - WESTERN AREA	03-00-6111	355
	AC SUBSTATION OIL CONTAINMENT - EASTERN AREA	03-00-6112	356
	AC SUBSTATION OIL CONTAINMENT - NORTHERN AREA	03-00-6113	357
	MICROWAVE & VHF SITES OIL SPILL CONTAINMENT	05-00-6566	358
	THOMPSON SERVICE CENTRE OIL SPILL CONTAINMENT	08-00-6585	359
	OPERATIONS & MTCE SPILL RESPONSE EQUIPMENT	09-00-7697	360
131-139	**DOMESTIC ITEM - T & D**		

** Volume 1 contains Power Supply Customer Service and Corporate Group items

CAPITAL EXPENDITU[illegible]AST (CEF99-1)
(IN MILLIONS [illegible]ARS)
FOR THE YEARS 1999/00 TO 2018/19

		Total	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	20 year Forecast
TRANSMISSION AND DISTRIBUTION																							
	TRANSMISSION FOR GENERATION																						
58	WUSKWATIM TRANSMISSION	66.5												1.1	1.2	2.7	2.6	8.2	25.8	25.1			66.5
263	HVDC CONVERSION BIPOLE 3/CONAWAPA TRANSMISSION	1,896.2										2.6	9.2	15.3	15.8	41.5	55.3	215.8	412.4	509.3	372.7	186.7	1,836.6
	INTERCONNECTIONS																						
79	MANITOBA > MINNESOTA 500kV TRANSMISSION UPGRADE (MMTU)																						
95	200MW ONTARIO HYDRO SALE - T/L UPGRADE	0.8	0.8																				0.8
268	HARVEY-GLENBORO 230KV LINE	16.0		1.6	6.4	8.0																	16.0
	TRANSMISSION																						
87	KETTLE AC TRANSMISSION IMPROVEMENTS	10.6	0.1	0.0	0.2	1.0	4.3	5.0															10.6
16	NORTH CENTRAL MANITOBA PROJECT	0.8	0.0	0.3	0.4																		0.8
30	THOMPSON>HERBLET LAKE 230kV TRANSMISSION	57.1			0.2	0.2	0.8	5.4	21.5	14.1	14.9												57.1
40	FLIN FLON - CLIFF LAKE TRANSFORMER REPLACEMENT	1.5	0.6	0.9																			1.5
47	HERBLET LAKE > THE PAS 230kV TRANSMISSION	55.3				0.2	0.5	1.0	0.3	1.1	3.4	16.4	19.0	6.7									48.5
57	DORSEY > NEEPAWA > CORNWALLIS 230kV LINE	18.5	16.8	1.7																			18.5
60	WINNIPEG > BRANDON 230kV TRANSMISSION	73.0			0.1	3.0	4.8	7.4	13.7	18.7	15.1	10.3											73.0
45	FT GARRY - PERIMETER SOUTH BANK REPLACEMENT	4.4			0.4	2.5	1.5																4.4
84	RIDGEWAY TRANSFORMER ADDITION	9.2					0.3	0.6	0.8	4.1	3.4												9.2
78	RIDGEWAY > ST. VITAL 230kV TRANSMISSION	1.7	1.7																				1.7
64	ST. VITAL TRANSFORMER ADDITION	9.0	0.3	3.6	4.0	1.0																	9.0
42	DORSEY-ROSSER 230kV TRANSMISSION IMPROVEMENTS	1.8	0.0	1.4	0.4																		1.8
27	DORSEY > ST. VITAL 230kV AC TRANSMISSION	7.7	0.0	1.3	5.3	1.1	0.0																7.7
96	DORSEY > LAVERENDRYE > ST. VITAL 230kV TRANSMISSION	25.9														1.7	3.5	10.7	10.0				25.9
21	ROSSER > SILVER 230kV TRANSMISSION	27.6	3.6	0.4	0.5	3.3	9.9	10.0															27.6
9	RAVEN LAKE > BIRTLE 230kV TRANSMISSION																						
94	BRANDON 115kV LOOP																						
39	RAVEN LAKE STATION 230-66kV TRANSFORMATION	8.3																0.6	1.5	3.0	3.3		8.3
98	VERMILION STATION STATIC VAR GENERATOR																						
18	NEEPAWA 230 -115kV STN	17.5					0.1	1.0	7.4	9.1													17.5
201	ASSINIBOINE - WILKES AVE 115-24 KV BANK 1 ADDITION	7.2	7.1	0.1																			7.2
202	ROSSER > MCPHILLIPS 115kV TRANSMISSION IMPROVEMENTS	2.4	0.0	0.1	0.4	1.8																	2.4
204	RICHER SOUTH 230-66kV TRANSFORMER ADDITION	4.9				0.4	0.4	2.3	1.8														4.9
205	PINE FALLS > BLOODVEIN 115kV TRANSMISSION LINE	29.1								0.2	0.2	1.0	1.7	7.0	15.6	3.4							29.1
207	ST. VITAL > STEINBACH 230kV TRANSMISSION	22.3						0.3	0.3	0.6	3.3	4.2	13.6										22.3
208	RIDGEWAY > SELKIRK 230kV TRANSMISSION	25.1				0.6	2.0	3.3	4.5	7.0	7.6												25.1
210	SOURIS > PEMBINA VALLEY 230kV TRANSMISSION	32.6								0.6	0.9	1.4	1.6	12.0	16.1								32.6
4	WINNIPEG AREA TRANSMISSION REFURBISHMENT	4.0	1.1	0.6	0.4	0.8	1.1	0.0															4.0
28	DORSEY STATION 230kV BREAKER REPLACEMENT	1.6	1.6																				1.6
43	DORSEY > US BORDER D602F 500KV AC T/L INSULATOR REPL.	2.7	1.2	0.5	0.4	0.6																	2.7
7	BIPOLE 1 & 2 LINE SPACER DAMPERS REPLACEMENT	5.1	0.7	2.5	1.9	0.0																	5.1
247	DORSEY 230kV BUS ENHANCEMENTS	16.0	0.4	0.9	3.2	7.0	4.6																16.0
251	FLIN FLON AREA TRANSMISSION IMPROVEMENTS	17.3	0.3	2.0	5.2	1.6	5.2	2.9															17.3
257	PINE FALLS-GREAT FALLS 115-66kV SUPPLY	9.4		0.9	2.7	3.4	1.2	1.1															9.4
	SUBTRANSMISSION																						
55	JENPEG > NORWAY HOUSE 66 kV SUB TRANSMISSION LINE	12.5	0.0	0.0	0.3	0.9	4.9	6.3															12.5
53	RUTTAN > SOUTH INDIAN LAKE 66 kV LINE	5.5	0.3	0.3	0.3	1.6	3.0																5.5
17	CENTRAL SUPPLY > PIKWITONEI & THICKET PORTAGE	0.7	0.0	0.7																			0.7
206	PINEY > SPRAGUE 66kV LINE	1.7	1.7	0.0																			1.7
209	BIRTLE SOUTH > ROSSBURN 66kV LINE	5.4				0.1	0.2	3.6	1.5														5.4
237	ST. BONIFACE-PLESSIS ROAD 115-25KV STATION	16.4	7.8	8.3	0.3																		16.4
238	ROSSER - OAK POINT 115-24KV STATION	18.5			0.0	0.7	2.0	10.1	5.7														18.5
239	ROSSER - OAK POINT BANK 2 ADDITION	9.8										0.8	6.2	2.7									9.8
240	ST. BONIFACE - PLESSIS ROAD BANK 2 ADDITION	4.9	0.1	1.6	3.2																		4.9
241	NEEPAWA 66KV SYSTEM	3.4			0.2	3.3																	3.4
242	RESTON/GLENBORO CAPACITY INCREASE	4.9	0.5	2.8	1.6																		4.9
80	ST. LEON 230-66KV TRANSF. ADD'N AND IPL EXPANSION	8.9	0.2	0.9	1.6	5.0	0.7	0.5															8.9
253	BRANDON EAST 115kV IMPROVEMENTS	1.0	1.0																				1.0
250	BRANDON CROCUS PLAINS 115-24kV BANK ADDITION	7.2		0.1	0.6	3.9	2.3	0.4															7.2
	DISTRIBUTION																						
86	DIESEL UPGRADING ENHANCEMENT	10.3	2.1	1.7	4.4	2.0																	10.3
221	VIRDEN AREA DISTRIBUTION CHANGES	10.0	4.2	1.3	1.6	0.9	1.0	1.0															10.0
217	DEFECTIVE RINJ CABLE REPLACEMENT	7.8	0.8	1.2	1.8	1.9	2.1																7.8
261	BRERETON LAKE STATION AREA	6.6		2.6	2.2	0.7	0.5	0.5	0.1														6.6
267	PAINT LAKE NEW FEEDER	1.6			1.8	(0.2)																	1.6
	COMMUNICATIONS, CONTROLS AND INFO TECHNOLOGY																						
10	EMS SCADA	2.1	2.1																				2.1
12	MICROWAVE RADIO REPLACEMENTS	48.1	9.0	3.3	9.6	8.1		1.6	16.5														48.1
218	LAN NETWORK EXPANSION																						
219	MAPINFO IMPLEMENTATION	10.7	4.4	4.3	2.0																		10.7
	OTHER																						
2	SITE REMEDIATION	5.5	1.3	2.2	0.9	1.1																	5.5
81	OIL CONTAINMENT	3.4	0.1	0.8	1.2	1.0	0.3																3.4
92	FIRE PROTECTION PROJECTS																						

CAPITAL EXPENDITU[illegible]AST (CEF99-1)
(IN MILLIONS[illegible]LARS)
FOR THE YEARS 1999/00 TO 2018/19

	Total	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	20 year Forecast
DOMESTIC ITEMS - TRANMISSION AND DISTRIBUTION		77.6	75.8	78.6	80.6	86.0	88.3	90.6	92.9	95.2	97.6	100.1	102.7	105.4	108.1	110.8	113.6	116.5	119.6	122.7	125.8	1,988.3
SUB-TOTAL TRANSMISSION AND DISTRIBUTION		149.5	126.6	144.5	148.0	139.7	152.6	164.7	148.3	143.8	134.2	151.4	147.5	154.1	157.4	172.1	348.8	566.1	657.0	498.7	312.5	4,617.7

CAPITAL EXPENDITURE FORECAST REVISIONS (CEF99-1)
(IN MILLIONS OF DOLLARS)
FOR THE YEARS 2000 TO 2018/19

		2000	2001	2002	2003	2004	2005		2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	20 year Forecast
TRANSMISSION AND DISTRIBUTION																					
	TRANSMISSION FOR GENERATION																				
58	WUSKWATIM TRANSMISSION										(0.8)	(0.9)	(2.1)	(2.1)	(7.2)	(24.2)	(23.5)				(60.8)
263	HVDC CONVERSION BIPOLE 3/CONAWAPA TRANSMISSION										2.6	9.2	15.3	15.8	41.5	55.3	215.8	412.4	509.3	372.7	186.7	1,836.6
	INTERCONNECTIONS																				
79	MANITOBA > MINNESOTA 500kV TRANSMISSION UPGRADE (MMTU)																				
95	200MW ONTARIO HYDRO SALE - T/L UPGRADE	0.8																			0.8
268	HARVEY-GLENBORO 230KV LINE		1.6	6.4	8.0																16.0
	TRANSMISSION																				
87	KETTLE AC TRANSMISSION IMPROVEMENTS	(1.5)	(2.4)	(2.3)	(1.8)	4.3	5.0														1.4
16	NORTH CENTRAL MANITOBA PROJECT	(0.7)	0.0	(0.1)	(0.0)																(0.8)
30	THOMPSON>HERBLET LAKE 230kV TRANSMISSION	(0.2)	(0.3)	(0.2)	(0.2)	(4.3)	(15.6)	8.0	(0.2)	14.9											1.9
40	FLIN FLON - CLIFF LAKE TRANSFORMER REPLACEMENT	0.3	0.9																		1.2
47	HERBLET LAKE > THE PAS 230kV TRANSMISSION				0.0	0.0	0.1	0.0	0.1	0.1	0.1	0.3	0.2								1.0
57	DORSEY > NEEPAWA > CORNWALLIS 230kV LINE	1.1	(4.9)																		(3.8)
60	WINNIPEG > BRANDON 230kV TRANSMISSION		(0.1)	(0.2)	(3.2)	(1.7)	(5.1)	(4.1)	2.7	5.2	10.3										3.9
45	FT GARRY - PERIMETER SOUTH BANK REPLACEMENT		(0.4)	0.2	(1.4)	1.5															(0.1)
84	RIDGEWAY TRANSFORMER ADDITION					0.0	0.1	0.1	0.1	0.0											0.3
78	RIDGEWAY > ST. VITAL 230kV TRANSMISSION	0.8																			0.8
64	ST. VITAL TRANSFORMER ADDITION	(2.9)	0.9	3.6	(1.0)																0.5
42	DORSEY-ROSSER 230kV TRANSMISSION IMPROVEMENTS	0.0	(0.1)	0.0																	(0.0)
27	DORSEY > ST. VITAL 230kV AC TRANSMISSION	(5.1)	(0.2)	4.9	1.1	0.0															0.7
96	DORSEY > LAVERENDRYE > ST. VITAL 230kV TRANSMISSION														0.1	0.2	0.0	0.0			0.3
21	ROSSER > SILVER 230kV TRANSMISSION	0.6	(3.6)	(10.7)	(4.2)	9.9	10.0														2.0
9	RAVEN LAKE > BIRTLE 230kV TRANSMISSION																				
94	BRANDON 115kV LOOP																				
39	RAVEN LAKE STATION 230-66kV TRANSFORMATION																0.1	0.1	0.1	0.0	0.2
98	VERMILION STATION STATIC VAR GENERATOR	(0.0)	(0.1)	(0.5)	(8.5)	(8.6)	(3.9)														(21.7)
18	NEEPAWA 230 -115kV STN	(0.3)	(0.4)	(1.0)	(10.1)	(10.5)	1.0	7.4	9.1												(4.8)
201	ASSINIBOINE - WILKES AVE 115-24 KV BANK 1 ADDITION	1.3	(1.2)																		0.1
202	ROSSER > MCPHILLIPS 115kV TRANSMISSION IMPROVEMENTS	(0.1)	(0.3)	(1.3)	1.8																0.2
204	RICHER SOUTH 230-66kV TRANSFORMER ADDITION				0.0	0.1	0.0	0.0													0.1
205	PINE FALLS > BLOODVEIN 115kV TRANSMISSION LINE	(0.1)	(0.1)	(0.8)	(1.4)	(5.3)	(13.9)	(3.0)	0.2	0.2	1.0	1.7	7.0	15.6	3.4						4.4
207	ST. VITAL > STEINBACH 230kV TRANSMISSION						0.0	0.0	0.1	0.1	0.2	0.1									0.6
208	RIDGEWAY > SELKIRK 230kV TRANSMISSION				0.1	0.1	0.1	0.2	0.1	0.1											0.6
210	SOURIS > PEMBINA VALLEY 230kV TRANSMISSION								0.0	0.0	0.1	0.1	0.2	0.3							0.7
4	WINNIPEG AREA TRANSMISSION REFURBISHMENT	0.4	(0.2)	(0.3)	0.1	0.2	0.0														0.3
28	DORSEY STATION 230kV BREAKER REPLACEMENT	0.6																			0.6
43	DORSEY > US BORDER D602F 500KV AC T/L INSULATOR REPLACEMENT	0.4	(0.3)	(0.5)	(0.6)																(1.0)
7	BIPOLE 1 & 2 LINE SPACER DAMPERS REPLACEMENT	(3.0)	(1.2)	(1.6)	0.0																(5.7)
247	DORSEY 230kV BUS ENHANCEMENTS	0.0	0.1	0.6	0.6	0.2															1.5
251	FLIN FLON AREA TRANSMISSION IMPROVEMENTS	0.3	2.0	5.2	1.6	5.2	2.9														17.3
257	PINE FALLS-GREAT FALLS 115-66kV SUPPLY		0.9	2.7	3.4	1.2	1.1														9.4
	SUBTRANSMISSION																				
55	JENPEG > NORWAY HOUSE 66 kV SUB TRANSMISSION LINE	(0.2)	(1.7)	(2.0)	(6.3)	4.9	6.3														1.1
53	RUTTAN > SOUTH INDIAN LAKE 66 kV LINE	0.2	(0.4)	(1.8)	(0.7)	3.0															0.3
17	CENTRAL SUPPLY > PIKWITONEI & THICKET PORTAGE	0.0	0.0																		0.1
206	PINEY > SPRAGUE 66kV LINE	0.5	0.0																		0.5
209	BIRTLE SOUTH > ROSSBURN 66kV LINE				0.0	0.0	(0.1)	(0.1)													(0.2)
237	SPRINGFIELD-ST. BONIFACE 115-25KV STATION	2.8	5.0	(6.7)																	1.1
238	ROSSER - OAK POINT 115-24KV STATION		(0.0)	(0.5)	(0.2)	(8.5)	4.2	5.7													0.6
239	ROSSER - OAK POINT BANK 2 ADDITION										0.1	(0.0)	(0.0)								0.0
240	SPRINGFIELD-ST. BONIFACE BANK 2 ADDITION	0.0	(0.0)	0.5																	0.5
241	NEEPAWA 66KV SYSTEM			(0.0)	(0.1)																(0.1)
242	RESTON/GLENBORO CAPACITY INCREASE	0.1	0.0	0.0																	0.1
80	ST. LEON 230-66KV TRANSFORMER ADD'N AND IPL EXPANSION	0.3	0.2	0.3	0.0	0.1	(0.6)														0.3
253	BRANDON EAST 115kV IMPROVEMENTS	0.1																			0.1
250	BRANDON CROCUS PLAINS 115-24kV BANK ADDITION		0.0	0.0	0.3	0.1	(0.0)														0.3
	DISTRIBUTION																				
86	DIESEL UPGRADING ENHANCEMENT	(0.9)	0.6	4.2	(3.5)																0.4
221	VIRDEN AREA DISTRIBUTION CHANGES	0.9	(0.0)	0.1	0.1	0.1	0.1														1.2
217	DEFECTIVE RINJ CABLE REPLACEMENT	(0.1)	(0.1)	(0.2)	(0.2)	(0.3)															(0.8)
261	BRERETON LAKE STATION AREA STUDY		2.6	2.2	0.7	0.5	0.5	0.1													6.6
267	PAINT LAKE NEW FEEDER			1.8	(0.2)																1.6
	COMMUNICATIONS, CONTROLS AND INFO TECHNOLOGY																				
10	EMS SCADA	1.6																			1.6
12	MICROWAVE RADIO REPLACEMENTS	3.2	0.8	(3.3)	4.7		0.1	0.6													6.0
218	LAN NETWORK EXPANSION																				
219	MAPINFO IMPLEMENTATION	(0.3)	1.5	(0.4)																	0.9

CAPITAL EXPENDITURE FORECAST REVISIONS (CEF99-1)
(IN MILLIONS OF DOLLARS)
FOR THE YEARS 2000 TO 2018/19

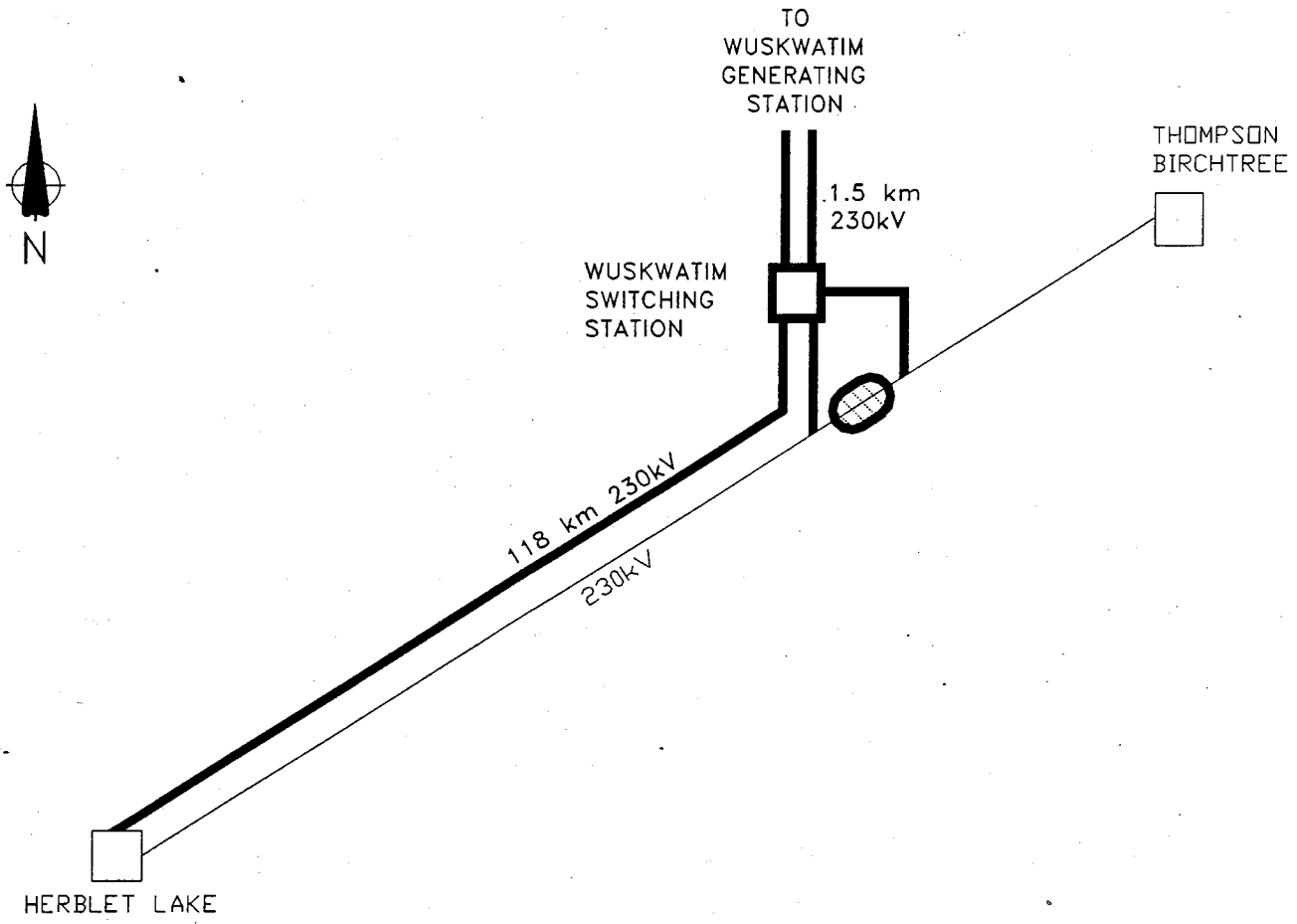
		2000	2001	2002	2003	2004	2005		2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018		20 year Forecast
	OTHER																					
2	SITE REMEDIATION	0.3	0.8	0.0	0.0																	1.1
81	OIL CONTAINMENT	0.0	0.1	0.1	0.2	0.0																0.5
92	FIRE PROTECTION PROJECTS											1.0	2.0	3.0	4.0	5.0	6.0	7.0	8.0	9.0	10.0	55.0
	DOMESTIC ITEMS - TRANMISSION AND DISTRIBUTION	(0.0)	(3.2)	(3.1)	(3.1)								(0.0)						(0.0)			(9.4)
	SUB-TOTAL TRANSMISSION AND DISTRIBUTION	**1.0**	**(3.0)**	**(4.5)**	**(23.9)**	**(7.8)**	**(7.8)**	**14.9**	**12.1**	**20.6**	**13.4**	**11.6**	**22.7**	**32.6**	**41.7**	**36.3**	**198.4**	**419.5**	**517.4**	**381.7**	**196.7**	**1,873.7**

CAPITAL BUDGET COMPLEX CONCEPTUAL DIAGRAM

WUSKWATIM TRANSMISSION

REVISED: 1999 - 10 - 01	ISSUED BY: WNZ

COMPLEX NO. 58



LEGEND

PROPOSED

EXISTING

SALVAGE

GRAND RAPIDS

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

COMPLEX STATUS: [X] Planned [ ] In progress

Complex no. 58

REVISION STATUS: [ ] New complex [X] In service change [ ] Concept change [ ] Estimate change only

COMPLEX: WUSKWATIM TRANSMISSION

Proposal

Perform environmental assessments and route selection, design and construct transmission and terminal facilities for Wuskwatim power transfer as follows:

Transmission: 230 KV lines 1 - 118 KM Wuskwatim - Herblet Lake, 2 - 1.5 KM Wuskwatim Switching Stn - Wuskwatim Generating Stn. Sectionalize existing Thompson Birchtree - Herblet Lake 230 KV line into Wuskwatim Switching Stn.

Terminations: Extend 230 KV facilities at Herblet Lake station. Construct 230 KV station at Wuskwatim. Communications: Microwave system.

JUSTIFICATION

[X] Load [ ] Service
[ ] Safety [ ] Efficiency
[X] Reliability [ ] Other

Explanation

Based on the 1999 Load Forecast, generation expansion studies indicate an additional generation source is required in 2016/17 Wuskwatim is the current economic choice. Transmission and terminating facilities are necessary to connect this new power source to the Manitoba network.

Estimate Level	COMPLEX START (yyyy mm)
L2	2008 04

IN SERVICE DATES AND AMOUNTS

2016 11	$25673	2016 12	$7596	2017 02	$25673	2017 03	$7596

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend								
Year 99/00								
00/01								
01/02								
02/03								
03/04								
04/05								
05/06								
06/07								
07/08								
08/09						792	-792	-100
09/10						881	-881	-100
10/11	799	221	46		1,066	2,085	-1,019	-49
11/12	799	241	157		1,197	2,092	-895	-43
12/13	1,765	586	344		2,695	7,249	-4,554	-63
13/14	1,478	533	584		2,595	24,156	-21,561	-89
14/15	5,116	2010	1,034		8,160	23,517	-15,357	-65
15/16	16,368	6790	2,596		25,754		25,754	
16/17	14,499	6424	4,145		25,068		25,068	
17/18								
18/19								
Beyond								
TOTAL	40,824	16,805	8,906		66,535	60,772	5,763	9

REVISION: In-service date deferred two years from 2014 to 2016.

Reviewed by ORIGINATOR	yyyy mm dd 99 11 03	Reviewed by COORDINATOR	yyyy mm dd 99 11 03
Reviewed by CONSTRUCTOR	yyyy mm dd 99 11 03	Approved by VICE PRESIDENT	yyyy mm dd 99 11 16

H2856/r Rev 99 03

Complex no. 58

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Advance or deferral impact

Delay in components of this transmission complex will curtail or prevent Wuskwatim capacity from being delivered to the Manitoba system.

Factors affecting timing or viability

Timing and rating of Wuskwatim Generating Station.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Wuskwatim G.S.-Wuskwatim Switch. Stn. 230KV T/L		601	613	632	19	3
Wuskwatim - Herblet Lake 230 KV T/L		20,109	20,511	21,110	599	3
Wuskwatim Switching Stn. 230KV Terminations		8,765	8,940	9,136	196	2
Grand Rapids - Line Reactor Circuit Switchers		1,380	1,408	1,449	41	3
Herblet Lake - Terminate Wuskwatim 230 KV T/L		3,693	3,767	3,818	51	1
Communications for Wuskwatim 230 KV T/L		4,373	4,460	4,678	218	5
TOTAL		38,921	39,699	40,823	1,124	3

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
9510	57,625	Estimate increased for sectionalization of Thompson Birchtree - Herblet Lake 230 kV line at Wuskwatim and line protection changes at Herblet Lake.
9610	64,197	Wuskwatim deferred 4 years to 2015
9710	62,819	Wuskwatim deferred 1 years to 2016
9810	60,772	In-service date advanaced two years from 2016 to 2014
9910	66,535	In-service date deferred two years from 2014 to 2016.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION
Complex 24	Wuskwatim Generating Station

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item

Title			Budget reference number
WUSKWATIM G.S. - WUSKWATIM SWITCHING STN. 230 KV LINES			02-00-6152
Originating division Planning & Control	Coordinating division Design	Constructing division Construction	Project Order Group (Range): 70227

DESCRIPTION:
DESIGN AND CONSTRUCT TWO (2) 1.5 KM SINGLE CIRCUIT STEEL TOWER TRANSMISSION LINES WITH 795 MCM CONDUCTOR.

JUSTIFICATION:
THIS ITEM PROVIDES TRANSMISSION FROM THE WUSKWATIM GENERATOR TRANSFORMERS TO THE WUSKWATIM AC SWITCHING STATION.

REFERENCE:
G&TPD REPORT 88-07, 'TRANSMISSION REQUIREMENTS FOR WUSKWATIM G.S. PRELIMINARY STUDIES'.

REVISION:
BASED ON THE 1999 POWER RESOURCE PLAN STUDIES, ISD DEFERRED TWO YEARS FROM 2014 TO 2016. REFLECTS REVISED ACTIVITY AND OVERHEAD RATES.

CONTINGENCY: $47 000

IN SERVICE DATES				Base estimate
2016 11 30	500			199803 L2
2017 02 28	501			Work start date 2013 04 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:						
2011/12	32	11	1			44
2012/13	73	24	9			106
2013/14	262	95	31			388
2014/15	234	90	52			376
TOTAL	601	220	93			914
REV. AMOUNTS:						
Authorized to date:						
Over(under)expend:						
Auth Req.: 2013/14	41	15	2			58
2014/15	89	34	11			134
2015/16	268	109	37			414
2016/17	234	101	60			395
TOTAL	632	259	110			1 001

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 02-00-6152

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1985 11	1 140	NEW ITEM.
1985 12	2 236	ISD DEFERRED TO 2012 FROM 1997.
1986 12	1 767	BASE DATE AND ESTIMATE REMAIN UNCHANGED. REVISED INTEREST AND ESCALATION RATES.
1987 11	2 006	BASE DATE REVISED FROM 1985 TO 1987. PROJECT ISD DEFERRED FROM 2009 TO 2012.
1988 11	2 159	BASE DATE AND ESTIMATE REVISED FROM 1987 TO 1988. ISD AND START DATE DEFERRED 2 YEARS. REFLECTS REVISED INTEREST AND ESCALATION RATES.
1989 10	2 013	PROJECT ADVANCED BY 2 YEARS, CASH FLOW REFINED AND ISD'S CHANGED TO COINCIDE WITH THOSE OF WUSKWATIM G.S.
1990 05	1 571	ISD ADVANCED 5 YEARS.
1990 10	2 222	START DATE DEFERRED 2 YEARS. REFLECTS ACTUAL COSTS FOR CONSTRUCTING SIMILAR LINES BETWEEN LIMESTONE G.S. & HENDAY S.S.
1991 10	2 482	ISD DEFERRED TO 2011 FROM 2008.
1992 10	1 878	IN SERVICE DATE ADVANCED 3 YEARS FROM 2013 10 01 & REDUCED ESCALATION RATES.
1993 03	1 806	ISD ADVANCED TO 2009 FROM 2010.
1993 10	1 629	ISD DEFERRED 1 YEAR TO 2010 10 01. DECREASE IN INTEREST AND ESCALATION RATES.
1994 10	1 514	ISD DEFERRED 1 YEAR TO 2011 10 01. REVISED INTEREST AND ESCALATION RATES.
1995 10	1 512	REVISED INTEREST AND ESCALATION RATES.
1996 06	1 665	ISD DEFERRED 4 YEARS FROM 2011 TO 2015.
1997 10	1 531	ISD DEFERRED 1 YEAR FROM 2015 TO 2016. REFLECTS REVISED INTEREST AND ESCALATION RATES AND CURRENT TRANSMISSION LINE COSTS.
1998 10	914	BASED ON THE 1998 POWER RESOURCE PLAN STUDIES, ISD ADVANCED TWO YEARS FROM 2016 TO 2014. REFLECTS CURRENT TRANSMISSION LINE COSTS.

ASSOCIATED PROJECTS

Budget reference number	Description
02-00-7005	WUSKWATIM - HERBLET LAKE 230 KV T/L
03-00-5301	HERBLET LAKE TERMINATE WUSKWATIM 230 KV T/L
03-00-7080	WUSKWATIM SWITCHING STATION 230 KV TERMINATIONS
03-00-8111	GRAND RAPIDS LINE REACTOR CIRCUIT SWITCHERS
05-00-5131	COMMUNICATIONS FOR WUSKWATIM 230 KV T/L

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item ___ Domestic Item

112

Title
WUSKWATIM - HERBLET LAKE 230 KV T/L

Budget reference number
02-00-7005

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	70228

DESCRIPTION:
CONDUCT ENVIRONMENTAL IMPACT ASSESSMENT, SELECT A ROUTE, AND OBTAIN LICENSING. ACQUIRE PROPERTY FOR RIGHT-OF-WAY. DESIGN AND CONSTRUCT APPROXIMATELY 118 KM OF SINGLE CIRCUIT 230 KV WOODPOLE LINE FROM WUSKWATIM SWITCHING STATION TO HERBLET LAKE USING 954 MCM CONDUCTOR.

OPEN THOMPSON BIRCHTREE - HERBLET LAKE 230KV LINE AND EXTEND INTO WUSKWATIM RETERMINATION, CREATING SECOND 230KV LINE FROM WUSKWATIM TO HERBLET LAKE AND 230KV LINE FROM WUSKWATIM TO THOMPSON BIRCHTREE.

JUSTIFICATION:
ELSEWHERE IN THE BUDGET JUSTIFICATION IS GIVEN FOR CONSTRUCTION OF WUSKWATIM GENERATING STATION. THIS ITEM PROVIDES FOR REQUIRED TRANSMISSION FACILITIES TO TRANSMIT WUSKWATIM GENERATED POWER TO THE SYSTEM.

REFERENCE:
G&TP REPORT 88-07 'TRANSMISSION REQUIREMENTS FOR WUSKWATIM G.S. PRELIMINARY STUDIES'

COMPLETION DATE FOR PROPERTY ACQUISITION: 2012 04 01.

REVISION:
BASED ON THE 1999 POWER RESOURCE PLAN STUDIES, ISD DEFERRED TWO YEARS FROM 2014 TO 2016. REFLECTS REVISED ACTIVITY AND OVERHEAD RATES.

CONTINGENCY: $1 581 000

IN SERVICE DATES		Base estimate
2016 11 30	17 404	199803 L2
2017 02 28	17 404	Work start date
		2010 04 01

PREV. AUTHORITY Authorized to date	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
2008/09	617	143	32			792
2009/10	617	159	106			882
2010/11	1 013	287	212			1 512
2011/12	742	227	348			1 317
2012/13	1 067	357	494			1 918
2013/14	9 607	3 451	1 261			14 319
2014/15	6 446	2 482	1 866			10 794
TOTAL	20 109	7 106	4 319			31 534
REV. AMOUNTS:						
Authorized to date						
Over(under)expend:						
Auth 2010/11	799	221	46			1 066
Req.: 2011/12	799	242	157			1 198
2012/13	1 279	420	313			2 012
2013/14	876	311	483			1 670
2014/15	1 201	461	640			2 302
2015/16	9 710	3 960	1 477			15 147
2016/17	6 446	2 801	2 166			11 413
TOTAL	21 110	8 416	5 282			34 808

Prepared by ___ yy mm dd COORDINATOR Approved by ___ yy mm dd Approved by ___ yy mm dd

Estimated by ORIGINATOR COORDINATING MANAGER ORIGINATING MANAGER

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 02-00-7005

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1984 12	31 389	ADVNC 2 YRS TO COINCIDE W WUSKWATIM GS. $100,000/KM UNIT CST.
1985 11	25 654	RVSD INT & ESC RATES. ISD DEFER 1 YR. LINE LENGTH DECRS 10KM.
1985 12	54 628	ISD DEFERRED TO 2012 FROM 1997,
1986 12	40 999	REVISED INTEREST & ESCALATION RATES.
1987 11	45 212	ISD DEFERRED FROM 2009 TO 2012
1988 11	99 774	ISD & START DATE DEFERRED 2 YRS. RVSD INT & ESC RATES. 230KV WUSKAWATIM STALL LAKE LINE REPLACES WUSKWATIM - PONTON LINE IN PROJECT.
1989 10	92 464	ISD ADVANCED 2 YRS TO COINCIDE WITH WUSKWATIM G.S.
1990 05	72 327	ISD DEFERRED 5 YEARS.
1990 10	73 785	CASH FLOW REFINED. PROJECT DEFERRED 1 YEAR.
1991 10	82 301	ISD DEFERRED TO 2013 FROM 2008.
1992 10	63 868	ISD ADVANCED 3 YRS FR 2013 10 01. REFLECTS INCREASED COSTS OF ENVIRONMENTAL REVIEW PROCESS & REDUCED ESCALATION RATES.
1993 03	30 711	CNSTR. OF 1ST LINE IN OTHER COMPLEX. ISD ADVNC 1 YR TO 2009.
1993 10	30 875	STALL LK NAME CHANGE TO HERBLET LK. ENVIRONMENTAL ACTIVITIES ADDED. ISD DFR'D 1 YEAR TO 2010 10 01. LINE CONDCTR SIZE CHNG TO 954 MCM.
1994 10	28 682	ISD DEFERRED 1 YR TO 2011 10 01. REVSD INT & ESC RATES.
1995 10	30 150	OPENING AND EXTENSION OF THOMPSON BIRCHTREE-HERBLET LAKE 230 KV LINE INTO WUSKWATIM ADDED.
1996 06	33 648	ISD DEFERRED FOUR YEARS FROM 2011 TO 2015.
1997 10	31 951	ISD DEFERRED 1 YEAR FROM 2015 TO 2016, USING WUSKWATIM GS 2 UNIT DESIGN.
1998 10	31 534	BASED ON THE 1998 POWER RESOURCE PLAN STUDIES, ISD ADVANCED TWO YEARS FROM 2016 TO 2014. REFLECTS CURRENT TRANSMISSION LINE COSTS.

ASSOCIATED PROJECTS

Budget reference number	Description
02-00-6152	WUSKWATIM G.S. - WUSKWATIM SWITCHING STN. 230 KV LINES
03-00-5301	HERBLET LAKE TERMINATE WUSKWATIM 230 KV T/L
03-00-7080	WUSKWATIM SWITCHING STATION 230 KV TERMINATIONS
03-00-8111	GRAND RAPIDS LINE REACTOR CIRCUIT SWITCHERS
05-00-5131	COMMUNICATIONS FOR WUSKWATIM 230 KV T/L

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item

113

Title	Budget reference number
WUSKWATIM SWITCHING STATION 230 KV TERMINATIONS	03-00-7080

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
anning & Control	Design	Construction	70229

DESCRIPTION:
CONDUCT ENVIRONMENTAL IMPACT ASSESSMENT, SELECT A SITE, ACQUIRE PROPERTY AND OBTAIN LICENSING FOR WUSKWATIM 230KV SWITCHING STATION. CONSTRUCT A 230KV SWITCHYARD TO TERMINATE TWO NEW LINES TO THE WUSKWATIM GENERATOR TRANSFORMERS AND ONE NEW LINE TO HERBLET LAKE. TERMINATE TWO LINES TO HERBLET LAKE AND THOMPSON BIRCHTREE FORMED BY SECTIONALIZING EXISTING THOMPSON BIRCHTREE-HERBLET LAKE 230KV CIRCUIT AT SWITCHING STATION SITE. FACILITIES ARE TO INCLUDE 5-230KV BREAKERS IN TWO BAYS, A BUILDING AND ASSOCIATED EQUIPMENT.

JUSTIFICATION:
ELSEWHERE IN THE BUDGET, JUSTIFICATION IS GIVEN FOR CONSTRUCTION OF WUSKWATIM GENERATING STATION. THIS ITEM PROVIDES FOR TERMINATION OF CIRCUITS REQUIRED TO TRANSMIT WUSKWATIM POWER TO THE TRANSMISSION NETWORK THROUGH THE WUSKWATIM SWITCHING STATION.

REFERENCE:
G&TP REPORT 88-07 'TRANSMISSION REQUIREMENTS FOR WUSKWATIM G.S. PRELIMINARY STUDIES'.

REVISION:
BASED ON THE 1999 POWER RESOURCE PLAN STUDIES, ISD DEFERRED TWO YEARS FROM 2014 TO 2016. REFLECTS REVISED ACTIVITY AND OVERHEAD RATES.

CONTINGENCY: $845,000

IN SERVICE DATES		Base estimate
2016 12 31	7 596	199704 L2
2017 03 31	7 594	Work start date 2012 04 01

PREV. AUTHORITY Authorized to date:	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
2010/11	423	127	24			574
2011/12	423	138	79			640
2012/13	2 916	1 031	293			4 240
2013/14	2 493	950	686			4 129
2014/15	2 510	1 021	933			4 464
TOTAL	8 765	3 267	2 015			14 047
REV. AMOUNTS:						
Authorized to date:						
Over(under)expend:						
Auth 2012/13	486	166	31			683
Req.: 2013/14	486	179	99			764
2014/15	3 048	1 206	327			4 581
2015/16	2 561	1 086	754			4 401
2016/17	2 555	1 152	1 054			4 761
TOTAL	9 136	3 789	2 265			15 190

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 03-00-7080

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1984 12	9 369	ISD ADVANCED 2 YEARS TO COINCIDE WITH REVISED WUSKWATIM ISD.
1985 12	25 639	ISD DEFERRRED TO 2012 FROM 1997.
1986 12	21 833	BASE DATE AND EST REMAIN UNCHANGED. REVISED IN & ESC RATES.
1987 11	24 780	BASE DATE REVISED FR 1985 TO 1987. EST CHANGED. ISD DEF FR. 2009 TO 2012.
1988 11	27 854	BASE DATE REVISED FROM 1987 TO 1988. NO SLD AVAILABLE. ISD & START DATE DEF. 2 YRS. REFLECTS REVISED INT AND ESC RATES. EST INCREASE DUE TO CHANGE FROM 4 TO 5 BREAKERS.
1989 10	23 960	PROJ ADVANCED BY 2 YEARS. CASH FLOW REFINED AND ISD'S CHANGED TO COINCIDE WITH WUSKWATIM G.S.
1990 05	18 589	ISD ADVANCED 5 YEARS.
1990 10	20 306	MAT. AND LABOUR EST INCREASED. PROJ. DEFERRED ONE YEAR.
1991 10	20 314	FST REMOVED FROM ALL MATL. ENGINEERING ESTM. REDUCED. ISD DEFERRED TO 2013 FROM 2008.
1992 10	14 561	ISD ADVANCED TO 2010 FROM 2013.
1993 03	14 000	ISD ADVANCED TO 2009 FROM 2010.
1993 10	13 661	STALL LAKE STATION NAME CHANGED TO HERBLET LAKE. ENVRNMNTL. ACTIVITIES ADDED. ISD DEFERRED 1 YR TO 2010 10 01. STRT DT ADVNCD 1 YR
1994 10	12 671	ISD DEFERRED 1 YR TO 2011 10 01. RVSD INTRST & ESCLTN RATES.
1995 10	12 702	REVISED INTEREST AND ESCALATION RATES
1996 10	13 951	ISD DEFERRED FOUR YEARS FROM 2011 TO 2015.
1997 10	14 602	ISD DEFERRED 1 YEAR FROM 2015 TO 2016. REFLECTS INTEREST AND ESCALATION RATES.
1998 10	14 047	BASED ON THE 1998 POWER RESOURCE PLAN STUDIES, ISD ADVANCED TWO YEARS FROM 2016 TO 2014.

ASSOCIATED PROJECTS

Budget reference number	Description
02-00-6152	WUSKWATIM G.S. - WUSKWATIM SWITCHING STN. 230 KV LINES
02-00-7005	WUSKWATIM - HERBLET LAKE 230 KV T/L
03-00-5301	HERBLET LAKE TERMINATE WUSKWATIM 230 KV T/L
03-00-8111	GRAND RAPIDS LINE REACTOR CIRCUIT SWITCHERS
05-00-5131	COMMUNICATIONS FOR WUSKWATIM 230 KV T/L

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item

114

Title
GRAND RAPIDS LINE REACTOR CIRCUIT SWITCHERS

Budget reference number
03-00-8111

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	70230

DESCRIPTION:
INSTALL 2-230KV CIRCUIT SWITCHERS ON THE LINE REACTORS OF 230KV CIRCUITS G8P AND G9F.

JUSTIFICATION:
ELSEWHERE IN THE BUDGET JUSTIFICATION IS GIVEN FOR CONSTRUCTION OF WUSKWATIM GENERATING STATION. THIS ITEM PROVIDES FOR ASSOCIATED TRANSMISSION FACILITIES AT GRAND RAPIDS TO PROVIDE REQUIRED SYSTEM VOLTAGE CONTROL.

REFERENCE:
G&TP REPORT 88-07 'TRANSMISSION REQUIREMENTS FOR WUSKWATIM G.S. PRELIMINARY STUDIES'.

REVISION:
BASED ON THE 1999 POWER RESOURCE PLAN STUDIES, ISD DEFERRED TWO YEARS FROM 2014 TO 2016. REFLECTS REVISED ACTIVITY AND OVERHEAD RATES.

CONTINGENCY: $133,000

IN SERVICE DATES		Base estimate
2016 11 30	1 145	199706 L2
2017 02 28	1 146	Work start date
		2014 04 01

	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
PREV. AUTHORITY Authorized to date:						
2012/13	136	49	8			193
2013/14	721	277	63			1 061
2014/15	523	214	119			856
TOTAL	1 380	540	190			2 110
REV. AMOUNTS:						
Authorized to date:						
Over(under)expend:						
Auth 2014/15	157	62	10			229
Req. 2015/16	758	323	70			1 151
2016/17	534	242	135			911
TOTAL	1 449	627	215			2 291

Prepared by: yy mm dd COORDINATOR — Approved by: yy mm dd Approved by: yy mm dd

Estimated by: ORIGINATOR — COORDINATING MANAGER — ORIGINATING MANAGER

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 03-00-8111

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1985 11	11 402	DEFERRED BY 1 YEAR TO COINCIDE WITH REVISED WUSKWATIM ISD. CONCEPT CHANGE.
1985 12	20 815	ISD DEFERRED TO 2012 FROM 1997.
1986 12	17 849	ISD ADVANCED 3 YEARS BASED ON REPORT PSPD 86-05.
1987 11	20 343	PROJECT ISD DEFERRED FROM 2009 TO 2012.
1988 11	17 565	ISD & S.D. DEFERRED 2 YEARS CST DEC DUE TO REMOVAL OF EQUIPMENT.
1989 10	15 640	PROJECT ADVANCED 2 YEARS. ISD CHANGED TO COINCIDE WITH WUSKWATIM G.S.
1990 05	12 135	ISD ADVANCED 5 YEARS.
1990 10	13 170	MATERIAL & LABOUR ESTIMATE INCREASED. PROJECT DEFERRED 1 YEAR.
1991 10	13 841	FST REMOVED FROM ALL MATERIAL.
1992 10	10 180	ISD ADVANCED TO 2010 FROM 2013.
1993 03	9 787	ISD ADVANCED TO 2009 FROM 2010.
1993 10	2 162	TERMINATION OF PONTON 230KV LINE TRANSFERRED TO MANASAN TRANS COMP BRN# 03-00-1696. ISD DEFERRED 1 YEAR TO 2010 10 01.
1994 10	1 961	ISD DEFERRED 1 YEAR TO 2011 10 01.
1995 10	1 968	REVISED INTEREST AND ESCALATION RATES.
1996 06	2 160	ISD DEFERRED 4 YEARS FROM 2011 TO 2015.
1997 10	2 182	ISD DEFERRED 1 YEAR FROM 2015 TO 2016 USING WUSKWATIM G.S. 2 UNIT DESIGN.
1998 10	2 110	BASED ON THE 1998 POWER RESOURCE PLAN STUDIES, ISD ADVANCED TWO YEARS FROM 2016 TO 2014.

ASSOCIATED PROJECTS

Budget reference number	Description
02-00-6152	WUSKWATIM G.S. - WUSKWATIM SWITCHING STN. 230 KV LINES
02-00-7005	WUSKWATIM - HERBLET LAKE 230 KV T/L
03-00-5301	HERBLET LAKE TERMINATE WUSKWATIM 230 KV T/L
03-00-7080	WUSKWATIM SWITCHING STATION 230 KV TERMINATIONS
05-00-5131	COMMUNICATIONS FOR WUSKWATIM 230 KV T/L

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item __ Domestic Item

115

Title: HERBLET LAKE TERMINATE WUSKWATIM 230 KV T/L

Budget reference number: 03-00-5301

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	70231

DESCRIPTION:
EXPAND HERBLET LAKE 230KV STATION TO TERMINATE 230KV WUSKWATIM-HERBLET LAKE LINE. INSTALLATION INCLUDES 1 - 230KV CIRCUIT BREAKER, 1-30 MVAR 230KV LINE REACTOR WITH CIRCUIT SWITCHER AND ASSOCIATED EQUIPMENT.
MODIFY PROTECTION EQUIPMENT AT HERBLET LAKE TO CO-ORDINATE WITH CREATION OF HERBLET LAKE - WUSKWATIM 230KV LINE FROM SECTIONALIZATION OF THOMPSON BIRCHTREE - HERBLET LAKE 230KV LINE AT WUSKWATIM.

JUSTIFICATION:
ELSEWHERE IN THE BUDGET, JUSTIFICATION IS GIVEN FOR TWO WUSKWATIM - HERBLET LAKE 230KV LINES. THIS ITEM PROVIDES FOR TERMINATION OF LINES AT HERBLET LAKE .

REFERENCE:
G&TP REPORT 88-07 'TRANSMISSION REQUIREMENTS FOR WUSKWATIM G.S. PRELIMINARY STUDIES'.

REVISION:
BASED ON THE 1999 POWER RESOURCE PLAN STUDIES, ISD DEFERRED TWO YEARS FROM 2014 TO 2016. REFLECTS REVISED ACTIVITY AND OVERHEAD RATES.

CONTINGENCY: $349,000

IN SERVICE DATES		Base estimate
2016 11 30	3 002	199706 L2
2017 02 28	3 003	Work start date
		2014 04 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:						
2012/13	256	91	15			362
2013/14	1 955	744	154			2 853
2014/15	1 482	601	313			2 396
TOTAL	3 693	1 486	482			5 611
REV. AMOUNTS:						
Authorized to date:						
Over(under)expend:						
Auth 2014/15	295	117	18			430
Req. 2015/16	2 022	857	170			3 049
2016/17	1 501	675	350			2 526
TOTAL	3 818	1 649	538			6 005

Prepared by: yy mm dd COORDINATOR — Approved by: yy mm dd — Approved by: yy mm dd

Estimated by: ORIGINATOR — COORDINATING MANAGER — ORIGINATING MANAGER

CAPITAL EXPENDITURE REVISION

Budget reference number 03-00-5301

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1984 12	12 273	NEW ITEM.
1985 11	13 540	BASE DATE UPDATED TO 1985. REVISED INTEREST AND ESCALATION RATES. ITEM DEFERRED 1 YEAR DUE TO RVS'D WUSKWATIN ISD. 10% UNALLOCATED ALLOWANCE INCLUDED.
1985 12	24 688	ISD DEFERRED TO 2012 FROM 1997.
1986 12	21 058	REVISED INTEREST AND ESCALATION RATES. TERM OF WUSKWATIN 230KV LINE ADDED.
1987 11	23 710	BASE DATE REVISED TO 1987. ISD DEFERRED FROM 2009 TO 2012.
1988 11	28 014	ISD & START DATE DEFERRED 2 YEARS. REVISED INTEREST AND ESCALATION RATES. WUSKWATIN T/L TERM. ADDITION.
1989 10	24 458	ISD ADVANCED 2 YEARS TO COINCIDE WITH WUSKWATIN G.S.
1990 05	18 992	ISD ADVANCED 5 YEARS.
1990 10	21 211	SALVAGED 115KV PONTON BREAKER FOR STALL LAKE INSTALLATION ADDED. MATERIAL LABOUR ESTIMATES INCREASED. PROJECT DEFERRED 1 YEAR.
1991 10	20 740	FST REMOVED FROM MATERIAL. BREAKER COSTS REDUCED 30%. RELOCATED 230KV LINE REACTOR FROM PONTON TO CLIFF LAKE LINE. ISD DEFERRED TO 2013 FROM 2008.
1992 10	15 264	ISD ADVANCED TO 2010 FROM 2013.
1993 03	1 376	ESTABLISHMENT OF STALL LAKE STATION & TERMINATE OF STALL LAKE 230KV LINES TRANSFERRED TO ANOTHER COMPLEX. ISD ADVANCED 1 YEAR TO 2009 FROM 2010.
1993 10	5 343	STALL LAKE 230KV STATION NAME CHANGED TO HERBLET LAKE. LINE REACTOR ADDED. ISD DEFERRED 1 YEAR TO 2010 10 01.
1994 10	4 846	ISD DEFERRED 1 YEAR TO 2011 10 01. REVISED INTEREST & ESCALATION RATES.
1995 10	5 345	PROTECTION MODIFICATIONS FOR WUSKWATIN 230KV LINE ADDED.
1996 06	6 208	ISD DEFERRED 4 YEARS FROM 2011 TO 2015.
1997 10	5 814	ISD DEFERRED 1 YEAR FROM 2015 TO 2016 USING WUSKWATIM GS 2 UNIT DESIGN.
1998 10	5 611	BASED ON THE 1998 POWER RESOURCE PLAN STUDIES, ISD ADVANCED TWO YEARS FROM 2016 TO 2014.

ASSOCIATED PROJECTS

Budget reference number	Description
02-00-6152	WUSKWATIM G.S. - WUSKWATIM SWITCHING STN. 230 KV LINES
02-00-7005	WUSKWATIM - HERBLET LAKE 230 KV T/L
03-00-7080	WUSKWATIM SWITCHING STATION 230 KV TERMINATIONS
03-00-8111	GRAND RAPIDS LINE REACTOR CIRCUIT SWITCHERS
05-00-5131	COMMUNICATIONS FOR WUSKWATIM 230 KV T/L

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item ___ Domestic Item 116

Title: COMMUNICATIONS FOR WUSKWATIM 230 KV T/L

Budget reference number: 05-00-5131

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
anning & Control	Planning & Control	Construction	70232

DESCRIPTION:
DESIGN, INSTALL, AND COMMISSION COMMUNICATION SYSTEM ADDITIONS REQUIRED FOR THE PROTECTION OF THE WUSKWATIM - THOMPSON BIRCHTREE AND TWO WUSKWATIM - HERBLET LAKE 230KV LINES.

JUSTIFICATION:
POWER LINE CARRIER, PROTECTION TONES AND AGC/SCADA SER EQUIPMENT ARE REQUIRED FOR THE OPERATION AND PROTECTION OF THE 230 KV TRANSMISSION FACILITIES REQUIRED BY THE WUSKWATIM GENERATING STATION.

REFERENCE:
G&TP REPORT 88-07 'TRANSMISSION REQUIREMENTS FOR WUSKWATIM G.S. PRELIMINARY STUDIES'. E&C MEMO, FILE 76, 1992 07 13, R.J. HAMLIN TO V.J. STECIUK: 'WUSKWATIM TRANSMISSION COMMUNICATIONS BUDGET REFERENCE 0905-00-5131'.

REVISION:
BASED ON THE 1999 POWER RESOURCE PLAN STUDIES, ISD DEFERRED TWO YEARS FROM 2014 TO 2016. REFLECTS REVISED ACTIVITY AND OVERHEAD RATES.

CONTINGENCY: $300,000

IN SERVICE DATES

2016 11 30	3 622
2017 02 28	3 620

Base estimate: 199704 L2

Work start date: 2014 01 01

PREV. AUTHORITY Authorized to date:	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
2011/12	67	23	1			91
2012/13	296	107	25			428
2013/14	954	375	77			1 406
2014/15	3 056	1 245	330			4 631
TOTAL	4 373	1 750	433			6 556
REV. AMOUNTS: Authorized to date: Over(under)expend:						
Auth 2013/14	74	28	1			103
Req: 2014/15	326	130	29			485
2015/16	1 049	455	88			1 592
2016/17	3 229	1 452	381			5 062
TOTAL	4 678	2 065	499			7 242

Prepared by: yy mm dd COORDINATOR Approved by: yy mm dd Approved by:

Estimated by: ORIGINATOR COORDINATING MANAGER ORIGINATING MANAGER

CAPITAL EXPENDITURE REVISION

Budget reference number 05-00-5131

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1984 12	3 328	NEW ITEM
1985 11	3 348	ESTIMATE REVIEWED. BASE DATE REVISED FROM 1984 TO 1985.
1985 12	6 671	ISD DEFERRED TO 2012 FROM 1997.
1986 12	5 364	BASE DATE & EST REMAIN UNCHANGED. REVISED INT & ESC RATES.
1987 11	6 156	EST. REVISED TO BASE YR 1987. ISD DEFERRED FR 2009 TO 2012.
1988 11	6 599	BASE DATE & EST. REVISED FR 87 TO 88. REFLECTS REV. INT & ESC RATES. ISD START DATE DEFERRED 2 YRS.
1989 10	6 089	PROJ. ADV 2 YRS. C/F REFINED & ISD CHANGED TO COINCIDE WITH WUSKWATIM G.S.
1990 05	4 775	ISD ADVANCED 5 YEARS.
1990 10	5 081	START DATE DEFERRED 1 YR & 4 MONTHS & C/F REFINED.
1991 10	5 509	ISD DEFERRED TO 2013 FROM 2008.
1992 10	13 275	ISD ADV TO 2010 FR 2103. A COMM. CHANGE OF SCOPE, FR PWR LINE CARRIER TO MICROWAVE RADIO, IS REQUIRED DUE TO AMOUNT OF PROJ. COMM TRAFFIC REQ. FOR THE INCREASED NO. OF T/L & STN. INVOLVED, UPGRADE LINE PROTECTION & MODERN PROTECTION EQUIP.
1993 03	2 562	ADJUSTED COMM. REQ. FOR REDUCED WUSKWATIM TRANS. ISD ADV. 1 YR TO 2009 10 01.
1993 10	6 420	STALL LAKE 230 KV NAME CHANGED TO HERBLET LAKE. ADJUSTED COMM. REQMNTS FOR REDUCED WUSKWATIM TRNSMSSN. ISD DEFERRED 1 YR TO 2010.
1995 10	5 948	REFLECTS NEW ESCALATION AND INTEREST RATES.
1996 10	6 565	ISD DEFERRED FOUR YEARS FROM 2011 TO 2015.
1997 10	6 739	ISD DEFERRED 1 YEAR FROM 2015 TO 2016, USING WUSKWATIM G.S. 2 UNIT DESIGN.
1998 10	6 556	BASED ON THE 1998 POWER RESOURCE PLAN STUDIES, ISD ADVANCED TWO YEARS FROM 2016 TO 2014.

ASSOCIATED PROJECTS

Budget reference number	Description
02-00-6152	WUSKWATIM G.S. - WUSKWATIM SWITCHING STN. 230 KV LINES
02-00-7005	WUSKWATIM - HERBLET LAKE 230 KV T/L
03-00-5301	HERBLET LAKE TERMINATE WUSKWATIM 230 KV T/L
03-00-7080	WUSKWATIM SWITCHING STATION 230 KV TERMINATIONS
03-00-8111	GRAND RAPIDS LINE REACTOR CIRCUIT SWITCHERS

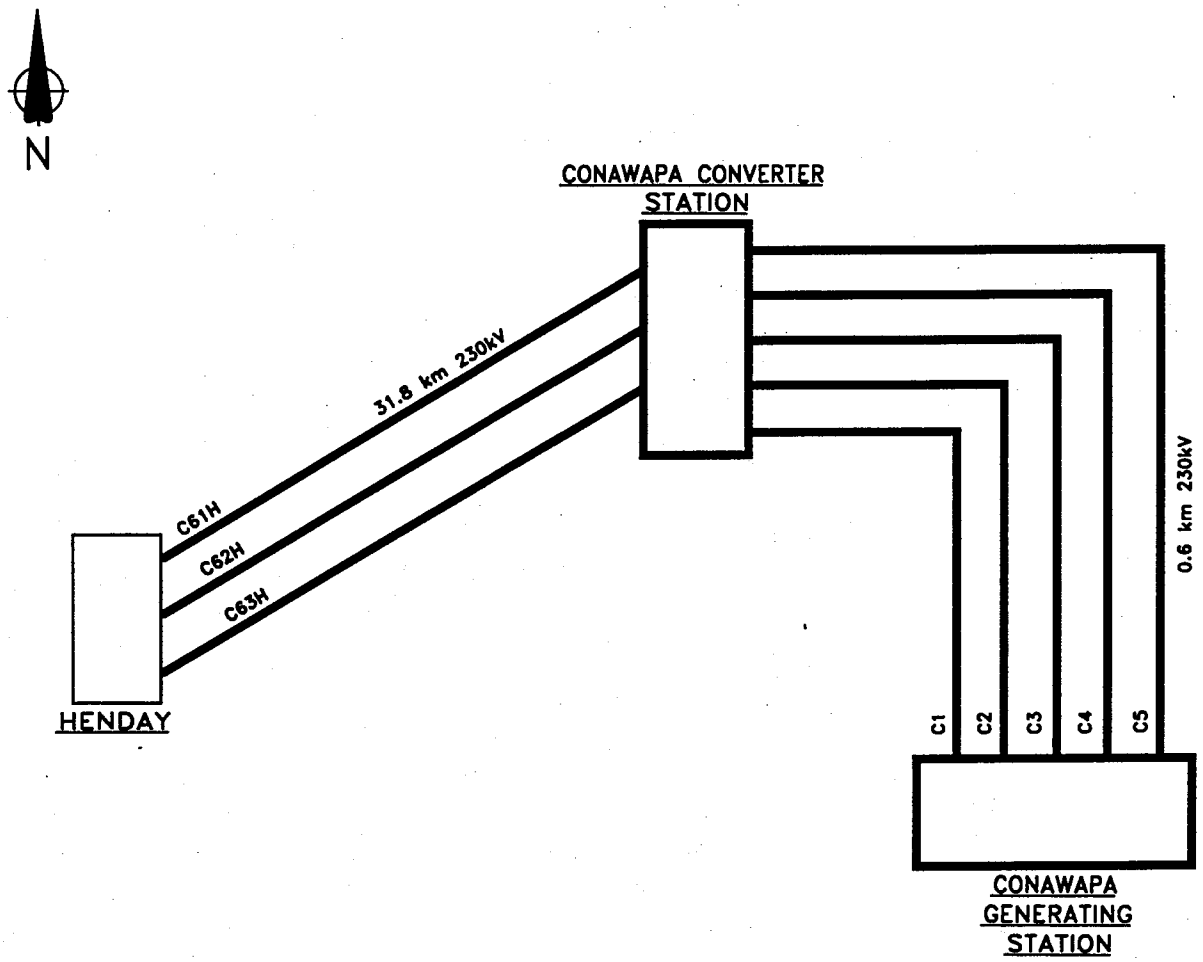
Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

CAPITAL BUDGET COMPLEX CONCEPTUAL DIAGRAM

CONAWAPA TRANSMISSION

REVISED: 1999 - 10 - 01	ISSUED BY: RWM

COMPLEX NO. 262



manitoba hydro

PLANNING AND CONTROL DIVISION

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

COMPLEX STATUS	Complex no.	REVISION STATUS
☒ Planned ☐ In progress	262	☒ New complex ☐ In service change ☐ Concept change ☐ Estimate change only

COMPLEX	CONAWAPA TRANSMISSION

Proposal

Perform environmental assesments and route selection, design and construct transmission and terminal facilities for Conawapa power transfer as follows:
Transmission: 230kV lines 3 - 31.8 KM Henday - Conawapa Converter Station, 5 - 0.6 KM Conawapa Converter Station to Conawapa Generating Station.
Terminations: Extend 230kV facilities at Henday station. Construct new 230kV facilities at Conawapa Converter station.
Communications: Integrate with Northern Collector communication system.

JUSTIFICATION	Explanation
☒ Load ☐ Service ☐ Safety ☐ Efficiency ☐ Reliability ☐ Other	Based on the 1999 Load Forecast, generation expansion studies indicate an additional generation source is required in 2018/19. Conawapa is the current economic choice. Transmission and terminating facilities are necessary to connect this new power source to the Manitoba network.

Estimate Level	COMPLEX START (yyyy mm)
L1	2008 04

IN SERVICE DATES AND AMOUNTS			

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend								
Year 99/00								
00/01								
01/02								
02/03								
03/04								
04/05								
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL								

REVISION	Conawapa reintroduced into the twenty year forecast. Forecast planning estimate is included in complex 263.

Reviewed by	yyyy mm dd	Reviewed by	yyyy mm dd
ORIGINATOR	99 11 08	COORDINATOR	99 11 03
Reviewed by	yyyy mm dd	Approved by	yyyy mm dd
CONSTRUCTOR	99 11 03	VICE PRESIDENT	99 11 16

H2856/r Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Complex no. 262

Advance or deferral impact

Delay in components of this transmission complex will curtail or prevent Conawapa capacity from being delivered to the Manitoba system.

Factors affecting timing or viability

Timing and rating of Conawapa Generating Station.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Conawapa GS - Conawapa Converter Stn 230kV T/L				1,058	1,058	
Henday - Conawapa Converter Stn 230kV T/L				20,438	20,438	
Henday Termination of Conawapa 230kV T/L						
Conawapa Converter Station						
Conawapa Transmission Telecontrol Facilities						
TOTAL				21,496	21,496	

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
1999 10	1,896,222	Conawapa reintroduced into the twenty year forecast. Forecast planning estimate is included in complex 263.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

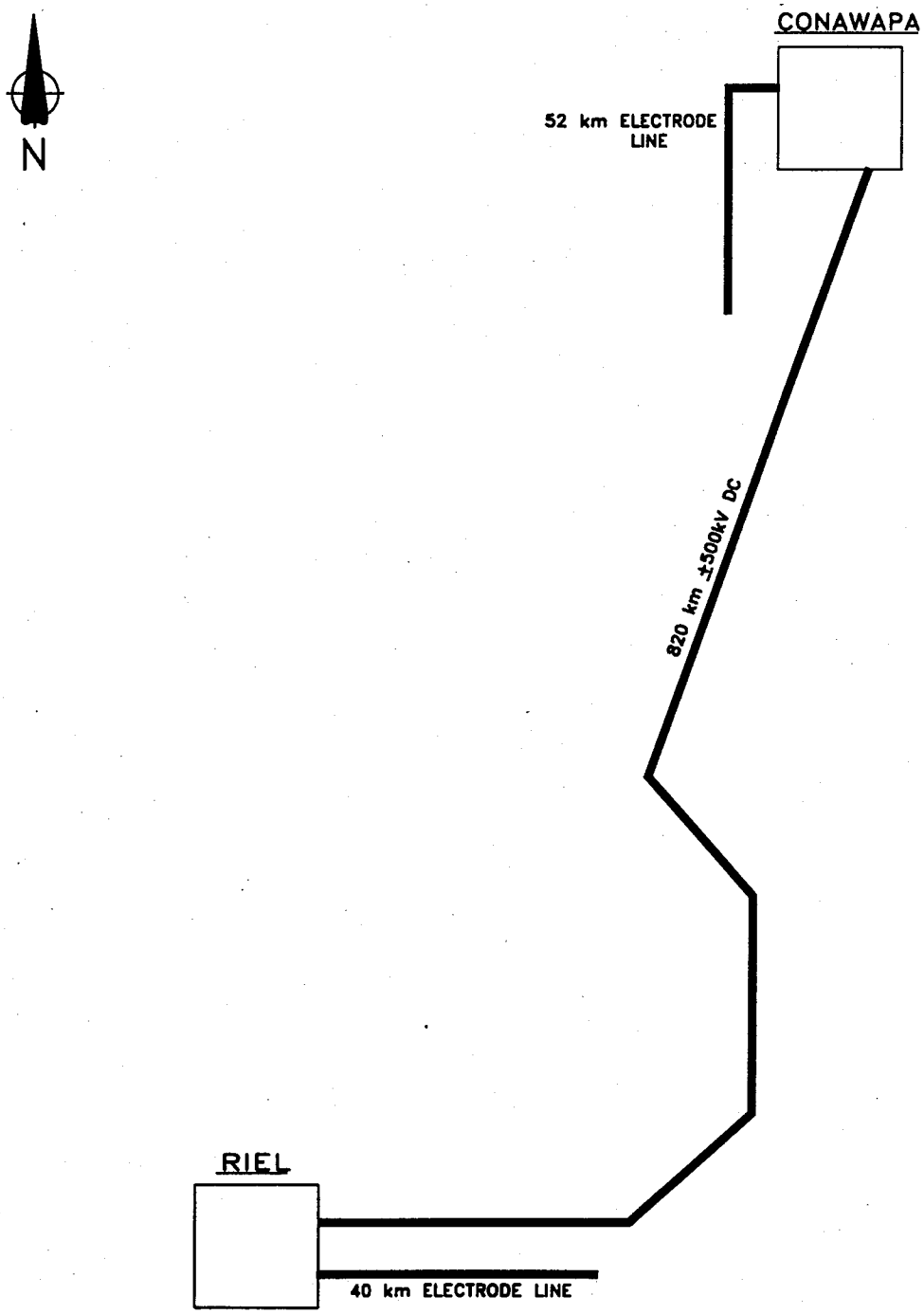
REFERENCE NUMBER	DESCRIPTION
264	Conawapa Generating Station
263	HVDC Bipole 3
265	Riel > Winnipeg AC Transmission
266	Dorsey > Riel 500kV AC T/L

CAPITAL BUDGET COMPLEX CONCEPTUAL DIAGRAM

HVDC CONVERSION
BIPOLE 3

REVISED: 1999 - 10 - 01	ISSUED BY: RWM

COMPLEX NO. 263



manitoba hydro

PLANNING AND CONTROL DIVISION

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

COMPLEX STATUS: [X] Planned [ ] In progress

Complex no. 263

REVISION STATUS: [X] New complex [ ] In service change [ ] Concept change [ ] Estimate change only

COMPLEX: HVDC BIPOLE 3

Proposal

Preform environmental assessments and route selection, design and construct transmission and terminal facilities to accomodate treansfer of Nelson River power to the Southern Manitoba system as follows:
Transmission: 51 KM DC Electrode line fron Conawapa Converter station to existing Electrode station. 40 KM DC electrode line from Riel to a new Electrode station.
Terminations: Construct Bipole 3 HVDC 1300 MW (with 50% overload capability) +/-500 kV stations at Conawapa and Riel. Extend 230 kV facilities at Henday station. Construct new 230kV station at Riel, including 3 - 300 MVAR Synchronous Condensers.
Communications: Fibre Optic or Microwave system.

JUSTIFICATION: [X] Load [ ] Service [ ] Safety [ ] Efficiency [X] Reliability [ ] Other

Explanation

Based on the 1999 Load Forecast, generation expansion studies indicate an additional generation source is required in 2018/19. Conawapa is the current economic choice. Bipole 3 facilities are necessary to connect this new power source to the Manitoba network.

Estimate Level	COMPLEX START (yyyy mm)
L1	2008 04

IN SERVICE DATES AND AMOUNTS

2019	$948111	2020	$758489	2021	$189622

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend								
Year 99/00								
00/01								
01/02								
02/03								
03/04								
04/05								
05/06								
06/07								
07/08								
08/09	2,480		104		2,584		2,584	
09/10	8,579		634		9,213		9,213	
10/11	13,490		1,790		15,280		15,280	
11/12	12,443		3,350		15,793		15,793	
12/13	35,379		6,116		41,495		41,495	
13/14	44,776		10,483		55,259		55,259	
14/15	193,763		22,033		215,796		215,796	
15/16	361,473		50,936		412,409		412,409	
16/17	412,938		96,409		509,347		509,347	
17/18	230,269		142,423		372,692		372,692	
18/19	55,524		131,160		186,684		186,684	
Beyond	0		59,670		59,670		59,670	
TOTAL	1,371,114		525,108		1,896,222		1,896,222	

REVISION: Bipole 3 reintroduced into the twenty year forecast.This complex captures all costs associated with Bipole 3, Conawapa transmission & related AC southern system additions.

Reviewed by ORIGINATOR	yyyy mm dd 99 11 05	Reviewed by COORDINATOR	yyyy mm dd 99 11 03
Reviewed by CONSTRUCTOR	yyyy mm dd 99 11 03	Approved by VICE PRESIDENT	yyyy mm dd 99 11 03

H2856/r Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Complex no. 263

Advance or deferral impact

Delay in components of this transmission complex will curtail or prevent Conawapa capacity from being delivered to the Manitoba system.

Factors affecting timing or viability

Timing and rating of Conawapa Generating Station.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE	
					Amount	%
Conawapa Bipole 3 Electrode Line						
Riel Biploe 3 Electrode Line						
Conawapa - Riel +/- 500kV DC T/L						
Riel Station Bipole 3						
Conawapa Station Bipole 3						
Riel Station Var Compensation						
Bipole 3 Telecontrol Facilities						
TOTAL						

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
1999 10	1,896,222	Bipole 3 reintroduced into the twenty year forecast.This complex captures all costs associated with Bipole 3, Conawapa transmission & related AC southern system additions.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION
264	Conawapa Generating Station
262	Conawapa Transmission
265	Riel > Winnipeg Transmission
266	Dorsey > Riel 500kV AC T/L

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

COMPLEX STATUS: [X] Planned [ ] In progress

Complex no. 265

REVISION STATUS: [X] New complex [ ] In service change [ ] Concept change [ ] Estimate change only

COMPLEX: RIEL - WINNIPEG AC TRANSMISSION

Proposal

Design and construct transmission and terminal facilities to accommodate transfer of power from Bipole 3 to the Southern Manitoba system as follows:
Transmission: Sectionalize 230kV St Vital Ridgeway lines and extend into Riel Station. Terminate pre-strung 230kV line from Riel to St Vital at those stations, resulting in 230kV lines from Riel to Ridgeway and 230kV lines from Riel to St Vital.
Terminations: Extend 230kV facilities at Riel and St Vital stations.
Communications: Intergrate with Riel - St Vital - Ridgeway area system.

JUSTIFICATION

[X] Load [ ] Service
[ ] Safety [ ] Efficiency
[X] Reliability [ ] Other

Explanation

These facilities connect HVDC Bipole 3 to the Manitoba 230kV network in the Winnipeg area. They provide flexibility of power supply to Winnipeg from Bipole 3 during normal conditions and contingencies.

Estimate Level	COMPLEX START yyyy mm

IN SERVICE DATES AND AMOUNTS			

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend								
Year 99/00								
00/01								
01/02								
02/03								
03/04								
04/05								
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL								

REVISION: Riel - Winnipeg AC Transmission reintroduced into the twenty year forecast. Forecast planning estimate is included in complex 263.

Reviewed by ORIGINATOR	yyyy mm dd 99 11 08	Reviewed by COORDINATOR	yyyy mm dd 99 11 03
Reviewed by CONSTRUCTOR	yyyy mm dd 99 11 03	Approved by VICE PRESIDENT	yyyy mm dd 99 11 16

H2856/r Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Complex no. 265

Advance or deferral impact

This transmission is required to connect HVDC Bipole 3 230kV AC facilities at Riel station to the Manitoba southern system. Delays of these facilities will prevent power from Bipole being delivered to the southern Manitoba system.

Factors affecting timing or viability

Change in HVDC Bipole 3
Manitoba Load

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE	
					Amount	%
Riel-St Vital & Riel-Ridgeway 230kV T/L						
St Vital 230kV Line Termination & Protection Changes						
Ridgeway Protection Changes						
Riel 230kV Stn-Term. of St Vital & Ridgeway Lines						
Riel-St Vital-Ridgeway 230kV Telecontrol						
TOTAL						

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
1999 10		Riel - Winnipeg AC Transmission reintroduced into the twenty year forecast. Forecast planning estimate is included in complex 263.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

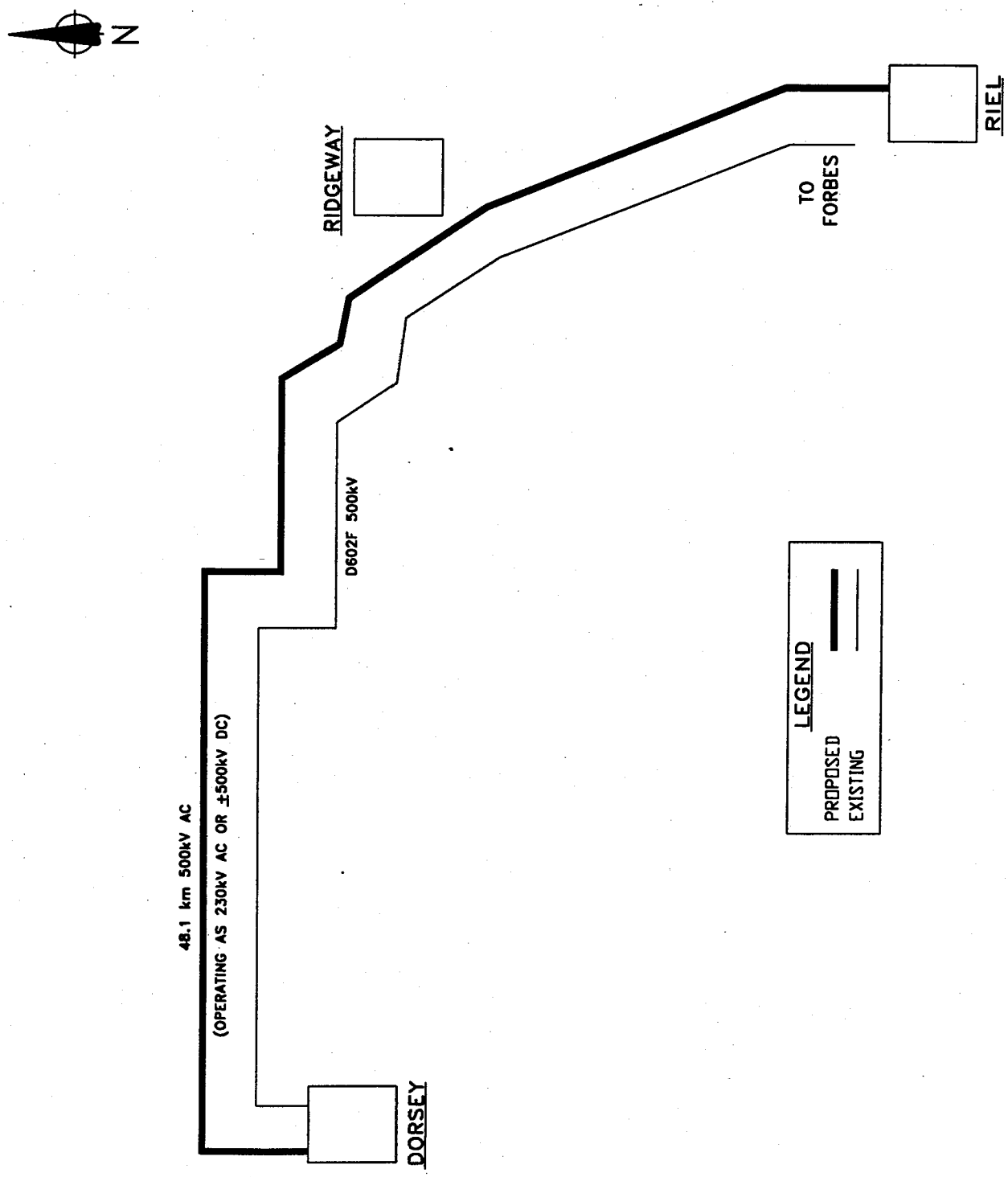
REFERENCE NUMBER	DESCRIPTION
264	Conawapa Generating Station
262	Conawapa Transmission
263	HVDC Biploe 3
266	Dorsey > Riel 500kV AC T/L

CAPITAL BUDGET COMPLEX CONCEPTUAL DIAGRAM

DORSEY–RIEL 500kV AC TRANSMISSION

REVISED: 1999 - 10 - 01	ISSUED BY: RWM

COMPLEX NO. 266



manitoba hydro

PLANNING AND CONTROL DIVISION

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

COMPLEX STATUS: [X] Planned [ ] In progress

Complex no. 266

REVISION STATUS: [X] New complex [ ] In service change [ ] Concept change [ ] Estimate change only

COMPLEX: DORSEY - RIEL 500kV AC T/L

Proposal

Design and construct transmission and terminal facilities to firm up supply to stations in east Winnipeg, and provide for paralleling of Dorsey and Riel HVDC convertors during emergencies in the future as follows:

Transmission: 500kV line (initially operated at 230kV) 48.1 KM Dorsey - Riel.
Terminations: 230kV circuit breakers at Dorsey and Riel stations. 500kV DC high speed switches at Dorsey and Riel Station. The switches will allow connection of the Dorsey - Riel line to Bipoles 2 and 3 to perform parallel operation of the bipoles.
Communications: Intergrated with existing facilities at Dorsey and Riel.

JUSTIFICATION

[X] Load [ ] Service
[ ] Safety [ ] Efficiency
[X] Reliability [ ] Other

Explanation

This line will initially operate at 230kV to supply to east Winnieg stations from Dorsey via Riel station. The 500kV switches on the Dorsey - Riel 500kV AC line will permit parallel operation of Bipoles 2 and 3 under emergency conditions involving loss of any HVDC line from the north, increasing system reliability.

Estimate Level	COMPLEX START yyyy mm

IN SERVICE DATES AND AMOUNTS			

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend								
Year 99/00								
00/01								
01/02								
02/03								
03/04								
04/05								
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL								

REVISION: Dorsey - Riel 500kV AC Transmission reintroduced into the twenty year forecast. Forecast planning estimate is included in complex 263.

Reviewed by ORIGINATOR	yyyy mm dd 99 11 08	Reviewed by COORDINATOR	yyyy mm dd 99 11 03
Reviewed by CONSTRUCTOR	yyyy mm dd 99 11 03	Approved by VICE PRESIDENT	yyyy mm dd 99 11 3[illegible]

H2856/r Rev 99 03

Complex no. 266

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Advance or deferral impact

This transmission is required for supply to stations in east Winnipeg, and for HVDC paralleling. Deferrel will result in overloads or curtailment of load during outages of Winnipeg area AC lines, and reduce HVDC operating reliability.

Factors affecting timing or viability

Manitoba Load.
HVDC Bipole3

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE	
					Amount	%
Dorsey - Riel 500kV T/L						
Dorsey - AC Termination of 500kV line from Riel						
Riel - AC Termination of 500kV line from Dorsey						
Dorsey - DC Termination of 500kV line from Riel						
Riel - DC Termination of 500kV line from Dorsey						
Dorsey - Riel 500kV Telecontrol						
TOTAL						

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy mm	TOTAL AMOUNT	AMENDMENT
1999 10		Dorsey - Riel 500kV AC Transmission reintroduced into the twenty year forecast. Forecast planning estimate is included in complex 263.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION
264	Conawapa Generating Station
262	Conawapa Transmission
263	HVDC Bipole 3
265	Riel > Winnipeg AC Transmission

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

COMPLEX STATUS: ☐ Planned ☒ In progress

Complex no. 95

REVISION STATUS: ☐ New complex ☐ In service change ☒ Concept change ☐ Estimate change only

COMPLEX: 200 MW ONTARIO HYDRO SALE - TRANSMISSION UPGRADE

Proposal

Design and construct terminal facilities to accommodate 200 MW Ontario Hydro Sale as follows:

Transmission: Investigate current carrying capacity of sections of 115 KV lines GT1 & ST2 extending from Great Falls to Seven Sisters. Refurbish lines as required to support high load currents.
Terminations: Reconductor line end spans of parallel double circuit 115 KV line WT34 at Whiteshell and Transcona stations to accommodate increased line current.
Stations: Replace bank 8 115kV phase shifting transformer at Whiteshell station and make site improvements to upgrade drainage and oil containment for bank 7 & 8.

JUSTIFICATION: ☐ Load ☐ Service ☐ Safety ☐ Efficiency ☐ Reliability ☒ Other

Explanation

Line GT1 & ST2 refurbishment and line WT34 end span reconductoring permit high current loading of supply lines into Seven Sisters to maintain Ontario export during low Winnipeg River generation and line outages. A new phase-shifting transformer is required to ensure maximum benefits during the 200 MW Ontario Hydro sale.

Estimate Level	COMPLEX START (yyyy mm)
L2-3	1995 05

IN SERVICE DATES AND AMOUNTS

1998 09	$3803	1998 10	$170	1998 11	$35	1998 12	($240)
1999 01	$12	1999 02	$13	1999 03	$159	1999 04	$103
1999 06	$477	1999 09	$2901				

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	6,291		378	2,214	4,455	4,471	-16	-0
Year 99/00	720	18	25		763		763	
00/01								
01/02								
02/03								
03/04								
04/05								
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	7,011	18	403	2,214	5,218	4,471	747	17

REVISION: Reflects increased costs due to mild winter and high water table, and higher complexity of phase shifter control replacement.

Reviewed by ORIGINATOR	yyyy mm dd 99 11 01	Reviewed by COORDINATOR	yyyy mm dd 99 11 03
Reviewed by CONSTRUCTOR	yyyy mm dd 99 11 03	Approved by VICE PRESIDENT	yyyy mm dd 99 11 16

H2856/r Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Complex no. 95

Advance or deferral impact

The proposed modifications are required to accommodate the 200 MW firm power sale to Ontario Hydro starting in 1998. Deferral would prevent delivery of contracted capacity during contingencies.

Factors affecting timing or viability

200 MW Ontario Sale Agreement.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Whiteshell>Transcona 110KV Reconductor WT34 Ends	104	77	79	104	25	32
Winnipeg River & Winnipeg 110KV T/L Refurbishmnt	465	459	468	422	-46	-10
Whiteshell Replace Bk 8 115kV Phase Shifting Transf	5,883	5,805	5,921	6,485	564	10
TOTAL	6,452	6,341	6,468	7,011	543	8

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
9510	2,662	Line refurbishment costs based on re-sagging conductors. Line refurbishment advanced 19 months and generator mods advanced 1 yr to co-ordinate with other work schedules.
9610	682	110 KV T/L refurbishment deferred 6 months to 1997 09 30. Cost est. decreases due to detailed field survey. Gen. synch. condenser conversion transferred to complex # 224
9710	4,052	Replace bank 8 115kV phase shifting transformer at Whiteshell station and make site improvements to upgrade drainage and oil containment for bank 7 & 8.
9810	4,471	Reflects 97/98 underexpend 0.5M, add'n of a phase shift'g transf, fibre optics, spare bushings, overload studies, more complex control work, inc const costs , + updated estimate bases.
1999 10	5,218	Reflects increased costs due to mild winter and high water table, and higher complexity of phase shifter control replacement.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item

117

Title			Budget reference number
WHITESHELL-TRANSCONA 110KV RECONDUCTOR WT34 END SECTIONS			02-00-5959
Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	70277

DESCRIPTION:
REPLACE 0.122 KM OF 336.4 MCM ACSR AT TRANSCONA END AND 0.067 KM OF 336.4 MCM ACSR AT WHITESHELL END OF 110 KV LINE WT34 WITH 795 MCM ACSR CONDUCTOR. REFURBISH THESE LINE SECTIONS TO ENSURE SUFFICIENT GROUND CLEARANCE FOR OPERATION TO A MAXIMUM CONDUCTOR TEMPERATURE OF 100 DEGREES C.

JUSTIFICATION:
FOR 200 MW SALE TO ONTARIO HYDRO WITH LOW WINNIPEG RIVER GENERATION AND NO CONTINGENCY, LINE WT34 BECOMES OVERLOADED. OVERLOADING IS CAUSED BY TWO PARALLEL CIRCUITS OF WT34 TERMINATING INTO SINGLE 336.4 MCM CONDUCTORS AT EITHER END OF LINE. THIS ITEM PROVIDES FOR RELIEVING LINE END OVERLOADS BY INSTALLING HIGHER CURRENT CAPACITY CONDUCTOR ON EACH END.

REFERENCE:
MANITOBA-ONTARIO POWER CONTRACT STUDY-PHASE II TRANSMISSION STUDY REPORT, NOVEMBER 1987. ELECTRICITY SALE AGREEMENT BETWEEN MHEB AND ONTARIO HYDRO, AUGUST 28, 1987. REPORT PSPD 94-1, 'SYSTEM IMPROVEMENTS TO SUPPORT 200 MW SALE TO ONTARIO HYDRO IN 1998'.

REVISION:
ITEM COMPLETE.

IN SERVICE DATES				Base estimate
1998 10 31	99	1999 02 28	-2	199804 L3
1998 11 30	6	1999 03 31	-0	
1998 12 31	0	1999 04 30	-0	Work start date
1999 01 31	2			1998 04 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:	104		1			105
1999/00	-27					-27
TOTAL	77		1			78
REV. AMOUNTS:						
Authorized to date:	104		1			105
Over(under)expend:						
Auth Req.:						
TOTAL	104		1			105

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 02-00-5959

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1994 10	31	NEW ITEM. TRANSFERRED FROM DOMESTIC BRN 9802-00-9212. ADDED MINIMUM GROUND CLEARANCE REQUIREMENTS.
1995 10	50	TRANSCONA END NOW INCLUDES PREVIOUSLY UNESTIMATED INTERMEDIATE STRUCTURE IN TERMINATION SPAN.
1996 10	53	ESTIMATE INCLUDES RISERS AT TRANSCONA AND WHITESHELL STATIONS.
1997 10	63	SCOPE UNCHANGED, ESTIMATE REFLECTS REVISED COSTING METHODOLOGY IMPLEMENTED WITH THE NEW FINANCIAL REPORTING SYSTEM.
1998 10	79	BASE ESTIMATE REVISED TO 1998. CONTINGENCY ADDED.
	13,000	

ASSOCIATED PROJECTS

Budget reference number	Description
02-00-5960	WINNIPEG RIVER AND WINNIPEG 110KV T/L REFURBISHMENT (WPGRTL)
03-00-8295	WHITESHELL - REPLACE BANK 8 115KV PHASE SHIFTING TRANSFORMER

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item

118

Title			Budget reference number
WINNIPEG RIVER AND WINNIPEG 110KV T/L REFURBISHMENT (WPGRTL)			02-00-5960
Originating division Planning & Control	Coordinating division Operating & Maintenance	Constructing division Construction	Project Order Group (Range): 60004

DESCRIPTION:
INVESTIGATE CURRENT CARRYING CAPACITY OF FOLLOWING 110 KV TRANSMISSION LINES. WHERE REQUIRED, REFURBISH THESE LINES TO SECURE SUFFICIENT GROUND CLEARANCE FOR LINE OPERATION AT A MAXIMUM CONDUCTOR TEMPERATURE OF 100 DEGREES C: LINE GT1-GREAT FALLS STN TO GT1/ST2 JUNCTION, EXCLUDING TRANSCONA-BEAUSEJOUR LINE SECTION. LINE ST2-SEVEN SISTERS STN TO GT1/ST2 JUNCTION, EXCLUDING TRANSCONA-BEAUSEJOUR LINE SECTN. NOTE: 110 KV LINES TR5, TV1, TV2 AND YH33 IN WINNIPEG AREA MUST ALSO BE REFURBISHED TO 100 DEGREES C. CAPACITY BY SAME ISD AS LINES GT1 AND ST2. REQUIRED REFURBISHMENT OF THESE LINES IS TO BE COMPLETED UNDER BRN --02-00-1259, WINNIPEG 230 AND 110KV NETWORK T/L REFURBISHMENT, PRIOR TO ISD OF THIS ITEM.

JUSTIFICATION:
TRANSMISSION LINES BUILT IN WINNIPEG-WHITESHELL AREA PRIOR TO 1970 WERE DESIGNED TO MAINTAIN MINIMUM GROUND CLEARANCE AT A MAXIMUM CONDUCTOR TEMPERATURE OF 50 DEGREES C. THE CURRENT LEVELS ON INDICATED LINES WHEN SERVING DOMESTIC LOAD AND 200 MW SALE TO ONTARIO HYDRO REQUIRES OPERATION UP TO A MAXIMUM CONDUCTOR TEMPERATURE OF 100 DEGREES C. THIS ITEM PROVIDES FOR REFURBISHMENT OF THESE LINES TO ENSURE SAFE OPERATING GROUND CLEARANCE.

REFERENCE:
REPORT PSPD 94-1, SYSTEM IMPROVEMENTS TO SUPPORT THE 200 MW SALE TO ONTARIO.

REVISION:
TO REFLECT ACTUAL COSTS OF PROJECT.

IN SERVICE DATES					Base estimate
1998 12 31	487	1999 04 30	20		199705 L3
1999 01 31	-1				Work start date
1999 02 28	-1				1995 05 01
1999 03 31	-0				

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:	421		83	-20		484
1999/00	31					31
TOTAL	452		83	-20		515
REV. AMOUNTS:						
Authorized to date:	421		83	-20		484
Over(under)expend:						
Auth 1999/00 Req.:	1					1
TOTAL	422		83	-20		485

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 02-00-5960

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1994 10	740	NEW ITEM
1995 10	836	ESTIMATE REVISED BASED ON RE-SAGGING THE CONDUCTORS. NO PROVISION IS MADE FOR REINFORCING TOWER STEELS OR RE-CONDUCTORING.
1996 10	589	ISD DEFERRED FROM 97 03 31 TO 97 09 30. DETAILED ESTIMATES BASED ON FIELD SURVEY. ORIGINAL ESTIMATES WERE BASED ON COST PER MILE. NEW WALL BUSHINGS AT SEVEN SISTERS G.S.

ASSOCIATED PROJECTS

Budget reference number	Description
02-00-5959	WHITESHELL-TRANSCONA 110KV RECONDUCTOR WT34 END SECTIONS
03-00-8295	WHITESHELL - REPLACE BANK 8 115KV PHASE SHIFTING TRANSFORMER

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	1					1	1
May							1
Jun							1
Jul							1
Aug							1
Sep							1
Oct							1
Nov							1
Dec							1
Jan							1
Feb							1
Mar							1
TOTAL	1					1	1
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item

119

Title			Budget reference number
WHITESHELL - REPLACE BANK 8 115KV PHASE SHIFTING TRANSFORMER			03-00-8295
Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	70463:70506

DESCRIPTION:
PURCHASE AND INSTALL A NEW 115KV 200 MVA PHASE-SHIFTING TRANSFORMER TO REPLACE THE EXISTING BANK 8 PHASE-SHIFTING TRANSFORMER AT WHITESHELL. REPLACE EXISTING BANK 7 AND BANK 8 PHASE-SHIFTER CONTROLS. MAKE SITE IMPROVEMENTS TO UPGRADE DRAINAGE IN THE STATION AND PROVIDE OIL CONTAINMENT FOR BANK 7 AND BANK 8.

JUSTIFICATION:
IN ORDER TO ENSURE A RELIABLE TRANSMISSION INTERFACE WITH ONTARIO HYDRO AND TO ENSURE MAXIMUM BENEFITS FROM THIS INTERFACE DURING THE 200MV SALE (1998-2003), A NEW PHASE-SHIFTING TRANSFORMER SHOULD BE INSTALLED TO REPLACE THE EXISTING BANK 8 PHASE-SHIFTING TRANSFORMER. THE BANK 7 PHASE-SHIFTING TRANSFORMER HAS FAILED AND IS CURRENTLY UNDER REPAIR AT THE ABB FACILITY IN GUELPH. THE BANK 8 TRANSFORMER IS SUBJECT TO A SIMILAR FAILURE, AND MUST BE REPAIRED OR REPLACED PRIOR TO THE START OF THE SALE. THE COST OF REPAIR AND THE RISK OF INCREASED COSTS TO EXPEDITE THE REPAIR OF BANK 8 SO IT IS AVAILABLE PRIOR TO THE START OF THE SALE, MAKES THE PURCHASE OF A NEW PHASE-SHIFTING TRANSFORMER MORE ECONOMICALY VIABLE AND LOWER RISK ALTERNATIVE. THE EXISTING CONTROLS EMPLOY OLD TECHNOLOGY FOR WHICH SPARE PARTS ARE NO LONGER AVAILABLE. ADDITIONALLY, MODIFICATIONS REQUIRED TO PROVIDE OPERATING FLEXIBILITY, AND TO ACCOMMODATE THE NEW SCADA SYSTEM ARE NOT FEASIBLE. SITE IMPROVEMENTS ARE REQUIRED TO IMPROVE STATION DRAINAGE AS SPRING SNOW MELT HAS CAUSED FLOODING OF THE CONTROL BUILDING WHICH COULD RESULT IN SHUTDOWN OF THE STATION, AND ALSO RESULTS IN A HIGH WATER TABLE IN THE STATION WHICH IS A HAZARD TO PERSONNEL DOING ROUTINE SWITCHING. OIL CONTAINMENT IS REQUIRED TO MEET FEDERAL AND PROVINCIAL LEGISLATION AND MANITOBA HYDRO GUIDELINES AS DETERMINED IN THE OIL CONTAINMENT ASSESSMENT REPORT PREPARED BY ACRES-WARDROP.

REFERENCE:
MEMO, T.E. TYMOFICHUK TO F.A. MACATAVISH 97 04 29, 'REPLACEMENT OF WHITESHELL PHASE SHIFTER BANK 8.'

REVISION:
REFLECTS REVISED ACTIVITY AND OVERHEAD RATES. CONTINGENCY HAS BEEN REMOVED. MILD WINTER WEATHER AND SOFT SOIL CONDITIONS CAUSED TRANSFORMER MOVE DIFFICULTIES INCREASING CONSTRUCTION COSTS; HIGH WATER TABLE CAUSED FOUNDATION MOVEMENT RESULTING IN RELEVELLING OF RAD BANK FOUNDATION REQUIREMENTS; PHASESHIFTER CONTROL REPLACEMENT MORE COMPLEX THAN ORIGINALLY ESTIMATED.

IN SERVICE DATES						Base estimate
1998 09 30	3 803	1999 01 31	11	1999 06 30	477	199803 L4
1998 10 31	71	1999 02 28	16	1999 09 30	2 899	
1998 11 30	29	1999 03 31	159			Work start date
1998 12 31	- 727	1999 04 30	83			1997 09 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:	5 766		293		-2 194	3 865
1999/00	12					12
TOTAL	5 778		293		-2 194	3 877
REV. AMOUNTS:						
Authorized to date:	5 766		293		-2 194	3 865
Over(under)expend:						
Auth 1999/00	719	18	25			762
Req.:						
TOTAL	6 485	18	318		-2 194	4 627

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 03-00-8295

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1997 10	3 462	NEW ITEM. BUDGET INCLUDES COST ASSIGNMENTS FOR CONTROLS UPGRADE, SITE IMPROVEMENTS SPARE DIVERTER SWITCHES AND BANK 8 PHASE SHIFTER INSTALLATION.
1998 10	3 877	INCREASE DUE TO PHASE SHIFTER, CONSTRUCTION COSTS, CONTROL WORK MORE COMPLEX THAN ANTICIPATED, & ADDITION OF FIBRE OPTIC INSTALLATION, SPARE BUSHINGS, DISPOSITION OF EXISTING PHASE SHIFTER #8, & OVERLOAD STUDIES FOR STEPUP UNIT.

ASSOCIATED PROJECTS

Budget reference number	Description
02-00-5959	WHITESHELL-TRANSCONA 110KV RECONDUCTOR WT34 END SECTIONS
02-00-5960	WINNIPEG RIVER AND WINNIPEG 110KV T/L REFURBISHMENT (WPGRTL)

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	170	3	4			177	177
May	170	4	4			178	355
Jun	170	5	5			180	535
Jul	70	2	3			75	610
Aug	70	2	4			76	686
Sep	69	2	5			76	762
Oct							762
Nov							762
Dec							762
Jan							762
Feb							762
Mar							762
TOTAL	719	18	25			762	762
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

COMPLEX STATUS: [X] Planned [ ] In progress

Complex no. 268

REVISION STATUS: [X] New complex [ ] In service change [ ] Concept change [ ] Estimate change only

COMPLEX: GLENBORO > HARVEY 230kV T/L

Proposal

Preform environmental assessment and route selection, design and construct transmission and terminal facilities for Harvey-Glenboro interconnection power transfer as follows:
Transmission: New 230kV line of 95 KM Glenboro > Harvey(border crossing)
Terminations: Extend 230kV facilities at Glenboro station.
Comminication: Intergrate with Glenboro area system.

JUSTIFICATION

[ ] Load [ ] Service
[ ] Safety [ ] Efficiency
[X] Reliability [X] Other

Explanation

A new interconnection is required for enhancement of import capability of 500 MW under the diversity agreement.

Estimate Level	COMPLEX START (yyyy mm)
L2	2000 04

IN SERVICE DATES AND AMOUNTS

2002 10	$15980			

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend								
Year 99/00								
00/01	1,483	25	60		1,568		1,568	
01/02	5,815	211	364		6,390		6,390	
02/03	7,117	399	506		8,022		8,022	
03/04								
04/05								
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	14,415	635	930		15,980		15,980	

REVISION: New Complex

Reviewed by ORIGINATOR	yyyy mm dd 99 11 08	Reviewed by COORDINATOR	yyyy mm dd 99 11 03
Reviewed by CONSTRUCTOR	yyyy mm dd 99 11 03	Approved by VICE-PRESIDENT	yyyy mm dd 99 11 [illegible]

H2856/r Rev 99 03

Complex no. 268

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Advance or deferral impact

Factors affecting timing or viability

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Glenboro > Harvey 230kV T/L				14,415	14,415	
TOTAL				14,415	14,415	

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
1999 10	15,980	New Complex

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item

120

Title			Budget reference number
GLENBORO-HARVEY 230KV T/L			02-00-8026
Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	81985

DESCRIPTION:
CONDUCT ENVIRONMENTAL IMPACT ASSESSMENT , SELECT A ROUTE, ACQUIRE PROPERTY FOR THE RIGHT-OF-WAY AND OBTAIN LICENCING, DESIGN AND CONSTRUCT 95 KM (TO THE BORDER CROSSING) OF SINGLE CIRCUIT 230 KV LINE USING 954 MCM ACSR CONDUCTOR. TERMINATE HARVEY 230 KV HARVEY LINE INTO THE RING BUS AT GLENBORO BY ADDING ONE 230 KV CIRCUIT BREAKER AND ASSOCIATED EQUIPMENT.
DESIGN, INSTALL AND COMMISSION REQUIRED TELECONTROL FACILITIES FOR OPERATION OF GLENBORO - HARVEY 230 KV LINE.

JUSTIFICATION:
REQUIRED FOR ENHANCEMENT OF IMPORT CAPABILITY OF 500 MW UNDER THE DIVERSITY AGREEMENT.

REFERENCE:
MANITOBA HYDRO-UNITED STATES NORTHWARD TRANSFER CAPACITY ENHANCEMENT STUDY REPORT PREPARED FOR THE MAPP RED RIVER VALLEY SUBREGIONAL PLANNING GROUP, JULY 1999.

REVISION:
NEW ITEM.

IN SERVICE DATES				Base estimate
2002 10 31	15 981			199909 L2
				Work start date 2000 04 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:						
TOTAL						
REV. AMOUNTS:						
Authorized to date:						
Over(under)expend:						
Auth 2000/01	1 483	25	60			1 568
Req.: 2001/02	5 815	212	364			6 391
2002/03	7 117	399	506			8 022
TOTAL	14 415	636	930			15 981

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 02-00-8026

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS

ASSOCIATED PROJECTS

Budget reference number	Description

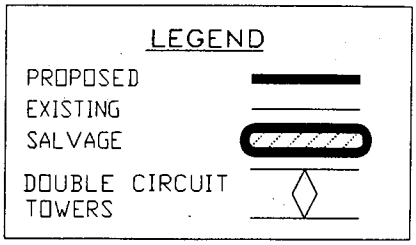
Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr	124	2				126	126
May	124	1	1			126	252
Jun	124	1	2			127	379
Jul	124	1	3			128	507
Aug	124	1	4			129	636
Sep	124	2	4			130	766
Oct	124	2	5			131	89[illegible]
Nov	123	3	6			132	1 02[illegible]
Dec	123	3	7			133	1 162
Jan	123	3	8			134	1 296
Feb	123	3	9			135	1 431
Mar	123	3	11			137	1 568
TOTAL	1 483	25	60			1 568	1 568

1999-09-28 11:17 AM

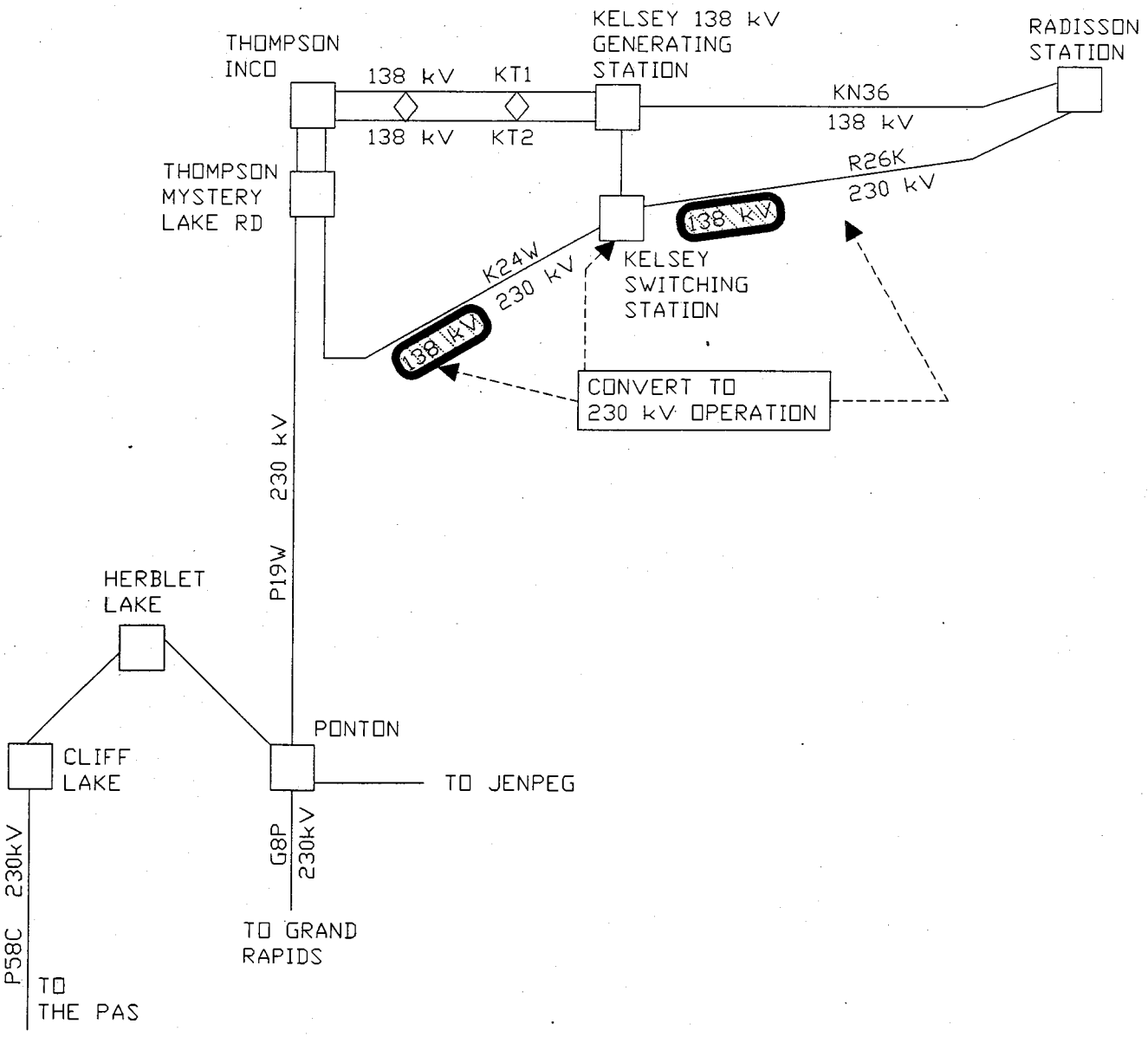
CAPITAL BUDGET COMPLEX CONCEPTUAL DIAGRAM

KETTLE AC TRANSMISSION IMPROVEMENTS

REVISED: 1999 - 10 - 01	ISSUED BY: WNZ
COMPLEX NO. 87	







H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

COMPLEX STATUS: ☐ Planned ☒ In progress

Complex no. 87

REVISION STATUS: ☐ New complex ☒ In service change ☐ Concept change ☐ Estimate change only

COMPLEX	KETTLE AC TRANSMISSION IMPROVEMENTS

Proposal

Design and reconnect AC transmission facilities in Northern AC system to enhance transmission system reliability as follows:

Transmission & Terminations: Convert Radisson-Kelsey line R26K & Kelsey-Thompson line K24W and associated station facilities at Thompson Mystery Lake Road, Kelsey, and Radisson to 230 KV operation. Install new 230KV circuit breaker at Thompson Mystery Lake Road. Install 230-138 KV 250 MVA transformer at Kelsey.

JUSTIFICATION

☐ Load ☐ Service
☐ Safety ☐ Efficiency
☒ Reliability ☐ Other

Explanation

The addition of Limestone has loaded the HVDC system to capacity. With Bipole 3 deferred, transmission system capacity and reliability margins for firm export sales can be partially restored economically by providing facilities to off-load 2 Kettle units from the DC system to the AC system if required.

Estimate Level	COMPLEX START (yyyy mm)
L3	1995 04

IN SERVICE DATES AND AMOUNTS					
2003 09	$1387	2004 09	$4679	2004 10	$5583

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	822		211		1,033	1,169	-136	-12
Year 99/00	-1		90		89	1,570	-1,481	-94
00/01	-49	1	95		47	2,400	-2,353	-98
01/02	71	5	104		180	2,437	-2,257	-93
02/03	775	73	153		1,001	2,766	-1,765	-64
03/04	3,623	421	290	55	4,279		4,279	
04/05	4,111	535	317	6	4,957		4,957	
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	9,352	1,035	1,260	61	11,586	10,342	1,244	12

REVISION Transmission, termination and communication items deferred three years and Kelsey transformer deferred two years to 2004 due to capital constraint reasons.

Reviewed by ORIGINATOR	yyyy mm dd 99 11 08	Reviewed by COORDINATOR	yyyy mm dd 99 11 03
Reviewed by CONSTRUCTOR	yyyy mm dd 99 11 03	Approved by VICE-PRESIDENT	yyyy mm dd 99 11 16

H2856/r Rev 99 03

Complex no. 87

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Advance or deferral impact

Deferral of these facilities would result in inadequate reliability of the transmission system to support system firm loads and exports and could result in lower extra-provincial revenues.

Factors affecting timing or viability

System load growth forecasts.
Timely completion of Herblet Lake - Flin Flon Cliff Lake 230 KV Transmission to permit Kettle AC power transfer.
Completion of studies to confirm Kettle AC operation protection and control requirements.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Radisson Convert R26K to 230KV & Reterm. K4/K5	1,173	1,269	1,294	1,304	10	1
Kelsey Stn Convert T/L K24W & R26K to 230 KV	575	655	668	687	19	3
Thompson MLR Convert T/L K24W to 230 KV Oprtn.	957	1,238	1,263	1,269	6	0
Ponton, Herblet Lk. & Cliff Lk>Ket AC Prtcn Chng	477	560	571	594	23	4
Kelsey Install 230-138 KV Transformer	3,753	3,952	4,031	4,041	10	0
Telecommunications for Kettle AC Operation	1,025	1,199	1,223	1,457	234	19
TOTAL	7,960	8,873	9,050	9,352	302	3

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
1995 10	69,154	Equip cost increases. Breaker relocation, protection and telecom facil added. Valve cooling removed. Kettle AC facil defer'd, Dorsey cooling, reactors, & transf defer'd.
1996 10	9,085	HVDC spares, Radisson SST1 relocation transferred to complex 223. Kelsey trnsfmr added from Notigi Transmission complex. Communic'n cost incr. ISD defer 2 yr to 1999
1997 10	10,014	Ponton Herblet & Cliff Lake Kettle protection changes, Retermination of K4/K5, and Telecommunication deferred 1 year to 2000.
1998 10	10,342	Reflects 97/98 underexpenditure 0.8M. Transmission, termination and communication items deferred one year. Kelsey transformer deferred two years.
1999 10	11,586	Transmission, termination and communication items deferred three years and Kelsey transformer deferred two years to 2004 due to capital constraint reasons.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION
Complex 30	Thompson - Herblet Lake 230 KV Transmission

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item

121

Title			Budget reference number
RADISSON CONVERT R26K TO 230KV & RETERMINATE K4/K5			03-00-3343
Originating division	Coordinating division	Constructing division	Project Order Group (Range):
anning & Control	Design	Construction	70033

DESCRIPTION:
FOR AC OPERATION OF 2 KETTLE UNITS, CONVERT 138 KV LINE R26K (RADISSON-KELSEY) BACK TO 230 KV OPERATION. RECOMMISION UNUSED 230-138 KV TRANSFORMER BANK 1. RETERMINATE LINE R26K TO 230 KV WINDING OF BANK 1, AND TERMINATE 138 KV WINDING TO PREVIOUS LINE R26K BREAKER POSITION IN 138 KV AC BAY. MODIFY THOMPSON-KELSEY-RADISSON 230KV PROTECTION SCHEME TO AVOID AN OPEN ENDED LINE FROM THOMPSON TO RADISSON. ISD 2002 09 30.
RECONNECT RADISSON LINES K4 & K5 138KV AC DISCONNECTS TO PERMIT CONNECTION OF KETTLE UNITS 5, 6, 7, AND 8 ONTO AC SYSTEM. PROVIDE INTERLOCKING BETWEEN DISCONNECTS OF LINES K1 & K4 TO PREVENT SIMULTANEOUS CONNECTION OF BOTH LINES ON RADISSON 138KV AC BUS. PROVIDE SIMILAR INTERLOCKING BETWEEN DISCONNECTS OF LINES K2 & K5. THIS ITEM ALSO INCLUDES REQUIRED CHANGES TO RADISSON/KETTLE/KELSEY/THOMPSON CROSSTRIPPING SCHEME, KETTLE JOINT CONTROLS, AND RADISSON PROTECTION SCHEMES. ISD 2003 09 30.

JUSTIFICATION:
THE ADDITION OF LIMESTONE, THE DELAY OF BIPOLE 3 AND THE INCREASED CAPACITY FOR EXPORT SALES JUSTIFIES TRANSMISSION ENHANCEMENTS BASED ON THE ECONOMICS OF EXPORT SALES AND INCREASED SYSTEM ADEQUACY AND RELIABILITY. THIS ITEM PROVIDES FOR REQUIRED CONVERSION OF LINE R26K TO 230 KV OPERATION AT RADISSON, AND FOR FACILITIES TO TRANSFER UP TO TWO KETTLE UNITS FOR ANY POTENTIAL OUTAGE CONTINGENCIES.

REFERENCE:
REPORT TPD 93-4, KETTLE AC TRANSMISSION OPTIONS. REPORT PSPD 94-2, ENHANCEMENT OF THE NELSON RIVER TRANSMISSION SYSTEM.

REVISION:
ISD OF R26K CONVERSION TO 230KV DEFERRED FROM 2000 09 30 TO 2003 09 30.
ISD OF K4/K5 RETERMINATION DEFERRED FROM 2001 09 30 TO 2004 09 30 FOR CAPITAL CONSTRAINT REASONS.

CONTINGENCY: $137 600

IN SERVICE DATES				Base estimate
2003 09 30	1 385			199803 L3
2004 09 30	463			Work start date
				1995 05 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:	407		130			537
1999/00	306	10	64			380
2000/01	486	32	56			574
2001/02	69	5	15			89
TOTAL	1 268	47	265			1 580
REV. AMOUNTS:						
Authorized to date:	407		130			537
Over(under)expend:						
Auth 1999/00			47			47
Req.: 2000/01			51			51
2001/02			55			55
2002/03	319	28	77			424
2003/04	509	61	68			638
2004/05	69	10	17			96
TOTAL	1 304	99	445			1 848

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

1999-09-28 11:17 AM

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 03-00-3343

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1993 02	1 098	NEW ITEM.
1993 10	942	DECREASE IN INTEREST AND ESCALATION RATES.
1994 10	814	IN-SERVICE DATE ADVANCED 4 YEARS TO 1996 10 31. ITEM TRANSFERRED TO NORTHERN TRANSMISSION RELIABILITY ENHANCEMENTS-STAGE 1'.REVISED INTEREST AND ESCALATION RATES.
1995 10	1 195	IN-SERVICE DATE DEFERRED 1 YEAR TO 1997 10 31. FACILITIES FROM CANCELLED BRN --03-00-5909 ADDED TO INCLUDE K4 & K5 FOR NORTHERN ACDUTY. CONTINGENCY INCREASED TO FACILITATE CROSS TRIP REQUIREMENTS.
1996 10	1 373	ISD DEFERRED FROM 1997 10 31 TO 1999 09 30.
1997 10	1 514	RETERMINATION OF K4/K5 ISD DEFERRED FROM 1999 09 30 TO 2000 09 30.
1998 10	1 580	ISD OF R26K CONVERSION TO 230KV DEFERRED FROM 1999 09 30 TO 2000 09 30. ISD OF K4/K5 RETERMINATION DEFERRED FROM 2000 09 30 TO 2001 09 30.

ASSOCIATED PROJECTS

Budget reference number	Description
03-00-3342	THOMPSON MYSTERY LAKE ROAD STN. CONVERT T/L K24W TO 230KV
03-00-4820	KELSEY STATION CONVERT T/L K24W & R26K TO 230KV OPERATION
03-00-6115	KELSEY INSTALL 230-138KV TRANSFORMER
03-00-6122	PONTON, HERBLET LK & CLIFF LK - KETTLE AC PROTECTION CHANGES
05-00-6556	TELECOMMUNICATIONS FOR KETTLE AC OPERATION

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr			4			4	4
May			4			4	8
Jun			4			4	12
Jul			4			4	16
Aug			4			4	20
Sep			4			4	24
Oct			4			4	28
Nov			4			4	32
Dec			4			4	36
Jan			4			4	40
Feb			4			4	44
Mar			3			3	47
TOTAL			47			47	47
2000/01 Apr			4			4	4
May			4			4	8
Jun			4			4	12
Jul			4			4	16
Aug			4			4	20
Sep			4			4	24
Oct			4			4	28
Nov			4			4	32
Dec			4			4	36
Jan			4			4	40
Feb			4			4	44
Mar			7			7	51
TOTAL			51			51	51

1999-09-28 11:17 AM

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item

122

Title			Budget reference number
KELSEY STATION CONVERT T/L K24W & R26K TO 230KV OPERATION			03-00-4820
Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	60003

DESCRIPTION:
FOR AC OPERATION OF 2 KETTLE UNITS, CONVERT 138 KV LINES K24W (KELSEY-THOMPSON) AND R26K (RADISSON-KELSEY) BACK TO 230 KV OPERATION. RECOMMISSION LINE K24W AND R26K TERMINATION BREAKERS 1, 2, AND 3 FOR 230 KV OPERATION. MODIFY THOMPSON - KELSEY - RADISSON 230KV PROTECTION SCHEME TO AVOID AN OPEN ENDED LINE FROM THOMPSON TO RADISSON.

JUSTIFICATION:
THE ADDITION OF LIMESTONE, THE DELAY OF BIPOLE 3 AND THE INCREASED CAPACITY FOR EXPORT SALES JUSTIFIES TRANSMISSION ENHANCEMENTS BASED ON THE ECONOMICS OF EXPORT SALES AND INCREASED SYSTEM ADEQUACY AND RELIABILITY. THIS ITEM PROVIDES FOR CONVERSION OF LINES K24W AND R26K TO 230 KV AT KELSEY TO PERMIT TWO KETTLE UNIT TRANSFER.

REFERENCE:
REPORT TPD 93-4, KETTLE AC TRANSMISSION OPTIONS.
REPORT PSPD 94-2, ENHANCEMENT OF THE NELSON RIVER TRANSMISSION SYSTEM.

REVISION:
ISD DEFERRED FROM 2000 09 30 TO 2004 09 30.

CONTINGENCY: $58,000

IN SERVICE DATES				Base estimate
2004 09 30	837			199706 L3
				Work start date 1995 05 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:	42		10			52
1999/00	181	6	14			201
2000/01	433	28	14			475
TOTAL	656	34	38			728
REV. AMOUNTS:						
Authorized to date:	42		10			52
Over(under)expend:						
Auth Req.: 1999/00			5			5
2000/01			5			5
2001/02			5			5
2002/03			6			6
2003/04	194	22	16			232
2004/05	451	64	17			532
TOTAL	687	86	64			837

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 03-00-4820

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1993 10	919	NEW ITEM. WAS FORMERLY BRN 9801-07-3021.
1994 10	782	IN-SERVICE DATE ADVANCED 4 YEARS TO 1996 10 31. ITEM TRANSFERRED TO NORTHERN TRANSMISSION RELIABILITY ENHANCEMENTS-STAGE 1'.REVISED INTEREST AND ESCALATION RATES.
1995 10	598	IN-SERVICE DATE DEFERRED 1 YEAR TO 1997 10 31. NORTHERN CROSS TRIP COSTS REDUCED BASED ON KNOWN COSTS.
1996 10	634	ISD DEFERRED 23 MONTHS FROM 1997 10 TO 1999 09.
1997 10	685	SCOPE UNCHANGED, ESTIMATE REFLECTS REVISED COSTING METHODOLOGY IMPLEMENTED WITH THE NEW FINANCIAL REPORTING SYSTEM. IT ALSO REFLECTS REVISED INTEREST AND ESCALATION RATES.
1998 10	728	ISD DEFERRED FROM 1999/09/30 TO 2000/09/30

ASSOCIATED PROJECTS

Budget reference number	Description
03-00-3342	THOMPSON MYSTERY LAKE ROAD STN. CONVERT T/L K24W TO 230KV
03-00-3343	RADISSON CONVERT R26K TO 230KV & RETERMINATE K4/K5
03-00-6115	KELSEY INSTALL 230-138KV TRANSFORMER
03-00-6122	PONTON, HERBLET LK & CLIFF LK - KETTLE AC PROTECTION CHANGES
05-00-6556	TELECOMMUNICATIONS FOR KETTLE AC OPERATION

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar			5			5	5
TOTAL			5			5	5
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar			5			5	5
TOTAL			5			5	5

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item

123

Title	Budget reference number
THOMPSON MYSTERY LAKE ROAD STN. CONVERT T/L K24W TO 230KV	03-00-3342

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	60002

DESCRIPTION:
FOR AC OPERATION OF 2 KETTLE UNITS, CONVERT LINE K24W (KELSEY-THOMPSON) BACK TO 230 KV OPERATION. SALVAGE 138 KV BYPASS STRUCTURE CONNECTING LINES K24W AND WB45 AND RETERMINATE K24W TO 230 KV STATION BAY. FACILITIES WILL INCLUDE 1 - 230KV CIRCUIT BREAKER. NOTE: 230KV CIRCUIT BREAKER R2, REMOVED FROM THOMPSON STATION AS PART OF FS9 BREAKER ROTATIONAL UPGRADE PROGRAM, IS REPLACED BY NEW BREAKER. COSTS INCLUDE NORTHERN CROSS TRIPPING REPLACEMENTS.

JUSTIFICATION:
THE ADDITION OF LIMESTONE, THE DELAY OF BIPOLE 3 AND THE INCREASED CAPACITY FOR EXPORT SALES JUSTIFIES TRANSMISSION ENHANCEMENTS BASED ON THE ECONOMICS OF EXPORT SALES AND INCREASED SYSTEM ADEQUACY AND RELIABILITY. THIS ITEM PROVIDES FOR CONVERSION OF LINE K24W TO 230 KV AT THOMPSON TO PERMIT TWO KETTLE UNIT TRANSFER.

REFERENCE:
REPORT TPD 93-4, KETTLE AC TRANSMISSION OPTIONS.
REPORT PSPD 94-2, ENHANCEMENT OF THE NELSON RIVER TRANSMISSION SYSTEM.

REVISION:
ISD DEFERRED FROM 2000 09 30 TO 2004 09 30 FOR CAPITAL CONSTRAINT REASONS.

CONTINGENCY: $120,000

IN SERVICE DATES				Base estimate
2004 09 30	1 554			199707 L3
				Work start date 1996 05 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:	63		20			83
1999/00	663	22	47	-54		678
2000/01	514	25	40			579
TOTAL	1 240	47	107	-54		1 340
REV. AMOUNTS:						
Authorized to date:	63		20			83
Over(under)expend:						
Auth 1999/00			7			7
Req.: 2000/01			8			8
2001/02			8			8
2002/03	72	9	9			90
2003/04	602	69	53	-54		670
2004/05	532	57	45			634
TOTAL	1 269	135	150	-54		1 500

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

1999-09-28 11:18 AM

MajCER(2) Rev. 97.09

CAPITAL EXPENDITURE REVISION

Budget reference number 03-00-3342

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1993 02	687	NEW ITEM.
1993 10	649	DECREASE IN INTEREST AND ESCALATION RATES.
1994 10	559	IN-SERVICE DATE ADVANCED 4 YEARS TO 1996 10 31. ITEM TRANSFERRED TO NORTHERN TRANSMISSION RELIABILITY ENHANCEMENTS-STAGE 1'.REVISED INTEREST AND ESCALATION RATES.
1995 10	941	230KV REPLACEMENT CIRCUIT BREAKER ADDED. IN-SERVICE DATE DEFERRED 1 YEAR TO 1997 10 31.
1996 10	699	IN SERVICE DATE DEFERRED 23 MONTHS TO 99 09 30. BASE INCREASE DUE TO INCREASE IN ESTIMATE FOR VOLTAGE TRANSFORMERS.
1997 10	1 324	ESTIMATE REFLECTS REVISED COSTING METHODOLOGY IMPLEMENTED WITH THE NEW FINANCIAL REPORTING SYSTEM. ALSO REFELCTS REVISED INTEREST AND ESCALATION RATES.
1998 10	1 341	ISD DEFERRED FROM 1999 09 30 TO 2000 09 30.

ASSOCIATED PROJECTS

Budget reference number	Description
03-00-3343	RADISSON CONVERT R26K TO 230KV & RETERMINATE K4/K5
03-00-4820	KELSEY STATION CONVERT T/L K24W & R26K TO 230KV OPERATION
03-00-6115	KELSEY INSTALL 230-138KV TRANSFORMER
03-00-6122	PONTON, HERBLET LK & CLIFF LK - KETTLE AC PROTECTION CHANGES
05-00-6556	TELECOMMUNICATIONS FOR KETTLE AC OPERATION

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr			1			1	1
May			1			1	2
Jun			1			1	3
Jul			1			1	4
Aug			1			1	5
Sep			1			1	6
Oct			1			1	7
Nov			1			1	8
Dec			1			1	9
Jan			1			1	10
Feb			1			1	11
Mar			-4			-4	7
TOTAL			7			7	7
2000/01 Apr			1			1	1
May			1			1	2
Jun			1			1	3
Jul			1			1	4
Aug			1			1	5
Sep			1			1	6
Oct			1			1	7
Nov			1			1	8
Dec			1			1	9
Jan			1			1	10
Feb			1			1	11
Mar			-3			-3	8
TOTAL			8			8	8

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item

124

Title			Budget reference number
PONTON, HERBLET LK & CLIFF LK - KETTLE AC PROTECTION CHANGES			03-00-6122
Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	71040

DESCRIPTION:
MODIFY PROTECTION EQUIPMENT AS REQUIRED AT PONTON, HERBLET LAKE, CLIFF LAKE, AND GRAND RAPIDS STATIONS IN CO-ORDINATION WITH SYSTEM ADJUSTMENTS TO ENABLE POWER TRANSFER FROM TWO KETTLE UNITS ONTO AC SYSTEM. MODIFICATIONS WILL INCLUDE CAPACITY TO SEND SIGNALS TO CROSS TRIP KETTLE AC AND KELSEY GENERATOR UNITS FOR TRIP OUT OF MAJOR 230KV LINES TERMINATING AT PONTON, HERBLET LAKE, AND CLIFF LAKE. CROSS TRIP FACILITIES WILL CO-ORDINATE WITH EXISTING AND MODIFIED RELATED FACILITIES ON THOMPSON - KELSEY - RADISSON 230-138KV NETWORK.

JUSTIFICATION:
THE ADDITION OF LIMESTONE, THE DELAY OF BIPOLE 3 AND THE INCREASED CAPACITY FOR EXPORT SALES JUSTIFIES TRANSMISSION ENHANCEMENTS BASED ON THE ECONOMICS OF EXPORT SALES AND INCREASED SYSTEM ADEQUACY AND RELIABILITY. THIS ITEM PROVIDES FOR FACILITIES TO TRANSFER UP TO TWO KETTLE UNITS AND MAINTENANCE OF TRANSIENT SYSTEM STABILITY FOR ANY POTENTIAL 230KV LINE OUTAGE CONTINGENCIES IN PONTON - HERBLET LAKE - CLIFF LAKE AREA.

REFERENCE:
REPORT TPD 93-4, 'KETTLE AC TRANSMISSION OPTIONS'. REPORT PSPD 94-2, 'ENHANCEMENT OF THE NELSON RIVER TRANSMISSION SYSTEM'.

REVISION:
ISD DEFERRED TWO YEARS FROM 2002-10-31 TO 2004-10-31 DUE TO FINANCIAL CONSTRAINTS.

CONTINGENCY: $48 000

IN SERVICE DATES				Base estimate
2004 10 31	722			199804 L2
				Work start date 1998 04 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:	18		6			24
1999/00	40		5			45
2000/01	20	1	7			28
2001/02	129	10	11			150
2002/03	355	32	20			407
TOTAL	562	43	49			654
REV. AMOUNTS:						
Authorized to date:	18		6			24
Over(under)expend:						
Auth 1999/00			2			2
Req.: 2000/01	21	1	3			25
2001/02	21	2	5			28
2002/03	21	2	8			31
2003/04	139	16	13			168
2004/05	374	47	23			444
TOTAL	594	68	60			722

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

1999-09-28 11:18 AM

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number: 03-00-6122

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1995 10	395	NEW ITEM.
1996 10	544	ISD DEFERRED FROM 1997 TO 1999. SCOPE CHANGE TO ADD GRAND RAPIDS PROTECTION. CORRECTION TO INTEREST CALCULATION FROM LAST YEAR.
1997 10	634	ISD DEFERRED 1 YEAR FROM 1999 10 31 TO 2000 20 31.
1998 10	654	ISD DEFERRED 2 YEARS FROM 2000-10-31 TO 2002-10-31 DUE TO FINANCIAL CONSTRAINTS.

ASSOCIATED PROJECTS

Budget reference number	Description
03-00-3342	THOMPSON MYSTERY LAKE ROAD STN. CONVERT T/L K24W TO 230KV
03-00-3343	RADISSON CONVERT R26K TO 230KV & RETERMINATE K4/K5
03-00-4820	KELSEY STATION CONVERT T/L K24W & R26K TO 230KV OPERATION
03-00-6115	KELSEY INSTALL 230-138KV TRANSFORMER
05-00-6556	TELECOMMUNICATIONS FOR KETTLE AC OPERATION

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar			2			2	2
TOTAL			2			2	2
2000/01 Apr	2					2	2
May	2					2	4
Jun	2					2	6
Jul	2					2	8
Aug	2					2	10
Sep	2					2	12
Oct	2					2	14
Nov	2					2	16
Dec	2					2	18
Jan	2					2	20
Feb	2					2	22
Mar	-1	1	3			3	25
TOTAL	21	1	3			25	25

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item

125

Title			Budget reference number
KELSEY INSTALL 230-138KV TRANSFORMER			03-00-6115
iginating division anning & Control	Coordinating division Design	Constructing division Construction	Project Order Group (Range): 71017

DESCRIPTION:
PURCHASE AND INSTALL 230-138-13.8 KV 150/200/250 MVA TRANSFORMER WITH +/- 10% OLTC AT KELSEY 230KV STATION. TERMINATE TRANSFORMER WITH EXISTING 230 KV AND 138 KV CIRCUIT BREAKERS PREVIOUSLY USED FOR KELSEY TRANSFORMER BANK 10. RECOMMISSION PREVIOUS TERMINATIONS OF TRANSFORMER BETWEEN KELSEY 230 KV AND 138 KV STATIONS.

JUSTIFICATION:
ELSEWHERE IN THE BUDGET JUSTIFICATION IS GIVEN FOR RADISSON-KELSEY LINE R26K AND KELSEY- THOMPSON LINE K24W TO BE CONVERTED FROM 138KV TO 230KV OPERATION FOR NORTHERN TRANSMISSION RELIABILITY ENHANCEMENT AND KETTLE AC OPERATIONS. ADDITION OF A KELSEY 230-138KV TRANSFORMER WILL INCREASE SYSTEM ECONOMIC BENEFITS BY DECREASING NETWORK LOSSES AND ENHANCING KELSEY/THOMPSON AREA OPERATING FLEXIBILITY AND VOLTAGE CONTROL.

REFERENCE:
SPED REPORT, 'KETTLE UNITS ON AC TRANSMISSION PROTECTION AND CONTROL REQUIREMENTS'.
SPED TM, 'KELSEY 230-138 KV TRANSFORMER ADDITION'

REVISION:
I.S.D. DEFERRED FROM 2002 10 31 TO 2004 10 31 DUE TO FINANCIAL CONSTRAINTS.

CONTINGENCY: $360,000.

IN SERVICE DATES				Base estimate
2004 10 31	4 861			199704 L2
				Work start date 1997 08 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:	69		2			71
1999/00	-18	1	3			-14
2000/01	296	19	18			333
2001/02	1 596	146	72	-1		1 813
2002/03	2 007	210	148	-6		2 359
TOTAL	3 950	376	243	-7		4 562
REV. AMOUNTS:						
Authorized to date:	69		2			71
Over(under)expend:						
Auth 1999/00	-1	1	6			6
Req.: 2000/01			7			7
2001/02	50	4	9			63
2002/03	330	33	27			390
2003/04	1 592	200	87	-1		1 878
2004/05	2 001	279	164	-6		2 438
TOTAL	4 041	517	302	-7		4 853

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number: 03-00-6115

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1995 10	4 951	NEW ITEM. ESTIMATES PREPARED BY SYSTEM PLANNING & ENVRNMENT.
1996 10	4 395	ITEM TRANSFERRED FROM 'NOTIGI 138KV TRANSMISSION' COMPLEX. ISD DATE ADVANCED 17 YEARS TO 2000 10 31. PREVIOUS PLANNING ESTIMATE DID NOT REFLECT CURRENT EQUIPMENT PRICES, ESPECIALLY POWER TRANSFORMER.
1997 10	4 424	SCOPE UNCHANGED. ESTIMATE REFLECTS REVISED COSTING METHODOLOGY IMPLEMENTED WITH THE NEW FINANCIAL REPORTING SYSTEM. ALSO REFLECTS REVISED INTEREST AND ESCALATION RATES.
1998 10	4 562	I.S.D. DEFERRED FROM 2000 10 31 TO 2002 10 31 DUE TO FINANCIAL CONSTRAINTS.

ASSOCIATED PROJECTS

Budget reference number	Description
03-00-3342	THOMPSON MYSTERY LAKE ROAD STN. CONVERT T/L K24W TO 230KV
03-00-3343	RADISSON CONVERT R26K TO 230KV & RETERMINATE K4/K5
03-00-4820	KELSEY STATION CONVERT T/L K24W & R26K TO 230KV OPERATION
03-00-6122	PONTON, HERBLET LK & CLIFF LK - KETTLE AC PROTECTION CHANGES
05-00-6556	TELECOMMUNICATIONS FOR KETTLE AC OPERATION

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun		-1	1				
Jul		-1	1				
Aug		-1	1				
Sep		-1	1				
Oct		-1	1				
Nov		-1	1				
Dec		-1	1				
Jan		-1	1				
Feb		-1	1				
Mar	-1	10	-3			6	6
TOTAL	-1	1	6			6	6
2000/01 Apr		-1	1				
May			1			1	1
Jun			1			1	2
Jul			1			1	3
Aug			1			1	4
Sep			1			1	5
Oct			1			1	6
Nov			1			1	7
Dec			1			1	8
Jan			1			1	9
Feb			1			1	10
Mar		1	-4			-3	7
TOTAL			7			7	7

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item

126

Title			Budget reference number
TELECOMMUNICATIONS FOR KETTLE AC OPERATION			05-00-6556
Originating division Planning & Control	Coordinating division Planning & Control	Constructing division Construction	Project Order Group (Range): 60032

DESCRIPTION:
DESIGN, INSTALL AND COMMISSION TELECOMMUNICATION FACILITIES FOR OPERATION, PROTECTION AND CONTROL OF 230KV AND 138KV TRANSMISSION FACILITY ADJUSTMENTS INSTALLED TO TRANSMIT TWO KETTLE UNIT POWER ON AC SYSTEM. FACILITIES WILL INCLUDE ENHANCEMENT OF EXISTING THOMPSON- KELSEY-RADISSON CROSSTRIP COMMUNICATIONS AND CO-ORDINATED DEVELOPMENT OF FACILITIES FOR CROSSTRIP OF KETTLE AC AND KELSEY UNITS FOR 230KV LINE TRIPOUTS IN PONTON - HERBLET LAKE - CLIFF LAKE AREA. FACILITES WILL INCLUDE TONE EQUIPMENT TO INTERFACE PROTECTION TO COMMUNICATION CHANNELS DERIVED FROM EXISTING OR NEW CARRIER FACILITIES, POINT ADDITIONS TO EXISTING OR PLANNED SUPERVISORY CONTROL SYSTEMS, AND FUTURE PROVISION FOR EXPANSION TO ACCOMMODATE THREE KETTLE AC UNIT TRANSFER.

JUSTIFICATION:
THE ADDITION OF LIMESTONE, THE DELAY OF BIPOLE 3 AND THE INCREASED CAPACITY FOR EXPORT SALES JUSTIFIES TRANSMISSION ENHANCEMENTS BASED ON THE ECONOMICS OF EXPORT SALES AND INCREASED SYSTEM ADEQUACY AND RELIABILITY. THIS ITEM PROVIDES FOR NECESSARY TELECOMMUNICATIONS FACILITIES TO OPERATE 230KV AND 138KV STATION AND LINE FACILITIES DEVELOPED TO ENABLE TWO KETTLE AC UNIT POWER TRANSFER

REFERENCE:
REPORT TPD 93-4, KETTLE AC TRANSMISSION OPTIONS.

REPORT PSPD 94-2, ENHANCEMENT OF THE NELSON RIVER TRANSMISSION SYSTEM.

REVISION:
ISD DEFERRED FROM 2001 10 31 TO 2004 09 30.

CONTINGENCY: $ 64,000

IN SERVICE DATES				Base estimate
2004 09 30	1 824			199901 L2
				Work start date 1996 04 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:	223		43			266
1999/00	360	15	41			416
2000/01	314	23	74			411
2001/02	298	28	59			385
TOTAL	1 195	66	217			1 478
REV. AMOUNTS:						
Authorized to date:	223		43			266
Over(under)expend:						
Auth 1999/00			23			23
Req.: 2000/01	-70		21			-49
2001/02			21			21
2002/03			23			23
2003/04	620	56	52			728
2004/05	684	77	51			812
TOTAL	1 457	133	234			1 824

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

CAPITAL EXPENDITURE REVISION

Budget reference number 05-00-6556

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1995 10	822	NEW ITEM. INCLUDES COMMUNICATIONS FACILITIES FROM CANCELLED BRN 03-00-5909.
1996 10	1 140	ISD DEFERRED FROM FALL 1997 TO FALL 1999. INCREASED COSTS DUE TO ADDITION OF PROJECT ADMINISTRATION COSTS, INCREASE IN OVERHEAD RATE FOR LABOUR, INCREASED INTEREST AND ESCALATION, AND ADDITION OF CONTINGENCY.
1997 10	1 434	ISD DEFERRED 1 YEAR FROM 1999 10 31 TO 2000 10 31.
1998 10	1 478	ISD DEFERRED FROM 2000 10 31 TO 2001 10 31.

ASSOCIATED PROJECTS

Budget reference number	Description
03-00-3342	THOMPSON MYSTERY LAKE ROAD STN. CONVERT T/L K24W TO 230KV
03-00-3343	RADISSON CONVERT R26K TO 230KV & RETERMINATE K4/K5
03-00-4820	KELSEY STATION CONVERT T/L K24W & R26K TO 230KV OPERATION
03-00-6115	KELSEY INSTALL 230-138KV TRANSFORMER
03-00-6122	PONTON, HERBLET LK & CLIFF LK - KETTLE AC PROTECTION CHANGES

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr			2			2	2
May			2			2	4
Jun			2			2	6
Jul			2			2	8
Aug			2			2	10
Sep			2			2	12
Oct			2			2	14
Nov			2			2	16
Dec			2			2	18
Jan			2			2	20
Feb			2			2	22
Mar			1			1	23
TOTAL			23			23	23
2000/01 Apr			2			2	2
May			2			2	4
Jun	-70		2			-68	-64
Jul			2			2	-62
Aug			2			2	-60
Sep			2			2	-58
Oct			2			2	-56
Nov			2			2	-54
Dec			2			2	-52
Jan			2			2	-50
Feb			2			2	-48
Mar			-1			-1	-49
TOTAL	-70		21			-49	-49

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

COMPLEX STATUS: [X] Planned [ ] In progress

Complex no. 30

REVISION STATUS: [ ] New complex [X] In service change [ ] Concept change [ ] Estimate change only

COMPLEX: THOMPSON - HERBLET LAKE 230 KV TRANSMISSION

Proposal

Perform environmental assessments and route selection, design and construct transmission and terminal facilities to transmit power of up to 3 Kettle units to the Southern AC System as follows;
Transmission: 230 KV line 166km Thompson Birchtree - Herblet Lake. Sectionalize 230 KV line K24W into Thompson Birchtree station.
Terminations: Establish station at Thompson Birchtree, line termination at Herblet Lake, and modify line protection at Kelsey and Thompson Mystery Lake Road associated with line K24W.
Communications: Protection for Kelsey - Thompson - Herblet Lake T/Ls.

JUSTIFICATION: [ ] Load [ ] Service [ ] Safety [ ] Efficiency [X] Reliability [ ] Other

Explanation

Construction of the Thompson Birchtree - Herblet Lake 230 KV line and sectionalization of the Kelsey - Thompson Mystery Lake Road 230 KV line K24W into Thompson Birchtree station are required to transmit up to three units of Kettle generation to Southern Manitoba on the AC system under winter conditions for system reliability enhancement.

Estimate Level	COMPLEX START (yyyy mm)
L2	2000 04

IN SERVICE DATES AND AMOUNTS			
2007 10	$57148		

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend								
Year 99/00						246	-246	-100
00/01						274	-274	-100
01/02	213	14	12		239	405	-166	-41
02/03	186	16	33		235	429	-194	-45
03/04	641	72	76		789	5,127	-4,338	-85
04/05	4,534	618	285		5,437	21,011	-15,574	-74
05/06	17,256	2690	1,594		21,540	13,520	8,020	59
06/07	9,311	1724	3,019		14,054	14,272	-218	-2
07/08	10,958	1504	2,392		14,854		14,854	
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	43,099	6,638	7,411		57,148	55,284	1,864	3

REVISION: Deferred one year 2007 due to capital constraint reasons.

Reviewed by ORIGINATOR	yyyy mm dd 99 11 08	Reviewed by COORDINATOR	yyyy mm dd 99 11 03
Reviewed by CONSTRUCTOR	yyyy mm dd 99 11 03	Approved by VICE PRESIDENT	yyyy mm dd 99 11 03

H2856/r Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Complex no.
30

Advance or deferral impact

Deferral of these facilities will limit the number of Kettle units that can be transferred to the northern AC system during DC contingency or maintenance outages and thereby reduce system reliability.

Factors affecting timing or viability

Environmental Licencing.
System load growth forecasts.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Thompson Birchtree-Herblet Lake 230KV T/L		28,663	29,236	28,764	-472	-2
Thompson Birchtree - Establish Station		7,812	7,968	8,130	162	2
Herblet Lake-Terminate Thmpsn Birchtree 230KV T/L		3,539	3,610	3,651	41	1
Thompson Mystry Lk-Prtctn. Chng for Birchtree T/L		216	220	236	16	7
Kelsey-Prtctn. Chng for Thmpsn Brchtree 230KV T/L		216	220	236	16	7
Communications for Thompson Birchtree 230KV T/L		1,859	1,996	2,081	85	4
TOTAL		42,305	43,250	43,098	-152	-0

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
9510	54,500	Reflects cost increases for line K24W sectionalization, protection modifications at line K24W termination stations, and added Thompson Birchtree station equipment.
9610	54,425	Revised escalation and interest rates. Complex name changed.
1997 10	54,174	Scope unchanged, estimate reflects revised costing methodology implemented with the new financial reporting system. Also reflects revised interest and escalation rates.
1998 10	55,284	Scope unchanged.
1999 10	57,148	Deferred one year to 2007 due to capital constraint reasons.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION
Complex 87	Kettle AC Transmission Improvements
Complex 63	Henday and Radisson Spare Converter Transformers

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item

127

Title			Budget reference number
THOMPSON BIRCHTREE - HERBLET LAKE 230KV T/L			02-00-7006
Originating division	Coordinating division	Constructing division	Project Order Group (Range):
anning & Control	Design	Construction	70278

DESCRIPTION:
CONDUCT ENVIRONMENTAL IMPACT ASSESSMENT, SELECT A ROUTE, OBTAIN LICENSING AND ACQUIRE PROPERTY FOR RIGHT-OF-WAY. DESIGN AND CONSTRUCT APPROXIMATELY 166 KM OF SINGLE CIRCUIT 230 KV WOODPOLE LINE FROM THOMPSON BIRCHTREE TO HERBLET LAKE USING 954 MCM CONDUCTOR. OPEN 230KV LINE K24W AND EXTEND INTO THOMPSON - BIRCHTREE STATION FOR RETERMINATION, CREATING 2 - 230KV LINES FROM THOMPSON BIRCHTREE TO THOMPSON MYSTERY LAKE ROAD AND KELSEY.

COMPLETION DATE FOR PROPERTY AQUISITION: 2002 12 01.

JUSTIFICATION:
THOMPSON-BIRCHTREE - HERBLET LAKE 230 KV LINE PROVIDES REQUIRED TRANSMISSION RELIABILITY ENHANCEMENT (STAGE 2) FOR SYSTEM LOAD SUPPORT. THE NEW LINE INCREASES NORTHERN AC CAPACITY TO TRANSMIT KETTLE GENERATION TO THE SOUTHERN NETWORK FROM 2 TO 3 KETTLE UNITS. LINE K24W IS SECTIONALIZED AT BIRCHTREE TO SUPPLY KETTLE POWER TO THE NEW HERBLET LAKE LINE.

REFERENCE:
TPD REPORT 93-4, 'KETTLE AC TRANSMISSION OPTIONS'.
GPD REPORT TM 93/5-GP, '1993/94 RELIABILITY EVALUATION OF REQUIREMENTS FOR GENERATION /TRANSMISSION ENHANCEMENTS'.

REVISION:
ISD DEFERRED FROM 2006 10 31 TO 2007 10 31.

CONTINGENCY: $2,603,000

IN SERVICE DATES				Base estimate
2007 10 31	38 643			199803 L2
				Work start date 2001 04 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:						
1999/00	230	7	9			246
2000/01	230	12	32			274
2001/02	323	24	59			406
2002/03	112	11	86			209
2003/04	3 906	459	239			4 604
2004/05	13 868	1 875	1 319			17 062
2005/06	4 668	752	2 246			7 666
2006/07	5 326	489	1 623			7 438
TOTAL	28 663	3 629	5 613			37 905
REV. AMOUNTS:						
Authorized to date:						
Over(under)expend:						
Auth 2001/02	213	14	12			239
Req.: 2002/03	186	16	33			235
2003/04	419	45	70			534
2004/05	4 040	546	242			4 828
2005/06	13 885	2 122	1 368			17 375
2006/07	4 685	839	2 332			7 856
2007/08	5 336	540	1 700			7 576
TOTAL	28 764	4 122	5 757			38 643

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

CAPITAL EXPENDITURE REVISION

Budget reference number 02-00-7006

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1984 12	4 262	ITEM ADV. FOR WUSKWATIM G.S. CONST PWR REV BASE YR TO 84, USE $1 000 000/KM AS UNIT COST.
1985 11	3 431	ROUTE SEL & R.O.W. COSTS PUT IN SEP BUD ITEM.REV INT & ESC. DEF 1 YR. CAUSE WUSKWATIM ISD BASE UPDATED FROM 84 TO 85.
1985 12	8 471	ISD DEFERRED TO 2007 FROM 1992.
1986 12	5 574	BASE DATE & EST REMAIN UNCHANGED. REV INT & ESC RATES.
1987 11	6 113	REV BASE DATE FR 85 TO 87. PROJ ISD DEF FR 2004 TO 2007.
1988 10	14 298	CHNG LN NME TO THOMPSON-BIRCHTREE-WUSKWATIM. REFL REV INT & ESC RTS.ISD & START DEF 2 YRS. INC IN LINE LGTH FROM 22 TO 48 KM.
1989 10	14 434	REFLECT 89 MAT COST. ISD & START ADV 2 YRS, DEC ESC COST.
1990 05	11 308	ISD ADVANCES 5 YEARS.
1990 10	11 621	CASH FLOW REV. START DATE ADV FROM 2004 04 TO 2000 04.
1991 10	13 291	ISD DEFERRED 5 YEARS.
1992 10	10 133	COMM. DATE ADV 3 YR FR 2008 & RED INT & ESC RTS.ISD ADV 3 YRFROM 2013.
1993 02	9 228	TRANS. FR WUSKWATIM COMPLEX. ISD ADV 10 YRS TO 2000 10.
1993 10	31 927	LN SEC 118 KM WUSKWATIM-HERBLET ADDED FRM CANC 02-3213. ENVIR ACT TRANS FR CANC 02-6145. LINE CONDUCTOR SZ INCR TO 954 MCM.
1994 10	35 249	ISD DEF 6 YRS TO 2006. REV INT & ESC RATES.
1995 10	36 969	OPENING AND EXTENSION OF LINE K24W INTO BIRCHTREE ADDED.
1996 10	36 961	REVISED INTEREST RATES.
1997 10	36 620	1,000,000 WERE ADDED TO STRINGING EXPENSES FOR OPENING/EXTENDING 230 KV CCT K24W.
1998 10	37 905	START DATE DEFERRED ONE YEAR.

ASSOCIATED PROJECTS

Budget reference number	Description
03-00-3344	HERBLET LAKE TERMINATE THOMPSON BIRCHTREE 230KV T/L
03-00-6116	THOMPSON MYSTERY LAKE PROTECTION CHANGES FOR BIRCHTREE T/L
03-00-6117	KELSEY PROTECTION CHANGES FOR THOMPSON BIRCHTREE 230KV T/L
03-00-8103	THOMPSON BIRCHTREE ESTABLISH STATION
05-00-3219	COMMUNICATIONS FOR THOMPSON BIRCHTREE 230 KV T/L

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item 128

Title			Budget reference number
THOMPSON BIRCHTREE ESTABLISH STATION			03-00-8103
Originating division Planning & Control	Coordinating division Design	Constructing division Construction	Project Order Group (Range): 70394

DESCRIPTION:
CONDUCT ENVIRONMENTAL IMPACT ASSESSMENT, SELECT A SITE, ACQUIRE PROPERTY AND OBTAIN LICENCING. ESTABLISH A 230KV SWITCHYARD AT THOMPSON BIRCHTREE. TERMINATE 230KV LINE TO HERBLET LAKE. TERMINATE SECTIONALIZED LINE K24W TO CREATE 230KV LINES TO THOMPSON MYSTERY LAKE ROAD AND KELSEY. FACILITIES TO INCLUDE 3-230KV CIRCUIT BREAKERS, A BUILDING AND ASSOCIATED EQUIPMENT.

JUSTIFICATION:
ELSEWHERE IN THE BUDGET, JUSTIFICATION IS GIVEN FOR THE THOMPSON BIRCHTREE - HERBLET LAKE 230 KV LINE. THIS ITEM PROVIDES FOR TERMINATION OF THAT LINE AT THOMPSON BIRCHTREE, AND TERMINATION OF LINE K24W LINE SECTIONS.

REFERENCE:
TPD REPORT 93-4, 'KETTLE AC TRANSMISSION OPTIONS'. GPD REPORT TM 93/5-GP, '1993/94 RELIABILITY EVALUATION OF REQUIREMENTS FOR GENERATION /TRANSMISSION ENHANCEMENTS'.

REVISION:
ISD DEFERRED FROM 2006 10 31 TO 2007 06 31.

CONTINGENCY: $751,000

IN SERVICE DATES				Base estimate
2007 10 31	10 646			199706 L2
				Work start date 2003 09 01

PREV. AUTHORITY Authorized to date:	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
2002/03	193	22	5			220
2003/04	332	44	34			410
2004/05	2 564	399	173			3 136
2005/06	2 482	442	456			3 380
2006/07	2 241	295	398			2 934
TOTAL	7 812	1 202	1 066			10 080
REV. AMOUNTS: Authorized to date: Over(under)expend:						
Auth 2003/04	222	29	5			256
Req.: 2004/05	382	56	40			478
2005/06	2 671	449	192			3 312
2006/07	2 576	492	496			3 564
2007/08	2 279	322	435			3 036
TOTAL	8 130	1 348	1 168			10 646

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

CAPITAL EXPENDITURE REVISION

Budget reference number 03-00-8103

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1984 12	6 500	THIS ITEM ADVANCED FOR WUSKWATIM G. S. CONSTRUCTION POWER REDUCED NO. OF BREAKERS REQUIRED.
1985 11	7 400	BASE DATE UPDATED TO 85.REVISED INT & ESC RATES. THIS ITEM DEFERRED 1 YR BECAUSE OF REVISED WUSKWATIM I.S.D. 10% UNALLOCATED ALLOWANCE INCLUDED.
1985 12	18 107	ISD DEFERRED TO 2007 FR.1992.
1986 12	12 019	BASE DATE & EST REMAIN UNCHANGED. REVISED INT & ESC RATES.
1987 11	13 343	BASE DATE REVISED FR 85 TO 87. EST. CHANGED.
1988 11	14 932	BASE DATE REVISED FR 87 TO 88. OVER 80% OF THE EST. INCREASEDUE TO BREAKER COST INCRS. NO APPROVED SLD. REVISED INT. & ESCLTN. RATESISD & START DATE DEFERRED 2 YRS. NAME CHANGE FROM PIPE LAKE TO BIRCHTREE
1989 10	13 039	ISD & START DATE ADVANCED 2 YRS.
1990 05	10 201	ISD ADVANCED 5 YRS.
1990 10	11 667	INCRS IN MAT. (BUS, HRDWR, INSULTRS, RELAY & METER) DUE TO PREVIOUS LOW ESTMT. START DATE DFR 1 YR. STN REQ'D 5 YRS BEFORE WUSKWTM.
1991 10	12 579	F.S.T. REMOVED FROM ALL MATERIAL. ISD DEFERRED 3 YEARS.
1992 10	9 247	ISD ADVANCED FROM 2013 10 01.
1993 02	8 386	TRANSFR'D FROM WUSKWATIM COMPLEX. ISD ADVNCD 10 YRS TO 2000.
1993 10	8 490	TRMNTN. HERBLET LK 230KV LINE REPLACE WUSKWTM TRMNTN. ESTIMTINCRS FOR INCLUDING ENVRNMNTL/PROPERTY COSTS, INCREASED SITE IMPROVEMENTCOSTS BASED ON HERBLET LAKE.
1994 10	9 360	ISD DEFERRED 6 YRS TO 2006 10 31. RVS'D INT. & ESCLTN RATES.
1995 10	9 903	UPDATED EQUIPMENT COSTS TO REFLECT CURRENT PRICES.
1996 06	9 857	REVISED INTEREST RATES. CORRECTION TO CALCULATED ESCALATION.
1997 10	10 149	SCOPE UNCHANGED, ESTIMATE REFLECTS COSTING METHODOLOGY IMPLEMENTED WITH THE NEW FINANCIAL REPORTING SYSTEM. ALSO, REFLECTS REVISED INTEREST AND ESCALATION RATES.
1998 10	10 080	NO CHANGE

ASSOCIATED PROJECTS

Budget reference number	Description
02-00-7006	THOMPSON BIRCHTREE - HERBLET LAKE 230KV T/L
03-00-3344	HERBLET LAKE TERMINATE THOMPSON BIRCHTREE 230KV T/L
03-00-6116	THOMPSON MYSTERY LAKE PROTECTION CHANGES FOR BIRCHTREE T/L
03-00-6117	KELSEY PROTECTION CHANGES FOR THOMPSON BIRCHTREE 230KV T/L
05-00-3219	COMMUNICATIONS FOR THOMPSON BIRCHTREE 230 KV T/L

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item

129

Title			Budget reference number
HERBLET LAKE TERMINATE THOMPSON BIRCHTREE 230KV T/L			03-00-3344
iginating division anning & Control	Coordinating division Design	Constructing division Construction	Project Order Group (Range): 70280

DESCRIPTION:
TERMINATE 230KV LINE TO THOMPSON BIRCHTREE. INSTALLATION INCLUDES 1-30 MVAR 230KV LINE REACTOR AND CIRCUIT SWITCHER, 1-230KV CIRCUIT BREAKER AND ASSOCIATED EQUIPMENT.

JUSTIFICATION:
ELSEWHERE IN THE BUDGET, JUSTIFICATION IS GIVEN FOR THE THOMPSON BIRCHTREE - HERBLET LAKE 230 KV LINE. THIS ITEM PROVIDES FOR LINE TERMINATION AT HERBLET LAKE STATION.

REFERENCE:
TPD REPORT 93-4, 'KETTLE AC TRANSMISSION OPTIONS'. GPD REPORT TM 93/5-GP, '1993/94 RELIABILITY EVALUATION OF REQUIREMENTS FOR GENERATION /TRANSMISSION ENHANCEMENTS'. TPD TM 93-20, 'FLIN FLON TRANSMISSION SECTIONALIZATION AT HERBLET LAKE'.

REVISION:
ISD DEFERRED FROM 2006 10 31 TO 2007 10 31.

CONTINGENCY: $336,000

IN SERVICE DATES				Base estimate
2007 10 31	4 670			199704 L2
				Work start date 2004 09 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:						
2003/04	96	14	2			112
2004/05	675	108	30			813
2005/06	1 508	269	155			1 932
2006/07	1 260	182	167			1 609
TOTAL	3 539	573	354			4 466
REV. AMOUNTS:						
Authorized to date:						
Over(under)expend:						
Auth 2004/05	111	16	3			130
Req.: 2005/06	700	120	34			854
2006/07	1 559	299	167			2 025
2007/08	1 281	200	180			1 661
TOTAL	3 651	635	384			4 670

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

1999-09-28 11:24 AM

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 03-00-3344

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1993 02	2 871	NEW ITEM.
1993 10	4 190	STALL LAKE 230 KV STATION NAME CHANGED TO HERBLET LAKE. SECTIONALIZATION OF PONTON - STALL LAKE - CLIFF LAKE 230 KV LINE WITH 2 - 230 KV BREAKERS DELETED. LINE REACTOR ADDED.
1994 10	4 525	IN-SERVICE DATE DEFERRED 6 YEARS TO 2006 10 31. REVISED INTEREST AND ESCALATION RATES.
1995 10	4 537	REVISED INTEREST AND ESCALATION RATES.
1997 10	4 491	SCOPE UNCHANGED, ESTIMATE REFLECTS REVISED COSTING METHODOLOGY IMPLEMENTED WITH THE NEW FINANCIAL REPORTING SYSTEM. IT ALSO REFLECTS INTEREST AND ESCALATION RATES.
1998 10	4 466	NO CHANGE

ASSOCIATED PROJECTS

Budget reference number	Description
02-00-7006	THOMPSON BIRCHTREE - HERBLET LAKE 230KV T/L
03-00-6116	THOMPSON MYSTERY LAKE PROTECTION CHANGES FOR BIRCHTREE T/L
03-00-6117	KELSEY PROTECTION CHANGES FOR THOMPSON BIRCHTREE 230KV T/L
03-00-8103	THOMPSON BIRCHTREE ESTABLISH STATION
05-00-3219	COMMUNICATIONS FOR THOMPSON BIRCHTREE 230 KV T/L

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item

130

Title			Budget reference number
THOMPSON MYSTERY LAKE PROTECTION CHANGES FOR BIRCHTREE T/L			03-00-6116
Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	70281

DESCRIPTION:
MODIFY PROTECTION EQUIPMENT AT THOMPSON MYSTERY LAKE ROAD TO CO-ORDINATE WITH CREATION OF THOMPSON MYSTERY LAKE ROAD - THOMPSON BIRCHTREE 230KV LINE FROM SECTIONALIZATION OF 230KV LINE K24W AT BIRCHTREE.

JUSTIFICATION:
ELSEWHERE IN THE BUDGET JUSTIFICATION IS GIVEN FOR SECTIONALIZATION OF 230KV LINE K24W AT THOMPSON BIRCHTREE STATION. THIS ITEM PROVIDES FOR NECESSARY PROTECTION CHANGES AT THOMPSON MYSTERY LAKE ROAD STATION TO ACCOMMODATE CREATION OF MYSTERY LAKE ROAD-BIRCHTREE 230KV LINE FROM K24W SECTIONALIZATION.

REFERENCE:
TPD REPORT 93-4, 'KETTLE AC TRANSMISSION OPTIONS'. GPD REPORT TM 93/5-GP, '1993/94 RELIABILITY EVALUATION OF REQUIREMENTS FOR GENERATION / TRANSMISSON ENHANCEMENTS'.

REVISION:
ISD DEFERED FROM 2006 10 31 TO 2007 10 31.

CONTINGENCY: $21,000

IN SERVICE DATES			Base estimate
2007 10 31	302		199706 L2
			Work start date 2006 04 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:						
2005/06	137	25	6			168
2006/07	79	15	10			104
TOTAL	216	40	16			272
REV. AMOUNTS:						
Authorized to date:						
Over(under)expend:						
Auth 2006/07	154	30	7			191
Req.: 2007/08	82	18	11			111
TOTAL	236	48	18			302

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

1999-09-28 11:24 AM

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number: 03-00-6116

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1995 10	266	NEW ITEM.
1996 06	265	REVISED INTEREST RATES.
1997 10	264	SCOPE UNCHANGED, ESTIMATE REFLECTS REVISED COSTING METHODOLOGY IMPLEMENTED WITH THE NEW FINANCIAL REPORTING SYSTEM. ALSO REFLECTS REVISED INTEREST AND ESCALATION RATES.
1998 10	284	NO CHANGE

ASSOCIATED PROJECTS

Budget reference number	Description
02-00-7006	THOMPSON BIRCHTREE - HERBLET LAKE 230KV T/L
03-00-3344	HERBLET LAKE TERMINATE THOMPSON BIRCHTREE 230KV T/L
03-00-6117	KELSEY PROTECTION CHANGES FOR THOMPSON BIRCHTREE 230KV T/L
03-00-8103	THOMPSON BIRCHTREE ESTABLISH STATION
05-00-3219	COMMUNICATIONS FOR THOMPSON BIRCHTREE 230 KV T/L

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item

131

Title			Budget reference number
KELSEY PROTECTION CHANGES FOR THOMPSON BIRCHTREE 230KV T/L			03-00-6117
Originating division Planning & Control	Coordinating division Design	Constructing division Construction	Project Order Group (Range): 70282

DESCRIPTION:
MODIFY PROTECTION EQUIPMENT AT KELSEY TO CO-ORDINATE WITH CREATION OF KELSEY - THOMPSON BIRCHTREE 230KV LINE FROM SECTIONALIZATION OF 230KV LINE K24W AT THOMPSON BIRCHTREE.

JUSTIFICATION:
ELSEWHERE IN THE BUDGET, JUSTIFICATION IS GIVEN FOR SECTIONALIZATION OF 230KV LINE K24W AT THOMPSON BIRCHTREE STATION. THIS ITEM PROVIDES FOR NECESSARY PROTECTION CHANGES AT KELSEY TO ACCOMMODATE CREATION OF KELSEY - THOMPSON BIRCHTREE 230KV LINE FROM SECTIONALIZATION OF LINE K24W.

REFERENCE:
TPD REPORT 93-4, 'KETTLE AC TRANSMISSION OPTIONS'. GPD REPORT TM 93/5-GP, '1993/94 RELIABILITY EVALUATION OF REQUIREMENTS FOR GENERATION / TRANSMISSION ENHANCEMENTS'.

REVISION:
ISD DEFERRED FROM 2006 10 31 TO 2007 10 31.

CONTINGENCY: $21,000

IN SERVICE DATES				Base estimate
2007 10 31	302			199706 L2
				Work start date 2006 04 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:						
2005/06	137	25	6			168
2006/07	79	15	10			104
TOTAL	216	40	16			272
REV. AMOUNTS:						
Authorized to date:						
Over(under)expend:						
Auth 2006/07	154	30	7			191
Req.: 2007/08	82	18	11			111
TOTAL	236	48	18			302

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 03-00-6117

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1996 06	266	REVISED INTEREST RATES.
1997 10	264	SCOPE UNCHANGED, ESTIMATE REFLECTS REVISED COSTING METHODOLOGY IMPLEMENTED WITH THE NEW FINANCIAL REPORTING SYSTEM. ALSO REFLECTS REVISED INTEREST AND ESCALATION RATES.
1998 10	272	NO CHANGE

ASSOCIATED PROJECTS

Budget reference number	Description
02-00-7006	THOMPSON BIRCHTREE - HERBLET LAKE 230KV T/L
03-00-3344	HERBLET LAKE TERMINATE THOMPSON BIRCHTREE 230KV T/L
03-00-6116	THOMPSON MYSTERY LAKE PROTECTION CHANGES FOR BIRCHTREE T/L
03-00-8103	THOMPSON BIRCHTREE ESTABLISH STATION
05-00-3219	COMMUNICATIONS FOR THOMPSON BIRCHTREE 230 KV T/L

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item

132

Title			Budget reference number
COMMUNICATIONS FOR THOMPSON BIRCHTREE 230 KV T/L			05-00-3219
Originating division: Planning & Control	Coordinating division: Planning & Control	Constructing division: Construction	Project Order Group (Range): 70283

DESCRIPTION:
DESIGN, INSTALL, AND COMMISSION COMMUNICATION SYSTEM ADDITIONS REQUIRED FOR PROTECTION OF 230 KV LINES FROM NEW THOMPSON BIRCHTREE STATION TO HERBLET LAKE, THOMPSON MYSTERY LAKE ROAD AND KELSEY.

JUSTIFICATION:
ELSEWHERE IN THE BUDGET, JUSTIFICATION IS GIVEN FOR THOMPSON - HERBLET LAKE 230 KV LINE AND THOMPSON BIRCHTREE STATION. THIS ITEM PROVIDES FOR COMMUNICATIONS, PROTECTION AND CONTROL FACILITIES FOR ALL LINES TERMINATING AT BIRCHTREE STATION.

REFERENCE:
TPD REPORT 93-4, 'KETTLE AC TRANSMISSION OPTIONS'. GPD REPORT TM 93/5-GP, ' 1993/94 RELIABILITY EVALUATION OF REQUIREMENTS FOR GENERATION / TRANSMISSION ENHANCEMENTS'

REVISION:
ISD DEFERRED FROM 2006 10 31 TO 2007 10 31.

CONTINGENCY: $ 20,000

IN SERVICE DATES				Base estimate
2007 10 31	2 587			199704 L2
				Work start date: 2006 04 01

PREV. AUTHORITY Authorized to date:	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
2005/06	167	30	8			205
2006/07	1 692	342	49			2 083
TOTAL	1 859	372	57			2 288
REV. AMOUNTS: Authorized to date: Over(under)expend:						
Auth 2006/07	183	36	9			228
Req.: 2007/08	1 898	406	55			2 359
TOTAL	2 081	442	64			2 587

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

MajCER(2).Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 05-00-3219

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1993 02	3 591	NEW ITEM.
1993 10	2 323	STALL LAKE 230 KV STATION NAME CHANGED TO HERBLET LAKE. REVISED ESTIMATE IS BASED ON CURRENT INFORMATION.
1994 10	2 562	IN-SERVICE DATE DEFERRED 6 YEARS TO 2006 10 31. FACILITIES FOR RADISSON-KELSEY-THOMPSON TRANSFERRED TO NEW BRN IN STAGE 1 COMPLEX. REVISED INTEREST AND ESCALATION RATES.
1995 10	2 558	REVISED ESCALATION AND INTEREST RATES.
1996 10	2 558	REVISED INTEREST RATES.
1997 10	2 388	SCOPE UNCHANGED, ESTIMATE REFLECTS REVISED COSTING METHODOLOGY IMPLEMENTED WITH THE NEW FINANCIAL REPORTING SYSTEM. ESTIMATE ALSO REFLECTS REVISED INTEREST AND ESCALATION RATES.
1998 10	2 288	NO CHANGE

ASSOCIATED PROJECTS

Budget reference number	Description
02-00-7006	THOMPSON BIRCHTREE - HERBLET LAKE 230KV T/L
03-00-3344	HERBLET LAKE TERMINATE THOMPSON BIRCHTREE 230KV T/L
03-00-6116	THOMPSON MYSTERY LAKE PROTECTION CHANGES FOR BIRCHTREE T/L
03-00-6117	KELSEY PROTECTION CHANGES FOR THOMPSON BIRCHTREE 230KV T/L
03-00-8103	THOMPSON BIRCHTREE ESTABLISH STATION

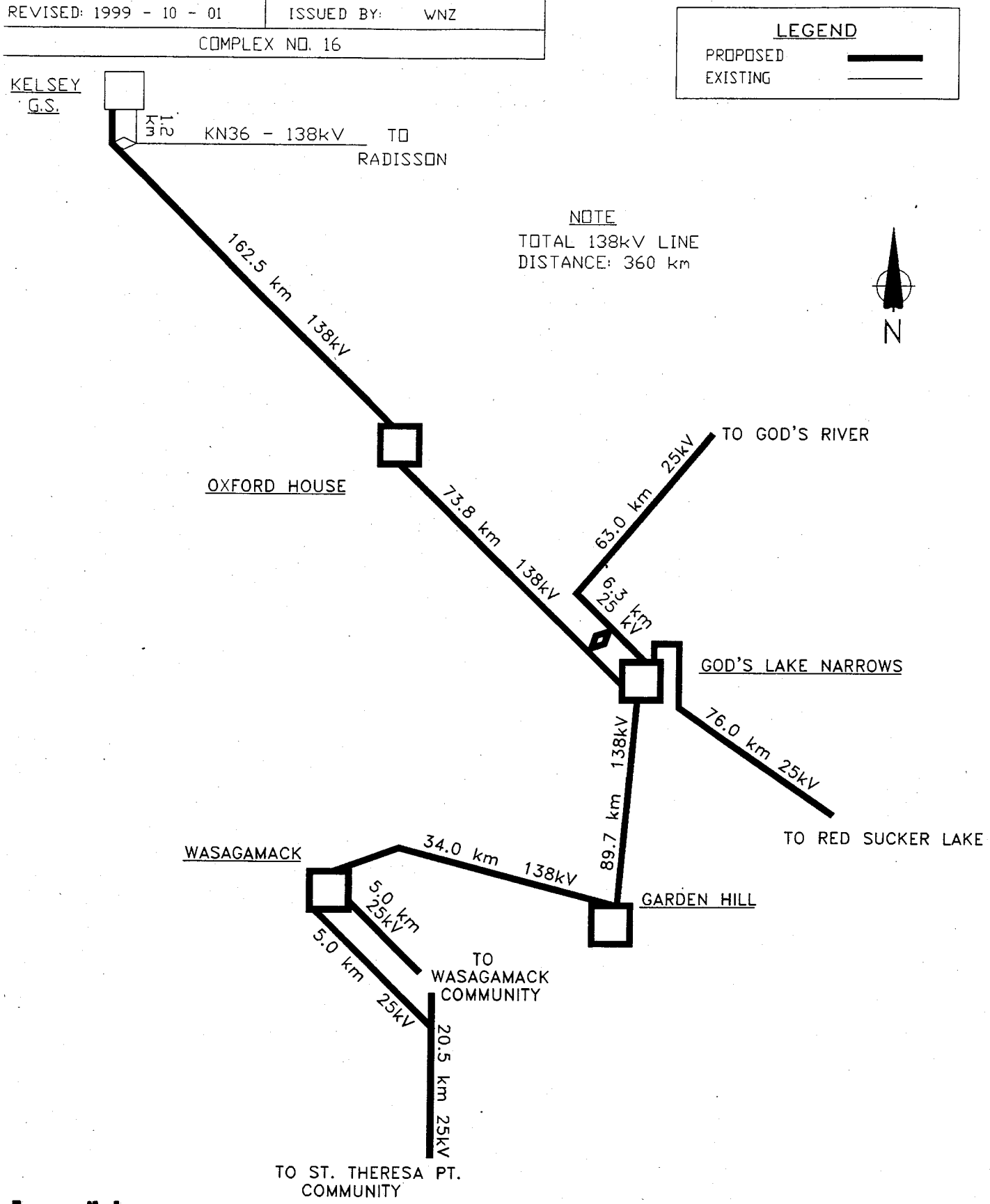
Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

CAPITAL BUDGET COMPLEX CONCEPTUAL DIAGRAM

NORTH CENTRAL MANITOBA TRANSMISSION

REVISED: 1999 - 10 - 01 | ISSUED BY: WNZ

COMPLEX NO. 16



manitoba hydro

PLANNING AND CONTROL DIVISION

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

COMPLEX STATUS: ☐ Planned ☒ In progress

Complex no. 16

REVISION STATUS: ☐ New complex ☐ In service change ☐ Concept change ☒ Estimate change only

COMPLEX: NORTH CENTRAL MANITOBA PROJECT

Proposal

Perform environmental assessments and route selection, design and construct transmission and terminal facilities for central supply to Island Lake communities from Kelsey as follows:
Transmission: 138 KV line 360 KM Kelsey - Oxford House - God's Lake Narrows - Garden Hill - Wasagamack. 25 KV feeder lines 63.0 KM God's Lake Narrows - God's River, 76.0 KM God's Lake Narrows - Red Sucker Lake, 30.5 KM of single/double circuit between Wasagamack station and Wasagamack & St. Theresa communities.
Terminations: Extend 138 KV facilities at Kelsey. Construct 138-25 KV distribution stations and required feeders at Oxford House, God's Lake Narrows, Garden Hill, and Wasagamack. Communications: VHF Mobile coverage using VHF repeaters. Supervisory control at Oxford House, God's Lake Narrows and Garden Hill.

JUSTIFICATION: ☒ Load ☒ Service ☐ Safety ☐ Efficiency ☒ Reliability ☐ Other

Explanation

The 138 KV line and associated distribution facilities will provide central supply to seven Island Lake communities, as per agreement between Manitoba Hydro, the aboriginal communities, the Manitoba Provincial government, and the Federal Government.

Estimate Level	COMPLEX START (yyyy mm)
L3	1990 01

IN SERVICE DATES AND AMOUNTS

1997 10	$85381	1998 04	$19916	1998 09	$400	1999 03	$40652
1999 04	$9936	1999 05	$8544	1999 07	$182	1999 12	$2753
2000 02	$753	2000 11	$210	2000 12	$1511	2001 12	$2742

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	147,420		18,826	149,616	16,630	16,649	-19	-0
Year 99/00	5,454	145	205	5,763	41	784	-743	-95
00/01	1,710	97	52	1,511	348	334	14	4
01/02	2,439	190	84	2,275	438	518	-80	-15
02/03	10			10	0	1	-1	-100
03/04								
04/05								
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	157,033	432	19,167	159,175	17,457	18,286	-829	-5

REVISION: Relects actual costs to completion.

Reviewed by ORIGINATOR	yyyy mm dd 99 11 08	Reviewed by COORDINATOR	yyyy mm dd 99 11 03
Reviewed by CONSTRUCTOR	yyyy mm dd 99 11 03	Approved by VICE PRESIDENT	yyyy mm dd 99 11 16

H2856/r Rev 99 03

Complex no. 16

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Advance or deferral impact

Delays in this project will extend the duration of limited supply of electricity to affected communities from diesel generation.

Factors affecting timing or viability

Environmental Licensing.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	%
North Central MB T/L ROW, Site Sel & Env Approval	1,542	6,243	6,368	7,107	739	12
North Central Manitoba 138 KV T/L	36,753	68,372	69,739	66,972	-2,767	-4
North Central Manitoba Community Involvement	1,252	5,088	5,190	5,054	-136	-3
Kelsey-Terminate 138 KV Line to Oxford House	2,114	1,558	1,589	1,559	-30	-2
Oxford House New 138-25 KV Station	3,476	8,335	8,502	8,379	-123	-1
God's Lake Narrows New 138-25 KV Station	6,481	9,058	9,239	9,048	-191	-2
Garden Hill New 138-25 KV Station	3,493	10,586	10,798	10,998	200	2
Wasagamack New 138-25 KV Station	3,289	7,479	7,629	7,153	-476	-6
Oxford House Community Central Supp (completed)	434	2,042	2,042	2,042	0	0
Gods River Community Central Supp (completed)	2,871	5,543	5,570	5,570	0	0
Red Sucker Lake Community - Central Supply	3,628	8,421	8,589	8,568	-21	-0
Island Lake Communities - Central Supply	1,292	8,777	8,953	9,445	492	5
God's Lake Narrows Community - Central Supply	575	1,793	1,829	1,770	-59	-3
Salvage of Diesel Sites-North Central Project	1,050	1,593	1,625	1,646	21	1
Soil Remediation of Diesel Sites-North Centrl Proj	8,176	7,955	8,114	8,066	-48	-1
North Central VHF Communications (completed)	430	365	365	365	0	0
St Theresa > Wasagamack Tie Feeder (completed)	3,291	3,291	3,291	3,291	0	0
TOTAL	80,147	156,499	159,432	157,033	-2,399	-2

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
9510	34,461	Design now replaces 15.1 km of river crossing line with steel towers. Stn site areas increased and costs for line & stn materials. Diesel site soil remediation added.
9610	19,582	Communctns advanced to 95 10 31. Cost incrs for site imprvmnts, oil spill containmnt, materials,overhead. Net cost reduced to reflect Provincial contribution.
1997 10	18,127	16 km dbl-cct line north of GLN changed to 6.3 km. RS feeder layout changed. ISD of OH-GLN 138 kV line & service to GLN & GR advanced 10 months to 97 09 30.
1998 10	18,286	ISD of line, Garden Hill station, and Wasagamack station deferred approx. 10 months due to poor winter road conditions.
1999 10	17,457	Reflects actual costs to completion.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item

133

Title			Budget reference number
NORTH CENTRAL MB T/L R-0-W, SITE SELECTION & ENV. APPROVAL			02-00-0229
Originating division Planning & Control	Coordinating division Design	Constructing division Construction	Project Order Group (Range): 70058

DESCRIPTION:
PERFORM ROUTE ENGINEERING, ENVIRONMENTAL ASSESSMENTS, OBTAIN LICENCES AND ACQUIRE PROPERTY FOR APPROXIMATELY 360 KM OF 138KV TRANSMISSION LINE CONNECTING KELSEY WITH OXFORD HOUSE, GOD'S LAKE NARROWS, GARDEN HILL AND WASAGAMACK, FOR 25KV DISTRIBUTION LINES CONNECTING GOD'S LAKE NARROWS TO GOD'S RIVER AND RED SUCKER LAKE, AND 25KV DISTRIBUTION LINE CONNECTING WASAGAMACK AND ST.THERESA POINT. PERFORM SITE SELECTION, ENVIRONMENTAL ASSESSMENTS, OBTAIN LICENCES AND ACQUIRE PROPERTY FOR STATION SITES AT OXFORD HOUSE, GOD'S LAKE NARROWS, GARDEN HILL AND WASAGAMACK.

JUSTIFICATION:
ELSEWHERE IN THE BUDGET, JUSTIFICATION IS GIVEN FOR THE DESIGN AND CONSTRUCTION OF A 138KV CENTRAL SUPPLY T/L BETWEEN KELSEY AND THE COMMUNITIES OF OXFORD HOUSE, GOD'S LAKE NARROWS, GARDEN HILL AND WASAGAMACK. THIS ITEM PROVIDES FOR ROUTE AND STATION SITE SELECTION, CONDUCTING THE ENVIRONMENTAL REVIEW PROCESS AND ACQUIRING THE LICENCE, AND ACQUISITION OF NECESSARY R.O.W. AND STATION SITES AT THESE COMMUNITIES.

REFERENCE:
REPORT SPD 83-12 ALTERNATIVES TO DIESEL ELECTRIC SUPPLY AT NORTHEAST ISOLATED COMMUNITIES.

REVISION:
ISD ADVANCED FROM 199905 TO 199903. ORDER 115365 WINTER ROAD 1998/1999 ADDED, VALUE $500,000. CONTINGENCY HAS BEEN REMOVED.

IN SERVICE DATES				Base estimate
1997 07 31	4 478	1999 04 30	902	199903 L5
1997 10 31	1 835			Work start date
1998 04 30	2 378			1989 12 01
1999 03 31	855			

	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
PREV. AUTHORITY Authorized to date:	6 216		3 329			9 545
1999/00	35	17	8			60
TOTAL	6 251	17	3 337			9 605
REV. AMOUNTS: Authorized to date:	6 216		3 329			9 545
Over(under)expend: Auth 1999/00 Req.:	891	12				903
TOTAL	7 107	12	3 329			10 448

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 02-00-0229

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1989 10	1 274	NEW ITEM.
1990 10	1 907	INCLUDES MONEY TRANSFERRED FROM DOMESTIC WO 43356 FOR PRELIMINARY WORK FIELD PROGRAM). COST INCREASE DUE TO INCREASED LENGTHOF LINE AND 1 ADDITIONAL STATION SITE, AND A MORE COMPLEX ENVIRONMENTAL AND REGULATORY PROCESS. ACCURACY UPGRADED FROM LEVEL 2 TO 3.
1991 10	3 050	ISD DEFERRED 9 MONTHS. CONSULTANTS FEES AND PARTICIPANT ASSISTANCE DURING HEARINGS ARE INCLUDED IN THIS YEAR'S ESTIMATE. THE ENVIRONMENTAL REVIEW PROCESS IS LENGTHENED DUE TO THE JOINT FEDERAL/ PROV. REVIEW PANAL. DISTRIBUTION LEVEL NOW 25 KV, PREVIOUSLY 12 KV.
1992 10	5 119	ISD DEFERRED FROM 1993 03 30 TO CONTINUE CAPITALZG' INTERESTUNTIL ISD OF ASSCTD. MAJOR PROJECT. LINE LENGTH INCRSD.17 KM TO 361 KM. GREATER CONSULTANT FEES TO MEET INFORMATION REQ'D FOR ENVRNMNTAL REVIEW.
1993 10	7 836	CONSULTANT FEE ESTMTS INCREASED $318000. MH SHARE ($400000) OF REVIEW PANEL EXPENSES NOT ANTICIPATED BY ENV. AFFRS IN 1992. MH COSTFOR CONSULTANT SUPPORT INCREASED $513000. LEGAL SURVEY ($551000) CHANGEDFROM RISK TO PART OF ESTIMATE. ADD ENG COST FOR STN SITE SELECT($275000)
1994 10	9 727	IN-SERVICE DATES DEFERRED 1 YEAR TO 1997 07 31 & 1998 07 31.INCREASE IN ESTIMATE DUE TO: ORIENTATION OF TRAPPERS AFFECTED BY LINE ROUTING; CONSULTING SERVICES FOR PUBLIC REVIEW AND FACILITATING THE COMPLETION OF COMMUNITY APPROVALS PROCESS; PROVINCIAL SHARE OF PANEL COSTS; AND ON-GOING EXTENSIVE PROCESS BETWEEN NORTHERN COMMUNITIES, MANITOBA HYDRO AND VARIOUS LEVELS OF GOVERNMENT. LINE LENGTH DECREASED BY 1 KM.
1995 10	9 660	REVISED INTEREST AND ESCALATION RATES.
1996 10	9 671	REFLECTS REVISED INTEREST RATES.
1997 10	9 887	ESTIMATE UNCHANGED. ISD'S REVISED TO MATCH THE TRANSMISSION LINE IN SERVICE DATES.
1998 10	9 606	OUTSTANDING WORK IS RELATED PRIMARILY TO THE LEGAL SURVEYS, WHICH HAS BEEN RESCHEDULED FOR COMPLETION BY 1999 07 31. COSTS FOR LEGAL SURVEYS NOW BASED ON PRICES RECEIVED FOR SURVEYING THE FIRST FEW PORTIONS OF THE TRANSMISSION LINE, RESULTING IN A DECREASE IN ESTIMATE. ISD ADDED TO REFLECT IN-SERVICE OF TEMPORARY 25 kV SUPPLY TO GARDEN HILL.

ASSOCIATED PROJECTS

Budget reference number	Description
02-00-0230	NORTH CENTRAL 138KV T/L
02-00-0231	NORTH CENTRAL-FEDERAL CAPITAL CONTRIBUTIONS-ELECTRIFICATION
02-00-0232	NORTH CENTRAL - COMMUNITY INVOLVEMENT
02-00-7993	NORTH CENTRAL-PROVINCIAL CAPITAL CONTRIBUTIONS
03-00-0615	GOD'S LAKE NARROWS NEW 138-25KV STATION
03-00-0616	GARDEN HILL NEW 138-25 KV STATION
03-00-0617	OXFORD HOUSE NEW 138-25 KV STATION
03-00-0618	KELSEY TERMINATE OXFORD HOUSE 138KV LINE
03-00-1648	WASAGAMACK NEW 138-25 KV STATION
04-00-0361	OXFORD HOUSE COMMUNITY - CENTRAL SUPPLY
04-00-0362	GOD'S RIVER COMMUNITY - CENTRAL SUPPLY
04-00-0363	RED SUCKER LAKE COMMUNITY - CENTRAL SUPPLY
04-00-0364	ISLAND LAKE COMMUNITIES - CENTRAL SUPPLY
04-00-0365	GOD'S LAKE NARROWS COMMUNITY - CENTRAL SUPPLY
04-00-0369	NORTH CENTRAL - SALVAGE OF DIESEL GENERATING STATIONS
04-00-6509	NORTH CENTRAL-FEDERAL CAPITAL CONTRIBUTIONS-SOIL REMEDIATION
04-00-6517	NORTH CENTRAL - SOIL REMEDIATION OF DIESEL SITES

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	339	9				348	348
May	264	1				265	613
Jun	9					9	622
Jul	10					10	632
Aug	10					10	642
Sep	10					10	652
Oct	45	1				46	698
Nov	47	1				48	746
Dec	128	1				129	875
Jan	9					9	884
Feb	9					9	893
Mar	11	-1				10	903
TOTAL	891	12				903	903
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

1999-09-28 11:29 AM

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item

134

Title			Budget reference number
NORTH CENTRAL 138KV T/L			02-00-0230
Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	70059

DESCRIPTION:
DESIGN AND CONSTRUCT APPROXIMATELY 360KM OF 138KV TRANSMISSION LINE FROM KELSEY TO OXFORD HOUSE, GOD'S LAKE NARROWS, GARDEN HILL AND WASAGAMACK. LINE CONSTRUCTION TO BE STAGED AS: 1997 07 31: KELSEY - OXFORD HOUSE 1998 07 31: OXFORD HOUSE - GOD'S LAKE NARROWS - GARDEN HILL. 1999 07 31 GARDEN HILL-WASAGAMACK. LINE DESIGN IS TO ACCOMMODATE 138 KV +10% NOMINAL OPERATING VOLTAGE. LINE IS TO BE CONSTRUCTED AS SINGLE CIRCUIT GUYED TUBULAR STEEL STRUCTURES USING 336.4 MCM ACSR CONDUCTOR EXCEPT FOR FOLLOWING SECTIONS: 1.2 KM 605 MCM ACSR FROM KELSEY ON UNUSED SIDE OF 138KV LINE KN36 DOUBLE CIRCUIT TOWERS. 80 KM OF WOODPOLE STRUCTURES USING 266.8 MCM CONDUCTOR FROM NELSON RIVER TO HIGH LAKE. 6.3 KM OF DOUBLE CCT 336 MCM DIRECTED NORTH FROM GOD'S LAKE NARROWS WITH 2ND SIDE BUILT FOR 25 OR 66 KV TO FORM PART OF FEEDER LINE TO GOD'S RIVER. 15.1 KM 336 MCM FOR NELSON, HAYS, AND ISLAND LAKE CROSSINGS ON STEEL TOWERS.

JUSTIFICATION:
AN AGREEMENT HAS BEEN SIGNED BETWEEN THE FEDERAL GOVERNMENT, THE PROVINCIAL GOVERNMENT AND MANITOBA HYDRO TO EXTEND CENTRAL ELECTRIC SUPPLY TO THE ISLAND LAKE COMMUNITIES ON A SHARED COST BASIS. THIS ITEM PROVIDES FOR THE DESIGN AND CONSTRUCTION OF THE TRANSMISSION LINE TO BRING CENTRAL SUPPLY FROM KELSEY INTO THE SEVEN AFFECTED COMMUNITIES.

REFERENCE:
REPORT SPD 83-12 ALTERNATIVES TO DIESEL ELECTRIC SUPPLY AT NORTHEAST ISOLATED COMMUNITIES.

REVISION:
CONTINGENCY OF $1,200,000 HAS BEEN REMOVED. LINE IS COMPLETE. INSERVICE DATE ADVANCED TO 99 03 31 FROM 99 05 31.

IN SERVICE DATES				Base estimate
1997 07 31	17 605	1999 04 30	576	199903 L3
1997 10 31	30 564			Work start date
1998 04 30	11 686			1991 01 01
1999 03 31	12 169			

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:	66 403		5 619	- 152		71 870
1999/00	2 233	11	180			2 424
TOTAL	68 636	11	5 799	- 152		74 294
REV. AMOUNTS:						
Authorized to date:	66 403		5 619	- 152		71 870
Over(under)expend:						
Auth 1999/00	521	7				528
Req.: 2000/01	48	2				50
TOTAL	66 972	9	5 619	- 152		72 448

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

1999-09-28 11:29 AM

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 02-00-0230

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1989 10	39 915	NEW ITEM.
1990 10	48 922	INCREASE REFLECTS FIELD PROGRAM CONDUCTED IN FALL 1989 THAT POINTED TO THE NEED FOR A SUBSTANTIALLY GREATER NUMBER OF ANCHORS THAN ORIGINALLY ESTIMATED. 138 KV LINE INCREASED 34KM TO INCLUDE NEW SECTION FROM GARDEN HILL TO WASAGAMACK REDUCING 25 KV FEEDER.
1991 10	56 991	ISD DEFERRED 1 YEAR. ENGINEERING, MAT'L & CONSTRUCTION COSTSINCREASED. REVISED CONSTRUCTION ESTIMATE TO INCLUDE ITEMS ORIGINALLY OVERLOOKED OR UNDERESTIMATED, IE: MAT'L DISTRIBTN, CLEARING, BORROWFILL.
1992 10	57 160	ISDS DEFER 1 YEAR. ROUTE CHNG INCRS LINE LENGTH 344 TO 361KM
1993 10	56 987	UPDATED INTEREST & ESCALATION RATES.
1994 10	61 425	TOTAL LINE LENGTH DECREASED 1 KM TO 360 KM. 1.2 KM OF 605 MCM DOUBLE CIRCUIT LINE & 16 KM OF 336 MCM DOUBLE CIRCUIT LINE REPLACES 266 MCM SINGLE CIRCUIT LINE. NOMINAL LINE VOLTAGE INCREASED TO 138KV +10%. COSTS FOR ENVIRONMENTAL PROTECTION, TRAPPER COMPENSATION AND COMMUNITY LIASON COMMITTEE ADDED. IN-SERVICE DATES DEFERRED 1 YEAR TO 1997 07 31 AND 1998 07 31.
1995 10	60 491	SOIL PROGRAM COSTS REVISED TO REFLECT COMPRESSED SCHEDULE. CONTRACT NEGOTIATION AND ADMINISTRATION COSTS INCREASED. PRICE INCREASES FOR WOOD POLES AND INSULATORS. 15.1 KM OF 336 MCM STEEL TOWERCROSSING LINE REPLACES 266 MCM LINE.
1996 10	59 252	ACTUAL MATERIAL PRICES ARE LOWER THAN ESTIMATES AS A RESULT OF FAVORABLE MARKET CONDITIONS.
1997 10	73 979	INCREASES DUE TO SINGLE-SOURCE NEGOTIATIONS FOR CLEARING AND CONSTRUCTION, HIGHER COSTS ASSOCIATED WITH THE DOUBLE CIRCUIT PORTION OF THE LINE AND ANCHOR INSTALLATION, AND MORE STEEL STRUCTURES IDENTIFIED DURING DETAILED TOWER SPOTTING. OXFORD TO GODS LAKE NARROWS PORTION OF LINE WILL BE BROUGHT IN SERVICE TEN MONTHS EARLY IN 1997 09 30. MORE ACCURATE CALCULATION OF ISD AMOUNTS.
1998 10	74 294	FINAL ISD DEFERRED 10 MONTHS FROM 1998 07 31 TO 1999 05 31. ISD ADDED TO REFLECT SPRING 1998 IN-SERVICE OF TEMPORARY 25 kV SUPPLY TO GARDEN HILL. CONTINGENCY REDUCED BASED ON WORK REMAINING.

ASSOCIATED PROJECTS

Budget reference number	Description
02-00-0229	NORTH CENTRAL MB T/L R-0-W, SITE SELECTION & ENV. APPROVAL
02-00-0231	NORTH CENTRAL-FEDERAL CAPITAL CONTRIBUTIONS-ELECTRIFICATION
02-00-0232	NORTH CENTRAL - COMMUNITY INVOLVEMENT
02-00-7993	NORTH CENTRAL-PROVINCIAL CAPITAL CONTRIBUTIONS
03-00-0615	GOD'S LAKE NARROWS NEW 138-25KV STATION
03-00-0616	GARDEN HILL NEW 138-25 KV STATION
03-00-0617	OXFORD HOUSE NEW 138-25 KV STATION
03-00-0618	KELSEY TERMINATE OXFORD HOUSE 138KV LINE
03-00-1648	WASAGAMACK NEW 138-25 KV STATION
04-00-0361	OXFORD HOUSE COMMUNITY - CENTRAL SUPPLY
04-00-0362	GOD'S RIVER COMMUNITY - CENTRAL SUPPLY
04-00-0363	RED SUCKER LAKE COMMUNITY - CENTRAL SUPPLY
04-00-0364	ISLAND LAKE COMMUNITIES - CENTRAL SUPPLY
04-00-0365	GOD'S LAKE NARROWS COMMUNITY - CENTRAL SUPPLY
04-00-0369	NORTH CENTRAL - SALVAGE OF DIESEL GENERATING STATIONS
04-00-6509	NORTH CENTRAL-FEDERAL CAPITAL CONTRIBUTIONS-SOIL REMEDIATION
04-00-6517	NORTH CENTRAL - SOIL REMEDIATION OF DIESEL SITES

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	60	1				61	61
May	50					50	111
Jun	50					50	161
Jul	44	1				45	206
Aug	53	1				54	260
Sep	53	1				54	314
Oct	35	1				36	350
Nov	35	1				36	386
Dec	35	1				36	422
Jan	35	1				36	458
Feb	35	1				36	494
Mar	36	-2				34	528
TOTAL	521	7				528	528
2000/01 Apr	8					8	8
May	8					8	16
Jun	8					8	24
Jul	8					8	32
Aug	8					8	40
Sep	8	2				10	50
Oct							50
Nov							50
Dec							50
Jan							50
Feb							50
Mar							50
TOTAL	48	2				50	50

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item

135

Title			Budget reference number
NORTH CENTRAL-FEDERAL CAPITAL CONTRIBUTIONS-ELECTRIFICATION			02-00-0231
Originating division onstruction	Coordinating division Construction	Constructing division Construction	Project Order Group (Range): 70060:72097

DESCRIPTION:
RECORD CONTRIBUTIONS FROM THE FEDERAL GOVERNMENT TOWARDS THE COST OF THE NORTH CENTRAL MANITOBA TRANSMISSION FACILITIES.

JUSTIFICATION:
A SHARED COST AGREEMENT DATED 1992 03 16 WITH AMENDING AGREEMENT NO.1 DATED 1995 03 31, HAS BEEN NEGOTIATED BETWEEN THE GOVERNMENT OF CANADA AND MANITOBA HYDRO TO EXTEND CENTRAL ELECTRICAL SUPPLY TO SEVEN COMMUNITIES IN NORTH CENTRAL MANITOBA. THE FEDERAL GOVERNMENT WILL CONTRIBUTE 75% OF THE FIXED COSTS (UP TO A MAXIMUM) AND 75% OF APPROVED RISK COSTS (UP TO A MAXIMUM).

REFERENCE:
REPORT SPD 83-12 'ALTERNATIVES TO DIESEL ELECTRIC SUPPLY AT NORTHEAST ISOLATED COMMUNITIES'.

REVISION:
UPDATED TO REFLECT ON AN ANNUAL BASIS CANADA'S SHARE (CURRENTLY ESTIMATED AT 75%) OF THE NEWLY REVISED CERS FOR THE NORTH CENTRAL PROJECT, COMPLEX #016 (EXCLUDING BRN 04-00-6517 FOR SOIL REMEDIATION, WHICH IS COVERED BY THE FEDERAL CONTRIBUTIONS FOR SOIL REMEDIATION BRN 04-00-6509).

IN SERVICE DATES			Base estimate 199804 L3
			Work start date 1990 03 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:					- 110 206	- 110 206
1999/00	-12 465				-2 000	-14 465
2000/01					-12	-12
2001/02					-8	-8
2002/03					-8	-8
TOTAL	-12 465				- 112 234	- 124 699
REV. AMOUNTS:						
Authorized to date:					- 110 206	- 110 206
Over(under)expend:						
Auth 1999/00					-2 216	-2 216
Req.: 2000/01					-53	-53
2001/02					-8	-8
2002/03					-8	-8
TOTAL					- 112 491	- 112 491

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 02-00-0231

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1989 07	-67 396	NEW ITEM.
1990 10	-84 226	INCREASE IS DIRECTLY PROPORTIONAL TO INCREASE IN PROJECTED COMPLEX COSTS. INTEREST REPRESENTS ADVANCEMENT OF THE PAYMENT SCHEDULE.
1991 10	-99 192	INCREASE IS DIRECTLY PROPORTIONAL TO INCREASE IN ESTIMATED COMPLEX COSTS. PROJECT IN-SERVICE DATES DEFERRED ONE YEAR.
1992 10	-84 367	PROJECT IN-SERVICE DATES WERE DEFERRED ONE YEAR. REVISED CONTRIBUTION REFLECTS THE AGREEMENT BETWEEN MANITOBA HYDRO AND THE PROVINCE OF MANITOBA WITH REGARD TO THE FIXING OF WATER POWER RENTAL RATES.
1993 10	-90 314	INCREASE IS DIRECTLY PROPORTIONAL TO INCREASE IN ESTIMATED COMPLEX COSTS.
1994 06	-90 314	REVISED TO REFLECT CONTRIBUTION RECEIVED IN 1994/95 AND ONE YEAR DEFERRAL OF THE COMPLEX.
1994 10	- 110 223	PROJECT IN-SERVICE DATES WERE DEFERRED ONE YEAR. INCREASE IS DIRECTLY PROPORTIONAL TO INCREASE IN ESTIMATED COMPLEX COSTS.
1995 05	- 110 223	TO REFLECT LARGE PREPAYMENT FROM FEDERAL GOV'T IN MARCH 1995
1995 10	- 103 965	FEDERAL CONTRIBUTIONS FOR THE SOIL REMEDIATION PORTION OF THE NORTH CENTRAL PROJECT TRANSFERRED TO NEW BRN 9604-00-6509. REVISIONALSO REFLECTS AMENDING AGREEMENT NO.1 TO THE NORTH CENTRAL HYDRO AGREEMENT, IN WHICH THE FEDERAL GOVERNMENT NOW AGREES TO PAY 75% OF THE COMPLEX COSTS DEFINED AS A MAXIMUM FIXED COST PLUS A MAXIMUM RISK COST. CASHFLOW REVISED TO REFLECT ANTICIPATED YEAR-END PAYMENTS AS HAS OCCURED OVER THE PAST TWO YEARS.
1996 10	- 103 325	TO REFLECT CANADA'S ANNUAL SHARE OF THE APPLICABLE COSTS UNDER THE NCP EXPENDITURE CERs.
1997 10	- 120 381	Revised to reflect Canada's share (currently estimated at 75%) of the corresponding expenditures CERs for the North Central Complex (excluding BRN 04-00-6517).
1998 10	- 124 699	UPDATED TO REFLECT ON AN ANNUAL BASIS CANADA'S SHARE (CURRENTLY ESTIMATED AT 75%) OF THE NEWLY REVISED CERS FOR THE NORTH CENTRAL PROJECT COMPLEX 016 (EXCLUDING BRN 04-00-6517 FOR SOIL REMEDIATION, WHICH IS COVERED BY THE FEDERAL CONTRIBUTIONS FOR SOIL REMEDIATION BRN 04-00-6509).

ASSOCIATED PROJECTS

Budget reference number	Description
02-00-0229	NORTH CENTRAL MB T/L R-0-W, SITE SELECTION & ENV. APPROVAL
02-00-0230	NORTH CENTRAL 138KV T/L
02-00-0232	NORTH CENTRAL - COMMUNITY INVOLVEMENT
02-00-7993	NORTH CENTRAL-PROVINCIAL CAPITAL CONTRIBUTIONS
03-00-0615	GOD'S LAKE NARROWS NEW 138-25KV STATION
03-00-0616	GARDEN HILL NEW 138-25 KV STATION
03-00-0617	OXFORD HOUSE NEW 138-25 KV STATION
03-00-0618	KELSEY TERMINATE OXFORD HOUSE 138KV LINE
03-00-1648	WASAGAMACK NEW 138-25 KV STATION
04-00-0361	OXFORD HOUSE COMMUNITY - CENTRAL SUPPLY
04-00-0362	GOD'S RIVER COMMUNITY - CENTRAL SUPPLY
04-00-0363	RED SUCKER LAKE COMMUNITY - CENTRAL SUPPLY
04-00-0364	ISLAND LAKE COMMUNITIES - CENTRAL SUPPLY
04-00-0365	GOD'S LAKE NARROWS COMMUNITY - CENTRAL SUPPLY
04-00-0369	NORTH CENTRAL - SALVAGE OF DIESEL GENERATING STATIONS
04-00-6509	NORTH CENTRAL-FEDERAL CAPITAL CONTRIBUTIONS-SOIL REMEDIATION
04-00-6517	NORTH CENTRAL - SOIL REMEDIATION OF DIESEL SITES

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr				-1 226		-1 226	-1 226
May				- 299		- 299	-1 525
Jun				-35		-35	-1 560
Jul				-95		-95	-1 655
Aug				-65		-65	-1 720
Sep				-65		-65	-1 785
Oct				-69		-69	-1 854
Nov				-67		-67	-1 921
Dec				- 129		- 129	-2 050
Jan				-38		-38	-2 088
Feb				- 128		- 128	-2 216
Mar							-2 216
TOTAL				-2 216		-2 216	-2 216
2000/01 Apr				-6		-6	-6
May				-6		-6	-12
Jun				-6		-6	-18
Jul				-23		-23	-41
Aug				-6		-6	-47
Sep				-6		-6	-53
Oct							-53
Nov							-53
Dec							-53
Jan							-53
Feb							-53
Mar							-53
TOTAL				-53		-53	-53

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item

136

Title			Budget reference number
NORTH CENTRAL - COMMUNITY INVOLVEMENT			02-00-0232
Originating division Construction	Coordinating division Construction	Constructing division Construction	Project Order Group (Range): 70100

DESCRIPTION:
DURING SITING AND CONSTRUCTION ACTIVITIES ASSOCIATED WITH THE NORTH CENTRAL PROJECT, TO CONTRACT A COMMUNITY SUPPORT AGENCY SO AS TO FACILITATE COMMUNITY INVOLVEMENT IN THE PROJECT. THIS AGENCY WOULD BE RESPONSIBLE FOR ESTABLISHING AND MAINTAINING EFFECTIVE COMMUNICATION NETWORKS AND INTERFACING BETWEEN THE COMMUNITIES AND MANITOBA HYDRO, CONTRACTORS ENGAGED BY MANITOBA HYDRO, THE FEDERAL AND PROVINCIAL GOVERNMENTS, AND THEIR RESPECTIVE AGENCIES, FOR PURPOSES OF ALERTING COMMUNITY RESIDENTS AS TO ACTIVITIES AND PROGRESS OF ALL PHASES OF THE PROJECT AND POTENTIAL BENEFITS INCLUDING TRAINING, EMPLOYMENT AND BUSINESS OPPORTUNITIES. TO PROVIDE FUNDS FOR THE DISSOLUTION OF WAPANUK.

JUSTIFICATION:
AN AGREEMENT HAS BEEN NEGOTIATED BETWEEN THE FEDERAL GOVERNMENT, THE PROVINCIAL GOVERNMENT AND MANITOBA HYDRO TO EXTEND CENTRAL ELECTRICAL SUPPLY TO SEVEN COMMUNITIES ON A COST SHARED BASIS. SECTION 17(2) OF THIS AGREEMENT REQUIRES THE ENGAGEMENT OF A COMMUNITY SUPPORT AGENCY SO AS TO FACILITATE THE COMMUNITIES OBTAINING OPTIMUM BENEFITS FROM THE PROJECT. SECTION 17(1) AND SCHEDULE C OF THE AGREEMENT REQUIRES MANITOBA HYDRO TO OPTIMIZE CONTRACT/SERVICE OPPORTUNITIES FOR LOCAL BUSINESSES.

REVISION:
REFLECTS COSTS TO COMPLETION

IN SERVICE DATES				Base estimate
1999 03 31	7 392			199803 L5
1999 04 30	109			Work start date 1990 02 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:	4 945		2 447			7 392
1999/00	77	1	213			291
2000/01	16					16
2001/02	11					11
2002/03	11					11
TOTAL	5 060	1	2 660			7 721
REV. AMOUNTS:						
Authorized to date:	4 945		2 447			7 392
Over(under)expend:						
Auth 1999/00	74					74
Req.: 2000/01	15					15
2001/02	10					10
2002/03	10					10
TOTAL	5 054		2 447			7 501

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

1999-09-28 11:29 AM

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 02-00-0232

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1989 10	1 036	NEW ITEM.
1990 10	1 834	COST ESTIMATE INCREASED TO REFLECT PROPOSALS RECEIVED FROM NEMCFC.
1991 10	1 980	CASH FLOW REVISED. IN-SERVICE DATES DELAYED ONE YEAR. ADDITIONAL FUNDS INCLUDED FOR EXTENDED DURATION.
1992 10	3 170	CASH FLOW REVISED. IN-SERVICE DATES DELAYED ONE YEAR. ADDITIONAL FUNDS INCLUDED FOR EXTENDED DURATION AND FOR FINANCIAL SUPPORT TO WAPANUK CORPORATION.
1993 10	4 650	THE FIRST NATION LEADERSHIP OF THE NORTH CENTRAL PROJECT HASAGREED TO THE FUNDING LEVELS UP TO DECEMBER 1993 AND AN ANTICIPATED COMMITMENT FOR THE NEXT TWELVE MONTHS. THE FORECAST FOR FUTURE YEARS ISBASED ON THE ANTICIAPTED REQUIREMENTS, SOME OF WHICH ARE STILL SUBJECT TO THE FORTHCOMING LICENSE CONDITIONS.
1994 10	6 906	INCREASED FUNDING FOR THE COMMUNITY SUPPORT AGENCY AND WAPANUK DUE TO A DELAY IN THE PROJECT RESULTING IN IN-SERVICE DATE DEFERRAL FROM 1997 07 31 TO 1998 07 31.
1995 10	8 248	INCREASED TO INCLUDE COSTS OF EXTERNAL AUDITS AND EXTENSION OF FUNDING FOR CSA FROM 1998 03 31 TO 1998 12 31. THREE NEW IN-SERVICE DATES ADDED TO COVER COMPLETION OF EXTERNAL AUDITS IN 1999, 2000, AND 2001.
1996 10	7 858	ESTIMATE ADJUSTED TO REFLECT DRAFT ONE YEAR AGREEMENT REACHED WITH THE CSA FOR 96/97.
1997 10	7 363	ESTIMATE REVISED TO REFLECT ACTUAL COSTS TO DATE PLUS REDUCED CSA BUDGET ESTABLISHED IN THE 1997/98 CSA AGREEMENT.
1998 10	7 740	IN-SERVICE DEFERRED BY SEVEN MONTHS (FROM 1998 12 31 TO 1999 07 31) DUE TO DELAY IN THE LAND LINE IN-SERVICE FOR GARDEN HILL AND WASAGAMACK.

ASSOCIATED PROJECTS

Budget reference number	Description
02-00-0229	NORTH CENTRAL MB T/L R-0-W, SITE SELECTION & ENV. APPROVAL
02-00-0230	NORTH CENTRAL 138KV T/L
02-00-0231	NORTH CENTRAL-FEDERAL CAPITAL CONTRIBUTIONS-ELECTRIFICATION
02-00-7993	NORTH CENTRAL-PROVINCIAL CAPITAL CONTRIBUTIONS
03-00-0615	GOD'S LAKE NARROWS NEW 138-25KV STATION
03-00-0616	GARDEN HILL NEW 138-25 KV STATION
03-00-0617	OXFORD HOUSE NEW 138-25 KV STATION
03-00-0618	KELSEY TERMINATE OXFORD HOUSE 138KV LINE
03-00-1648	WASAGAMACK NEW 138-25 KV STATION
04-00-0361	OXFORD HOUSE COMMUNITY - CENTRAL SUPPLY
04-00-0362	GOD'S RIVER COMMUNITY - CENTRAL SUPPLY
04-00-0363	RED SUCKER LAKE COMMUNITY - CENTRAL SUPPLY
04-00-0364	ISLAND LAKE COMMUNITIES - CENTRAL SUPPLY
04-00-0365	GOD'S LAKE NARROWS COMMUNITY - CENTRAL SUPPLY
04-00-0369	NORTH CENTRAL - SALVAGE OF DIESEL GENERATING STATIONS
04-00-6509	NORTH CENTRAL-FEDERAL CAPITAL CONTRIBUTIONS-SOIL REMEDIATION
04-00-6517	NORTH CENTRAL - SOIL REMEDIATION OF DIESEL SITES

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	18					18	18
May	18					18	36
Jun	18					18	54
Jul	2					2	56
Aug	2					2	58
Sep	2					2	60
Oct	2					2	62
Nov	2					2	64
Dec	2					2	66
Jan	2					2	68
Feb	2					2	70
Mar	4					4	74
TOTAL	74					74	74
2000/01 Apr	1					1	1
May	1					1	2
Jun	1					1	3
Jul	1					1	4
Aug	1					1	5
Sep	1					1	6
Oct	1					1	7
Nov	1					1	8
Dec	1					1	9
Jan	1					1	10
Feb	1					1	11
Mar	4					4	15
TOTAL	15					15	15

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item

137

Title			Budget reference number
NORTH CENTRAL-PROVINCIAL CAPITAL CONTRIBUTIONS			02-00-7993
Originating division Construction	Coordinating division Construction	Constructing division Construction	Project Order Group (Range): 70062:70477

DESCRIPTION:
REFLECT ANNUAL LIABILITY OF THE PROVINCE OF MANITOBA TOWARDS THEIR SHARE OF COSTS FOR THE NORTH CENTRAL PROJECT.

JUSTIFICATION:
A SHARED COST AGREEMENT DATED 1992 03 16 WITH AMENDING AGREEMENT NO.1 DATED 1995 03 31, HAS BEEN NEGOTIATED BETWEEN THE GOVERNMENT OF MANITOBA AND MANITOBA HYDRO TO EXTEND CENTRAL ELECTRICAL SUPPLY TO SEVEN COMMUNITIES IN NORTH CENTRAL MANITOBA. THE PROVINCIAL GOVERNMENT'S LIABILITY IS 15% OF THE FIXED COSTS (UP TO A MAXIMUM) AND 15% OF APPROVED RISK COSTS (UP TO MAXIMUM). SUBSEQUENTLY, AN ADMINISTRATIVE AGREEMENT WAS SIGNED BETWEEN THE PROVINCE AND HYDRO DATED 1995 07 10 WHICH OUTLINES HOW THEIR LIABILITY WILL BE MET.

REFERENCE:
REPORT SPD 83-12 'ALTERNATIVES TO DIESEL ELECTRIC SUPPLY AT NORTHEAST ISOLATED COMMUNITIES'.

REVISION:
UPDATED TO REFLECT ON AN ANNUAL BASIS THE PROVINCE OF MANITOBA'S SHARE (CURRENTLY ESTIMATED AT 15%) OF THE NEWLY REVISED CERS FOR THE NORTH CENTRAL PROJECT COMPLEX #016.

IN SERVICE DATES						Base estimate
1998 04 30	-4 205	1998 09 30	-81	1999 01 31	-1	199903 L3
1998 05 31	-36	1998 10 31	-0	1999 02 28	-2	
1998 07 31	-10	1998 11 30	-1	1999 03 31	-2 289	Work start date
1998 08 31	-5	1998 12 31	-7	1999 04 30	6 637	1996 04 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:					-22 195	-22 195
1999/00	-2 568				- 807	-3 375
2000/01					- 262	- 262
2001/02					- 408	- 408
2002/03					-2	-2
TOTAL	-2 568				-23 674	-26 242
REV. AMOUNTS:						
Authorized to date:					-22 195	-22 195
Over(under)expend:						
Auth 1999/00					- 858	- 858
Req.: 2000/01					- 270	- 270
2001/02					- 412	- 412
2002/03					-2	-2
TOTAL					-23 737	-23 737

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 02-00-7993

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1996 10	-22 037	NEW ITEM.
1997 10	-25 452	Updated to reflect on an annual basis the Province of Manitoba's share 15%) of the corresponding expenditures under the North Central Project Complex #016.
1998 10	-26 242	UPDATED TO REFLECT ON AN ANNUAL BASIS THE PROVINCE OF MANITOBA'S SHARE CURRENTLY ESTIMATED AT 15%) OF THE NEWLY REVISED CERS FOR THE NORTH CENTRAL PROJECT COMPLEX #016.

ASSOCIATED PROJECTS

Budget reference number	Description
02-00-0229	NORTH CENTRAL MB T/L R-0-W, SITE SELECTION & ENV. APPROVAL
02-00-0230	NORTH CENTRAL 138KV T/L
02-00-0231	NORTH CENTRAL-FEDERAL CAPITAL CONTRIBUTIONS-ELECTRIFICATION
02-00-0232	NORTH CENTRAL - COMMUNITY INVOLVEMENT
03-00-0615	GOD'S LAKE NARROWS NEW 138-25KV STATION
03-00-0616	GARDEN HILL NEW 138-25 KV STATION
03-00-0617	OXFORD HOUSE NEW 138-25 KV STATION
03-00-0618	KELSEY TERMINATE OXFORD HOUSE 138KV LINE
03-00-1648	WASAGAMACK NEW 138-25 KV STATION
04-00-0361	OXFORD HOUSE COMMUNITY - CENTRAL SUPPLY
04-00-0362	GOD'S RIVER COMMUNITY - CENTRAL SUPPLY
04-00-0363	RED SUCKER LAKE COMMUNITY - CENTRAL SUPPLY
04-00-0364	ISLAND LAKE COMMUNITIES - CENTRAL SUPPLY
04-00-0365	GOD'S LAKE NARROWS COMMUNITY - CENTRAL SUPPLY
04-00-0369	NORTH CENTRAL - SALVAGE OF DIESEL GENERATING STATIONS
04-00-6509	NORTH CENTRAL-FEDERAL CAPITAL CONTRIBUTIONS-SOIL REMEDIATION
04-00-6517	NORTH CENTRAL - SOIL REMEDIATION OF DIESEL SITES

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr				- 249		- 249	- 249
May				-66		-66	- 315
Jun				- 103		- 103	- 418
Jul				- 116		- 116	- 534
Aug				- 106		- 106	- 640
Sep				- 107		- 107	- 747
Oct				-20		-20	- 767
Nov				-24		-24	- 791
Dec				-32		-32	- 823
Jan				-8		-8	- 831
Feb				-27		-27	- 858
Mar							- 858
TOTAL				- 858		- 858	- 858
2000/01 Apr				-2		-2	-2
May				-3		-3	-5
Jun				-63		-63	-68
Jul				-67		-67	- 135
Aug				-55		-55	- 190
Sep				-56		-56	- 246
Oct				-3		-3	- 249
Nov				-14		-14	- 263
Dec				-4		-4	- 267
Jan				-1		-1	- 268
Feb				-1		-1	- 269
Mar				-1		-1	- 270
TOTAL				- 270		- 270	- 270

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item

138

Title			Budget reference number
OXFORD HOUSE NEW 138-25 KV STATION			03-00-0617
Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	70095

DESCRIPTION:
DESIGN AND CONSTRUCT A NEW 138-25 KV STATION NEAR OXFORD HOUSE C/W 3-7.5/10/12.5 MVA 3 PHASE +/- 15% OLTC TRANSFORMERS (1 TRANSFORMER ON HOT STANDBY). FACILITIES TO INCLUDE SUPERVISORY CONTROL AND PROVISION FOR A FUTURE 138 KV LINE BREAKER.

JUSTIFICATION:
ELSEWHERE IN THE BUDGET, JUSTIFICATION IS PROVIDED FOR THE CONSTRUCTION OF A NEW 138 KV LINE TO THE ISLAND LAKE AREA. THIS STATION PROVIDES TRANSFORMATION TO DISTRIBUTION LEVEL.

REFERENCE:
REPORT SPD 83-12, ALTERNATIVES TO DIESEL-ELECTRIC SUPPLY AT NORTHEAST ISOLATED COMMUNITIES.

REVISION:
REFLECTS COSTS TO COMPLETION

IN SERVICE DATES						Base estimate
Prior Total	8 495	1998 09 30	8	1999 01 31	0	199903 L5
1998 06 30	5	1998 10 31	0	1999 02 28	0	
1998 07 31	1	1998 11 30	1	1999 03 31	-7	Work start date
1998 08 31	6	1998 12 31	1	1999 05 31	444	1993 11 01

	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
PREV. AUTHORITY						
Authorized to date:	8 369		575	-12		8 932
1999/00	-18			- 300		- 318
TOTAL	8 351		575	- 312		8 614
REV. AMOUNTS:						
Authorized to date:	8 369		575	-12		8 932
Over(under)expend:						
Auth 1999/00 Req.:	10	-1		- 300		- 291
TOTAL	8 379	-1	575	- 312		8 641

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

CAPITAL EXPENDITURE REVISION

Budget reference number 03-00-0617

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1990 10	4 517	ESTIMATE REVISED TO DETAILED LEVEL 3 AND REFLECTS ALL CONCEPT CHANGES AND RESULTS OF SITE INVESTIGATIONS TO DATE INCLUDING THE FALL 1989 FIELD PROGRAM.
1991 10	4 372	I.S.D. DEFERRED FROM 94-07-31 TO 95-07-31. F.S.T. REMOVED FROM MAJOR EQUIPMENT. DECREASE IN INTEREST AND ESCALATION RATES. DISTRIBUTION LEVEL NOW 25 KV, PREVIOUSLY 12 KV.
1992 10	4 123	I.S.D. DEFERRED FROM 95-07-31 TO 96-07-31.
1993 10	4 555	ESTIMATE INCREASE DUE TO INCREASE OF SECONDARY BUS VOLTAGE TO 25 KV, ACCESS ROAD LENGTHED TO 2.6 KM, ADDED OIL CONTAINMENT COSTS.
1994 10	6 882	IN-SERVICE DATE DEFERRED 1 YEAR TO 1997 07 31. SIGNIFICANT CONCEPT CHANGES: SUPERVISORY CONTROL ADDED, TRANSFORMERS CHANGED FROM SINGLE PHASE TO 3-7.5 MVA THREE PHASE OLTC.
1995 10	8 155	SPARE TRANSFORMER CONNECTED TO HIGH SIDE ADDED, REFLECTING ENGINEERING DIVSN. DESIGN CHANGES AND FINAL LAYOUT. COST INCREASED BY 1.132 MILLION, OF WHICH MATERIAL PRICE INCREASES REPRESENT 47%, SITE IMPROVEMENTS AND NEW CONTRACT 31%, ENGINEERING 17%, HAULAGE SERVICES 8%,OVERHEAD 23%, AND OTHER MINOR INCREASES 12%, TOTALLING 138%. DECREASES REPRESENT CONTINGENCY 3% AND OIL PROCESSOR SALVAGE 35%. THE TRANSFORMERS AND OIL PROCESSOR MATERIAL COSTS HAVE INCREASED SIGNIFICANTLY AND THE STATION SITE AREA IS LARGER.
1996 10	8 115	SUPERVISORY CONTROLLED 25KV MOTOR MECHANISMS ADDED TO DISCONNECTS ($25K). SITE IMPROVEMENTS INCREASED ($145K) AS DID OIL CONTAINMENT ESTIMATES 45K).
1997 10	8 489	SCOPE UNCHANGED. INCREASE MAINLY A RESULT OF HIGHER THAN ESTIMATED CONSTRUCTION COSTS DUE TO A LATE START HAVING FORCED THE NEED FOR WINTER WORK AND INCREASED OVERTIME IN ORDER TO MAINTAIN THE ISD. SALVAGE CREDIT REDUCED BASED ON THE SALE PRICE NOW ANTICIPATED FOR THE OIL PROCESSING UNIT THAT WAS PURCHASED FOR THE NORTH CENTRAL PROJECT.
1998 10	8 614	ITEM ESSENTIALLY COMPLETE. 1998/99 CASH FLOW TO COVER COMPLETION OF STATION SUPERVISORY CONTROL, WHILE 1999/00 CASH FLOW COVERS SALVAGE OF THE OIL PROCESSING UNIT FOLLOWING 138 kV IN-SERVICE AT GARDEN HILL AND WASAGAMACK.

ASSOCIATED PROJECTS

Budget reference number	Description
02-00-0229	NORTH CENTRAL MB T/L R-0-W, SITE SELECTION & ENV. APPROVAL
02-00-0230	NORTH CENTRAL 138KV T/L
02-00-0231	NORTH CENTRAL-FEDERAL CAPITAL CONTRIBUTIONS-ELECTRIFICATION
02-00-0232	NORTH CENTRAL - COMMUNITY INVOLVEMENT
02-00-7993	NORTH CENTRAL-PROVINCIAL CAPITAL CONTRIBUTIONS
03-00-0615	GOD'S LAKE NARROWS NEW 138-25KV STATION
03-00-0616	GARDEN HILL NEW 138-25 KV STATION
03-00-0618	KELSEY TERMINATE OXFORD HOUSE 138KV LINE
03-00-1648	WASAGAMACK NEW 138-25 KV STATION
04-00-0361	OXFORD HOUSE COMMUNITY - CENTRAL SUPPLY
04-00-0362	GOD'S RIVER COMMUNITY - CENTRAL SUPPLY
04-00-0363	RED SUCKER LAKE COMMUNITY - CENTRAL SUPPLY
04-00-0364	ISLAND LAKE COMMUNITIES - CENTRAL SUPPLY
04-00-0365	GOD'S LAKE NARROWS COMMUNITY - CENTRAL SUPPLY
04-00-0369	NORTH CENTRAL - SALVAGE OF DIESEL GENERATING STATIONS
04-00-6509	NORTH CENTRAL-FEDERAL CAPITAL CONTRIBUTIONS-SOIL REMEDIATION
04-00-6517	NORTH CENTRAL - SOIL REMEDIATION OF DIESEL SITES

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	10					10	10
May		-1			- 300	- 301	- 291
Jun							- 291
Jul							- 291
Aug							- 291
Sep							- 291
Oct							- 291
Nov							- 291
Dec							- 291
Jan							- 291
Feb							- 291
Mar							- 291
TOTAL	10	-1			- 300	- 291	- 291
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item

139

Title			Budget reference number
KELSEY TERMINATE OXFORD HOUSE 138KV LINE			03-00-0618
Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	60005

DESCRIPTION:
TERMINATE NEW NORTH CENTRAL 138KV LINE BY INSTALLING 1 - 138 KV CIRCUIT BREAKER AND ASSOCIATED EQUIPMENT. RELOCATE EXISTING LINE KN36 TERMINATION IN ORDER TO AVOID A LINE CROSSOVER, INCLUDING THE MOTOR OPERATED 138 KV TIE SWITCH BETWEEN KN36 AND THE SPLIT LAKE LINE. INSTALL A MOTOR OPERATED 138 KV TIE SWITCH BETWEEN THE NORTH CENTRAL LINE AND THE SPLIT LAKE LINE. SALVAGE 138KV BREAKER ON SPLIT LAKE LINE AND REPLACE WITH NEW BREAKER WITH SAME SPECIFICATIONS AS NORTH CENTRAL LINE BREAKER.

JUSTIFICATION:
ELSEWHERE IN THE BUDGET, JUSTIFICATION IS PROVIDED FOR THE DESIGN AND CONSTRUCTION OF A NEW 138KV SUPPLY LINE TO THE ISLAND LAKES AREA. THIS ITEM PROVIDES FOR THE TERMINATION AT KELSEY.

REFERENCE:
REPORT SPD 83-12 ALTERNATIVES TO DIESEL ELECTRIC SUPPLY AT NORTHEAST ISOLATED COMMUNITIES.

REVISION:
ITEM COMPLETE

IN SERVICE DATES						Base estimate
1997 07 31	1 725	1998 09 30	0	1999 03 31	1	199902 L5
1998 04 30	0	1998 11 30	1	1999 06 30	22	
1998 05 31	-5	1998 12 31	0			Work start date
1998 06 30	0	1999 02 28	2			1993 09 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:	1 549		187	-5		1 731
1999/00	10					10
TOTAL	1 559		187	-5		1 741
REV. AMOUNTS:						
Authorized to date:	1 549		187	-5		1 731
Over(under)expend:						
Auth 1999/00 Req.:	10					10
TOTAL	1 559		187	-5		1 741

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

1999-09-28 11:29 AM

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 03-00-0618

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1989 10	3 557	NEW ITEM.
1990 10	2 680	ESTIMATE REVISED TO DETAILED LEVEL 3 AND REFLECTS ALL CONCEPT CHANGES AND RESULTS OF SITE INVESTIGATIONS MADE TO DATE INCLUDING THE FALL 1989 FIELD PROGRAM.
1991 10	2 649	TIE SWITCH BETWEEN NORTH CENTRAL LINE AND KN36 RELOCATED TO CONNECT NORTH CENTRAL LINE AND SPLIT LAKE LINE. RELOCATION OF TIE SWITCH BETWEEN KN36 AND SPLIT LAKE LINE ADDED. FST REMOVED FROM MAJOR EQUIPMENT. IN-SERVICE DATE DEFERRED ONE YEAR TO 1995 07 31. DISTRIBUTION LEVEL NOW 25KV, PREVIOUSLY 12KV.
1992 10	2 501	IN-SERVICE DATE DEFERRED FROM 1995 07 31 TO 1996 07 31.
1993 10	1 632	ESTIMATE DECREASED FOR RELOCATION OF 138.KV LINE KN36 AND SWITCHYARD EXPANSION DONE IN 1993 TO ACCOMMODATE ADDITION OF SPLIT LAKE LINE (COST SHARED BETWEEN TWO PROJECTS). ADD PLANNING TRANSIENT STUDIES.
1994 10	2 167	SPLIT LAKE LINE BREAKER REPLACEMENT ADDED. IN-SERVICE DATE DEFERRED 1 YEAR TO 1997 07 31. PLANNING TRANSIENT STUDY COSTS TO BE SPLIT BETWEEN ALL COMPLEX STATION ITEMS.
1995 10	1 914	MORE DETAILED ANALYSIS DONE AT THE SUBACCOUNT LEVEL WHICH RESULTED IN A SLIGHTLY REDUCED BASE ESTIMATE.
1996 10	1 921	REVISED INTEREST RATES.
1997 10	1 918	ESTIMATE AND SCHEDULE UNCHANGED. ISD'S ADJUSTED TO MATCH THE T/L ISD'S.
1998 10	1 741	PROJECT SUBSTANTIALLY COMPLETE; REMAINING CASH FLOW TO COVER OUTSTANDING STATION DESIGN AND COMMUNICATIONS ENGINEERING. REDUCTION A RESULT OF THE 1997/98 ACTUAL COSTS FOR ELECTRICAL CONSTRUCTION AND COMMISSIONING COMING IN LOWER THAN ESTIMATED.

ASSOCIATED PROJECTS

Budget reference number	Description
02-00-0229	NORTH CENTRAL MB T/L R-0-W, SITE SELECTION & ENV. APPROVAL
02-00-0230	NORTH CENTRAL 138KV T/L
02-00-0231	NORTH CENTRAL-FEDERAL CAPITAL CONTRIBUTIONS-ELECTRIFICATION
02-00-0232	NORTH CENTRAL - COMMUNITY INVOLVEMENT
02-00-7993	NORTH CENTRAL-PROVINCIAL CAPITAL CONTRIBUTIONS
03-00-0615	GOD'S LAKE NARROWS NEW 138-25KV STATION
03-00-0616	GARDEN HILL NEW 138-25 KV STATION
03-00-0617	OXFORD HOUSE NEW 138-25 KV STATION
03-00-1648	WASAGAMACK NEW 138-25 KV STATION
04-00-0361	OXFORD HOUSE COMMUNITY - CENTRAL SUPPLY
04-00-0362	GOD'S RIVER COMMUNITY - CENTRAL SUPPLY
04-00-0363	RED SUCKER LAKE COMMUNITY - CENTRAL SUPPLY
04-00-0364	ISLAND LAKE COMMUNITIES - CENTRAL SUPPLY
04-00-0365	GOD'S LAKE NARROWS COMMUNITY - CENTRAL SUPPLY
04-00-0369	NORTH CENTRAL - SALVAGE OF DIESEL GENERATING STATIONS
04-00-6509	NORTH CENTRAL-FEDERAL CAPITAL CONTRIBUTIONS-SOIL REMEDIATION
04-00-6517	NORTH CENTRAL - SOIL REMEDIATION OF DIESEL SITES

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	3					3	3
May	3					3	6
Jun	4					4	10
Jul							10
Aug							10
Sep							10
Oct							10
Nov							10
Dec							10
Jan							10
Feb							10
Mar							10
TOTAL	10					10	10
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item

140

Title			Budget reference number
GOD'S LAKE NARROWS NEW 138-25KV STATION			03-00-0615
riginating division anning & Control	Coordinating division Design	Constructing division Construction	Project Order Group (Range): 70096

DESCRIPTION:
DESIGN AND CONSTRUCT A NEW 138-25KV STATION NEAR GOD'S LAKE NARROWS C/W 3-7.5/10/12.5 MVA 3 PHASE +/-15% OLTC TRANSFORMERS (1 TRANSFORMER ON HOT STANDBY), 1-138KV (+10%) CIRCUIT BREAKER, 2-5 MVAR LINE REACTORS (5 LIMB CORE) AND ASSOCIATED CIRCUIT SWITCHERS, SUPERVISORY CONTROLS, AND PROVISION FOR A 3RD 5 MVAR LINE REACTOR AND CIRCUIT SWITCHER.

JUSTIFICATION:
ELSEWHERE IN THE BUDGET, JUSTIFICATION IS PROVIDED FOR THE CONSTRUCTION OF A NEW 138KV LINE INTO THE ISLAND LAKE AREA. THIS STATION PROVIDES TRANSFORMATION TO THE DISTRIBUTION LEVEL. A 138KV CIRCUIT BREAKER PROVIDES PROTECTION FOR THE GOD'S LAKE - WASAGAMACK LINE SECTION. LINE REACTORS LIMIT MAXIMUM VOLTAGE UNDER LIGHT LOAD CONDITIONS.

REFERENCE:
REPORT SPD 83-12, 'ALTERNATIVES TO DIESEL ELECTRIC SUPPLY AT NORTHEAST ISOLATED COMMUNITIES'.

REVISION:
REFLECTS COSTS TO COMPLETION

IN SERVICE DATES						Base estimate
Prior Total	9 491	1998 09 30	8	1999 01 31	0	199903 L5
1998 06 30	0	1998 10 31	1	1999 02 28	0	
1998 07 31	12	1998 11 30	4	1999 03 31	0	Work start date
1998 08 31	5	1998 12 31	-2	1999 04 30	262	1994 07 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:	9 038		733	-12		9 759
1999/00	19					19
TOTAL	9 057		733	-12		9 778
REV. AMOUNTS:						
Authorized to date:	9 038		733	-12		9 759
Over(under)expend:						
Auth 1999/00 Req.:	10					10
TOTAL	9 048		733	-12		9 769

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 03-00-0615

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1989 10	8 177	NEW ITEM.
1990 10	8 817	ESTIMATE REVISED TO DETAILED LEVEL 3 AND REFLECTS ALL CONCEPT CHANGES AND RESULTS OF SITE INVESTIGATIONS MADE TO DATE INCLUDING THE FALL 1989 FIELD PROGRAM.
1991 10	8 506	I.S.D. DEFERRED FROM 95-07-31 TO 96-07-31. F.S.T. REMOVED FROM MAJOR EQUIPMENT. DECREASE IN INTEREST AND ESCALATION RATES.
1992 10	7 953	ISD DEFERRED FROM 1996 07 31 TO 1997 07 31.
1993 10	6 638	LOCATION OF THE STATION ON THE LAND FARM SITE HAS RESULTED IN AN OVERALL REDUCTION IN THE ROAD AND SITE PREPARATION ESTIMATE. STATION AREA REDUCED TO 90M X 100M. ESTM INCLUDES OIL CONTAINMENT COSTS.
1994 10	9 718	IN-SERVICE DATE DEFERRED 1 YEAR TO 1998 07 31. SIGNIFICANT CONCEPT CHANGES: SUPERVISORY CONTROL ADDED; HIGH SPEED GROUNDING SWITCH REMOVED; LINE REACTORS REDUCED TO 5 MVAR; TRANSFORMERS CHANGED FROM SINGLE PHASE TO 3-7.5 MVA THREE PHASE OLTC.
1995 10	10 820	SPARE TRANSFORMER CONNECTED TO HIGH SIDE ADDED, REFLECTING ENGINEERING DIVSN. DESIGN CHANGES AND FINAL LAYOUT. COST INCREASED BY $740,000, OF WHICH MATERIAL PRICE INCREASES REPRESENT 83%, SITE IMPROVEMENTS AND NEW CONTRACT 14%, ENGINEERING 12%, HAULAGE SERVICES 20%, AND OVERHEAD 35%, TOTALLING 164%. DECREASES REPRESENT CONTINGENCY 9%, OIL PROCESSOR SALVAGE 54%, AND OTHER MINOR DECREASES 1%. THE TRANSFORMER AND OIL PROCESSOR MATERIAL COSTS HAVE INCREASED SIGNIFICANTLY AND THE STATION SITE AREA IS LARGER.
1996 10	10 442	ESTIMATE ACCURACY LEVEL REVISED RESULTING IN A SLIGHT DECREASE.
1997 10	9 826	IN-SERVICE DATE ADVANCED BY TEN MONTHS. DELETED PURCHASE AND SALVAGE OF OIL PROCESSING UNIT.
1998 10	9 779	ITEM SUBSTANTIALLY COMPLETE. REMAINING CASH FLOW TO COVER COMPLETION OF STATION SUPERVISORY CONTROL.

ASSOCIATED PROJECTS

Budget reference number	Description
02-00-0229	NORTH CENTRAL MB T/L R-0-W, SITE SELECTION & ENV. APPROVAL
02-00-0230	NORTH CENTRAL 138KV T/L
02-00-0231	NORTH CENTRAL-FEDERAL CAPITAL CONTRIBUTIONS-ELECTRIFICATION
02-00-0232	NORTH CENTRAL - COMMUNITY INVOLVEMENT
02-00-7993	NORTH CENTRAL-PROVINCIAL CAPITAL CONTRIBUTIONS
03-00-0616	GARDEN HILL NEW 138-25 KV STATION
03-00-0617	OXFORD HOUSE NEW 138-25 KV STATION
03-00-0618	KELSEY TERMINATE OXFORD HOUSE 138KV LINE
03-00-1648	WASAGAMACK NEW 138-25 KV STATION
04-00-0361	OXFORD HOUSE COMMUNITY - CENTRAL SUPPLY
04-00-0362	GOD'S RIVER COMMUNITY - CENTRAL SUPPLY
04-00-0363	RED SUCKER LAKE COMMUNITY - CENTRAL SUPPLY
04-00-0364	ISLAND LAKE COMMUNITIES - CENTRAL SUPPLY
04-00-0365	GOD'S LAKE NARROWS COMMUNITY - CENTRAL SUPPLY
04-00-0369	NORTH CENTRAL - SALVAGE OF DIESEL GENERATING STATIONS
04-00-6509	NORTH CENTRAL-FEDERAL CAPITAL CONTRIBUTIONS-SOIL REMEDIATION
04-00-6517	NORTH CENTRAL - SOIL REMEDIATION OF DIESEL SITES

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	10					10	10
May							10
Jun							10
Jul							10
Aug							10
Sep							10
Oct							10
Nov							10
Dec							10
Jan							10
Feb							10
Mar							10
TOTAL	10					10	10
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item

141

Title			Budget reference number.
GARDEN HILL NEW 138-25 KV STATION			03-00-0616
iginating division anning & Control	Coordinating division Design	Constructing division Construction	Project Order Group (Range): 70097

DESCRIPTION:
DESIGN AND CONSTRUCT A NEW 138-25 KV STATION AT GARDEN HILL C/W 3-7.5/10/12.5 MVA 3 PHASE +/-15% OLTC TRANSFORMERS (1 TRANSFORMER ON HOT STANDBY), 2-5 MVAR LINE REACTORS (5 LIMB CORE) AND ASSOCIATED CIRCUIT SWITCHERS, SUPERVISORY CONTROLS, AND PROVISION FOR A FUTURE 138 KV LINE BREAKER.

JUSTIFICATION:
ELSEWHERE IN THE BUDGET, JUSTIFICATION IS PROVIDED FOR THE CONSTRUCTION OF A NEW 138KV LINE INTO THE ISLAND LAKE AREA. THIS STATION PROVIDES TRANSFORMATION TO THE DISTRIBUTION LEVEL.

REFERENCE:
REPORT SPD 83-12 ALTERNATIVES TO DIESEL ELECTRIC SUPPLY AT NORTHEAST ISOLATED COMMUNITIES.

REVISION:
CIVIL CONSTRUCTION COSTS HIGHER THAN ESTIMATED DUE TO CONTRACTED MACHINERY NOT BEING AVAILABLE AND LOCAL CREWS REQUIRE LONGER THAN ANTICIPATED TO COMPLETE THE WORK. THE BLOCKADE OF ROAD BY THE CROSS LAKE BAND PREVENTED DELIVERY OF THE TRANSFORMER AND REMOVAL OF CONTRACTOR'S EQUIPMENT. ADDITIONAL COSTS WERE INCURRED WITH MOBILIZING CREWS AND EQUIPMENT TWICE, AND THE INSTALLING OF A TEMPORARY POWER SUPPLY TO GARDEN HILL THROUGH GOD'S LAKE NARROWS. REMAINING ESTIMATE REFLECTS COSTS TO COMPLETION.

IN SERVICE DATES				Base estimate
1999 03 31 1999 04 30	12 146 290			199906 L5
				Work start date 1994 07 01

	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
PREV. AUTHORITY Authorized to date: 1999/00	10 740 -88		1 436 86	-45		12 131 -2
TOTAL	10 652		1 522	-45		12 129
REV. AMOUNTS: Authorized to date: Over(under)expend:	10 740		1 436	-45		12 131
Auth 1999/00 Req.: 2000/01	253 5	2				255 5
TOTAL	10 998	2	1 436	-45		12 391

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number: 03-00-0616

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1990 10	4 700	ESTIMATE REVISED TO DETAILED LEVEL 3 AND REFLECTS ALL CONCEPT CHANGES AND RESULTS OF SITE INVESTIGATIONS MADE TO DATE INCLUDING THE FALL 1989 FIELD PROGRAM.
1991 10	4 563	I.S.D. DEFERRED FROM 95-07-31 TO 96-07-31. F.S.T. REMOVED FROM MAJOR EQUIPMENT. DECREASE IN INTEREST AND ESCALATION RATES. DISTRIBUTION LEVEL NOW 25KV, PREVIOUSLY 12 KV.
1992 10	4 261	I.S.D. DEFERRED FROM 96-07-31 TO 97-07-31.
1993 10	4 012	ESTIMATE CHANGE DUE TO INCREASE IN ACCESS ROAD LENGTH TO 1.5KM AND THE ADDITION OF COSTS FOR OIL CONTAINMENT AND REMOTE GROUND GRID OFFSET BY A LARGE DECREASE IN CIVIL COSTS.
1994 10	9 715	IN-SERVICE DATE DEFERRED 1 YEAR TO 1998 07 31. SIGNIFICANT CONCEPT CHANGES: LINE REACTORS & SUPERVISORY CONTROL ADDED; TRANSFORMERSCHANGED FROM SINGLE PHASE TO 3-7.5 MVA THREE PHASE OLTC.
1995 10	9 920	SPARE TRANSFORMER CONNECTED TO HIGH SIDE ADDED, REFLECTING ENGINEERING DIVSN. DESIGN CHANGES AND FINAL LAYOUT. COST INCREASED BY $308,000, OF WHICH SITE IMPROVEMENTS AND NEW CONTRACTS REPRESENT 32%, ENGINEERING 31%, HAULAGE SERVICES 46%, AND OVERHEAD 63%, TOTALLING 172%.DECREASES REPRESENT CONTINGENCY 35%, AND OTHER MINOR DECREASES 31%. THE STATION SITE AREA IS LARGER.
1996 10	9 593	ESTIMATE ACCURACY LEVEL REVISED RESULTING IN A SLIGHT DECREASE.
1997 10	10 001	ADD'NL ENG. REQ'D TO DETERMINE EXTENT OF HIGH WATER AND GRANULAR BASE PROBLEM. HAD TO SWITCH TO REMOTE GROUND GRID. INCREASED ENG. AND MATERIAL COSTS FOR LOCAL AND SUPERVISORY CONTROLS. ADD'NL MATERIAL REQUIREMENTS FOR HARDWARE & INSULATORS.
1998 10	12 129	ISD DEFERRED NINE MONTHS (FROM 1998 07 31 TO 1999 04 30) DUE TO POOR WINTER ROAD CONDITIONS. WET FALL CONDITIONS AND THEN WINTER WORK CAUSED HIGHER THAN ESTIMATED COSTS FOR CIVIL CONSTRUCTION WORK. ELECTRICAL CONSTRUCTION AND COMMISSIONING ESTIMATES INCREASED BASED ON EXPERIENCE AT GOD'S LAKE NARROWS STATION.

ASSOCIATED PROJECTS

Budget reference number	Description
02-00-0229	NORTH CENTRAL MB T/L R-0-W, SITE SELECTION & ENV. APPROVAL
02-00-0230	NORTH CENTRAL 138KV T/L
02-00-0231	NORTH CENTRAL-FEDERAL CAPITAL CONTRIBUTIONS-ELECTRIFICATION
02-00-0232	NORTH CENTRAL - COMMUNITY INVOLVEMENT
02-00-7993	NORTH CENTRAL-PROVINCIAL CAPITAL CONTRIBUTIONS
03-00-0615	GOD'S LAKE NARROWS NEW 138-25KV STATION
03-00-0617	OXFORD HOUSE NEW 138-25 KV STATION
03-00-0618	KELSEY TERMINATE OXFORD HOUSE 138KV LINE
03-00-1648	WASAGAMACK NEW 138-25 KV STATION
04-00-0361	OXFORD HOUSE COMMUNITY - CENTRAL SUPPLY
04-00-0362	GOD'S RIVER COMMUNITY - CENTRAL SUPPLY
04-00-0363	RED SUCKER LAKE COMMUNITY - CENTRAL SUPPLY
04-00-0364	ISLAND LAKE COMMUNITIES - CENTRAL SUPPLY
04-00-0365	GOD'S LAKE NARROWS COMMUNITY - CENTRAL SUPPLY
04-00-0369	NORTH CENTRAL - SALVAGE OF DIESEL GENERATING STATIONS
04-00-6509	NORTH CENTRAL-FEDERAL CAPITAL CONTRIBUTIONS-SOIL REMEDIATION
04-00-6517	NORTH CENTRAL - SOIL REMEDIATION OF DIESEL SITES

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	151					151	151
May	17					17	168
Jun	4					4	172
Jul	7					7	179
Aug	11					11	190
Sep	47	1				48	238
Oct	3					3	241
Nov							241
Dec							241
Jan							241
Feb							241
Mar	13	1				14	255
TOTAL	253	2				255	255
2000/01 Apr	5					5	5
May							5
Jun							5
Jul							5
Aug							5
Sep							5
Oct							5
Nov							5
Dec							5
Jan							5
Feb							5
Mar							5
TOTAL	5					5	5

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item

142

Title			Budget reference number
WASAGAMACK NEW 138-25 KV STATION			03-00-1648
Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	70098

DESCRIPTION:
DESIGN AND CONSTRUCT A NEW 138-25 KV STATION AT WASAGAMACK C/W 3-7.5/10/12.5 MVA 3 PHASE +/- 15% OLTC TRANSFORMERS (1 TRANSFORMER ON HOT STANDBY).

JUSTIFICATION:
ELSEWHERE IN THE BUDGET, JUSTIFICATION IS PROVIDED FOR THE CONSTRUCTION OF A NEW 138 KV LINE TO THE ISLAND LAKE AREA. THIS STATION PROVIDES TRANSFORMATION TO THE DISTRIBUTION LEVEL.

REFERENCE:
REPORT SPD 83-12 - 'ALTERNATIVES TO DIESEL-ELECTRIC SUPPLY AT NORTHEAST ISOLATED COMMUNITIES'.

REVISION:
REFLECTS COSTS TO COMPLETION. INSERVICE DATE HAS BEEN ADVANCED FROM 1999 05 31 TO 1999 04 30.

IN SERVICE DATES				Base estimate
1999 03 31	8 138			199906 L5
1999 04 30	141			Work start date
				1994 06 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:	6 998		1 125	-1		8 122
1999/00	522	1	123			646
TOTAL	7 520	1	1 248	-1		8 768
REV. AMOUNTS:						
Authorized to date:	6 998		1 125	-1		8 122
Over(under)expend:						
Auth 1999/00	119					119
Req.: 2000/01	36	1				37
TOTAL	7 153	1	1 125	-1		8 278

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 03-00-1648

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1990 10	4 466	NEW ITEM.
1991 10	4 234	I.S.D. DEFERRED FROM 95-07-31 TO 96-07-31. F.S.T. REMOVED FROM MAJOR EQUIPMENT. DECREASE IN INTEREST AND ESCALATION RATES. DISTRIBUTION LEVEL NOW 25 KV, PREVIOUSLY 12 KV.
1992 10	3 967	I.S.D. DEFERRED FROM 96-07-31 TO 97-07-31.
1993 10	3 967	ESTIMATE INCREASE DUE TO INCREASE OF ACCESS ROAD LENGTH TO 1.8KM AND THE ADDITION OF COSTS FOR OIL CONTAINMENT AND REMOTE GROUND GRID. DECREASE IN INTEREST AND ESCALATION RATES.
1994 10	5 397	IN-SERVICE DATE DEFERRED 1 YEAR TO 1998 07 31. SIGNIFICANT CONCEPT CHANGES: TRANSFORMERS CHANGED FROM SINGLE PHASE TO 3-7.5 MVA 3-PHASE OLTC; STN. SITE CHANGE INCREASES ACCESS ROADFROM 1.8 TO 5 KM.
1995 10	6 299	SPARE TRANSFORMER CONNECTED TO HIGH SIDE ADDED, REFLECTING ENGINEERING DIVSN. DESIGN CHANGES AND FINAL LAYOUT. COST INCREASED BY $867,000, OF WHICH MATERIAL PRICE INCREASES REPRESENT 38%, SITE IMPROVEMENTS AND NEW CONTRACT 16%, ENGINEERING 10%, HAULAGE SERVICES 9%,OVERHEAD 19%, AND OTHER MINOR INCREASES 15%, TOTALLING 107%, WHILE CONTINGENCY DECREASED BY 7%. THE TRANSFORMER COST HAS INCREASED SIGNIFICANTLY AND THE STATION SITE AREA IS LARGER.
1996 10	7 168	25KV MOTOR MECHANISMS ADDED TO DISCONNECTS ($25K). RTM CONTROL BUILDING 118K) AND RADIO COMMUNICATION ADDED ($33K). THE SITE IMPROVEMENTS INCREASED ($411K) AS DID THE FOUNDATIONS AND OIL SPILL CONTAINMENT ESTIMATES (238K).
1997 10	8 023	INCREASE PRIMARILY A RESULT OF: SITE IMPROVEMENT ($640,000)/ACCESS ROAD 110,000) COSTS WERE HIGHER THAN ESTIMATED DUE TO PROBLEMS IN OBTAINING SUITABLE ROAD TOPPING MATERIAL, AND ADDITIONAL EXCAVATION REQUIRED FOR DITCHING AND SIDE SLOPING OF THE SITE (NOT PREVIOUSLY ANTICIPATED IN THE DESIGN WHICH INCREASED SURVEYS COSTS ($66,000); ADDITIONAL MATERIAL REQUIREMENTS FOR HARDWARE & INSULATORS ($53,000) AND COMMUNICATIONS/MTS COST INCREASES ($149,000) FOLLOWING THE DETAILED DESIGN REVIEW. NCREASES OFFSET BY A REDUCTION IN CONTINGENCY FROM $367,000.
1998 10	8 767	ISD DEFERRED TEN MONTHS FROM 1998 07 31 TO 1999 05 31 DUE TO POOR WINTER ROAD CONDITIONS.

ASSOCIATED PROJECTS

Budget reference number	Description
02-00-0229	NORTH CENTRAL MB T/L R-0-W, SITE SELECTION & ENV. APPROVAL
02-00-0230	NORTH CENTRAL 138KV T/L
02-00-0231	NORTH CENTRAL-FEDERAL CAPITAL CONTRIBUTIONS-ELECTRIFICATION
02-00-0232	NORTH CENTRAL - COMMUNITY INVOLVEMENT
02-00-7993	NORTH CENTRAL-PROVINCIAL CAPITAL CONTRIBUTIONS
03-00-0615	GOD'S LAKE NARROWS NEW 138-25KV STATION
03-00-0616	GARDEN HILL NEW 138-25 KV STATION
03-00-0617	OXFORD HOUSE NEW 138-25 KV STATION
03-00-0618	KELSEY TERMINATE OXFORD HOUSE 138KV LINE
04-00-0361	OXFORD HOUSE COMMUNITY - CENTRAL SUPPLY
04-00-0362	GOD'S RIVER COMMUNITY - CENTRAL SUPPLY
04-00-0363	RED SUCKER LAKE COMMUNITY - CENTRAL SUPPLY
04-00-0364	ISLAND LAKE COMMUNITIES - CENTRAL SUPPLY
04-00-0365	GOD'S LAKE NARROWS COMMUNITY - CENTRAL SUPPLY
04-00-0369	NORTH CENTRAL - SALVAGE OF DIESEL GENERATING STATIONS
04-00-6509	NORTH CENTRAL-FEDERAL CAPITAL CONTRIBUTIONS-SOIL REMEDIATION
04-00-6517	NORTH CENTRAL - SOIL REMEDIATION OF DIESEL SITES

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	30					30	30
May	22					22	52
Jun	2					2	54
Jul							54
Aug	2					2	56
Sep	14					14	70
Oct	13					13	83
Nov							83
Dec							83
Jan							83
Feb							83
Mar	36					36	119
TOTAL	119					119	119
2000/01 Apr	36	1				37	37
May							37
Jun							37
Jul							37
Aug							37
Sep							37
Oct							37
Nov							37
Dec							37
Jan							37
Feb							37
Mar							37
TOTAL	36	1				37	37

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item

143

Title			Budget reference number
RED SUCKER LAKE COMMUNITY - CENTRAL SUPPLY			04-00-0363
Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	93315

DESCRIPTION:
GOD'S LAKE NARROWS TO RED SUCKER LAKE.

STAGE 1: (POG #72294, PREV W/O #48926)
REBUILD RED SUCKER LAKE DISTRIBUTION TO ACCEPTABLE STANDARDS. COMPLETION: 1998 03 31.

STAGE 2: (POG #72293, PREV W/O #48876) EXTEND 76.0 KM Z-2/0 ACSR 25 kV LINE. COMPLETION: 1998 03 31.

STAGE 3: (POG #71661)
CONVERT RED SUCKER DISTRIBUTION TO 25 kV. COMPLETION: 1998 03 31.

JUSTIFICATION:
THE ABOVE ADDITIONS AND MODIFICATIONS ARE NECESSARY IN ORDER TO PROVIDE CENTRAL ELECTRICAL SUPPLY TO THE COMMUNITY OF RED SUCKER LAKE.

REFERENCE:
REPORT SPD 83-12 'ALTERNATIVES TO DIESEL ELECTRIC SUPPLY AT NORTHEAST ISOLATED COMMUNITIES'.

REVISION:
ITEM COMPLETE. INCREASE A RESULT OF:
1) LINE LENGTH EXTENSION REQUESTED BY THE RED SUCKER LAKE 1ST NATION
2) DESIGN CHANGE REQUIRED AT WEBBER LAKE
3) LOST TIME DUE TO CLEARING NOT COMPLETED AS REQUIRED AT GOD'S LAKE NARROWS END
4) POOR WINTER CONDITIONS FOR TRANSPORTING MATERIALS & ACCESSING WORK AREAS
5) INCREASED HELICOPTER USAGE.
6) CHARGES INCURRED IN MARCH 1998 ARE REFLECTED IN FISCAL 1998/99

IN SERVICE DATES						Base estimate
Prior Total	8 952	1998 09 30	-7	1999 01 31	0	199902 L5
1998 06 30	3	1998 10 31	19	1999 02 28	9	
1998 07 31	13	1998 11 30	-0	1999 03 31	7	Work start date
1998 08 31	0	1998 12 31	0	1999 04 30	7	1991 07 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:	8 561		435	- 107	-18	8 871
1999/00	- 118					- 118
TOTAL	8 443		435	- 107	-18	8 753
REV. AMOUNTS:						
Authorized to date:	8 561		435	- 107	-18	8 871
Over(under)expend:						
Auth 1999/00 Req.:	7					7
TOTAL	8 568		435	- 107	-18	8 878

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

MajCER(2) Rev. 97.09

CAPITAL EXPENDITURE REVISION

Budget reference number: 04-00-0363

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1990 10	5 081	BASED ON THE SPECIFIC DISTRIBUTION SYSTEMS UPGRADE WORK, INSTEAD OF UNIT COSTING. REVISED INTEREST AND ESCALATION RATES.
1991 10	5 680	INCREASED COST PER ACRE,FOR BRUSH CLEARING. I.S.D. DEFERRED ONE YEAR.
1992 10	5 467	BETTER APPLICATION OF CREW RELOCATION COSTS. ESTIMATE INCLUDES LINE STRUCTURE CONVERTABLE TO 66 KV. REDUCED INTEREST AND ESCALATION RATES. FINAL I.S.D. DEFERRED ONE YEAR.
1993 10	5 595	ENGINEERING COSTS ADJUSTED TO ACCOUNT FOR LESSER REQUIREMENTFOR GEOTECHNICAL SUPPORT. CONSTRUCTION LABOUR & EXPENSE RATES ADJUSTED THROUGH CONSULTATION WITH CONSTRUCTION DEPARTMENT. DOLLARS IN-SERVICE HAVE BEEN ADJUSTED TO REFLECT EACH STAGE AS IT IS PUT INTO SERVICE. INCREASED BRUSH CLEARING COSTS. BRUSH CLEARING ACREAGE REQUIREMENTS WERE ADJUSTED TO INCREASE THE R/W WIDTH FROM 30M TO 36.3M TO CONFORM TO THE FINAL ENVIRONMENTAL IMPACT STMT.
1994 10	6 562	COST FLOWS REFLECT DEFERRAL OF NCP IN-SERVICE DATE BY 1 YR; ON SITE FIELD INVESTIGATION REVEALED INCREASED DIST'N AREA; INCREASED GEOTECHNICAL SUPPORT CHARGES TO LOCATE LINE ROUTE AND FLAG FOR CLEARING;DECREASE IN LINE ROUTE BY 3.4 KM.
1995 10	6 414	IMPROVED ESTIMATING TOOL (RUCES); FLOWS REVISED FOR INTEREST AND ESCALATION.
1996 10	6 639	ESTIMATE INCREASED DUE TO MATERIAL COST INCREASE OF 232 AND OVERHEAD INCREASED BY 66.
1997 04	6 917	Estimate increased (+295) mainly due to changes in overhead (+628) and interest (-375).

ASSOCIATED PROJECTS

Budget reference number	Description
02-00-0229	NORTH CENTRAL MB T/L R-0-W, SITE SELECTION & ENV. APPROVAL
02-00-0230	NORTH CENTRAL 138KV T/L
02-00-0231	NORTH CENTRAL-FEDERAL CAPITAL CONTRIBUTIONS-ELECTRIFICATION
02-00-0232	NORTH CENTRAL - COMMUNITY INVOLVEMENT
02-00-7993	NORTH CENTRAL-PROVINCIAL CAPITAL CONTRIBUTIONS
03-00-0615	GOD'S LAKE NARROWS NEW 138-25KV STATION
03-00-0616	GARDEN HILL NEW 138-25 KV STATION
03-00-0617	OXFORD HOUSE NEW 138-25 KV STATION
03-00-0618	KELSEY TERMINATE OXFORD HOUSE 138KV LINE
03-00-1648	WASAGAMACK NEW 138-25 KV STATION
04-00-0361	OXFORD HOUSE COMMUNITY - CENTRAL SUPPLY
04-00-0362	GOD'S RIVER COMMUNITY - CENTRAL SUPPLY
04-00-0364	ISLAND LAKE COMMUNITIES - CENTRAL SUPPLY
04-00-0365	GOD'S LAKE NARROWS COMMUNITY - CENTRAL SUPPLY
04-00-0369	NORTH CENTRAL - SALVAGE OF DIESEL GENERATING STATIONS
04-00-6509	NORTH CENTRAL-FEDERAL CAPITAL CONTRIBUTIONS-SOIL REMEDIATION
04-00-6517	NORTH CENTRAL - SOIL REMEDIATION OF DIESEL SITES

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	7					7	7
May							7
Jun							7
Jul							7
Aug							7
Sep							7
Oct							7
Nov							7
Dec							7
Jan							7
Feb							7
Mar							7
TOTAL	7					7	7
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item

144

Title			Budget reference number
ISLAND LAKE COMMUNITIES - CENTRAL SUPPLY			04-00-0364
Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	93316

DESCRIPTION:
EXTEND CENTRAL SUPPLY TO GARDEN HILL, ST. THERESA AND WASAGAMACK. COMPLETION 1999 05 31.

STAGE 1: (POG #72298) REBUILD GARDEN HILL DISTRIBUTION.
STAGE 2: (POG #71656) REBUILD ST. THERESA DISTRIBUTION.
STAGE 3: (POG #72297) REBUILD WASAGAMACK DISTRIBUTION.
STAGE 4: (POG #72295) EXTEND FEEDERS FROM GARDEN HILL STATION TO GARDEN HILL.
STAGE 5: (POG #71659) CONVERT ST. THERESA TO 25 KV.
STAGE 6: (POG #72296) EXTEND FEEDERS FROM WASAGAMACK STATION.
STAGE 7: (POG #71657) CONVERT GARDEN HILL TO 25 KV.
STAGE 8: (POG #71658) CONVERT WASAGAMACK TO 25 KV.
STAGE 9: (POG #71883) TEMPORARY 25 KV SERVICE TO GARDEN HILL.
STAGE 10: (POG #71889) SALVAGE OF TEMPORARY 25 KV SERVICE TO GARDEN HILL

NOTE: STAGE 6, WASAGAMACK STATION RELOCATED TO APPROX FIVE KM WEST OF NURSING STATION.

JUSTIFICATION:
THE ABOVE ADDITIONS AND MODIFICATIONS ARE NECESSARY IN ORDER TO PROVIDE CENTRAL ELECTRIC SUPPLY TO THE COMMUNITIES OF GARDEN HILL, ST. THERESA, AND WASAGAMACK.

REFERENCE:
REPORT SPD 83-12 'ALTERNATIVES TO DIESEL ELECTRIC SUPPLY AT NORTHEAST ISOLATED COMMUNITIES'.

REVISION:
ESTIMATE INCREASE PRIMARILY A RESULT OF HIGHER ACTUAL COSTS DUE TO POOR WINTER CONDITIONS AND LACK OF FROST IN 1997/98 AND 1998/99 FOR TRANSPORTING MATERIALS, ACCESSING THE WORK AREAS, ROCKSET REQUIREMENTS, BRUSHING OUT RE-GROWTH OF FEEDERS. THERE WERE ADDITIONAL COSTS ASSOCIATED WITH PROVIDING TEMPORARY 25 KV SERVICE IN LIEU OF MEETING THE ISD FOR 138 KV SERVICE. ALSO EXTRA MOBILIZATION/DEMOBILIZATION COSTS DUE TO STRETCHING OUT OF ENTIRE PROJECT.

IN SERVICE DATES						Base estimate
1998 04 30	1 334	1998 08 31	0	1998 12 31	0	199902 L3
1998 05 31	0	1998 09 30	0	1999 01 31	0	
1998 06 30	-24	1998 10 31	-1	1999 03 31	2 142	Work start date
1998 07 31	-0	1998 11 30	1	1999 05 31	8 041	1991 05 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:	8 989		1 949	- 425	- 178	10 335
1999/00	-33	1	68	- 263		- 227
TOTAL	8 956	1	2 017	- 688	- 178	10 108
REV. AMOUNTS:						
Authorized to date:	8 989		1 949	- 425	- 178	10 335
Over(under)expend:						
Auth Req.: 1999/00	456	1	98	- 135		420
TOTAL	9 445	1	2 047	- 560	- 178	10 755

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 04-00-0364

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1990 10	1 858	INCREASE IN SCOPE BY ADDING GARDEN HILL FEEDER, REVISED INTEREST AND ESCALATION RATES, INCREASED ACCURACY LEVEL, TRANSFER OF $458,000 (GROSS) TO BRN 9004000360.
1991 10	4 669	INCREASE IN SCOPE BY ADDING SECOND GARDEN HILL FEEDER. INCREASED ESCALATION AND INTEREST COSTS. DISTRIBUTION CHANGED FROM 12KVTO 25KV. WASAGAMACK STATION LOCATION CHANGED, RESULTING IN THE NEED FORTHE CONSTRUCTION OF 2-Z-266.8 MCM ACSR 25KV FEEDERS FROM WASAGAMACK STATION TO TIE LINE. I.S.D. DEFERRED ONE YEAR.
1992 10	3 058	REROUTING OF SECOND FEEDER FROM GARDEN HILL TO COMMUNITY. BETTER APPLICATION OF CREW COSTS. REDUCED INTEREST AND ESCALATION RATES.FINAL I.S.D. DEFERRED ONE YEAR.
1993 10	3 443	ENGINEERING COSTS INCREASED. CONSTRUCTION LABOUR & EXPENSE RATES INCREASED THROUGH CONSULTATION WITH CONSTRUCTION DEPT. DOLLARS IN-SERVICE HAVE BEEN ADJ. TO REFLECT EACH STAGE AS PUT IN SERVICE.
1994 10	6 751	COST FLOWS REFLECT DEFERRAL OF NCP IN-SERVICE DATE BY 1 YR; ON SITE FIELD INVESTIGATION REVEALED INCREASED DIST'N AREA; COST INCREASE DUE TO WASAGAMACK STATION RELOCATION AND CORRESPONDING ADDITIONAL FEEDER CONSTRUCTION.
1995 10	6 559	IMPROVED ESTIMATING TOOL (RUCES); FLOWS REVISED FOR INTEREST AND ESCALATION.
1996 10	8 398	ESTIMATE DUE TO: MATERIAL COST INCREASES FROM 1995(92); MATERIAL COST INCREASE FOUND NECESSARY DURING FINAL DESIGN PROCESS (164); L&E INCREASE FOR ADDITIONAL MATERIAL(233); INCREASED OVERHEAD (162) RISK CLAIM ITEMS INCURRED INCLUDING DELAY IN APPROVAL AND WORK STOPPAGE (234); OFF SEASON WORK L&E(646); BRUSH CLEARING(47); DECREASE MTS CONTRIBUTION FOR ANCHORING(13) INCREASED SALVAGE CREDITS(26).NCREASED SALVAGE CREDITS(26).
1997 10	9 066	Estimate increased (+686) mainly due to L&E (+543), i.e. local sourcing and contracting problems.
1999 10	10 108	ISD for remaining work deferred to 1999 05 31 as a result of poor winter conditions. Estimate increase primarily a result of higher actual costs due to poor winter conditions additional costs associated with providing temporary service.

ASSOCIATED PROJECTS

Budget reference number	Description
02-00-0229	NORTH CENTRAL MB T/L R-0-W, SITE SELECTION & ENV. APPROVAL
02-00-0230	NORTH CENTRAL 138KV T/L
02-00-0231	NORTH CENTRAL-FEDERAL CAPITAL CONTRIBUTIONS-ELECTRIFICATION
02-00-0232	NORTH CENTRAL - COMMUNITY INVOLVEMENT
02-00-7993	NORTH CENTRAL-PROVINCIAL CAPITAL CONTRIBUTIONS
03-00-0615	GOD'S LAKE NARROWS NEW 138-25KV STATION
03-00-0616	GARDEN HILL NEW 138-25 KV STATION
03-00-0617	OXFORD HOUSE NEW 138-25 KV STATION
03-00-0618	KELSEY TERMINATE OXFORD HOUSE 138KV LINE
03-00-1648	WASAGAMACK NEW 138-25 KV STATION
04-00-0361	OXFORD HOUSE COMMUNITY - CENTRAL SUPPLY
04-00-0362	GOD'S RIVER COMMUNITY - CENTRAL SUPPLY
04-00-0363	RED SUCKER LAKE COMMUNITY - CENTRAL SUPPLY
04-00-0365	GOD'S LAKE NARROWS COMMUNITY - CENTRAL SUPPLY
04-00-0369	NORTH CENTRAL - SALVAGE OF DIESEL GENERATING STATIONS
04-00-6509	NORTH CENTRAL-FEDERAL CAPITAL CONTRIBUTIONS-SOIL REMEDIATION
04-00-6517	NORTH CENTRAL - SOIL REMEDIATION OF DIESEL SITES

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	218	1	48			267	267
May	219		50			269	536
Jun	9				-64	-55	481
Jul	10				-71	-61	420
Aug							420
Sep							420
Oct							420
Nov							420
Dec							420
Jan							420
Feb							420
Mar							420
TOTAL	456	1	98		- 135	420	420
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item

145

Title			Budget reference number
GOD'S LAKE NARROWS COMMUNITY - CENTRAL SUPPLY			04-00-0365
Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	93317

DESCRIPTION:
STAGE 1: (POG #72300, PREV W/O #48942)
REBUILD GOD'S LAKE NARROWS DISTRIBUTION SYSTEM. COMPLETION: 1997 09 30.

STAGE 2: (POG #72299, PREV W/O #43208)
CONVERT GOD'S LAKE NARROWS TO 25 kV. COMPLETION: 1997 09 30.

JUSTIFICATION:
THE ABOVE ADDITIONS AND MODIFICATIONS ARE NECESSARY IN ORDER TO PROVIDE CENTRAL ELECTRICAL SUPPLY TO THE COMMUNITY OF GOD'S LAKE NARROWS.

REFERENCE:
REPORT SPD 83-12 'ALTERNATIVES TO DIESEL ELECTRIC SUPPLY AT NORTHEAST ISOLATED COMMUNITIES'.

REVISION:
ITEM IN SERVICE. SOME MINOR SALVAGE ACTIVITIES REMAIN TO BE COMPLETED.

IN SERVICE DATES						Base estimate
1997 10 31	1 897	1998 09 30	-34	1999 04 30	136	199902 L5
1998 06 30	2	1998 10 31	-6			
1998 07 31	4	1998 12 31	16			Work start date
1998 08 31	0	1999 03 31	0			1991 07 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:	1 770		245	-82	-41	1 892
1999/00	30					30
TOTAL	1 800		245	-82	-41	1 922
REV. AMOUNTS:						
Authorized to date:	1 770		245	-82	-41	1 892
Over(under)expend:						
Auth Req.:						
TOTAL	1 770		245	-82	-41	1 892

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 04-00-0365

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1989 10	433	NEW ITEM.
1990 10	742	USED SPECIFIC SYSTEMS UPGRADE WORK COSTING INSTEAD OF UNIT COSTING. REVISED INTEREST AND ESCALATION RATES. HIGHER ACCURACY LEVEL.
1991 10	901	BRUSH CLEARING COSTS NOT IDENTIFIED IN 1990 ESTIMATE. I.S.D. DEFERRED ONE YEAR
1992 10	1 060	BETTER APPLICATION OF CREW RELOCATION COSTS. REVISED ROUTINGOF SECOND FEEDER FROM STATION TO COMMUNITY. FINAL I.S.D. DEFERRED 1 YEAR
1993 10	1 198	INCREASED ENGINEERING COSTS. CONSTRUCTION LABOUR AND EXPENSERATES ADJUSTED WITH CONSTRUCTION DEPT CONSULTATION. DOLLARS IN-SERVICE ADJUSTED TO REFLECT EACH STAGE AS IT IS PUT INTO SERVICE.
1994 10	1 369	COST FLOWS REFLECT DEFERRAL OF NCP IN-SERVICE DATE BY 1 YEARON SITE FIELD INVESTIGATION REVEALED INCREASED DIST'N AREA. DELETION OF 2ND FEEDER ROUTE TO GLN.
1995 10	1 339	IMPROVED ESTIMATING TOOL (RUCES); FLOWS REVISED FOR INTEREST AND ESCALATION.
1996 10	1 479	ESTIMATE INCREASED DUE TO: MATERIAL COST INCREASES FROM 1995(78); MATERIAL COST INCREASE FOUND NECESSARY DURING FINAL DESIGN PROCESS(34); L&E INCREASE FOR ADDITIONAL MATERIAL(23); INCREASED OVERHEAD(30); INCREASED SALVAGE CREDITS(18).
1997 10	1 886	Estimate increased (+409) mainly due to L&E, i.e. local sourcing and contracting propblems. ISD advanced by ten months.
1999 10	1 922	Item in service. Some minor salvage activities remain to be completed.

ASSOCIATED PROJECTS

Budget reference number	Description
02-00-0229	NORTH CENTRAL MB T/L R-0-W, SITE SELECTION & ENV. APPROVAL
02-00-0230	NORTH CENTRAL 138KV T/L
02-00-0231	NORTH CENTRAL-FEDERAL CAPITAL CONTRIBUTIONS-ELECTRIFICATION
02-00-0232	NORTH CENTRAL - COMMUNITY INVOLVEMENT
02-00-7993	NORTH CENTRAL-PROVINCIAL CAPITAL CONTRIBUTIONS
03-00-0615	GOD'S LAKE NARROWS NEW 138-25KV STATION
03-00-0616	GARDEN HILL NEW 138-25 KV STATION
03-00-0617	OXFORD HOUSE NEW 138-25 KV STATION
03-00-0618	KELSEY TERMINATE OXFORD HOUSE 138KV LINE
03-00-1648	WASAGAMACK NEW 138-25 KV STATION
04-00-0361	OXFORD HOUSE COMMUNITY - CENTRAL SUPPLY
04-00-0362	GOD'S RIVER COMMUNITY - CENTRAL SUPPLY
04-00-0363	RED SUCKER LAKE COMMUNITY - CENTRAL SUPPLY
04-00-0364	ISLAND LAKE COMMUNITIES - CENTRAL SUPPLY
04-00-0369	NORTH CENTRAL - SALVAGE OF DIESEL GENERATING STATIONS
04-00-6509	NORTH CENTRAL-FEDERAL CAPITAL CONTRIBUTIONS-SOIL REMEDIATION
04-00-6517	NORTH CENTRAL - SOIL REMEDIATION OF DIESEL SITES

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item

146

Title			Budget reference number
NORTH CENTRAL - SALVAGE OF DIESEL GENERATING STATIONS			04-00-0369
Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Operating & Maintenance	Operating & Maintenance	Operating & Maintenance	70101:70106

DESCRIPTION:
SALVAGE EXISTING DIESEL PLANTS AND EQUIPMENT, WITH THE FOLLOWING COMPLETION DATES:

1. WASAGAMACK 95 01 31 COMPLETE
2. OXFORD HOUSE 98 09 30 POG #70101 COMPLETE
3. ST. THERESA 00 02 28 POG #70102
4. GODS LAKE NARROWS 98 09 30 POG #70103 COMPLETE
5. GARDEN HILL 00 02 28 POG #70104
6. RED SUCKER 99 03 31 POG #70105
7. GOD'S RIVER 98 09 30 POG #70106 COMPLETE

JUSTIFICATION:
DIESEL SITES TO BE DE-COMMISSIONED AS PART OF THE NORTH CENTRAL PROJECT.

REFERENCE:
REPORT SPD 83-12 'ALTERNATIVES TO DIESEL ELECTRIC SUPPLY AT NORTHEAST ISOLATED COMMUNITIES'.

REVISION:
REVISED TO REFLECT ACTUAL COSTS TO COMPLETION FOR OXFORD HOUSE, GOD'S LAKE NARROWS AND GOD'S RIVER SITES. INITIATION OF SALVAGE COMMENCED FOR GARDEN HILL AND STE. THERESA POINT IN 1999/02, FOUR MONTHS EARLIER THAN PLANNED, TO TAKE ADVANTAGE OF AVAILABLE BACK HAUL LOADS. REFLECTS UPDATED ACTIVITY AND OVERHEAD RATES.

IN SERVICE DATES						Base estimate
1995 01 31	86	1998 12 31	0	1999 04 30	386	199805 L3
1998 09 30	291	1999 01 31	0	1999 07 31	160	Work start date
1998 10 31	1	1999 02 28	-0	2000 02 28	753	1992 07 01
1998 11 30	0	1999 03 31	56			

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:	1 099		50	- 272		877
1999/00	421	32	10	- 367		96
TOTAL	1 520	32	60	- 639		973
REV. AMOUNTS:						
Authorized to date:	1 099		50	- 272		877
Over(under)expend:						
Auth 1999/00	525	15	21	- 374		187
Req.: 2000/01	22	1				23
TOTAL	1 646	16	71	- 646		1 087

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 04-00-0369

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1989 10	1 022	NEW ITEM
1990 10	1 179	REVISED TO A HIGHER DEGREE OF ACCURACY
1991 10	2 255	REVISION ALLOWS $250,000 OF BASE DOLLARS PER SITE, INSTEAD OF $150,000 PREVIOUSLY ESTIMATED. THE R & D PROJECT AT PUKATAWAGAN FOR CLEANUP OF THAT SIGHT GAVE US A BETTER INSIGHT OF THE WORK COMPLEXITY.
1992 10	4 230	REVISION ALLOWS $500,000 OF BASE DOLLARS PER SITE, INSTEAD OF $250,000 PREVIOUSLY ESTIMATED. ALSO, SURVEYS TO DATE INDICATE, WE WILL FIND CONSIDERABLE CONTAMINATION AT GREATER DEPTHS THAN PREVIOUSLY EXPECTED.
1993 10	9 756	REVISION TO REFLECT ANTICIPATED COSTS BASED ON ACTUAL EXPENDITURES AT PUKATAWAGAN AND GODS LAKE NARROWS OLD SITE. THE LATER SITE IS IN THE SAME GEOGRAPHIC AREA WITH A SIMILAR SITE HISTORY TO ALL NORTH CENTRAL SITES AND THE AMOUNT OF CONTAMINATED SOIL WAS 200% MORE THAN EXPECTED. I.S.D. ADJUSTED FROM 94/06 - 00/06 TO 95/09 - 99/09.
1994 10	9 570	COST FLOWS REFLECT DEFERRAL OF NCP IN-SERVICE DATE BY 1 YEAR
1995 10	137	ESTIMATE REVISED TO REFLECT ACTUAL AND FORECAST COSTS TO COMPLETE WORK AT WASAGAMACK, AND ESC. TO 1995 DOLLARS FOR OTHER SITES. CASH FLOWS REVISED TO REFLECT CURRENT PLAN. COSTS ASSOCIATED WITH SOIL REMEDIATION HAVE BEEN MOVED TO NEW BRN 9304-00-6517.
1996 10	125	ESTIMATE REVISED TO REFLECT ACTUAL COSTS TO COMPLETE WORK AT WASAGAMACK.
1997 10	1 399	REVISION REFLECTS DETAILED ESTIMATES FOR EACH SITE TO BE DECOMMISSIONED. ISD's HAVE BEEN ADVANCED ONE YEAR TO REFLECT CURRENT PROJECTED LAND LINE ISD's.
1998 10	974	REVISED ESTIMATES PREPARED TO REFLECT NEW IN SERVICE DATES. ST. THERESA POINT AND GARDEN HILL DEFERRED ONE YEAR TO 2000/02 TO RELECT CURRENT PROJECTED LAND LINE ISD's. OXFORD HOUSE AND GOD'S RIVER DEFERRED FOUR MONTHS TO 1998 06. DECREASE IN ESTIMATE MAINLY DUE TO REDUCED HAULAGE COSTS EXPERIENCED THROUGH USE OF BACKHAUL LOADS.

ASSOCIATED PROJECTS

Budget reference number	Description
02-00-0229	NORTH CENTRAL MB T/L R-0-W, SITE SELECTION & ENV. APPROVAL
02-00-0230	NORTH CENTRAL 138KV T/L
02-00-0231	NORTH CENTRAL-FEDERAL CAPITAL CONTRIBUTIONS-ELECTRIFICATION
02-00-0232	NORTH CENTRAL - COMMUNITY INVOLVEMENT
02-00-7993	NORTH CENTRAL-PROVINCIAL CAPITAL CONTRIBUTIONS
03-00-0615	GOD'S LAKE NARROWS NEW 138-25KV STATION
03-00-0616	GARDEN HILL NEW 138-25 KV STATION
03-00-0617	OXFORD HOUSE NEW 138-25 KV STATION
03-00-0618	KELSEY TERMINATE OXFORD HOUSE 138KV LINE
03-00-1648	WASAGAMACK NEW 138-25 KV STATION
04-00-0361	OXFORD HOUSE COMMUNITY - CENTRAL SUPPLY
04-00-0362	GOD'S RIVER COMMUNITY - CENTRAL SUPPLY
04-00-0363	RED SUCKER LAKE COMMUNITY - CENTRAL SUPPLY
04-00-0364	ISLAND LAKE COMMUNITIES - CENTRAL SUPPLY
04-00-0365	GOD'S LAKE NARROWS COMMUNITY - CENTRAL SUPPLY
04-00-6509	NORTH CENTRAL-FEDERAL CAPITAL CONTRIBUTIONS-SOIL REMEDIATION
04-00-6517	NORTH CENTRAL - SOIL REMEDIATION OF DIESEL SITES

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr			3		- 120	- 117	- 117
May							- 117
Jun	4		1			5	- 112
Jul	131	3	2			136	24
Aug	2		2			4	28
Sep	2		2			4	32
Oct	2		2			4	36
Nov	2		2			4	40
Dec	2		2			4	44
Jan	2		2			4	48
Feb	379	12	2		- 137	256	304
Mar	-1		1		- 117	- 117	187
TOTAL	525	15	21		- 374	187	187
2000/01 Apr							
May							
Jun							
Jul	22	1				23	23
Aug							23
Sep							23
Oct							23
Nov							23
Dec							23
Jan							23
Feb							23
Mar							23
TOTAL	22	1				23	23

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item

147

Title			Budget reference number
NORTH CENTRAL - SOIL REMEDIATION OF DIESEL SITES			04-00-6517
Originating division	Coordinating division	Constructing division	Project Order Group (Range):
perating & Maintenance	Construction	Construction	70111:70122

DESCRIPTION:
INVESTIGATE SITES AND PERFORM SOIL REMEDIATION, UNDER THE FOLLOWING COMPLETION SCHEDULE:

	Investigation	Remediation
1. WASAGAMACK	95 06 30 (W.O. #45617)	95 12 13 (W.O. #44144)
2. OXFORD HOUSE	98 11 30 (POG #70111)	99 12 31 (POG #70112)
3. ST. THERESA	00 11 30 (POG #70113)	01 12 31 (POG #70114)
4. GOD'S LAKE NARROWS	99 05 31 (POG #70115)	99 05 31 (POG #70116)
5. GARDEN HILL	00 11 30 (POG #70117)	01 12 31 (POG #70118)
6. RED SUCKER	99 11 30 (POG #70119)	00 12 31 (POG #70120)
7. GOD'S RIVER	98 11 30 (POG #70121)	99 12 31 (POG #70122)

JUSTIFICATION:
ELSEWHERE IN THE BUDGET, JUSTIFICATION IS GIVEN TO EXTEND CENTRAL SUPPLY TO NORTH CENTRAL MANITOBA. THIS ITEM PROVIDES FOR REMEDIATION OF DE-COMMISSIONED DIESEL SITES.

REFERENCE:
REPORT SPD 83-12 ALTERNATIVES TO DIESEL ELECTRIC SUPPLY AT NORTHEAST ISOLATED COMMUNITIES.

REVISION:
REFLECTS REVISED ACTIVITY AND OVERHEAD RATES.

This BRN contains Deleted, Blocked, or Closed Orders.

IN SERVICE DATES						Base estimate
1995 12 31	1 211	1999 11 30	101	2001 12 31	2 742	199804 L3
1999 03 31	1	1999 12 31	2 652			Work start date
1999 04 30	254	2000 11 30	210			1992 04 01
1999 05 31	60	2000 12 31	1 511			

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:	1 475		61			1 536
1999/00	2 502	117	87			2 706
2000/01	1 572	107	53			1 732
2001/02	2 412	214	86			2 712
TOTAL	7 961	438	287			8 686
REV. AMOUNTS:						
Authorized to date:	1 475		61			1 536
Over(under)expend:						
Auth 1999/00	2 578	109	87			2 774
Req.: 2000/01	1 584	93	52			1 729
2001/02	2 429	190	84			2 703
TOTAL	8 066	392	284			8 742

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 04-00-6517

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1995 10	9 498	NEW ITEM TRANSFERRED FROM BRN 9304-00-0369. ESTIMATE REVISED TO REFLECT ACTUAL AND FORECAST COSTS TO COMPLETE WORK AT WASAGAMACK, AND ESCALATION TO 1995 DOLLARS FOR THE OTHER SITES. CASH FLOWS REVISED TO REFLECT CURRENT.
1996 10	9 147	WASAGAMACK SITE INVESTIGATION & SOIL REMEDIATION COMPLETED UNDER BUDGET. REMAINDER OF ESTIMATE ESCALATED TO 1996 DOLLARS AND CASK FLOWS ADJUSTED. IN SERVICE DATES CONSOLIDATED.
1997 10	9 178	ESTMATE UNCHANGED; IN-SERVICE DATES REVISED TO REFLECT CURRENT SCHEDULE FOR COMPLETION OF THE WORK.
1998 10	8 685	Investigation at God's Lake Narrows revealed no contamination beyond site property, therefore Transport Canada have agreed to take over the site as-is. Site investigation costs for God's Lake Narrows have therefore been reduced, while the Remediation costs for that site have virtually been elimated (some allowance for closing out of the project). Estimate and schedule for the remaining sites are unchanged.

ASSOCIATED PROJECTS

Budget reference number	Description
02-00-0229	NORTH CENTRAL MB T/L R-0-W, SITE SELECTION & ENV. APPROVAL
02-00-0230	NORTH CENTRAL 138KV T/L
02-00-0231	NORTH CENTRAL-FEDERAL CAPITAL CONTRIBUTIONS-ELECTRIFICATION
02-00-0232	NORTH CENTRAL - COMMUNITY INVOLVEMENT
02-00-7993	NORTH CENTRAL-PROVINCIAL CAPITAL CONTRIBUTIONS
03-00-0615	GOD'S LAKE NARROWS NEW 138-25KV STATION
03-00-0616	GARDEN HILL NEW 138-25 KV STATION
03-00-0617	OXFORD HOUSE NEW 138-25 KV STATION
03-00-0618	KELSEY TERMINATE OXFORD HOUSE 138KV LINE
03-00-1648	WASAGAMACK NEW 138-25 KV STATION
04-00-0361	OXFORD HOUSE COMMUNITY - CENTRAL SUPPLY
04-00-0362	GOD'S RIVER COMMUNITY - CENTRAL SUPPLY
04-00-0363	RED SUCKER LAKE COMMUNITY - CENTRAL SUPPLY
04-00-0364	ISLAND LAKE COMMUNITIES - CENTRAL SUPPLY
04-00-0365	GOD'S LAKE NARROWS COMMUNITY - CENTRAL SUPPLY
04-00-0369	NORTH CENTRAL - SALVAGE OF DIESEL GENERATING STATIONS
04-00-6509	NORTH CENTRAL-FEDERAL CAPITAL CONTRIBUTIONS-SOIL REMEDIATION

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	29	1	2			32	32
May	44	1	1			46	78
Jun	614	24	1			639	717
Jul	613	25	5			643	1 360
Aug	583	25	10			618	1 978
Sep	583	26	14			623	2 601
Oct	20	1	18			39	2 640
Nov	53	2	18			73	2 713
Dec	24	2	18			44	2 757
Jan	5					5	2 762
Feb	5					5	2 767
Mar	5	2				7	2 774
TOTAL	2 578	109	87			2 774	2 774
2000/01 Apr	5	1				6	6
May	13	1				14	20
Jun	387	22				409	429
Jul	387	23	3			413	842
Aug	331	20	6			357	1 199
Sep	331	20	9			360	1 559
Oct	10	1	11			22	1 58
Nov	75	6	11			92	1 673
Dec	18		11			29	1 702
Jan	8	1				9	1 711
Feb	8	1				9	1 720
Mar	11	-3	1			9	1 729
TOTAL	1 584	93	52			1 729	1 729

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item

148

Title	Budget reference number
NORTH CENTRAL-FEDERAL CAPITAL CONTRIBUTIONS-SOIL REMEDIATION	04-00-6509

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Construction	Construction	Construction	70063:70478

DESCRIPTION:
RECORD CONTRIBUTIONS FROM THE FEDERAL GOVERNMENT TOWARDS THE COST OF SOIL REMEDIATION AT THE SEVEN NORTH CENTRAL MANITOBA DIESEL SITES.

JUSTIFICATION:
A SHARED COST AGREEMENT HAS BEEN NEGOTIATED BETWEEN THE GOVERNMENT OF CANADA AND MANITOBA HYDRO TO REMEDIATE THE SEVEN NORTH CENTRAL MANITOBA DIESEL SITES FOLLOWING DECOMMISSIONING

REVISION:
UPDATED TO REFLECT CANADA'S REVISED ANNUAL SHARE OF THE UPDATED SOIL REMEDIATION ITEM BRN 04-00-6517. CANADA'S PREPAYMENT PLUS INTEREST WILL NOW ACCRUE TO AN AMOUNT THAT WILL COVER 68% OF THE SOIL REMEDIATION COSTS, UP FROM THE PREVIOUS 66%.

IN SERVICE DATES			Base estimate
			199903 L3
			Work start date
			1995 04 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:					- 880	- 880
1999/00	- 129				-1 789	-1 918
2000/01					-1 140	-1 140
2001/02					-1 789	-1 789
TOTAL	- 129				-5 598	-5 727
REV. AMOUNTS:						
Authorized to date:					- 880	- 880
Over(under)expend:						
Auth 1999/00					-1 880	-1 880
Req.: 2000/01					-1 188	-1 188
2001/02					-1 855	-1 855
TOTAL					-5 803	-5 803

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 04-00-6509

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1995 10	-11 850	NEW ITEM. Calculation based on 75% of expenditures under BRN 04-00-6517.
1996 10	-6 067	Reflects Canada's revised annual share of the Soil Remediation item BRN 04-00-6517.
1997 10	-5 776	Reflects Canada's revised share (63%) of the Soil Remediation item BRN 04-00-6517.
1998 10	-5 727	UPDATED TO REFLECT CANADA'S REVISED ANNUAL SHARE OF THE UPDATED SOIL REMEDIATION ITEM BRN 04-00-6517. A REDUCTION IN THAT BRN MEANS THAT CANADA'S PREPAYMENT PLUS INTEREST WILL NOW ACCRUE TO AN AMOUNT THAT WILL COVER 66% OF THE SOIL REMEDIATION COSTS, UP FROM THE PREVIOUS 63%.

ASSOCIATED PROJECTS

Budget reference number	Description
02-00-0229	NORTH CENTRAL MB T/L R-0-W, SITE SELECTION & ENV. APPROVAL
02-00-0230	NORTH CENTRAL 138KV T/L
02-00-0231	NORTH CENTRAL-FEDERAL CAPITAL CONTRIBUTIONS-ELECTRIFICATION
02-00-0232	NORTH CENTRAL - COMMUNITY INVOLVEMENT
02-00-7993	NORTH CENTRAL-PROVINCIAL CAPITAL CONTRIBUTIONS
03-00-0615	GOD'S LAKE NARROWS NEW 138-25KV STATION
03-00-0616	GARDEN HILL NEW 138-25 KV STATION
03-00-0617	OXFORD HOUSE NEW 138-25 KV STATION
03-00-0618	KELSEY TERMINATE OXFORD HOUSE 138KV LINE
03-00-1648	WASAGAMACK NEW 138-25 KV STATION
04-00-0361	OXFORD HOUSE COMMUNITY - CENTRAL SUPPLY
04-00-0362	GOD'S RIVER COMMUNITY - CENTRAL SUPPLY
04-00-0363	RED SUCKER LAKE COMMUNITY - CENTRAL SUPPLY
04-00-0364	ISLAND LAKE COMMUNITIES - CENTRAL SUPPLY
04-00-0365	GOD'S LAKE NARROWS COMMUNITY - CENTRAL SUPPLY
04-00-0369	NORTH CENTRAL - SALVAGE OF DIESEL GENERATING STATIONS
04-00-6517	NORTH CENTRAL - SOIL REMEDIATION OF DIESEL SITES

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr				-17		-17	-17
May				-28		-28	-45
Jun				- 435		- 435	- 480
Jul				- 438		- 438	- 918
Aug				- 421		- 421	-1 339
Sep				- 425		- 425	-1 764
Oct				-27		-27	-1 791
Nov				-50		-50	-1 841
Dec				-29		-29	-1 870
Jan				-3		-3	-1 873
Feb				-3		-3	-1 876
Mar				-4		-4	-1 880
TOTAL				-1 880		-1 880	-1 880
2000/01 Apr				-4		-4	-4
May				-10		-10	-14
Jun				- 282		- 282	- 296
Jul				- 284		- 284	- 580
Aug				- 245		- 245	- 825
Sep				- 247		- 247	-1 072
Oct				-15		-15	-1 087
Nov				-62		-62	-1 149
Dec				-20		-20	-1 169
Jan				-7		-7	-1 176
Feb				-7		-7	-1 183
Mar				-5		-5	-1 188
TOTAL				-1 188		-1 188	-1 188

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

COMPLEX STATUS	Complex no.	REVISION STATUS
☐ Planned ☒ In progress	40	☐ New complex ☒ In service change ☐ Concept change ☐ Estimate change only

COMPLEX	FLIN FLON CLIFF LAKE TRANSFORMER REPLACEMENT

Proposal

Replace one 230 KV breaker at The Pas Ralls Island.

Replace Flin Flon Cliff Lake 125 MVA Transformer Bank No. 1 with 230-115-13.8 KV 120/160/200 MVA autotransformer.

JUSTIFICATION

☒ Load ☐ Service
☐ Safety ☐ Efficiency
☒ Reliability ☐ Other

Explanation

The new transformer will match the rating of the existing bank no. 2 and will provide firm capacity for Flin Flon area loads. The Pas 230KV replacement breaker is required for switching of Flin Flon Cliff Lake tertiary capacitors by line P58C breakers at The Pas.

Estimate Level	COMPLEX START (yyyy mm)
L3	1993 11

IN SERVICE DATES AND AMOUNTS

1997 07	$510	1997 09	$13	1997 10	$45	1998 05	$28
1999 02	$12	1999 12	$101	2000 10	$4582		

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	2,858		274	29	3,103	3,825	-722	-19
Year 99/00	368	2	229		599	295	304	103
00/01	1,342	33	186	690	871		871	
01/02								
02/03								
03/04								
04/05								
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	4,568	35	689	719	4,573	4,120	453	11

REVISION	ISD of Cliff Lake transformer deferred one year to 2000 10 31 to address single contingency outages during bank replacement.

Reviewed by ORIGINATOR	yyyy mm dd 99 11 08	Reviewed by COORDINATOR	yyyy mm dd 99 11 03
Reviewed by CONSTRUCTOR	yyyy mm dd 99 11 03	Approved by VICE PRESIDENT	yyyy mm dd 99 11 16

H2856/r Rev 99 03

Complex no. 40

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Advance or deferral impact

Deferral of the transformer will force curtailment of Flin Flon area town and HBM&S loads during outages of transformer bank no. 2. Deferral of the breaker replacement will require continued dependance on back-up protection systems to protect an existing breaker at The Pas from capacitive load interruption damage.

Factors affecting timing or viability

Flin Flon area load growth.
Sask Power requirement for Island Falls generation on the Sask Power northern system.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Flin Flon Cliff Lk.-Replace 230-115KV Trnsfmr No1	2,672	3,735	3,810	3,932	122	3
The Pas Ralls Island - Replace 230KV Breaker	476	634	647	636	-11	-2
TOTAL	3,148	4,369	4,457	4,568	111	2

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
9510	3,506	Reflects transformer price increases.
9610	2,679	The Pas 230KV breaker replacement transferred from Flin Flon-Cliff Lake Transformer Addition complex. Transformer cost estimate decreased based on latest costs.
1997 10	2,630	Scope unchanged, estimate reflects revised costing methodology implemented with the new financial reporting system. Also reflects revised interest and escalation rates.
1998 10	4,120	Reflects FP&P addition, increased engineering and const costs to fit larger transformer. ISD of Cliff Lake transformer deferred one year to 1999 10 31 due to damage during shipping.
1999 10	4,573	ISD of Cliff Lake transformer deferred one year to 2000 10 31 to address single contingency outages during bank replacement.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION
Complex 76	Flin Flon Cliff Lake Transformer Addition
Complex 46	Herblet Lake - Flin Flon 230 Transmission

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item __ Domestic Item

149

Title
FLIN FLON CLIFF LAKE REPLACE 230-115 KV TRANSFORMER BANK #1

Budget reference number
03-00-4818

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	60055

DESCRIPTION:
SALVAGE 230-115KV TRANSFORMER BANK NO. 1 AND REPLACE WITH NEW 230-115-13.8KV 120/160/200 MVA AUTOTRANSFORMER WITH LTC RANGE OF +10/-15% (IDENTICAL TO TRANSFORMER BANK NO. 2)

JUSTIFICATION:
TRANSFORMER IS REQUIRED TO PROVIDE FIRM CAPACITY FOR CLIFF LAKE LOAD DURING CONTINGENCY OUTAGE OF 230-115 KV TRANSFORMER BANK 2

REFERENCE:
REPORT TPD 93-1, FLIN FLON AREA TRANSMISSION IMPROVEMENTS - STAGE 2

REVISION:
ISD DEFERRED ONE YEAR FROM 1999 10 31 TO 2000 10 31 TO ADDRESS SINGLE CONTINGENCY OUTAGES DURING BANK REPLACEMENT AS OUTLINED IN M GOLDSBOROUGH MEMO OF 1999 05 05.

CONTINGENCY: $180,000

IN SERVICE DATES		Base estimate
2000 10 31	4 583	199803 L3
		Work start date
		1995 11 01

	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
PREV. AUTHORITY						
Authorized to date:	2 317		202			2 519
1999/00	1 427	21	165	- 690		923
TOTAL	3 744	- 21	367	- 690		3 442
REV. AMOUNTS:						
Authorized to date:	2 317		202			2 519
Over(under)expend:						
Auth 1999/00	273	2	228			503
Req.: 2000/01	1 342	33	186	- 690		871
TOTAL	3 932	35	616	- 690		3 893

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

1999-08-21 05:19 PM

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 03-00-4818

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1993 10	3 420	NEW ITEM.
1994 10	3 123	REVISED INTEREST AND ESCALATION RATES.
1995 10	3 506	PRICE INCREASE DUE TO INCREASED COST FOR AUTO TRANSFORMER.
1996 10	2 237	A DETAILED REVIEW OF THE ESTIMATE RESULTED IN A DECREASE TO ENGINEERING, MATERIAL AND LABOUR.
1997 10	2 176	ESTIMATE REFLECTS REVISED COSTING METHODOLOGY IMPLEMENTED WITH THE NEW FINANCIAL REPORTING SYSTEM. IT ALSO REFLECTS REVISED INTEREST AND ESCALATION RATES.
1998 10	3 442	INCREASE REFLECTS ADDITION OF FP&P REQUIREMENT OUTLINED IN FP&P REPORT DATED 97-11-26. ALSO, INCREASED ENGINEERING AND CONSTRUCTION COSTS ASSOCIATED WITH RELOCATION OF EXISTING MAJOR EQUIPMENT DUE TO INCREASED PHYSICAL SIZE OF NEW TRANSFORMER. ISD DEFERRED TO 1999 10 31 DUE TO DAMAGE OF TRANSFORMER DURING SHIPPING AND THE NEED FOR IT TO BE RETURNED TO THE FACTORY FOR REPAIRS.

ASSOCIATED PROJECTS

Budget reference number	Description
03-00-7226	THE PAS RALLS ISLAND - REPLACE 230KV BREAKER

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr			18			18	18
May	25		18			43	61
Jun	25		18			43	104
Jul	25		18			43	147
Aug	25	-1	19			43	190
Sep	25		19			44	234
Oct	25		19			44	278
Nov	25		19			44	322
Dec	25		20			45	367
Jan	25		20			45	412
Feb	25		20			45	457
Mar	23	3	20			46	503
TOTAL	273	2	228			503	503
2000/01 Apr	649	6	21			676	676
May	59	3	26			88	764
Jun	71	2	27			100	864
Jul	18	1	27			46	910
Aug	22		28			50	960
Sep	62	3	28			93	1 053
Oct	355	13	29		- 690	- 293	76
Nov	89	5				94	854
Dec	17					17	871
Jan							871
Feb							871
Mar							871
TOTAL	1 342	33	186		- 690	871	871

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item

150

Title: THE PAS RALLS ISLAND - REPLACE 230KV BREAKER

Budget reference number: 03-00-7226

ginating division	Coordinating division	Constructing division	Project Order Group (Range):
anning & Control	Design	Construction	70034

DESCRIPTION:
SALVAGE EXISTING 230KV BREAKER 'R5' TERMINATING LINE P58C AT THE PAS RALLS ISLAND STATION. REPLACE WITH A NEW BREAKER CAPABLE OF INTERRUPTING CAPACITIVE CURRENT.

JUSTIFICATION:
ELSEWHERE IN THE BUDGET JUSTIFICATION IS PROVIDED FOR ADDITION OF TERTIARY CAPACITORS ON THE 230-115-13.8 KV CLIFF LAKE TRANSFORMERS. THIS ITEM PROVIDES FOR SWITCHING OF CAPACITORS BY LINE P58C 230KV BREAKERS AT THE PAS. ONLY BREAKER 'R5' REQUIRES REPLACEMENT.

REFERENCE:
REPORT TPD 93-1, 'FLIN FLON AREA TRANSMISSION IMPROVEMENTS - STAGE 2'
TPD TM 93-16 'BREAKER RECOMMENDATION RESULTING FROM THE ADDITION OF CAPACITORS AT FLIN FLON CLIFF LAKE STATION'
MEMO, G. NEUFELD TO V. KOSCHIK, 1997 05 02, 'THE PAS RALLS ISLAND POG123402 - OVEREXPENDITURE WARNING'

REVISION:
REFLECTS REVISED ACTIVITY AND OVERHEAD RATES.

CONTINGENCY: $11,000

IN SERVICE DATES						Base estimate
Prior Total	573	1998 05 31	12	1999 01 31	1	199803 L4
1998 02 28	-0	1998 06 30	0	1999 02 28	10	
1998 03 31	5	1998 07 31	0	1999 03 31	0	Work start date
1998 04 30	6	1998 11 30	1	1999 12 31	102	1993 11 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date	541		73	-29		585
1999/00	94					94
TOTAL	635		73	-29		679
REV. AMOUNTS:						
Authorized to date:	541		73	-29		585
Over(under)expend:						
Auth Req.: 1999/00	95		1			96
TOTAL	636		74	-29		681

Prepared by: yy mm dd COORDINATOR — Approved by: yy mm dd Approved by: yy mm dd

Estimated by: ORIGINATOR — COORDINATING MANAGER — ORIGINATING MANAGER

1999-08-21 05:23 PM

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 03-00-7226

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1993 10	693	NEW ITEM.
1994 10	453	ORIGINAL ESTIMATE INCLUDED REPLACEMENT OF BREAKER CT'S AND STRUCTURES. THESE ARE NOW NOT BEING REPLACED THEREFORE REDUCED ENGINEERING, LABOUR, AND MATERIAL COSTS.
1995 10	419	IN-SERVICE DATE DEFERRED 2 YEARS TO 1997 08 31. SALVAGE VALUE OF BREAKER OMITTED IN PREVIOUS ESTIMATE.
1996 10	442	NEW ITEM. TRANSFERRED FROM BRN # 9403-00-4825. COMPLEX 76.
1997 10	457	SCOPE UNCHANGED, ESTIMATE REFLECTS REVISED COSTING METHODOLOGY IMPLEMENTED WITH THE NEW FINANCIAL REPORTING SYSTEM. ALSO, REFLECTS REVISED INTEREST AND ESCALATION RATES.
1998 10	679	SALVAGE VALUE OF 230 KV BREAKER LESS THAN ORIGINALLY ESTIMATED. ADDITIONAL FUNDS REQ'D TO ADDRESS REMEDIAL FOUNDATION WORK, PLUS ITEMS IDENTIFIED IN ABOVE REFERENCED MEMO 'OVEREXPENDITURE WARNING'.

ASSOCIATED PROJECTS

Budget reference number	Description
03-00-4818	FLIN FLON CLIFF LAKE REPLACE 230-115 KV TRANSFORMER BANK #1

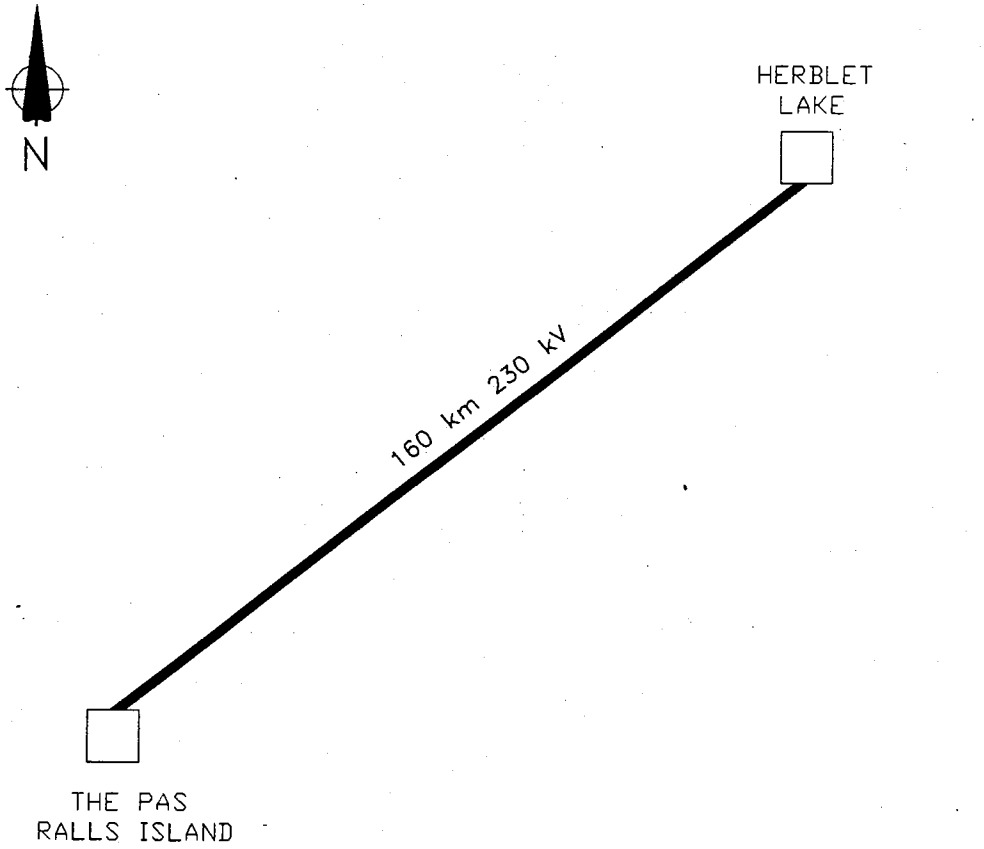
Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	11	-1				10	10
May	11	-1				10	20
Jun	11					11	31
Jul	11					11	42
Aug	11					11	53
Sep	11					11	64
Oct	11					11	75
Nov	11					11	86
Dec	7	2	1			10	96
Jan							96
Feb							96
Mar							96
TOTAL	95		1			96	96
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

CAPITAL BUDGET COMPLEX CONCEPTUAL DIAGRAM

HERBLET LAKE – THE PAS 230KV TRANSMISSION

REVISED: 1999 - 10 - 01	ISSUED BY: WNZ

COMPLEX NO. 47



manitoba hydro

PLANNING AND CONTROL DIVISION

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

COMPLEX STATUS	Complex no.	REVISION STATUS
☒ Planned ☐ In progress	47	☐ New complex ☐ In service change ☐ Concept change ☒ Estimate change only

COMPLEX	HERBLET LAKE - THE PAS 230 KV TRANSMISSION

Proposal

Perform environmental assessments and route selection, design and construct transmission and terminal facilities to provide firm supply to Flin Flon Cliff Lake and The Pas Ralls Island as follows:

Transmission: 230 KV line 160 KM Herblet Lake - The Pas Ralls Island.

Terminations: Extend 230 KV facilities at Herblet Lake and The Pas Ralls Island stations.

Communications: Upgrade and co-ordinate with existing Herblet Lake and The Pas facilities.

JUSTIFICATION	Explanation
☒ Load ☐ Service ☐ Safety ☐ Efficiency ☒ Reliability ☐ Other	The line is required to provide firm supply and voltage support for increasing Flin Flon and The Pas area loads.

Estimate Level	COMPLEX START (yyyy mm)
L2	2002 04

IN SERVICE DATES AND AMOUNTS				
2010 10	$48550			

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend								
Year 99/00								
00/01								
01/02								
02/03	140	14	6		160	155	5	3
03/04	384	47	31		462	440	22	5
04/05	779	113	91		983	932	51	5
05/06	91	15	149		255	244	11	5
06/07	785	154	189		1,128	1,052	76	7
07/08	2,484	544	356		3,384	3,235	149	5
08/09	12,383	3008	1,040		16,431	16,330	101	1
09/10	12,604	3294	3,140		19,038	18,742	296	2
10/11	3,285	942	2,480		6,707	6,459	248	4
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	32,935	8,131	7,482		48,548	47,589	959	2

REVISION	Scope unchanged.

Reviewed by ORIGINATOR	yyyy 99 mm 11 dd 08	Reviewed by COORDINATOR	yyyy 99 mm 11 dd 03
Reviewed by CONSTRUCTOR	yyyy 99 mm 11 dd 03	Approved by VICE-PRESIDENT	yyyy 99 mm 11 dd 3[illegible]

H2856/r Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Complex no. 47

Advance or deferral impact

Deferral will force curtailment of Flin Flon and The Pas area loads during outages of 230 KV supply lines in the Flin Flon - The Pas - Herblet Lake area.

Factors affecting timing or viability

Flin Flon and The Pas area load growth.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Herblet Lake - The Pas Ralls Island 230 KV T/L		26,141	26,664	26,553	-111	-0
Herblet Lake Stn. - Terminate The Pas 230 KV T/L		3,524	3,594	3,626	32	1
The Pas Ralls Islnd-Terminate Herblet Lk 23KV T/L		1,989	2,029	2,107	78	4
Communicatn for Herblet Lake-The Pas RI 230KV T/L		605	617	647	30	5
TOTAL		32,259	32,904	32,933	29	0

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
9510	49,662	Revised escalation and interest rates.
9610	49,630	Revised escalation and interest rates.
1997 10	47,621	Scope unchanged, estimate reflects revised costing methodology implemented with the new financial reporting system. Also reflects revised interest and escalation rates.
1998 10	47,589	Scope unchanged.
1999 10	48,548	Scope unchanged.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item ___ Domestic Item

151

Title: HERBLET LAKE - THE PAS RALLS ISLAND 230KV T/L

Budget reference number: 02-00-1243

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	70291

DESCRIPTION:
CONDUCT ENVIRONMENTAL IMPACT ASSESSMENT, SELECT A ROUTE, OBTAIN LICENSING AND ACQUIRE PROPERTY FOR RIGHT-OF-WAY. DESIGN AND CONSTRUCT APROXIMATELY 160 KM OF 230 KV STEEL TOWER LINE USING 954 MCM CONDUCTOR FROM HERBLET LAKE TO THE PAS RALLS ISLAND.

JUSTIFICATION:
LINE IS REQUIRED TO FIRM UP LOAD AND PROVIDE VOLTAGE SUPPORT FOR INCREASING FLIN FLON CLIFF LAKE AND THE PAS RALLS ISLAND AREA LOADS.
(NOTE: DUE TO POSSIBILITY OF NEW OR EXPANDED LOADS IN FLIN FLON - THE PAS AREA, A 2004 IN SERVICE DATE IS ALSO BEING PROTECTED)

REFERENCE:
1. REPORT TPD 93-1, 'FLIN FLON AREA TRANSMISSION IMPROVEMENTS - STAGE 2'
2. TPD TM 93-20. 'FLIN FLON TRANSMISSION SECTIONALIZATION AT HERBLET LAKE'

NOTE: COMPLETION DATE FOR PROPERTY ACQUISITION: 2007 04 01.

REVISION:
REFLECTS REVISED ACTIVITY AND OVERHEAD RATES.

CONTINGENCY: $0.

IN SERVICE DATES		Base estimate
2010 10 31	39 779	199706 L2
		Work start date
		2002 04 01

PREV AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:						
2002/03	134	14	6			154
2003/04	362	48	30			440
2004/05	732	113	86			931
2005/06	88	16	140			244
2006/07	726	150	176			1 052
2007/08	2 203	507	327			3 037
2008/09	11 269	2 863	941			15 073
2009/10	10 299	2 798	2 681			15 778
2010/11	328	95	2 015			2 438
TOTAL	26 141	6 604	6 402			39 147
REV AMOUNTS:						
Authorized to date:						
Over(under)expend:						
Auth 2002/03	140	15	6			161
Req. 2003/04	384	48	31			463
2004/05	779	113	91			983
2005/06	91	15	149			255
2006/07	785	154	189			1 128
2007/08	2 301	504	352			3 157
2008/09	11 361	2 761	978			15 100
2009/10	10 380	2 704	2 870			15 954
2010/11	332	93	2 153			2 578
TOTAL	26 553	6 407	6 819			39 779

Prepared by: yy mm dd COORDINATOR — Approved by: yy mm dd — Approved by: yy mm dd

Estimated by: ORIGINATOR — COORDINATING MANAGER — ORIGINATING MANAGER

CAPITAL EXPENDITURE REVISION

Budget reference number 02-00-1243

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1990 05	118 486	NEW ITEM.
1990 10	72 103	THIS ITEM PREVIOUSLY INCLUDED ALL NECESSARY TRANSMISSION LINES AND WORK NECESSARY FOR THE CONNECTION FOR THE MANASAN G.S. TO THE NORTHERN AC SYSTEM. SPECIFIC LINES NOW REFLECTED SEPARATELY.
1991 10	0	ITEM DEFERRED INDEFINITELY.
1992 10	54 553	PROJECT REINTRODUCED INTO POWER RESOURCE PLAN.
1993 03	73 430	ISD DEFERRED 8 YEARS TO 2024 FROM 2016 DUE TO 1000 MW OH SALE CANCELLATION.
1993 10	41 335	ITEM TRANSFERRED FROM MANASAN TRANSMISSION COMPLEX. LINE LENGTH INCREASED BY 10 KM. LINE CONDUCTOR SIZE INCREASED TO 954 MCM. STALL LAKE 230 KV STATION NAME CHANGED TO HERBLET LAKE. PROJECT ADVANCED14 YEARS. DECREASE IN INTEREST AND ESCALATION RATES.
1994 10	41 229	WORK START DATE ADVANCED 1 YEAR. CONTINGENCY OF $2.5 MILLIONADDED TO ALLOW FOR INCREASED COSTS ASSOCIATED WITH NORTHERN CONSTRUCTION. REVISED INTEREST AND ESCALATION RATES.
1995 10	41 121	REVISED INTEREST AND ESCALATION RATES.
1996 10	73 635	REVISED INTEREST RATES
1997 10	39 220	SCOPE UNCHANGED, ESTIMATE REFLECTS REVISED COSTING METHODOLOGY IMPLEMENTED WITH THE NEW FINANCIAL REPORTING SYSTEM. ALSO, REFLECTS REVISED INTEREST AND ESCALATION RATES.
1998 10	39 147	NO CHANGE.

ASSOCIATED PROJECTS

Budget reference number	Description
03-00-1694	HERBLET LAKE STATION TERMINATE THE PAS 230KV T/L
03-00-1695	
05-00-4509	COMMUNICATIONS FOR HERBLET LAKE - THE PAS RALLS ISLAND 230KV

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item ___ Domestic Item 152

Title
HERBLET LAKE STATION TERMINATE THE PAS 230KV T/L

Budget reference number
03-00-1694

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	70292

DESCRIPTION:
TERMINATE THE 230KV LINE FROM THE PAS RALLS ISLAND. FACILITIES WILL INCLUDE 1-230KV BREAKER, 1-230KV 30MVAR LINE REACTOR WITH 230KV CIRCUIT SWITCHER AND ALL ASSOCIATED EQUIPMENT.

JUSTIFICATION:
ELSEWHERE IN THE BUDGET, JUSTIFICATION IS GIVEN FOR CONSTRUCTION OF HERBLET LAKE - THE PAS RALLS ISLAND 230 KV LINE. THIS ITEM PROVIDES FOR TERMINATION OF THAT LINE AT HERBLET LAKE.

REFERENCE:
1. REPORT TPD 93-1, 'FLIN FLON AREA TRANSMISSION IMPROVEMENTS - STAGE 2'
2. TPD TM 93-20, 'FLIN FLON TRANSMISSION SECTIONALIZATION AT HERBLET LAKE'

REVISION:
REFLECTS REVISED ACTIVITY AND OVERHEAD RATES.

CONTINGENCY: $333,000

IN SERVICE DATES: 2010 10 31 — 5 038

Base estimate: 199706 L2

Work start date: 2007 09 01

PREV. AUTHORITY Authorized to date.	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
2007/08	95	22	3			120
2008/09	702	178	35			915
2009/10	1 485	409	177			2 071
2010/11	1 242	371	193			1 806
TOTAL	3 524	980	408			4 912
REV. AMOUNTS: Authorized to date: Over(under)expend:						
Auth 2007/08	109	24	3			136
Req. 2008/09	726	176	38			940
2009/10	1 531	405	194			2 130
2010/11	1 260	363	209			1 832
TOTAL	3 626	968	444			5 038

Prepared by — yy mm dd — COORDINATOR
Approved by — yy mm dd — COORDINATING MANAGER
Approved by — yy mm dd — ORIGINATING MANAGER
Estimated by — ORIGINATOR

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 03-00-1694

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1997 10	4 917	SCOPE UNCHANGED, ESTIMATE REFLECTS REVISED COSTING METHODOLOGY IMPLEMENTED WITH THE NEW FINANCIAL REPORTING SYSTEM. ALSO, REVISED INTEREST AND ESCALATION RATES.
1998 10	4 912	NO CHANGE

ASSOCIATED PROJECTS

Budget reference number	Description
02-00-1243	HERBLET LAKE - THE PAS RALLS ISLAND 230KV T/L
03-00-1695	
05-00-4509	COMMUNICATIONS FOR HERBLET LAKE - THE PAS RALLS ISLAND 230KV

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

1999-08-21 05:19 PM

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item

153

Title
THE PAS RALLS ISLAND TERMINATE HERBLET LAKE 230KV T/L

Budget reference number
03-00-1695

ginating division	Coordinating division	Constructing division	Project Order Group (Range):
anning & Control	Design	Construction	70293

DESCRIPTION:
TERMINATE 230KV LINE FROM HERBLET LAKE, FACILITIES WILL INCLUDE 1-230KV BREAKER AND ASSOCIATED EQUIPMENT

JUSTIFICATION:
ELSEWHERE IN THE BUDGET JUSTIFICATION IS GIVEN FOR CONSTRUCTION OF HERBLET LAKE - THE PAS RALLS ISLAND 230 KV LINE. THIS ITEM PROVIDES FOR TERMINATION OF THAT LINE AT THE PAS RALLS ISLAND.

REFERENCE:
1. REPORT TPD 93-1, 'FLIN FLON AREA TRANSMISSION IMPROVEMENTS - STAGE 2'
2. TPD TM 93-20, 'FLIN FLON TRANSMISSION SECTIONALIZATION AT HERBLET LAKE'

REVISION:
REFLECTS REVISED ACTIVITY AND OVERHEAD RATES.

CONTINGENCY: $191,000

2010 10 31	2 883	IN SERVICE DATES				Base estimate 199706 L2 Work start date 2008 01 01
PREV. AUTHORITY Authorized to date	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
2007/08	64	14	1			79
2008/09	257	64	21			342
2009/10	589	163	63			815
2010/11	1 079	322	90			1 491
TOTAL	1 989	563	175			2 727
REV. AMOUNTS Authorized to date Over(under)expend						
Auth 2007/08	73	17	1			91
Req. 2008/09	296	71	24			391
2009/10	627	168	74			869
2010/11	1 111	318	103			1 532
TOTAL	2 107	574	202			2 883

Prepared by: yy mm dd COORDINATOR — Approved by: yy mm dd Approved by: yy mm dd
Estimated by: ORIGINATOR — COORDINATING MANAGER — ORIGINATING MANAGER

1999-08-21 05:19 PM

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 03-00-1695

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1990 10	6 143	PREVIOUSLY UNDER BRN # 03-00-1682.
1991 10	0	ITEM DEFERRED INDEFINITELY.
1992 10	4 536	PROJECT REINTRODUCED INTO POWER RESOURCE PLAN.
1993 03	6 105	ISD DEFERRED 8 YEARS TO 2024 FROM 2016 DUE TO 1000 MW OH SALE CANCELLATION.
1993 10	3 056	ITEM TRANSFERRED FROM MANASAN TRANSMISSION COMPLEX. STALL LAKE 230 KV STATION NAME CHANGED TO HERBLETT LAKE. DECREASE IN INTEREST AND ESCALATION RATES.
1994 10	2 825	UPDATED ENGINEERING AND EQUIPMENT COSTS. REVISED INTEREST AND ESCALATION RATES.
1995 10	2 774	UPDATED ENGINEERING AND EQUIPMENT COSTS . REVISED INTEREST AND ESCALATION RATES.
1996 10	2 759	REVISED INTEREST RATES. CORRECTION TO CALCULATED ESCALATION.
1997 10	2 689	SCOPE UNCHANGED, ESTIMATE REFLECTS REVISED COSTING METHODOLOGY IMPLEMENTED WITH THE NEW FINANCIAL REPORTING SYSTEM. ALSO, REFLECTS REVISED INTEREST AND ESCALATION RATES.
1998 10	2 727	NO CHANGE CONTINGENCY: $191,000

ASSOCIATED PROJECTS

Budget reference number	Description
02-00-1243	HERBLET LAKE - THE PAS RALLS ISLAND 230KV T/L
03-00-1694	HERBLET LAKE STATION TERMINATE THE PAS 230KV T/L
05-00-4509	COMMUNICATIONS FOR HERBLET LAKE - THE PAS RALLS ISLAND 230KV

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item ___ Domestic Item 154

Title: COMMUNICATIONS FOR HERBLET LAKE - THE PAS RALLS ISLAND 230KV

Budget reference number: 05-00-4509

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
anning & Control	Planning & Control	Construction	70294

DESCRIPTION:
DESIGN, INSTALL, AND COMMISSION COMMUNICATION SYSTEM ADDITIONS REQUIRED FOR THE PROTECTION OF HERBLET LAKE - THE PAS RALLS ISLAND 230 KV LINE.

JUSTIFICATION:
ELSEWHERE IN THE BUDGET, JUSTIFICATION IS GIVEN FOR THE CONSTRUCTION OF HERBLET LAKE - THE PAS RALLS ISLAND 230KV LINE. THIS ITEM PROVIDES FOR COMMUNICATIONS, PROTECTION AND CONTROL FACILITIES FOR THIS LINE.

REFERENCE:
1. REPORT TPD 93-1, 'FLIN FLON AREA TRANSMISSION IMPROVEMENTS - STAGE 2'
2. TPD TM 93-20, ' FLIN FLON TRANSMISSION SECTIONALIZATION AT HERBLET LAKE'

REVISION:
REFLECTS REVISED ACTIVITY AND OVERHEAD RATES.

CONTINGENCY: $50,000.

IN SERVICE DATES		Base estimate
2010 10 31	851	199704 L2
		Work start date
		2009 10 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:						
2009/10	59	18	1			78
2010/11	546	165	14			725
TOTAL	605	183	15			803
REV. AMOUNTS:						
Authorized to date:						
Over(under)expend:						
Auth 2009/10	65	18	2			85
Req. 2010/11	582	169	15			766
TOTAL	647	187	17			851

Prepared by	yy mm dd	Approved by	yy mm dd	Approved by	yy mm dd
COORDINATOR		COORDINATING MANAGER		ORIGINATING MANAGER	
Estimated by					
ORIGINATOR					

1999-08-21 05:29 PM

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number: 05-00-4509

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1993 10	124	DECREASE IN INTEREST AND ESCALATION RATES.
1994 10	149	ITEM TRANSFERRED TO WINNIPEG-BRANDON 500 KV T/L COMPLEX TO CO-ORDINATE WITH LINE R.O.W. ACQUISITION. ISD DEFERRED TO 1998 04 01.
1995 10	145	REVISED CASH FLOW, ESCALATION AND INTEREST RATES.
1996 10	758	REVISED INTEREST RATES.
1997 10	794	ESTIMATE REFLECTS REVISED COSTING METHODOLOGY IMPLEMENTED WITH THE NEW FINANCIAL REPORTING SYSTEM. ALSO REVISED INTEREST AND ESCALATION RATES REFLECTED.
1998 10	803	NO CHANGE.

ASSOCIATED PROJECTS

Budget reference number	Description
02-00-1243	HERBLET LAKE - THE PAS RALLS ISLAND 230KV T/L
03-00-1694	HERBLET LAKE STATION TERMINATE THE PAS 230KV T/L
03-00-1695	

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

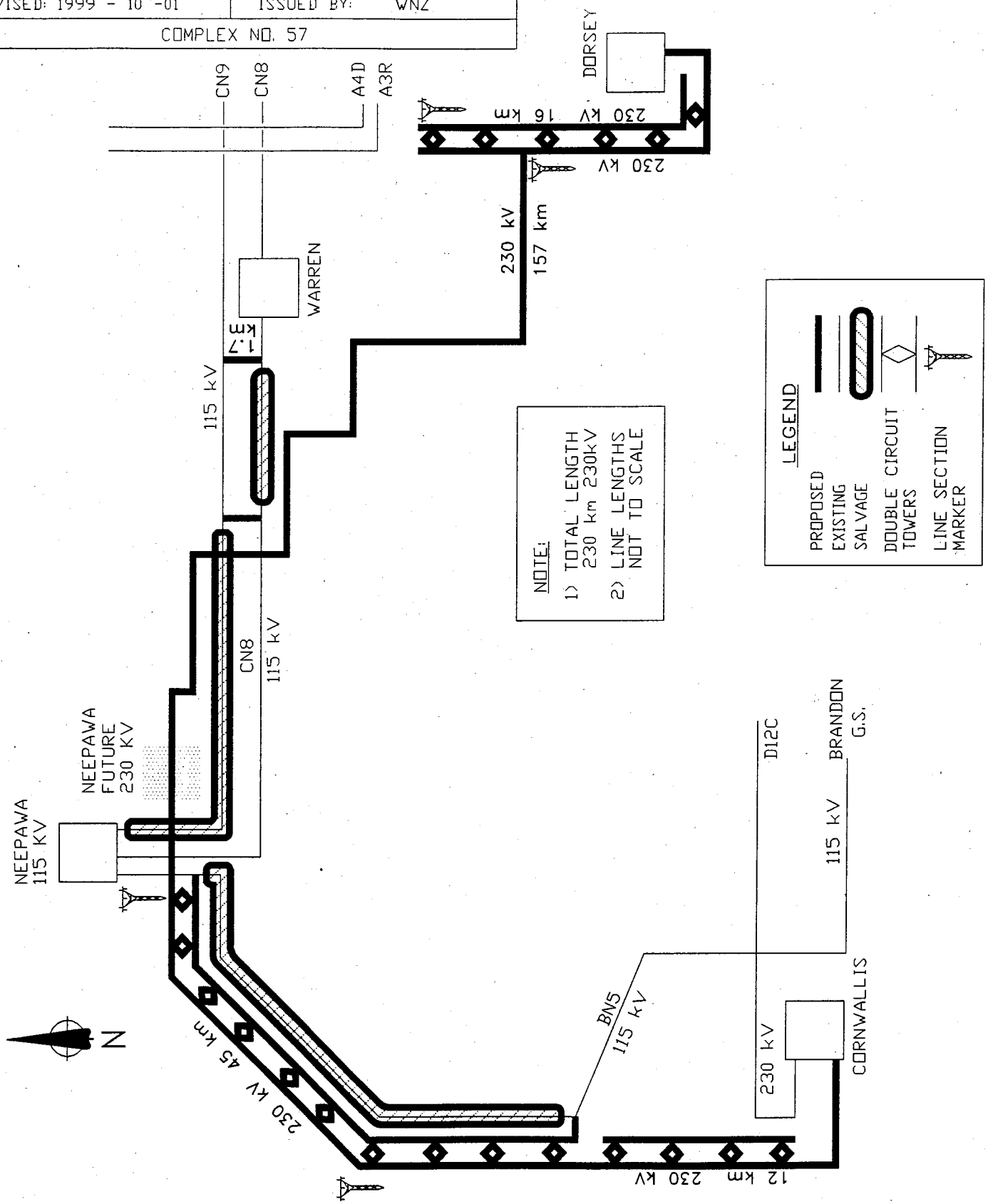
1999-08-21 05:29 PM

CAPITAL BUDGET COMPLEX CONCEPTUAL DIAGRAM

DORSEY–NEEPAWA–CORNWALLIS 230KV LINE

REVISED: 1999 - 10 -01 | ISSUED BY: WNZ

COMPLEX NO. 57



manitoba hydro

PLANNING AND CONTROL DIVISION

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

COMPLEX STATUS	Complex no.	REVISION STATUS
☐ Planned ☒ In progress	57	☐ New complex ☒ In service change ☐ Concept change ☐ Estimate change only

COMPLEX: DORSEY - NEEPAWA - CORNWALLIS 230 KV LINE

Proposal

Perform environmental assessments and route selection, design and construct transmission and terminal facilities to provide firm supply to Brandon as follows: Transmission: 230 KV line Dorsey - Neepawa - Cornwallis (D-N-C), consisting of 73 KM on double circuit and 157 KM on single circuit towers. New 115 KV line of 1.7 KM Warren-Line CN9 Tap. Salvage 63 KM of 115 KV line CN8 from Warren towards Neepawa and 79 KM of 115 KV line CN9 from Neepawa towards Warren. Salvage 52 KM of 115 KV line BN5 from Neepawa to north of Brandon and replace with east side of 230 KV line operating at 115 KV as 2nd circuit on D-N-C towers. Terminations: Extend 230 KV facilities at Dorsey and Cornwallis stations. Salvage 15 MVAR transformer reactor & 1 reactor switching breaker. Install 2-20 MVAR 13.2 KV shunt reactors and 3 transformer reactor switching breakers. Purchase property for future Neepawa 230 KV station. Communications: Integrate with existing Dorsey and Cornwallis facilities.

JUSTIFICATION	Explanation
☒ Load ☐ Service ☐ Safety ☐ Efficiency ☒ Reliability ☐ Other	These facilities provide transmission improvements required by 1999 to supply Brandon area future load growth. They also defer the future Winnipeg - Brandon 230 KV transmission complex and provide for future Neepawa area support. One new reactor will replace an existing reactor in deteriorated condition. Both reactors are required to control 230 KV voltage at Cornwallis under light load conditions.

Estimate Level	COMPLEX START (yyyy mm)
L2-3	1991 09

IN SERVICE DATES AND AMOUNTS							
1998 03	$2100	1998 04	$440	1999 07	$624	2000 04	$46978

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	28,466		3,195	7	31,654	25,861	5,793	22
Year 99/00	13,483	51	3,258		16,792	15,703	1,089	7
00/01	1,357	12	319		1,688	6,605	-4,917	-74
01/02								
02/03								
03/04								
04/05								
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	43,306	63	6,772	7	50,134	48,169	1,965	4

REVISION: ISD deferred 6 months to 2000 04 30 by Transmission Line Construction.

Reviewed by ORIGINATOR	yyyy mm dd 99 11 05	Reviewed by COORDINATOR	yyyy mm dd 99 11 03
Reviewed by CONSTRUCTOR	yyyy mm dd 99 11 03	Approved by VICE-PRESIDENT	yyyy mm dd 99 11 18

H2856/r Rev 99 03

Complex no. 57

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Advance or deferral impact

Deferral will reduce firm load support of the Brandon area. Delay in completing this line will impact on the retermination of Ashern - Dorsey 230KV line and subsequent Winnipeg area transmission improvements.

Factors affecting timing or viability

Manitoba Load.
Brandon thermal generation service life.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Dorsey-Neepawa-Cornwallis 230 KV T/L	39,924	37,388	38,136	37,597	-539	-1
Neepawa Station - Land Purchase	596	389	397	391	-6	-2
Cornwallis-Terminate Dorsey (Neepawa) 230KV T/L	2,855	2,766	2,821	2,643	-178	-6
Dorsey-Terminate Cornwallis (Neepawa) 230KV T/L	1,953	1,561	1,592	1,743	151	9
Cornwallis-Tertiary Reactor R12 and Bkr. Rplcmnt.	995	591	603	602	-1	-0
Dorsey-Neepawa-Cornwallis 230KV Line Commnctn.	183	293	299	331	32	11
TOTAL	46,506	42,988	43,848	43,307	-541	-1

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
9510	54,204	In-service date of 214 km of line from HVDC line ROW to Cornwallis deferred 1 year to 1998 10 31. Reflects cost decreases for station engineering, material, and labour.
9610	51,613	ISD for 214 km of line deferred 1 year to 1999 10 31. Cornwallis transformer reactor and switching breaker added. Cost decreases for line materials, station engineering
1997 10	47,344	Scope unchanged, reflects revised costing methodology implemented with the new financial reporting system, and revised interest and escalation rates.
1998 10	48,169	Scope unchanged.
1999 10	50,134	ISD deferred 6 months to 2000 04 30 by Transmission Line Construction.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION
Complex 60	Winnipeg - Brandon 230 KV Transmission
Complex 51	Ashern - Dorsey 230KV Line Changes

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item ___ Domestic Item 155

Title: DORSEY-NEEPAWA-CORNWALLIS 230KV T/L

Budget reference number: 02-00-1235

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	60025:60047

DESCRIPTION:
CONDUCT ENVIRONMENTAL IMPACT ASSESSMENT, SELECT A ROUTE, ACQUIRE PROPERTY FOR RIGHT-OF-WAY AND OBTAIN LICENCING, DESIGN AND CONSTRUCT A 230 KV WOODPOLE & STEEL LINE FROM DORSEY TO CORNWALLIS VIA NEEPAWA WITH A TOTAL LENGTH OF APPROXIMATELY 230.0 KM. LINE SECTIONS ARE: - 16 KM DBL CCT 1272 MCM FROM DORSEY NORTH TO EAST/NORTH ROUTE ANGLE OF LINES A3R & A4D. - 157 KM OF SINGLE CCT 954 MCM FROM LOCALE 10 KM NORTH OF DORSEY TO NEEPAWA 110KV STN. - 45 KM DBL CCT 954 MCM FROM NEEPAWA 110 KV STN. TO LOCALE 12 KM NORTH OF CORNWALLIS. - 12 KM DBL CCT 1272 MCM FROM END OF DBL CCT 954 MCM TO CORNWALLIS 230 KV STATION. SALVAGE 63 KM OF 110 KV CCT CN8 FROM WARREN TOWARDS NEEPAWA AND 79 KM OF 110 KV CCT CN9 FROM NEEPAWA TOWARDS WARREN. SALVAGE 52 KM OF 110 KV CCT BN5 FROM NEEPAWA TOWARDS CORNWALLIS AND REPLACE WITH EAST SIDE OF NEW DOUBLE CIRCUIT 230 KV LINE FROM NEEPAWA TO LOCALE 4.7 KM NORTH OF CORNWALLIS WHERE IT IS RECONNECTED TO BN5 TO COMPLETE LINE. CONDUCT ENVIRONMENTAL PROCEDURES, DESIGN AND CONSTRUCT 1.7 KM OF 110 KV 266 MCM CCT FROM WARREN TO LINE CN9. JOIN OPEN ENDS OF LINES CN8 AND CN9 (200 M SPAN) RESULTING FROM SALVAGE TO RE-ESTABLISH A 110 KV CIRCUIT FROM WARREN TO NEEPAWA. NOTE: 16 KM DBL CCT FROM DORSEY TO LINES A3R/A4D REQUIRED IN-SERVICE BY 1998 03 31 TO ACCOMMODATE ASHERN-DORSEY 230KV LINE CHANGES COMPLEX.

JUSTIFICATION:
THIS ITEM PROVIDES INITIAL AC SYSTEM IMPROVEMENTS REQUIRED TO TRANSMIT POWER TO BRANDON TO SUPPLY FUTURE LOAD GROWTH, THEREBY DEFERRING WINNIPEG-BRANDON 500 KV TRANSMISSION. IT ALSO PROVIDES FOR FUTURE NEEPAWA AREA SUPPORT, OUTLETS FOR NORTHERN AC SYSTEM BURNTWOOD RIVER GENERATION, AND LINE A4D RECONNECTION INTO DORSEY TO UPGRADE WINNIPEG AREA TRANSMISSION.

REFERENCE:
1) TP REPORT 89-3 WESTERN MANITOBA SYSTEM DEVELOPMENT ALTERNATIVES, RECOMMENDATION #6.
2) MEMO B.D. RINDALL TO C.V. THIO, 1999 01 05; AND C.V. THIO TO B.D. RINDALL, 1999 01 15.

REVISION:
INSERVICE DATE DEFERRED FROM 1999 10 31 TO 2000 04 30 AS REQUESTED BY TRANSMISSION LINE CONSTRUCTION AND AGREED TO BY SYSTEM PLANNING. THIS RESULTS IN AN INCREASE TO CAPITALIZED INTEREST. 1.7 KM OF 110 KV CCT FROM WARREN TO CN9 WAS CHANGED FROM 336 MCM TO 266 MCM. REFLECTS REVISED ACTIVITY AND OVERHEAD RATES.

CONTINGENCY: $520,000

IN SERVICE DATES

1998 03 31	2 100
2000 04 30	41 851

Base estimate: 199902 L3

Work start date: 1991 09 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:	26 317		3 092	-2		29 407
1999/00	5 568	208	1 471			7 247
2000/01	5 581					5 581
TOTAL	37 466	208	4 563	-2		42 235
REV. AMOUNTS:						
Authorized to date:	26 317		3 092	-2		29 407
Over(under)expend:						
Auth 1999/00	10 365	15	2 949			13 329
Req.: 2000/01	915	11	287			1 213
TOTAL	37 597	26	6 328	-2		43 949

Prepared by: yy mm dd COORDINATOR — Approved by: yy mm dd — Approved by: yy mm dd

Estimated by: ORIGINATOR — COORDINATING MANAGER — ORIGINATING MANAGER

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 02-00-1235

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1990 10	57 554	NEW ITEM.
1991 10	54 352	DECREASE IN INTEREST AND ESCALATION RATES.
1992 10	48 327	DECREASE IN INTEREST AND ESCALATION RATES.
1993 10	54 459	ENVIRONMENTAL ACTIVITIES TRANSFERRED FROM CANCELLED ITEM BRN 9202-00-1236. SALVAGE OF 7.2 KM OF 110 KV LINE DELETED.
1994 10	47 014	TOTAL 230KV LINE LENGTH REDUCED 15.2 KM. FURTHER REDUCTION REFLECTS PREFERRED LINE ROUTE SELECTION, INDEPENDENT OF BRANDON EHV SITESELECTION PROCESS. SALVAGE OF 110KV CCT CN9 ADDED. TOTAL 110KV SALVAGE INCREASED 15 KM. STRINGING OF 2ND SIDE OF 1272 MCM DBL CCT SECTIONS ADDED AT DORSEY AND BRANDON ENDS.
1995 10	47 318	IN-SERVICE DATE FOR 214 KM OF LINE DEFERRED 1 YEAR TO 1998 10 31. REFLECTS REVISED INTEREST AND ESCALATION RATES.
1996 10	44 200	ISD FOR 214 KM OF LINE DEFERRED ONE YEAR TO 1999 10 31. ESTIMATE REVISED TO REFLECT CURRENT MARKET PRICES FOR MATERIAL RESULTS IN A SUBSTANTIAL REDUCTION.
1997 10	40 974	16KM DBL CCT FROM DORSEY NORTH TO A3R & A4D COMPLETED APPROXIMATELY $ 500,000 UNDER BUDGET. CONTINGENCY REDUCED DUE TO SLOWER ESCALATION OF MATERIAL AND LABOUR.
1998 10	42 234	INCREASED INTEREST DUE TO CAPITALIZING LESS COSTS AT A LATER DATE THAN PREVIOUSLY ESTIMATED.

ASSOCIATED PROJECTS

Budget reference number	Description
03-00-1661	NEEPAWA STATION LAND PURCHASE
03-00-1662	CORNWALLIS TERMINATE DORSEY (NEEPAWA) 230KV T/L
03-00-1663	DORSEY TERMINATE CORNWALLIS (NEEPAWA) 230KV T/L
03-00-6190	CORNWALLIS TERTIARY REACTOR R12 AND BREAKER REPLACEMENT
05-00-1252	DORSEY-NEEPAWA-CORNWALLIS 230KV LINE COMMUNICATIONS COMPLEX

Forecasted Mthly Exp	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	1 082		190			1 272	1 272
May	5 288		199			5 487	6 759
Jun	392		237			629	7 388
Jul	62	1	241			304	7 692
Aug	298	1	244			543	8 235
Sep	328	2	247			577	8 812
Oct	173	2	251			426	9 238
Nov	1 042	2	254			1 298	10 536
Dec	675	2	263			940	11 476
Jan	316	2	270			588	12 064
Feb	295	2	274			571	12 635
Mar	414	1	279			694	13 329
TOTAL	10 365	15	2 949			13 329	13 329
2000/01 Apr	794	10	287			1 091	1 091
May	110	1				111	1 202
Jun	11					11	1 213
Jul							1 213
Aug							1 213
Sep							1 213
Oct							1 213
Nov							1 213
Dec							1 213
Jan							1 213
Feb							1 213
Mar							1 213
TOTAL	915	11	287			1 213	1 213

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item ___ Domestic Item 156

Title
NEEPAWA STATION LAND PURCHASE

Budget reference number
03-00-1661

ginating division	Coordinating division	Constructing division	Project Order Group (Range):
anning & Control	Planning & Control	Property	72009

DESCRIPTION:
CONDUCT THE NECESSARY ENVIRONMENTEA
AL IMPACT STUDIES, OBTAIN AND ACQUIRE THE PROPERTY TO DEVELOP A FUTURE NEEPAWA 230-115KV TERMINAL STATION NEAR EXISTING NEEPAWA 115KV STATION ALONG R.O.W. OF DORSEY-NEEPAWA-CORNWALLIS 230KV LINE. PREFORM ENGINEERING STUDY TO ASSESS REQUIREMENT AND VIABLILITY FOR UPGRADE OF EXISTING NEEPAWA 115-66KV STATION FACILITIES AND STRUCTURES. THESE ACTIVITIES ARE TO OCCUR IN CONJUNCTION WITH R.O.W. SELECTION PROCESS FOR DORSEY-NEEPAWA-CORNWALLIS 230KV LINE.

JUSTIFICATION:
THIS ITEM PROVIDES FOR ACQUISITION OF PROPERTY FOR CONSTRUCTION OF FUTURE 230KV STATION FACILITIES TO PARTIALLY SUPPORT WESTERN MANITOBA LOAD GROWTH. IT ALSO PROVIDES FOR DETERMINATION OF REQUIREMENTS TO UPGRADE EXISTING NEEPAWA FACILITIES TO PROPERLY CO-ORDINATE WITH CONSTRUCTION AND OPERATION OF NEW 230-115KV STATION.

REFERENCE:
TP REPORT 89-3 WESTERN MANITOBA SYSTEM DEVELOPMENT ALTERNATIVES, RECOMMENDATION #7.

REVISION:
ITEM COMPLETED.

IN SERVICE DATES

						Base estimate
1998 04 30	440	1998 11 30	2	1999 04 30	-1	199707 L5
1998 05 31	-3	1998 12 31	-0			
1998 06 30	1	1999 02 28	-0			Work start date
1998 09 30	0	1999 03 31	0			1997 04 01

PREV AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date	391		48			439
1999/00	1					1
TOTAL	392		48			440
REV. AMOUNTS:						
Authorized to date:	391		48			439
Over(under)expend:						
Auth Req.:						
TOTAL	391		48			439

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

1999-08-21 05:18 PM

CAPITAL EXPENDITURE REVISION

Budget reference number 03-00-1661

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1990 10	216	NEW ITEM.
1991 10	202	DECREASE IN INTEREST AND ESCALATION RATES.
1992 10	906	REVISED SCOPE OF WORK. ADJUSTED TO CONTINUE CAPITALIZING INTEREST UNTIL THE ISD OF ASSOCIATED MAJOR PROJECT.
1993 10	492	REFLECTS LATEST ESTIMATE OF COSTS.
1994 10	552	REFINED ESTIMATE - REDUCED PROPERTY REQUIREMENTS.
1995 10	502	STATION SITE REQUIREMENTS CHANGED TO PROVIDE FOR INCREASED FUTURE DEVELOPMENT OF 115KV FACILITIES. IN-SERVICE DATE DEFERRED 1 YEARTO 1998 10 31.
1996 10	594	ISD DEFERRED ONE YEAR TO 1999 10 31. STUDY FOR NEEPAWA 115KV STATION UPGRADE REQUIREMENTS ADDED.
1997 10	484	LICENCE RECEIVED AND LAND CONDITIONALLY ACQUIRED.
1998 10	440	ITEM COMPLETE

ASSOCIATED PROJECTS

Budget reference number	Description
02-00-1235	DORSEY-NEEPAWA-CORNWALLIS 230KV T/L
03-00-1662	CORNWALLIS TERMINATE DORSEY (NEEPAWA) 230KV T/L
03-00-1663	DORSEY TERMINATE CORNWALLIS (NEEPAWA) 230KV T/L
03-00-6190	CORNWALLIS TERTIARY REACTOR R12 AND BREAKER REPLACEMENT
05-00-1252	DORSEY-NEEPAWA-CORNWALLIS 230KV LINE COMMUNICATIONS COMPLEX

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item ___ Domestic Item 157

Title: CORNWALLIS TERMINATE DORSEY (NEEPAWA) 230KV T/L

Budget reference number: 03-00-1662

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	60000

DESCRIPTION:
INSTALL ONE 230KV CIRCUIT BREAKER AND ASSOCIATED EQUIPMENT IN CORNWALLIS 230KV SWITCHYARD TO TERMINATE THE DORSEY (VIA NEEPAWA) LINE. TERMINATION WILL INCLUDE A 230KV 30 MVAR SHUNT LINE REACTOR WITH A 230KV CIRCUIT SWITCHER AND ASSOCIATED EQUIPMENT. DESIGN AND INSTALL PROTECTION AS REQUIRED AT CORNWALLIS STATION FOR THE NEW LINE. REPLACE D12C LINE PROTECTION AT CORNWALLIS.

JUSTIFICATION:
ELSEWHERE IN THE BUDGET JUSTIFICATION IS GIVEN FOR A 230KV CIRCUIT FROM WINNIPEG TO BRANDON VIA NEEPAWA. THIS ITEM PROVIDES FOR TERMINATION OF THAT LINE AT CORNWALLIS.

REFERENCE:
TP REPORT 89-3 WESTERN MANITOBA SYSTEM DEVELOPMENT ALTERNATIVES, RECOMMENDATION #9.
MEMO, S.M. INNES TO W. ZURBA, 1997 10 22, 'PROTECTION UPGRADES'.

REVISION:
SCOPE INCREASED TO INCLUDE REPLACEMENT OF OLD WESTINGHOUSE RTU, HOWEVER OFFSET BY DECREASE DUE TO REACTOR COST SUBSTANTIALLY LESS THAN ORIGINALLY ESTIMATED. ISD DEFERRED FROM 1999 08 TO 2000 04.

CONTINGENCY: $264,000

IN SERVICE DATES: 2000 04 30 — 2 870

Base estimate: 199903 L3

Work start date: 1994 02 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date	661		23			684
1999/00	1 653	34	60			1 747
2000/01	473	1				474
TOTAL	2 787	35	83			2 905
REV. AMOUNTS:						
Authorized to date:	661		23			684
Over(under)expend.						
Auth 1999/00	1 718	15	171			1 904
Req. 2000/01	264		18			282
TOTAL	2 643	15	212			2 870

Prepared by: yy mm dd COORDINATOR — Approved by: yy mm dd — Approved by: yy mm dd

Estimated by: ORIGINATOR — COORDINATING MANAGER — ORIGINATING MANAGER

CAPITAL EXPENDITURE REVISION

Budget reference number 03-00-1662

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1990 10	4 320	NEW ITEM.
1991 10	3 815	9% F.S.T. REMOVED FROM ALL MATERIAL.
1992 10	3 507	THE COST OF THE CIRCUIT SWITCHER AND BREAKER INCREASED 15%. DECREASE IN ESCALATION RATES.
1993 10	3 876	THE BUDGET PRICE QUOTATION FOR THE REACTOR DOUBLED OVER LASTYEAR'S PRICE.
1994 10	3 870	REVISED ENGINEERING AND EQUIPMENT COSTS AND OVERHEAD RATES. DECREASE IN ESCALATION RATES.
1995 10	2 959	IN-SERVICE DATE DEFERRED 1 YEAR TO 1998 10 31. LEVEL III DETAIL ESTIMATE PREVIOUS LEVEL II) RESULTED IN DECREASES IN ENGINEERING, MATERIAL & LABOUR COSTS.
1996 10	3 036	IN-SERVICE DATE DEFERRED FROM 98 10 31 TO 99 10 30.
1997 10	2 936	ESTIMATE REFLECTS REVISED COSTING METHODOLOGY IMPLEMENTED WITH THE NEW FINANCIAL REPORTING SYSTEM. IT ALSO REFLECTS REVISED INTEREST AND ESCALATION RATES.
1998 10	2 905	NO CHANGE

ASSOCIATED PROJECTS

Budget reference number	Description
02-00-1235	DORSEY-NEEPAWA-CORNWALLIS 230KV T/L
03-00-1661	NEEPAWA STATION LAND PURCHASE
03-00-1663	DORSEY TERMINATE CORNWALLIS (NEEPAWA) 230KV T/L
03-00-6190	CORNWALLIS TERTIARY REACTOR R12 AND BREAKER REPLACEMENT
05-00-1252	DORSEY-NEEPAWA-CORNWALLIS 230KV LINE COMMUNICATIONS COMPLEX

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	189	2	5			196	196
May	802	2	6			810	1 006
Jun	264	1	12			277	1 283
Jul	92	1	14			107	1 390
Aug	120	2	14			136	1 526
Sep	124	3	15			142	1 668
Oct	126	3	16			145	1 813
Nov	1	1	17			19	1 832
Dec			18			18	1 850
Jan			18			18	1 868
Feb			18			18	1 886
Mar			18			18	1 904
TOTAL	1 718	15	171			1 904	1 904
2000/01 Apr	264		18			282	282
May							282
Jun							282
Jul							282
Aug							282
Sep							282
Oct							282
Nov							282
Dec							282
Jan							282
Feb							282
Mar							282
TOTAL	264		18			282	282

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item

158

Title: DORSEY TERMINATE CORNWALLIS (NEEPAWA) 230KV T/L

Budget reference number: 03-00-1663

)inating division	Coordinating division	Constructing division	Project Order Group (Range):
ɹnning & Control	Design	Construction	60039

DESCRIPTION:
TERMINATE CORNWALLIS (VIA NEEPAWA) 230 KV LINE IN BAY 13 AT DORSEY. INSTALLATION WILL INCLUDE 1-230 KV CIRCUIT BREAKER AND ASSOCIATED EQUIPMENT. DESIGN AND INSTALL PROTECTION AS REQUIRED AT DORSEY 230 KV STATION FOR THE NEW LINE. REPLACE D12C LINE PROTECTION AT DORSEY.

JUSTIFICATION:
ELSEWHERE IN THE BUDGET JUSTIFICATION IS GIVEN FOR A 230KV CIRCUIT FROM WINNIPEG TO BRANDON VIA NEEPAWA. THIS ITEM PROVIDES FOR TERMINATION OF THAT LINE AT DORSEY.

REFERENCE:
1) TP REPORT 89-3 WESTERN MANITOBA SYSTEM DEVELOPMENT ALTERNATIVES, RECOMMENDATION #8.
MEMO, S.M. INNES TO W. ZURBA, 1997 10 22, 'PROTECTION UPGRADES'.

REVISION:
ISD CHANGED TO 2000-04-30 DUE TO DEFERRAL OF DORSEY-NEEPAWA-CORNWALLIS 230KV TRANSMISSION LINE (02-1235) ALTHOUGH D12C PROTECTION REPLACEMENT WAS IDENTIFIED IN 1998 CER DESCRIPTION, COSTS HAD NOT BEEN INCLUDED.

CONTINGENCY: $137,000

IN SERVICE DATES: 2000 04 30 — 1 902

Base estimate: 199901 L3

Work start date: 1995 03 01

	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
PREV. AUTHORITY						
Authorized to date:	773		24			797
1999/00	252	16	30			298
2000/01	550	1				551
TOTAL	1 575	17	54			1 646
REV. AMOUNTS						
Authorized to date:	773		24			797
Over(under)expend						
Auth 1999/00	833	10	113			956
Req. 2000/01	137		12			149
TOTAL	1 743	10	149			1 902

Prepared by: yy mm dd COORDINATOR — Approved by: yy mm dd Approved by

Estimated by: ORIGINATOR — COORDINATING MANAGER — ORIGINATING MANAGER

1999-08-21 05:18 PM

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 03-00-1663

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1990 10	2 991	NEW ITEM.
1991 10	2 661	9% F.S.T. REMOVED FROM ALL MATERIAL.
1992 10	2 410	DECREASE IN ESCALATION RATES.
1993 10	2 366	LINE TERMINATION MOVED FROM BAY 14 TO BAY 13.
1994 10	2 410	REVISED EQUIPMENT COSTS & OVERHEAD RATES. DCRS. IN ESCALATN.
1995 10	2 138	ESTIMATE REDUCED TO REFLECT ACTUAL COSTS ON A RECENT SIMILARLINE TERMINATION PROJECT. IN-SERVICE DATE DEFERRED 1 YEAR TO 1998 10 31.
1996 10	1 474	ISD DEFERRED 1 YEAR TO 1999 10 31. A DETAILED REVIEW OF THE ESTIMATE RESULTED IN A DECREASE IN ENGINEERING AND LABOUR COSTS.
1997 10	1 540	DESIGN AND INSTALL PROTECTION AS REQUIRED AT DORSEY 230 KV STATION FOR THE NEW LINE. REPLACE D12C LINE PROTECTION AT DORSEY.
1998 10	1 646	ESTIMATE REVISED BASED ON UPDATED CONSTRUCTION COSTS RESULTING IN A SLIGHT INCREASE.

ASSOCIATED PROJECTS

Budget reference number	Description
02-00-1235	DORSEY-NEEPAWA-CORNWALLIS 230KV T/L
03-00-1661	NEEPAWA STATION LAND PURCHASE
03-00-1662	CORNWALLIS TERMINATE DORSEY (NEEPAWA) 230KV T/L
03-00-6190	CORNWALLIS TERTIARY REACTOR R12 AND BREAKER REPLACEMENT
05-00-1252	DORSEY-NEEPAWA-CORNWALLIS 230KV LINE COMMUNICATIONS COMPLEX

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	31	-1	6			36	36
May	56		6			62	98
Jun	177	2	6			185	283
Jul	149	1	8			158	441
Aug	113	1	9			123	564
Sep	149	3	9			161	725
Oct	137	2	11			150	875
Nov	15		12			27	902
Dec	5		12			17	919
Jan			12			12	931
Feb			12			12	943
Mar	1	2	10			13	956
TOTAL	833	10	113			956	956
2000/01 Apr	137		12			149	149
May							149
Jun							149
Jul							149
Aug							149
Sep							149
Oct							149
Nov							149
Dec							149
Jan							149
Feb							149
Mar							149
TOTAL	137		12			149	149

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item

159

Title
CORNWALLIS TERTIARY REACTOR R12 AND BREAKER REPLACEMENT

Budget reference number
03-00-6190

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	71025

DESCRIPTION:
REPLACE EXISTING 13.2KV 15 MVAR REACTOR IN POSITION R12 WITH A 13.2KV 20 MVAR REACTOR. REPLACE AN ASSOCIATED REACTOR SWITCHING BREAKER.

JUSTIFICATION:
SHUNT REACTORS ARE REQUIRED AT CORNWALLIS TO MAINTAIN CONTINUOUS 230KV VOLTAGE CONTROL IN THE BRANDON AREA UNDER LIGHT LOAD CONDITIONS. THE EXISTING REACTOR IN POSITION R12 BEING REPLACED IS CAPABLE OF ONLY 2 HOURS OF OPERATION UNDER EMERGENCY CONDITIONS. AN ASSOCIATED SWITCHING BREAKER IS REQUIRED TO REPLACE A BREAKER THAT FAILED IN THE FALL OF 1995.

REFERENCE:
MEMO, W.N. ZURBA TO C.V. THIO, 1996 04 25, 'CORNWALLIS TERTIARY REACTOR (R12) REPLACEMENT'

REVISION:
REFLECTS REVISED ACTIVITY AND OVERHEAD RATES.

CONTINGENCY: $65,000

IN SERVICE DATES

1999 07 31 625

Base estimate
199804 L3

Work start date
1996 10 01

	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
PREV. AUTHORITY						
Authorized to date	205		6	-5		206
1999/00	399	2	14			415
TOTAL	604	2	20	-5		621
REV. AMOUNTS:						
Authorized to date:	205		6	-5		206
Over(under)expend:						
Auth Req. 1999/00	397	10	7			414
TOTAL	602	10	13	-5		620

Prepared by — yy mm dd — COORDINATOR — Approved by — yy mm dd — Approved by — yy mm dd
Estimated by — ORIGINATOR — COORDINATING MANAGER — ORIGINATING MANAGER

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 03-00-6190

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1996 10	1 098	NEW ITEM.
1997 10	1 090	SCOPE UNCHANGED, ESTIMATE REFLECTS REVISED COSTING METHODOLOGY IMPLEMENTED WITH THE NEW FINANCIAL REPORTING SYSTEM. ALSO REFLECTS REVISED INTEREST AND ESCALATION RATES.
1998 10	621	MAJOR EQUIPMENT COSTS LESS THAN ANTICIPATED, CONTINGENCY REDUCED.

ASSOCIATED PROJECTS

Budget reference number	Description
02-00-1235	DORSEY-NEEPAWA-CORNWALLIS 230KV T/L
03-00-1661	NEEPAWA STATION LAND PURCHASE
03-00-1662	CORNWALLIS TERMINATE DORSEY (NEEPAWA) 230KV T/L
03-00-1663	DORSEY TERMINATE CORNWALLIS (NEEPAWA) 230KV T/L
05-00-1252	DORSEY-NEEPAWA-CORNWALLIS 230KV LINE COMMUNICATIONS COMPLEX

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	23	1	1			25	25
May	33		2			35	60
Jun	70	2	2			74	134
Jul	105	1	2			108	242
Aug	21					21	263
Sep	21					21	284
Oct	21					21	305
Nov	21					21	326
Dec	21	1				22	348
Jan	21	1				22	370
Feb	21	1				22	392
Mar	19	3				22	414
TOTAL	397	10	7			414	414
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item 160

Title: DORSEY-NEEPAWA-CORNWALLIS 230KV LINE COMMUNICATIONS COMPLEX

Budget reference number: 05-00-1252

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
anning & Control	Planning & Control	Construction	70167

DESCRIPTION:
DESIGN AND INSTALL COMMUNICATIONS FACILITIES FOR THE OPERATION, CONTROL AND PROTECTION OF THE DORSEY-NEEPAWA-CORNWALLIS 230 KV LINE. THIS INCLUDES THE COST OF TONE EQUIPMENT TO INTERFACE PROTECTION TO THE COMMUNICATIONS CHANNELS DERIVED FROM EXISTING OR NEW CARRIER FACILITIES AND POINT ADDITIONS TO EXISTING OR PLANNED SUPERVISORY CONTROL SYSTEMS. UPGRADE COMMUNICATIONS EQUIPMENT ASSOCIATED WITH LINE D12C PROTECTION AT DORSEY AND CORNWALLIS STATIONS.

JUSTIFICATION:
ELSEWHERE IN THE BUDGET JUSTIFICATION IS GIVEN FOR A 230KV CIRCUIT FROM WINNIPEG TO BRANDON VIA NEEPAWA. THIS ITEM PROVIDES FOR COMMUNICATIONS, PROTECTION AND CONTROL REQUIREMENTS FOR THE PROJECT.

REFERENCE:
TP REPORT 89-3 WESTERN MANITOBA SYSTEM DEVELOPMENT ALTERNATIVES, RECOMMENDATION #10.
MEMO, S.M. INNES TO W. ZURBA, 1997 10 22, 'PROTECTION UPGRADES'.

REVISION:
ISD DEFERRED FROM 1999 10 31 TO 2000 04 30.

CONTINGENCY: $ 10,000

IN SERVICE DATES

2000 04 30 354

Base estimate: 199901 L2

Work start date: 1998 09 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date	119		2			121
1999/00	185	5	13			203
TOTAL	304	5	15			324
REV. AMOUNTS:						
Authorized to date	119		2			121
Over(under)expend						
Auth 1999/00	171	1	17			189
Req 2000/01	41	1	2			44
TOTAL	331	2	21			354

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

CAPITAL EXPENDITURE REVISION

Budget reference number 05-00-1252

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1990 10	268	NEW ITEM.
1991 10	246	DECREASE IN INTEREST AND ESCALATION RATES.
1992 10	219	DECREASE IN INTEREST AND ESCALATION RATES.
1993 10	214	DECREASE IN INTEREST AND ESCALATION RATES.
1994 10	206	REVISED INTEREST AND ESCALATION RATES.
1995 10	210	IN-SERVICE DATE DEFERRED 1 YEAR TO 1998 10 31.
1996 10	287	ISD DEFERRED 1 YEAR TO 1999 10 31. ENGINEERING, MATERIAL AND LABOUR COSTS INCREASED DUE TO ADDITION OF DIZC PROTECTION TONES AS PER MINUTES OF TRANSMISSION PLANNING MEETING DATED 95 11 29.
1997 04	319	ESTIMATE REFLECTS REVISED COSTING METHODOLOGY WITH THE NEW FINANCIAL REPORTING SYSTEM. IT ALSO REFLECTS INTEREST AND ESCALATION RATES.
1998 10	325	NO CHANGE.

ASSOCIATED PROJECTS

Budget reference number	Description
02-00-1235	DORSEY-NEEPAWA-CORNWALLIS 230KV T/L
03-00-1661	NEEPAWA STATION LAND PURCHASE
03-00-1662	CORNWALLIS TERMINATE DORSEY (NEEPAWA) 230KV T/L
03-00-1663	DORSEY TERMINATE CORNWALLIS (NEEPAWA) 230KV T/L
03-00-6190	CORNWALLIS TERTIARY REACTOR R12 AND BREAKER REPLACEMENT

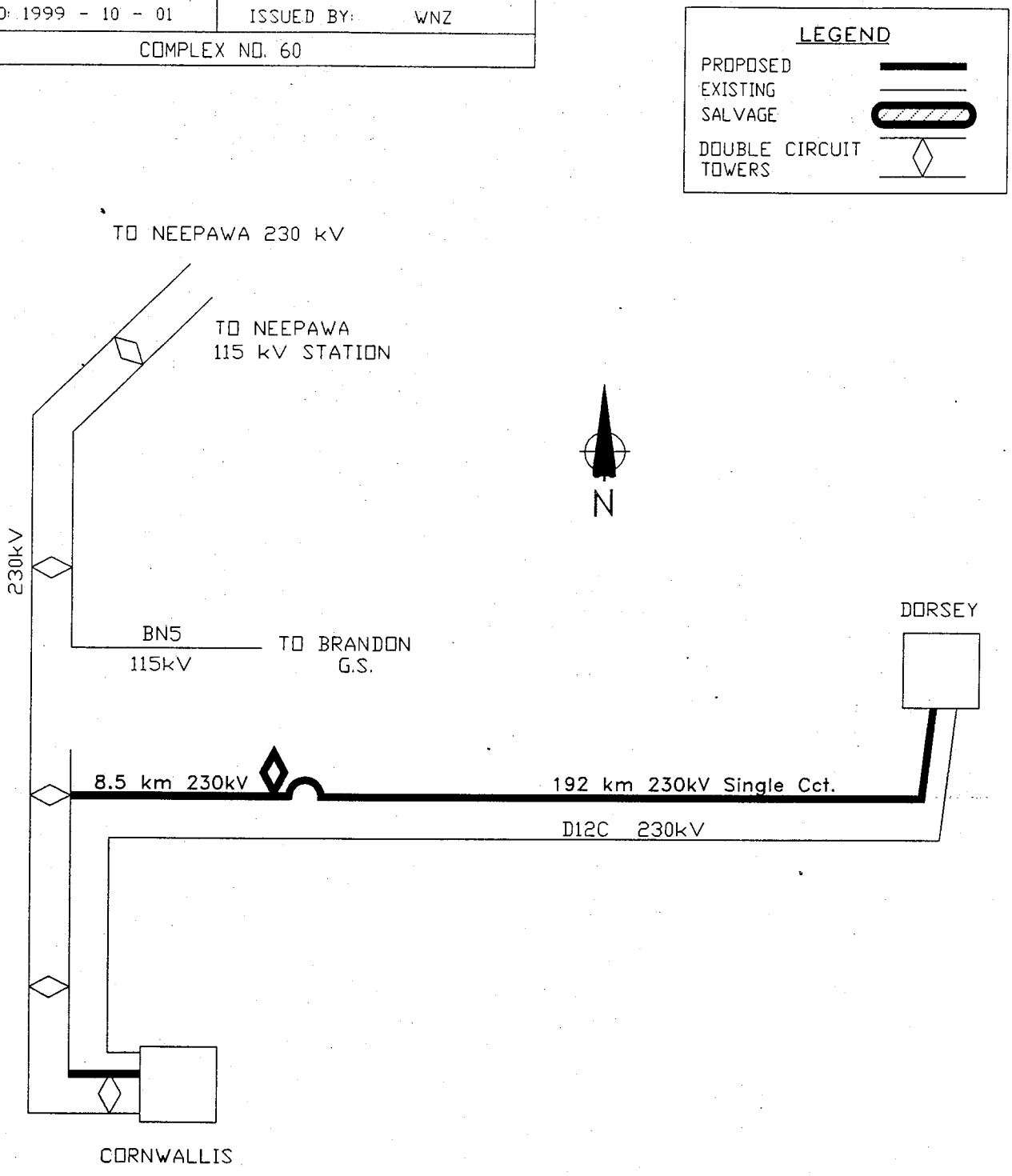
Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	13		1			14	14
May	13		1			14	28
Jun	13	1	1			15	43
Jul	13	1	1			15	58
Aug	13	1	1			15	73
Sep	13	1	1			15	88
Oct	13	1	1			15	103
Nov	13		2			15	118
Dec	13		2			15	133
Jan	13		2			15	148
Feb	13		2			15	163
Mar	28	-4	2			26	189
TOTAL	171	1	17			189	189
2000/01 Apr	14		2			16	16
May	14					14	30
Jun	13	1				14	44
Jul							44
Aug							44
Sep							44
Oct							44
Nov							44
Dec							44
Jan							44
Feb							44
Mar							44
TOTAL	41	1	2			44	44

CAPITAL BUDGET COMPLEX CONCEPTUAL DIAGRAM

WINNIPEG – BRANDON 230KV TRANSMISSION

REVISED: 1999 - 10 - 01 | ISSUED BY: WNZ

COMPLEX NO. 60



manitoba hydro

PLANNING AND CONTROL DIVISION

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

COMPLEX STATUS: ☐ Planned ☒ In progress

Complex no. 60

REVISION STATUS: ☐ New complex ☒ In service change ☐ Concept change ☐ Estimate change only

COMPLEX: WINNIPEG - BRANDON 230 KV TRANSMISSION

Proposal

Perform environmental assessments and route selection, design and construct transmission and terminal facilities to provide firm supply to Brandon as follows:
Transmission: 230 KV line 192 KM Dorsey - Brandon, 230 KV double circuit line with only one side strung 8.5 KM Brandon - location north of Cornwallis. Connect to unused 230 KV line north of Cornwallis to create Dorsey - Cornwallis 230 KV circuit.

Terminations: Extend 230 KV facilities at Dorsey and Cornwallis stations.

Communications: Integrate with existing facilities at Dorsey and Cornwallis stations.

JUSTIFICATION

☒ Load ☐ Service
☐ Safety ☐ Efficiency
☒ Reliability ☐ Other

Explanation

These facilities provide transmission improvements required by 2007 to supply Brandon area future load growth.

Estimate Level	COMPLEX START (yyyy mm)
L2	1989 04

IN SERVICE DATES AND AMOUNTS

2003 03	$159	2007 10	$8731	2008 10	$64119

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	-2		2		0		0	
Year 99/00								
00/01						67	-67	-100
01/02	62	4	3		69	237	-168	-71
02/03	2,657	211	119		2,987	6,145	-3,158	-51
03/04	3,933	399	429		4,761	6,432	-1,671	-26
04/05	5,749	729	943		7,421	12,517	-5,096	-41
05/06	10,355	1556	1,823		13,734	17,822	-4,088	-23
06/07	13,151	2286	3,245		18,682	15,944	2,738	17
07/08	9,474	1235	4,380		15,089	9,913	5,176	52
08/09	6,000	1305	2,961		10,266		10,266	
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	51,379	7,725	13,905		73,009	69,077	3,932	6

REVISION: Deferred one year 2007 due to capital constraint reasons.

Reviewed by ORIGINATOR	yyyy mm dd 99 11 08	Reviewed by COORDINATOR	yyyy mm dd 99 11 03
Reviewed by CONSTRUCTOR	yyyy mm dd 99 11 03	Approved by VICE-PRESIDENT	yyyy mm dd 99 11 16

H2856/r Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Complex no. 60

Advance or deferral impact

Deferral will reduce firm supply to the Brandon area.

Factors affecting timing or viability

Manitoba Load.
Brandon thermal generation service life.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Dorsey West Property Requirements		134	137	136	-1	-1
Winnipeg - Brandon 230 KV T/L		44,105	44,987	44,528	-459	-1
Cornwallis - Terminate Dorsey 230 KV T/L		3,072	3,133	3,242	109	3
Dorsey - Terminate Brandon 230 KV T/L		3,117	3,179	3,286	107	3
Winnipeg - Brandon Communications		182	186	186	0	0
TOTAL		50,610	51,622	51,378	-244	-0

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
9510	150,317	230 KV line reactor deleted. Planning (EMTP) studies added. Reflects additional property costs for EHV station.
9610	75,389	Concept change to 230 KV from 500 KV operating at 230 KV. Brandon EHV land purchase trnsfr'd to another complex. Dorsey West prop. requmnt def 4 1/2 years to 02 09 30.
1997 10	77,330	Scope unchanged, estimate reflects revised costing methodology implemented with the new financial reporting system. Also reflects revised interest and escalation rates.
1998 10	69,078	Revised to reflect current transmission line costs (previously reflected historic costs) and to defer the transmission line ISD 1 year.
1999 10	73,009	Deferred one year 2007 due to capital constraint reasons.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION
Complex 57	Dorsey - Neepawa - Cornwallis 230 KV Line

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item

161

Title			Budget reference number
DORSEY WEST PROPERTY REQUIREMENTS			02-00-5137
iginating division anning & Control	Coordinating division Design	Constructing division Design	Project Order Group (Range): 70029

DESCRIPTION:
ACQUIRE THE NECESSARY R.O.W. TO FACILITATE FUTURE TRANSMISSION EGRESS TO THE WEST FROM DORSEY STATION. MAJORITY OF THE PROPERTY HAS BEEN SECURED WITH THE EXCEPTION OF CERTAIN PARCELS WHICH ARE TO BE FINALIZED.

JUSTIFICATION:
LAND ACQUISITION IN POPULATED AREAS IS BECOMING INCREASINGLY DIFFICULT, WITH LONGER LEAD TIMES REQUIRED AND HIGHER COSTS. RIGHT-OF-WAY FOR ALL FUTURE CONTEMPLATED EHV LINES IN THE WINNIPEG AREA ARE TO BE ACQUIRED AS THEY BECOME AVAILABLE.

REFERENCE:
REPORT SPD 75-1 500 KV U.S. LINES ROUTES IN THE METRO AREA AND SOUTH EAST EHV STATION SITE. REPORT SPD 78-26 RIGHT-OF-WAY REQUIREMENTS WEST AND SOUTH OF DORSEY STATION. REPORT TP 89-3 WESTERN MANITOBA SYSTEM DEVELOPMENT ALTERNATIVES, RECOMMENDATION 15.

REVISION:
ISD DEFERRED FROM 2002 03 31 TO 2003 03 31.

CONTINGENCY: $ 14,700

IN SERVICE DATES				Base estimate
2003 03 31	160			199707 L2
				Work start date 1989 04 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:	-2		3			1
2000/01	61	2	3			66
2001/02	75	5	8			88
TOTAL	134	7	14			155
REV. AMOUNTS:						
Authorized to date:	-2		3			1
Over(under)expend:						
Auth 2001/02	62	3	3			68
Req.: 2002/03	76	6	9			91
TOTAL	136	9	15			160

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 02-00-5137

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1984 12	111	NEW ITEM
1985 12	116	BASE ESTIMATE REMAINS UNCHANGED. START DATE ADVANCED BY 5 MONTHS. I.S.D DEFERRED BY 7 MONTHS
1986 12	110	BASE DATE AND ESTIMATE REMAINS UNCHANGED. REVISED INTEREST AND ESCALATION RATES.
1987 11	103	BASE ESTIMATE CHANGED FROM 1984 TO 1987.
1988 11	104	ISD DEFERRED FROM 1988.03.31 TO 1990.03.31. BASE ESTIMATE CHANGED FROM 1987 TO 1988. REVISED INTEREST AND ESCALATION RATES.
1989 10	143	PROJECT COMPLETELY RE-ESTIMATED. EXPENDITURES SPREAD OVER 5YEARS INSTEAD OF 1 YEAR. HIGHER INTEREST COST.
1990 10	144	INCREASE DUE TO INTEREST RATE INCREASE.
1991 10	145	IN SERVICE DATE DEFERRED 1 YEAR.
1992 10	128	DECREASE IN ESCALATION AND INTEREST RATES.
1993 10	124	DECREASE IN INTEREST AND ESCALATION RATES.
1994 10	149	ITEM TRANSFERRED TO WINNIPEG-BRANDON 500 KV T/L COMPLEX TO CO-ORDINATE WITH LINE R.O.W. ACQUISITION. ISD DEFERRED TO 1998 04 01.
1995 10	145	REVISED CASH FLOW, ESCALATION AND INTEREST RATES.
1996 10	191	ISD DEFERRED 4 1/2 YEARS TO 2002 09 30.
1997 10	163	ISD ADVANCED 3 YEARS FROM 2002 09 30 TO 1999 09 30.
1998 10	155	ISD DEFERRED FROM 1999 09 30 TO 2002 03 31 TO COINCIDE WITH DORSEY-RIEL SOUTH LOOP PROPERTY ACQUISITION.

ASSOCIATED PROJECTS

Budget reference number	Description
02-00-7994	WINNIPEG - BRANDON 230KV T/L
03-00-7078	CORNWALLIS TERMINATE DORSEY 230KV T/L
03-00-7079	DORSEY TERMINATE BRANDON 230KV T/L
05-00-1260	WINNIPEG - BRANDON COMMUNICATIONS FOR 230 KV LINE

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item

162

Title			Budget reference number
WINNIPEG - BRANDON 230KV T/L			02-00-7994
Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	71008

DESCRIPTION:
CONDUCT ENVIRONMENTAL IMPACT ASSESSMENT, SELECT A ROUTE, OBTAIN LICENSING AND ACQUIRE PROPERTY FOR RIGHT-OF-WAY. DESIGN AND CONSTRUCT APPROXIMATELY 192 KM OF 230KV SELF SUPPORTING STEEL LINE USING 954 MCM ACSR CONDUCTOR FROM DORSEY TO BRANDON. DESIGN AND CONSTRUCT ABOUT 8.5 KM 230KV DOUBLE CIRCUIT TOWER STRUNG ONLY ON SOUTH SIDE WITH 1272 MCM ACSR CONDUCTOR FROM BRANDON END OF NEW 954 MCM CIRCUIT TO LOCALE 1.5 KM NORTH OF CORNWALLIS STATION. CONNECT 8.5 KM LINE SECTION TO 192 KM LINE SECTION AND TO UNUSED EAST SIDE SECTION OF DOUBLE CIRCUIT 230KV LINE WHICH EXTENDS TO CORNWALLIS 230KV STATION. SWING AND RE-TERMINATE 3 EXISTING 230KV LINES AT CORNWALLIS.

JUSTIFICATION:
THIS ITEM PROVIDES FOR PART OF THE SYSTEM IMPROVEMENTS REQUIRED TO TRANSMIT POWER TO THE BRANDON AREA TO SUPPLY FUTURE LOAD GROWTH.

NOTE: COMPLETION DATE FOR PROPERTY ACQUISITION: 2003 10 31

REVISION:
ISD DEFERRED FROM 2007 10 31 TO 2008 10 31.

CONTINGENCY: $2 647 000

IN SERVICE DATES				Base estimate
2008 10 31	64 120			199807 L2
				Work start date 2002 04 01

PREV. AUTHORITY Authorized to date:	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
2001/02	138	5	6			149
2002/03	5 696	291	158			6 145
2003/04	4 378	472	738			5 588
2004/05	8 384	1 097	1 422			10 903
2005/06	10 759	1 650	2 525			14 934
2006/07	8 750	810	3 573			13 133
2007/08	6 000	1 200	2 713			9 913
TOTAL	44 105	5 525	11 135			60 765
REV. AMOUNTS: Authorized to date: Over(under)expend:						
Auth 2002/03	2 580	206	110			2 896
Req.: 2003/04	3 933	399	429			4 761
2004/05	4 924	610	905			6 439
2005/06	8 958	1 319	1 681			11 958
2006/07	10 897	1 855	2 885			15 637
2007/08	7 236	889	4 038			12 163
2008/09	6 000	1 305	2 961			10 266
TOTAL	44 528	6 583	13 009			64 120

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 02-00-7994

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1996 10	67 226	NEW ITEM DUE TO CONCEPT CHANGE, REPLACES BRN 9302-00-7002,'WINNIPEG BRANDON 500KV T/L.
1997 10	69 036	ESTIMATE REFLECTS REVISED COSTING METHODOLOGY IMPLEMENTED WITH THE NEW FINANCIAL REPORTING SYSTEM. IT ALSO REFLECTS REVISED INTEREST AND ESCALATION RATES.
1998 10	60 765	I.S.D. DEFERRED FROM 2006 10 31 TO 2007 10 31 DUE TO FINANCIAL CONSTRAINT. ESTIMATE DECREASE REFLECTS UPDATED CURRENT TRANSMISSION LINE COSTS.

ASSOCIATED PROJECTS

Budget reference number	Description
02-00-5137	DORSEY WEST PROPERTY REQUIREMENTS
03-00-7078	CORNWALLIS TERMINATE DORSEY 230KV T/L
03-00-7079	DORSEY TERMINATE BRANDON 230KV T/L
05-00-1260	WINNIPEG - BRANDON COMMUNICATIONS FOR 230 KV LINE

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item

163

Title			Budget reference number
CORNWALLIS TERMINATE DORSEY 230KV T/L			03-00-7078
Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	70295

DESCRIPTION:
INSTALL ONE 230KV CIRCUIT BREAKER AND ASSOCIATED EQUIPMENT TO ALLOW TERMINATION OF THE DORSEY LINE AT CORNWALLIS. SWING OVER THE 230KV LINES AT CORNWALLIS FROM GLENBORO, NEEPAWA AND RESTON AND RETERMINATE THEM AT DIFFERENT LOCATIONS IN THE CORNWALLIS STATION TO TERMINATE THE NEW DORSEY LINE IN BAY 1 POSITION PREVIOUSLY USED FOR NEEPAWA LINE.

NOTE: 230KV LINE REACTOR IN BAY 1 PREVIOUSLY CONNECTED TO NEEPAWA LINE WILL NOW BE USED ON NEW DORSEY LINE.

JUSTIFICATION:
ELSEWHERE IN THE BUDGET JUSTIFICATION IS GIVEN FOR CONSTRUCTION OF A 230KV LINE FROM WINNIPEG TO BRANDON. THIS ITEM PROVIDES FOR TERMINATION OF THE LINE AT CORNWALLIS.

REVISION:
ISD DEFERRED FROM 2006 10 31 TO 2007 10 31.

CONTINGENCY AMOUNT: $298,000

IN SERVICE DATES				Base estimate
2007 10 31	4 215			199704 L2
				Work start date 2004 04 01

PREV. AUTHORITY Authorized to date:	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
2003/04	347	47	15			409
2004/05	620	97	59			776
2005/06	1 083	193	157			1 433
2006/07	1 022	143	150			1 315
TOTAL	3 072	480	381			3 933
REV. AMOUNTS:						
Authorized to date:						
Over(under)expend:						
Auth 2004/05	400	58	18			476
Req.: 2005/06	672	114	69			855
2006/07	1 122	215	175			1 512
2007/08	1 048	157	167			1 372
TOTAL	3 242	544	429			4 215

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number: 03-00-7078

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1977 11	993	ESTIMATE REVISED.
1978 11	1 202	ISD DEFERRED FROM 1983 TO 1989.
1979 11	1 532	ISD DEFERRED FROM 1989 TO 1992.
1980 11	1 548	REFLECTS REVISED INT & ESC RATES.
1981 11	2 136	REFLECTS REVISED INT & ESC RATES.
1982 12	2 721	REVISED INT AND ESC RATES.
1983 12	5 425	PROVISION FOR 500KV OPER. REV INT & ESC RATES.
1984 12	5 185	B/D & EST UNCHNG. REFLECTS REV INT & ESC RATES.
1985 12	4 677	B/D & EST UNCHNG. REV INT & ESC RATES.
1986 12	4 707	ITEM DEFERRED 7 YEARS. REVISED INT AND ESC RATES.
1987 11	4 173	ESTIMATE CHANGED.
1988 11	4 635	NO SLD AVAILABLE. REV INT & ESC RATES.
1989 10	4 826	THE INCR IS MAINLY DUE TO PRICE INCR FOR BRKS & REACTORS.
1990 05	5 068	ISD DEFERRED TO 2000.
1990 10	10 117	ISD DEFERRED 8 YRS. CONCEPT CHNG AS OUTLINED IN RPT TP 89-3.
1991 10	8 695	FST REMOVED FROM ALL MAT. DECREASE IN INT & ESC RATES.
1992 10	6 945	ISD ADVANCED TO 2006 10 31 FOR LOAD GROWTH AT CANADIAN OCCI-DENTAL PETROLEUM. CCT SWTCHER & BRKR COST INCRS 15%. ESC RATE DECREASE.
1993 10	6 268	DECREASE IN INTEREST AND ESCALATION RATES.
1994 10	6 301	REACTOR PRICE INCREASED. REVISED INTEREST & ESCALATION RATES
1995 10	3 845	230KV LINE REACTOR DELETED.
1996 06	3 824	COMPLEX CONCEPT CHANGE TO 230 kV LINE FROM 500 kV OPERATING AT 230 kV.
1997 10	3 930	SCOPE UNCHANGED ESTIMATE REFLECTS REVISED COSTING METHODOLOGY IMPLEMENTED WITH THE NEW FINANCIAL REPORTING SYSTEM. ALSO, REFLECTS REVISED INTEREST AND ESCALATION RATES.
1998 10	3 933	NO CHANGE.

ASSOCIATED PROJECTS

Budget reference number	Description
02-00-5137	DORSEY WEST PROPERTY REQUIREMENTS
02-00-7994	WINNIPEG - BRANDON 230KV T/L
03-00-7079	DORSEY TERMINATE BRANDON 230KV T/L
05-00-1260	WINNIPEG - BRANDON COMMUNICATIONS FOR 230 KV LINE

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item

164

Title			Budget reference number
DORSEY TERMINATE BRANDON 230KV T/L			03-00-7079
Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	70296

DESCRIPTION:
TERMINATE NEW BRANDON 230KV LINE IN BAY 13 AT DORSEY. INSTALLATION WILL INCLUDE 1 - 230KV CIRCUIT BREAKER AND ASSOCIATED EQUIPMENT.

JUSTIFICATION:
ELSEWHERE IN THE BUDGET, JUSTIFICATION IS GIVEN FOR CONSTRUCTION OF A 230KV LINE FROM WINNIPEG TO BRANDON. THIS ITEM PROVIDES FOR TERMINATION OF THE LINE AT DORSEY.

REVISION:
ISD DEFERRED FROM 2006 10 31 TO 2007 10 31.

CONTINGENCY: $300,000

IN SERVICE DATES				Base estimate
2007 10 31	4 284			199706 L2
				Work start date
				2004 04 01

PREV. AUTHORITY Authorized to date:	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
2003/04	369	50	16			435
2004/05	670	105	63			838
2005/06	1 066	190	164			1 420
2006/07	1 012	141	153			1 306
TOTAL	3 117	486	396			3 999
REV. AMOUNTS: Authorized to date: Over(under)expend:						
Auth 2004/05	425	61	20			506
Req.: 2005/06	725	124	73			922
2006/07	1 101	211	183			1 495
2007/08	1 035	156	170			1 361
TOTAL	3 286	552	446			4 284

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

CAPITAL EXPENDITURE REVISION

Budget reference number 03-00-7079

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1976 11	867	NEW ITEM.
1977 11	993	ESTIMATE REVISED
1978 11	1 202	ISD DEFERRED FROM 1983 TO 1989.
1979 11	1 532	ISD DEFERRED FROM 1989 TO 1992.
1980 11	1 548	REFLECTS REV INT & ESC RATES.
1981 11	2 136	REFLECTS REV INT & ESC RATES.
1982 12	2 721	REFLECTS REV INT & ESC RATES.
1983 12	5 425	REFLECTS PRO. FOR 500KV OPER. RESULTING IN INCR. COSTS & REVINT & ESC RATES.
1984 12	5 185	REFLECTS REV INT & ESC RATES.
1985 12	4 677	REV INT & ESC RATES.
1986 12	4 073	ITEM DEFERRED 7 YRS. REV EST, INT & ESC RATES.
1987 11	3 469	ESTIMATE CHANGED.
1988 11	3 316	SD REV FR 97 04 TO 97 02. NO SLD AVAIL. REV INT & ESC RATES.
1989 10	3 265	EST IS BASED ON 1989 PRICES.
1990 05	3 429	ISD DEFERRED TO 2000.
1990 10	5 120	ISD DEF 8 YRS. CONCEPT CHNG AS OUTLINED IN RPT TP 89-3. N
1991 10	4 313	FST REMOVED FR ALL MAT. DECREASE IN ESC. RATES.
1992 10	3 415	ISD ADV TO 2006 10 31 TO ACCOMMODATE INDUSTRIAL LOAD GROWTH IN THE BRANDON AREA AT CANADIAN OCCIDENTAL PETROLEUM. DEC. IN ESC RATES.
1993 10	4 178	RETERMINATION OF LINE D12C ADDED, INCLUDING REPLACEMENT OF LINE D12C PROTECTION TO ACCOMMODATE THE NEW BRANDON 500 KV LINE.
1994 10	3 949	REVISED ENGINEERING ESTIMATE. REFLECTS NEW OVERHEAD, INTEREST AND ESCALATION RATES.
1995 10	3 959	REVISED INTEREST AND ESCALATION RATES.
1996 06	3 940	COMPLEX CONCEPT CHANGE TO 230KV LINE FROM 500KVLINE OPERATING AT 230KV. LINE D12C RETERMINATION AT DORSEY NO LONGER REQUIRED.
1997 10	3 981	SCOPE UNCHANGED, ESTIMATE REFLECTS REVISED COSTING METHODOLOGY IMPLEMENTED WITH THE NEW FINANCIAL REPORTING SYSTEM. ALSO, REFLECTS REVISED INTEREST AND ESCALATION RATES.
1998 10	3 999	NO CHANGE.

ASSOCIATED PROJECTS

Budget reference number	Description
02-00-5137	DORSEY WEST PROPERTY REQUIREMENTS
02-00-7994	WINNIPEG - BRANDON 230KV T/L
03-00-7078	CORNWALLIS TERMINATE DORSEY 230KV T/L
05-00-1260	WINNIPEG - BRANDON COMMUNICATIONS FOR 230 KV LINE

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item

165

Title			Budget reference number
WINNIPEG - BRANDON COMMUNICATIONS FOR 230 KV LINE			05-00-1260
Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Planning & Control	Construction	70297

DESCRIPTION:
DESIGN AND INSTALL COMMUNICATIONS FACILITIES FOR THE OPERATION, CONTROL AND PROTECTION OF THE WINNIPEG-BRANDON 230KV T/L. INSTALLATION WILL INCLUDE TONE EQUIPMENT TO INTERFACE PROTECTION TO THE COMMUNICATION CHANNELS DERIVED FROM EXISTING OR NEW CARRIER FACILITIES AND POINT ADDITIONS TO EXISTING OR PLANNED SUPERVISORY CONTROL SYSTEMS.

JUSTIFICATION:
ELSEWHERE IN THE BUDGET JUSTIFICATION IS GIVEN FOR A 230KV LINE FROM WINNIPEG TO BRANDON. THIS ITEM PROVIDES COMMUNICATIONS, PROTECTION AND CONTROL REQUIREMENTS FOR THE PROJECT.

REFERENCE:
1) REPORT SPD 75-22 'WINNIPEG-BRANDON EHV TRANSMISSION ADDITION.'
2) REPORT SPD 78-22 'LETELLIER-ST. LEON 230KV TRANSMISSION ADDITION AND SUPPLY TO WESTERN MANITOBA.'
3) REPORT H&TPD 86-11 'WESTERN MANITOBA MAJOR AC TRANSMISSION 1986-2006,' RECOMMENDATIONS #2 & #25
4) REPORT TP 89-3 'WESTERN MANITOBA SYSTEM DEVELOPMENT ALTERNATIVES,' RECOMMENDATION #18.

REVISION:
ISD DEFERRED FROM 2006 10 31 TO 2007 10 31.

CONTINGENCY: $15,000

IN SERVICE DATES				Base estimate
2007 10 31	231			199704 L2
				Work start date 2006 04 01

PREV. AUTHORITY Authorized to date:	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
2005/06	28	5	1			34
2006/07	154	31	5			190
TOTAL	182	36	6			224
REV. AMOUNTS: Authorized to date: Over(under)expend:						
Auth 2006/07	31	6	1			38
Req.: 2007/08	155	33	5			193
TOTAL	186	39	6			231

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 05-00-1260

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1990 10	360	NEW ITEM.
1991 10	313	DECREASE IN INTEREST AND ESCALATION RATES.
1992 10	249	IN SERVICE DATE ADVANCED TO 2006 10 31 TO ACCOMMODATE INDUSTRIAL LOAD GROWTH IN BRANDON AREA AT CANADIAN OCCIDENTAL PETROLEUM.
1993 10	221	DECREASE IN INTEREST AND ESCALATION RATES.
1994 10	205	REVISED INTEREST AND ESCALATION RATES.
1995 10	204	REVISED INTEREST AND ESCALATION RATES.
1996 10	208	COMPLEX CONCEPT CHANGE TO 230KV LINE FROM 500KV LINE OPERATING AT 230KV.
1997 10	223	SCOPE UNCHANGED, ESTIMATE REFLECTS REVISED COSTING METHODOLOGY IMPLEMENTED WITH THE NEW FINANCIAL REPORTING SYSTEM. ALSO, REFLECTS REVISED INTEREST AND ESCALATION RATES.
1998 10	224	NO CHANGE.

ASSOCIATED PROJECTS

Budget reference number	Description
02-00-5137	DORSEY WEST PROPERTY REQUIREMENTS
02-00-7994	WINNIPEG - BRANDON 230KV T/L
03-00-7078	CORNWALLIS TERMINATE DORSEY 230KV T/L
03-00-7079	DORSEY TERMINATE BRANDON 230KV T/L

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

COMPLEX STATUS	Complex no.	REVISION STATUS
☒ Planned ☐ In progress	45	☐ New complex ☒ In service change ☐ Concept change ☐ Estimate change only

COMPLEX	FT. GARRY PERIMETER SOUTH BANK REPLACEMENTS

Proposal

Replace 2 - 7.5/10 mva, 3ph transformers with 2 - 15/20/25 mva 66-12.47y/7.2 kv 3ph transformers c/w LTC's at Ft. Garry-Perimeter South station.

JUSTIFICATION	Explanation
☒ Load ☐ Service ☐ Safety ☐ Efficiency ☐ Reliability ☐ Other	The non-firm capacity of the Ft. Garry- Perimeter South station will be exceeded in 1996/97. This station supplies south Ft. Garry and Lasalle area (both fast growing communities) and provides a back-up supply to St. Norbert single bank station.

Estimate Level	COMPLEX START (yyyy mm)
L2	2000 04

IN SERVICE DATES AND AMOUNTS				
2003 07	$4503			

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend								
Year 99/00								
00/01						367	-367	-100
01/02	349	27	14		390	218	172	79
02/03	2,163	223	94		2,480	3,840	-1,360	-35
03/04	1,419	120	93	149	1,483		1,483	
04/05								
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	3,931	370	201	149	4,353	4,425	-72	-2

REVISION	Deferred one year to 2003 07 31 due to capital constraint reasons.

Reviewed by ORIGINATOR	yyyy mm dd	Reviewed by COORDINATOR	yyyy mm dd
	99 11 08		99 11 03
Reviewed by CONSTRUCTOR	yyyy mm dd	Approved by VICE-PRESIDENT	yyyy mm dd
	99 11 03		99 11 16

H2856/r Rev 99 03

Complex no. 45

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Advance or deferral impact

Thermal capacity of 2 - 7.5/10 mva banks will be exceeded.

Factors affecting timing or viability

Load growth.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
FT. GARRY PERIMETER SOUTH BANK REPLMNT		4,317	4,403	3,930	-473	-11
TOTAL		4,317	4,403	3,930	-473	-11

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
9510	3,494	Environmental approval costs included.
9610	3,661	ISD deferred 2 years to 2000 07 31.
9710	4,146	Increase due to scope change to rebuild 12KV bus, replace reclosers, replace 66KV structure, add 66KV breakers.
1998 10	4,425	ISD deferred 2 years to 2002 07 31.
1999 10	4,353	Deferred one year 2003 07 31 due to capital constraint reasons.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item

166

Title			Budget reference number
FT. GARRY PERIMETER SOUTH BANK REPLACEMENTS			03-00-5936
Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	72034

DESCRIPTION:
REPLACE 2-7.5/10 MVA, 3 PH TRANSFORMERS WITH 2-15/20/25 MVA 66-12.47Y/7.2 KV 3 PH TRANSFORMERS C/W LTC'S.

JUSTIFICATION:
THE NON-FIRM CAPACITY OF FT. GARRY PERIMETER SOUTH STATION (SET BY THE THERMAL CAPACITY OF 2-7.5/10 MVA BANKS) WILL BE EXCEEDED IN 1996/97. THIS STATION SUPPLIES SOUTH FORT GARRY AND LASALLE AREAS (BOTH FAST GROWING COMMUNITIES) AND PROVIDES A BACK-UP SUPPLY TO ST. NORBERT SINGLE BANK STATION. REPLACEMENT OF THE EXISTING BANKS WITH 15/20/25 MVA UNITS, IS THE MOST ECONOMICAL SOLUTION TO THE GROWING 12 KV LOAD, AND WILL PROVIDE SUFFICIENT CAPACITY WELL BEYOND THE YEAR 2000.

REFERENCE:
CENTRAL REGION REPORT CR91-51, RECOMMENDATION 2.3.1. C.R. REF.# 91.190.

REVISION:
ISD DEFERRED FROM 2002 07 31 TO 2003 07 31 DUE TO BUDGET CONSTRAINTS. REFLECTS REVISED ACTIVITY AND OVERHEAD RATES.

CONTINGENCY: $348,000

IN SERVICE DATES				Base estimate
2003 07 31	4 502			199707 L2
				Work start date 2001 04 01

PREV. AUTHORITY Authorized to date:	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
1999/00						
2000/01	331	22	14			367
2001/02	129	-1	90			218
2002/03	3 857	105	27	- 149		3 840
TOTAL	4 317	126	131	- 149		4 425
REV. AMOUNTS:						
Authorized to date:						
Over(under)expend:						
Auth 2001/02	348	28	14			390
Req.: 2002/03	2 163	223	94			2 480
2003/04	1 419	120	93	- 149		1 483
TOTAL	3 930	371	201	- 149		4 353

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number: 03-00-5936

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1994 10	3 342	NEW ITEM (TRANSFERRED FROM DOMESTIC BRN 9503-00-2302).
1995 10	3 494	ENVIRONMENTAL APPROVAL COSTS INCLUDED.
1996 10	3 661	ISD DEFERRED 2 YEARS FROM 1998 07 31 TO 2000 07 31.
1997 10	4 146	INCREASE DUE TO SCOPE CHANGE TO REBUILD 12KV BUS, REPLACE RECLOSERS, REPLACE 66KV STRUCTURE, ADD 66KV BREAKERS.
1998 10	4 425	ISD DEFERRED TWO YEARS FROM 2000 07 31 TO 2002 07 31.

ASSOCIATED PROJECTS

Budget reference number	Description

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

COMPLEX STATUS: [X] Planned [ ] In progress

Complex no. 84

REVISION STATUS: [ ] New complex [ ] In service change [ ] Concept change [X] Estimate change only

COMPLEX: RIDGEWAY TRANSFORMER ADDITION

Proposal

Design and construct terminal facilities at Ridgeway as follows:

Terminations: Extend 230 & 66 KV facilities at Ridgeway station, including 3rd 230-66 KV 125 MVA transformer and circuit breakers.

JUSTIFICATION: [X] Load [ ] Service [ ] Safety [ ] Efficiency [X] Reliability [ ] Other

Explanation: This transformer is required in 2007 to supply increased Winnipeg load.

Estimate Level	COMPLEX START yyyy mm
L2	2003 09

IN SERVICE DATES AND AMOUNTS

2007 10 31	$9179			

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend								
Year 99/00								
00/01								
01/02								
02/03								
03/04	261	33	6		300	262	38	15
04/05	448	65	47		560	492	68	14
05/06	633	108	99		840	764	76	10
06/07	3,201	613	310		4,124	4,063	61	2
07/08	2,475	524	355		3,354	3,320	34	1
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	7,018	1,343	817		9,178	8,901	277	3

REVISION: Scope unchanged.

Reviewed by ORIGINATOR	yyyy mm dd 99 11 08	Reviewed by COORDINATOR	yyyy mm dd 99 11 03		
Reviewed by CONSTRUCTOR	yyyy mm dd 99 11 03	Approved by VICE-PRESIDENT	yyyy mm dd 99 11 16		

H2856/r Rev 99 03

Complex no.
84

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Advance or deferral impact

Deferral will decrease supply reliability in Ridgeway area in the event of an outage of existing Ridgeway 230-66 KV transformer.

Factors affecting timing or viability

Manitoba Load.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Ridgeway 230 KV Switchyard - Transformer Addition		6,772	6,907	7,018	111	2
TOTAL		6,772	6,907	7,018	111	2

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
1995 10	8,936	Reflects transformer price increase.
1996 10	8,894	Revised interest rates and correction to calculated escalation.
1997 10	8,894	Reflects revised cost flows and methodology implemented with the new financial reporting system.
1998 10	8,901	Scope unchanged.
1999 10	9,178	Scope unchanged.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item

— 167

Title
RIDGEWAY 230KV TRANSFORMER ADDITION

Budget reference number
03-00-1673

iginating division	Coordinating division	Constructing division	Project Order Group (Range):
anning & Control	Design	Construction	70305

DESCRIPTION:
INSTALL A 230-66KV TRANSFORMER RATED 75/100/125 MVA WITH +/-10% OLTC TAP RANGE. INSTALLATION WILL INCLUDE A 230KV BREAKER AND A 66KV BREAKER AND ASSOCIATED EQUIPMENT FOR TERMINATION OF THE NEW TRANSFORMER.

JUSTIFICATION:
THIS ITEM PROVIDES FOR SUPPLY OF INCREASED WINNIPEG LOAD IN 2007.

REFERENCE:
PSPD TM 94-6, 'WINNIPEG AND INTERLAKE TRANSMISSION CHANGES FOR 1994 IFF'

REVISION:
REFLECTS REVISED ACTIVITY AND OVERHEAD RATES.

CONTINGENCY: $605,000

IN SERVICE DATES		Base estimate
2007 10 31	9 178	199706 L2
		Work start date
		2003 09 01

PREV. AUTHORITY Authorized to date:	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
2003/04	226	32	5			263
2004/05	390	60	41			491
2005/06	574	104	86			764
2006/07	3 142	636	286			4 064
2007/08	2 440	543	337			3 320
TOTAL	6 772	1 375	755			8 902
REV. AMOUNTS:						
Authorized to date:						
Over(under)expend:						
Auth Req. 2003/04	261	33	6			300
2004/05	448	66	47			561
2005/06	633	107	99			839
2006/07	3 201	613	310			4 124
2007/08	2 475	524	355			3 354
TOTAL	7 018	1 343	817			9 178

Prepared by: yy mm dd	Approved by: yy mm dd	Approved by:	yy mm dd
COORDINATOR			
Estimated by:			
ORIGINATOR	COORDINATING MANAGER	ORIGINATING MANAGER	

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number: 03-00-1673

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1990 05	12 823	NEW ITEM.
1990 10	11 553	ESTIMATE AND CASH FLOW REVISED.
1991 10	11 427	FED SALES TAX REMOVED FROM ALL MATERIAL. DECREASE IN INTRST.& ESCLTN RATES. TRANSFRMR ESTIMATE WITH 1991 PRICES INCRSD FROM LAST YR.
1992 10	9 949	DECREASE IN ESCALATION RATES.
1993 10	8 941	DECREASE IN INTEREST & ESC. RATE. WORK START ADVNCE 4 MONTHS
1994 10	8 222	REVISED INTEREST AND ESCALATION RATES.
1995 10	8 936	REVISED TO REFLECT INCREASED POWER TRANSFORMER PRICE.
1996 06	8 894	REVISED INTEREST RATES. CORRECTION TO CALCULATED ESCALATION.
1997 10	8 894	SCOPE UNCHANGED, ESTIMATE REFLECTS REVISED COSTING METHODOLOGY IMPLEMENTED WITH THE NEW FINANCIAL REPORTING SYSTEM. ALSO, REFLECTS REVISED INTEREST AND ESCALATION RATES.
1998 10	8 902	NO CHANGE

ASSOCIATED PROJECTS

Budget reference number	Description

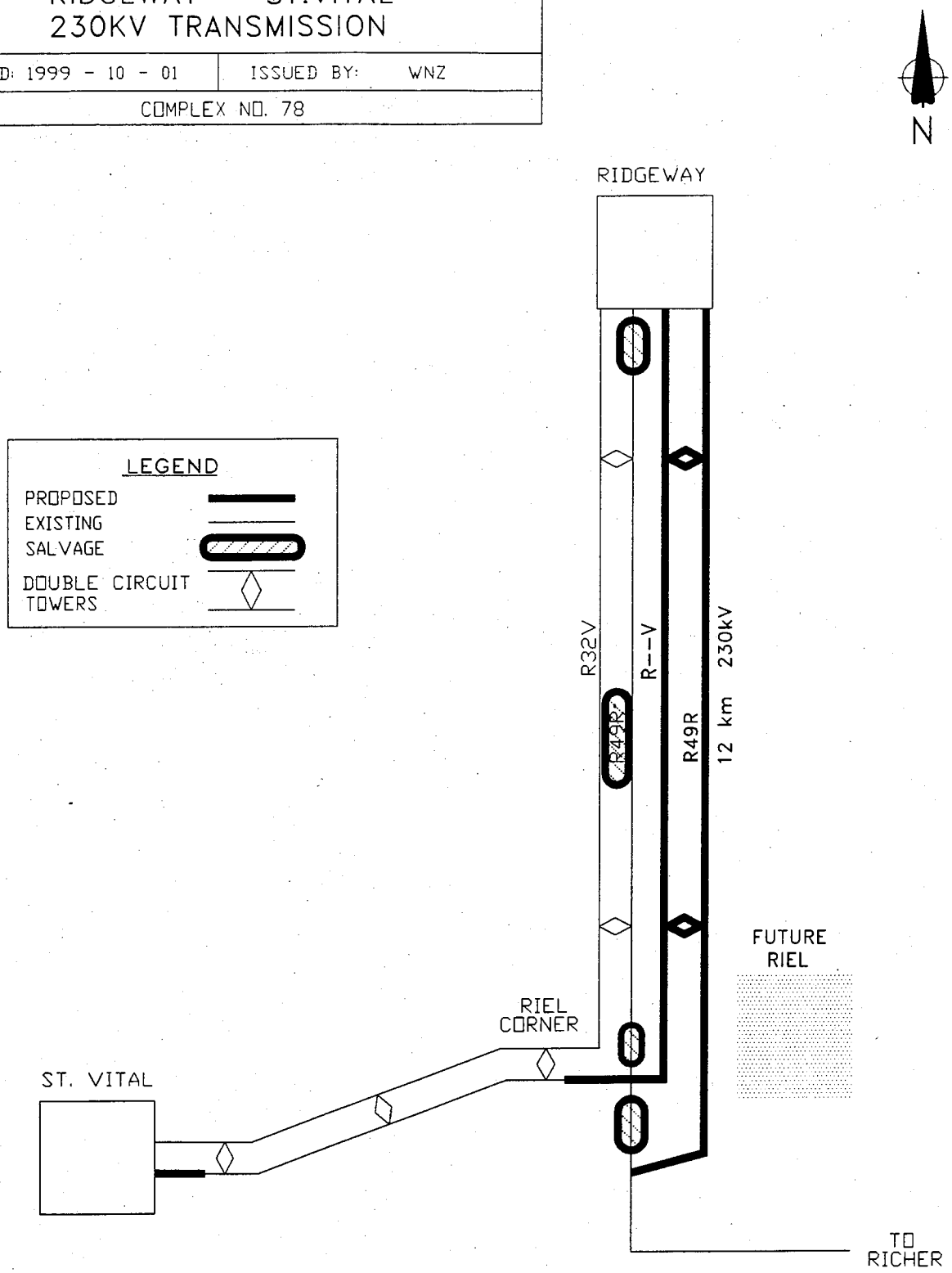
Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

CAPITAL BUDGET COMPLEX CONCEPTUAL DIAGRAM

RIDGEWAY – ST.VITAL 230KV TRANSMISSION

REVISED: 1999 - 10 - 01	ISSUED BY: WNZ

COMPLEX NO. 78



manitoba hydro

PLANNING AND CONTROL DIVISION

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

COMPLEX STATUS: ☐ Planned ☒ In progress

Complex no. 78

REVISION STATUS: ☐ New complex ☐ In service change ☐ Concept change ☒ Estimate change only

COMPLEX: RIDGEWAY - ST. VITAL 230 KV TRANSMISSION

Proposal

Perform environmental assessments and obtain licences, design and construct transmission and terminal facilities to provide firm supply to St. Vital station as follows:
Transmission: Construct 12.0 KM double circuit 230 KV line Ridgeway - Riel Future Station Site. Open 230 KV line R49R at Ridgeway and Riel site and reconnect south section at Riel site to Ridgeway using east side of new double circuit. Connect west side of new double circuit at Riel site to unused circuit extending to St. Vital. This results in 2nd Ridgeway-St. Vital 230 KV line, re-establishment of Ridgeway - Richer 230 KV line R49R , and one unenergized new Ridgeway-Riel Site line.
Terminations: Extend 230 & 115 KV facilities at St. Vital station, including a 2nd 230-115 KV 250 MVA transformer and 230 & 115 KV circuit breakers. Extend 230 KV facilities at Ridgeway. Communications: Integrate with existing east Winnipeg facilities.

JUSTIFICATION		Explanation
☒ Load	☐ Service	This complex provides transmission system improvements for firm supply to the St. Vital area.
☐ Safety	☐ Efficiency	
☒ Reliability	☐ Other	

Estimate Level	COMPLEX START (yyyy mm)
L2-3	1994 09

IN SERVICE DATES AND AMOUNTS

1998 10	$3610	1998 11	$71	1999 02	$96	1999 03	$18662
1999 04	$419	1999 06	$470	1999 07	$299	1999 09	$810
1999 10	$92	1999 12	$194				

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	20,888		2,171	73	22,986	21,289	1,697	8
Year 99/00	1,612	22	29		1,663	903	760	84
00/01								
01/02								
02/03								
03/04								
04/05								
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	22,500	22	2,200	73	24,649	22,192	2,457	11

REVISION: Revised to reflect the inclusion of a FP&P deluge system for banks 7&8, and site improvements at St Vital; higher costs for termination, communications and compressed air system.

Reviewed by ORIGINATOR	yyyy mm dd 99 11 05	Reviewed by COORDINATOR	yyyy mm dd 99 11 03
Reviewed by CONSTRUCTOR	yyyy mm dd 99 11 03	Approved by VICE PRESIDENT	yyyy mm dd 99 11 16

H2856/r Rev 99 03

Complex no. 78

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Advance or deferral impact

Deferral will limit firm supply to the St Vital area and also effect firmness of Ontario Hydro 200 MW Sale and supply to TCPL.

Factors affecting timing or viability

Manitoba Load.
Ontario Hydro 200 MW Sale.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Ridgeway-St. Vital & Ridgeway-Richer 230 KV T/L	3,576	4,243	4,328	4,092	-236	-5
St. Vital Transformer Addition & Line Terminat'ns	11,798	12,156	12,399	13,700	1,301	10
Ridgeway - Terminate St. Vital & Richer 230KV T/L	3,121	3,436	3,505	3,562	57	2
Ridgeway Stn upgrade Compressed Air System	703	517	527	703	176	33
Ridgeway-St. Vital-Richer 230KV Telecontrol Rqmts	282	294	300	443	143	48
TOTAL	19,480	20,646	21,059	22,500	1,441	7

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
9510	25,145	Transformer price increase and concept chg- using both sides of new double circuit line, additional 230KV circuit breaker at St. Vital, and incr 230KV bay developments.
9610	19,697	Re-establish R49R advnc 2 months to 1998 04 30. Commnctns advnce 4 months to 1998 06 30. 115 KV line sections inside St. Vtl for tfr add. Cost dcrs. matrl, engnrng, labor
1997 10	20,177	Scope unchanged, estimate reflects revised costing methodology implemented with the new financial reporting system. Also reflects revised interest and escalation rates.
1998 10	22,192	Revised to reflect 97/98 overexpenditure 1.9M, higher transmission line material costs and five months ISD delay of St Vital transformer.
1999 10	24,649	Revised to reflect the inclusion of a FP&P deluge system for banks 7&8, and site improvements at St Vital; higher costs for termination, communications and compressed air

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION
Complex 64	St. Vital Transformer Addition
Complex 27	Dorsey - St. Vital 230 KV Transmission
Complex 95	200 MW Ontario Hydro Sale - Transmission Upgrade

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item

Title: RIDGEWAY - ST. VITAL & RIDGEWAY - RICHER 230 KV T/L

Budget reference number: 02-00-3201

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	60013

DESCRIPTION:
CONDUCT ENVIRONMENTAL IMPACT ASSESSMENT AND OBTAIN NECESSARY APPROVALS AND LICENSES FOR RIDGEWAY - ST. VITAL AND RIDGEWAY - RICHER 230 KV LINES ALONG EXISTING RIGHT-OF-WAY. DESIGN AND CONSTRUCT 12.0 KM OF DOUBLE CIRCUIT 230 KV LINE STRUNG ON BOTH SIDES WITH 1272 MCM ACSR ALONG LINE R32V RIGHT-OF-WAY FROM RIDGEWAY TO RIEL CORNER. OPEN RIDGEWAY- RICHER 230KV LINE R49R AT RIEL CORNER AND CONNECT RICHER END TO EAST SIDE OF NEW DOUBLE CIRCUIT LINE. EXTEND NORTH END OF EAST SIDE OF NEW DOUBLE CIRCUIT INTO RIDGEWAY FOR RETERMINATION OF RIDGEWAY - RICHER LINE. CONNECT WEST SIDE OF NEW DOUBLE CIRCUIT LINE AT RIEL CORNER TO UNUSED LINE ON SOUTH SIDE OF 230KV DOUBLE CIRCUIT FROM RIEL CORNER TO ST. VITAL. EXTEND WEST END OF UNUSED LINE INTO ST. VITAL AND WEST SIDE OF NEW DOUBLE CIRCUIT LINE INTO RIDGEWAY TO COMPLETE NEW RIDGEWAY - ST. VITAL 230KV CIRCUIT. BUILD 115KV LINE SECTIONS INSIDE ST VITAL STATION TO CONNECT 230-115KV TRANSFORMERS TO ASSOCIATED 115KV CIRCUIT BREAKERS. **** COMPLETION DATE FOR ENVIRONMENTAL ACTIVITIES: 1997 04 01 **** NOTE: LINE SECTION OF FORMER 230KV LINE R49R FROM RIDGEWAY TO RIEL CORNER IS LEFT OPEN AT BOTH ENDS TO BECOME PART OF FUTURE DORSEY-ST VITAL 230KV CIRCUIT. NOTE: RETERMINATION OF R49R TO EAST SIDE OF NEW D/C LINE TO BE COMPLETED BY 1998 04 30. IN-SERVICE DATE OF NEW RIDGEWAY-ST VITAL 230KV LINE IS 1998 06 30 IN COORDINATION WITH DEVELOPMENT OF ST VITAL STATION.

JUSTIFICATION:
THIS ITEM PROVIDES FOR PART OF SYSTEM CHANGES TO TRANSMIT POWER FROM DORSEY TO EASTERN HALF OF WINNIPEG. IT IS REQUIRED TO ACCOMMODATE WINNIPEG AREA LOAD GROWTH (INCLUDING WINNIPEG HYDRO), ONTARIO HYDRO 200 MW SALE IN 1998 AND DEFERRAL OF RIEL STATION. ELSEWHERE IN THE BUDGET IS AN ITEM FOR ADDITION OF A 2ND ST. VITAL 230-115 KV TRANSFORMER. THIS ITEM PROVIDES FOR FIRM SUPPLY TO ADDED TRANSFORMER AND MAINTAINING RICHER SUPPLY OUT OF RIDGEWAY STATION.

REFERENCE:
PSPD TM 94-6, WINNIPEG AND INTERLAKE TRANSMISSION CHANGES FOR 1994 IFF. PSPD TM 95-7, RECOMMENDED CHANGES TO ST. VITAL STATION DEVELOPMENT. PSPD TM 95-14, RIDGEWAY STATION - 1998 IMPROVEMENTS.

REVISION:
REFLECTS ACTUAL COSTS TO COMPLETION.

CONTINGENCY: $ 10 000

IN SERVICE DATES

1999 03 31	4 568
1999 09 30	82

Base estimate: 199903 L4

Work start date: 1995 12 01

	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
PREV. AUTHORITY Authorized to date:	4 055		557	-45		4 567
1999/00	-86					-86
TOTAL	3 969		557	-45		4 481
REV. AMOUNTS:						
Authorized to date:	4 055		557	-45		4 567
Over(under)expend:						
Auth Req.: 1999/00	37		1			38
TOTAL	4 092		558	-45		4 605

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 02-00-3201

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1992 10	3 143	NEW ITEM. REPLACES MAJOR PORTION OF BRN 9602-00-6157.
1993 10	3 511	ENVIRONMENTAL ACTIVITIES ADDED. PROJECTED MATERIAL COSTS USED INSTEAD OF CURRENT SUPPRESSED MARKET PRICES.
1994 10	4 695	CONCEPT CHANGE: 12 KM 230KV DOUBLE CCT RIDGEWAY-RIEL CORNER REPLACES 7.5 KM DOUBLE CCT ST. VITAL-RIEL CORNER. RICHER LINE TERMINATED AT RIDGEWAY INSTEAD OF ST. VITAL.
1995 10	4 510	NEW RIDGEWAY-ST. VITAL LINE USES NEW DOUBLE CIRCUIT SECTION INSTEAD OF OLD LINE R49R. CONCEPT CHANGE OVERESTIMATED IN 1994. NEW DETAIL ESTIMATE PREPARED RESULTING IN A DECREASE.
1996 10	4 500	ISD FOR R49R RETERMINATION ADVANCED TWO MONTHS TO 1998 04 30. ST. VITAL STATION 115KV LINE SECTIONS ADDED.
1997 10	3 790	REDUCTION IS ATTRIBUTED PRIMARILY TO LOWER CONDUCTOR AND STEEL TOWER COSTS.
1998 10	4 481	INCREASE DUE TO HIGHER CONSTRUCTION COSTS AND ESCALATION IN CONDUCTOR BASE METAL PRICES.

ASSOCIATED PROJECTS

Budget reference number	Description
03-00-6361	ST. VITAL TRANSFORMER ADDITION & LINE TERMINATIONS
03-00-8330	RIDGEWAY STATION - UPGRADE COMPRESSED AIR SYSTEM
03-00-8493	RIDGEWAY - TERMINATE ST. VITAL AND RICHER 230 KV T/L
05-00-3205	RIDGEWAY-ST. VITAL-RICHER 230 KV TELECONTROL REQUIREMENTS

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	14					14	14
May	1					1	15
Jun	14					14	29
Jul	1					1	30
Aug	4	1				5	35
Sep	3	-1	1			3	38
Oct							38
Nov							38
Dec							38
Jan							38
Feb							38
Mar							38
TOTAL	37		1			38	38
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item

169

Title			Budget reference number
ST. VITAL TRANSFORMER ADDITION & LINE TERMINATIONS			03-00-6361
iginating division	Coordinating division	Constructing division	Project Order Group (Range):
anning & Control	Design	Construction	70159

DESCRIPTION:
CONDUCT ENVIRONMENTAL IMPACT ASSESSMENT, ACQUIRE PROPERTY AND OBTAIN LICENCING FOR EXPANSION OF EXISTING ST. VITAL 230-115 KV STATION. INSTALL A 230-115 KV TRANSFORMER RATED 150/200/250 MVA WITH +/- 10% OLTC TAP RANGE IN 230 KV BAY 3. SALVAGE ALL EQUIPMENT IN 230 KV BAY 1 INCLUDING CIRCUIT BREAKER. MOVE 230-115 KV TRANSFORMER FROM BAY 1 TO BAY 2 AND RECONNECT TO EXISTING 115KV BANK TERMINATION BREAKER. TERMINATE 2 - 230 KV LINES TO RIDGEWAY IN BAY 2. REPLACE R32V LINE PROTECTION AT ST. VITAL. FACILITIES WILL INCLUDE 4 - 230 KV CIRCUIT BREAKERS, 1 - 115 KV CIRCUIT BREAKER, ASSOCIATED EQUIPMENT, AND FULL DEVELOPMENT OF 230 KV BAY 2 AND PARTIAL BAY 3.

NOTE: 230 KV BAY 1 WILL BE REDEVELOPED IN THE ST. VITAL TRANSFORMER ADDITION COMPLEX. INSTALLATION OF NEW TRANSFORMER IN BAY 3, ADDITION OF BAY 2 WITH 4 - 230KV BREAKERS, AND TERMINATION OF NEW 230KV RIDGEWAY LINE TO BE COMPLETED BY 1998 06 30 TO PERMIT SALVAGE OF BAY 1 AND RELOCATION TO BAY 2.

JUSTIFICATION:
THIS ITEM PROVIDES FOR PART OF SYSTEM CHANGES TO TRANSMIT POWER FROM DORSEY TO EASTERN HALF OF WINNIPEG. IT IS REQUIRED TO ACCOMMODATE WINNIPEG AREA LOAD GROWTH (INCLUDING WINNIPEG HYDRO), ONTARIO HYDRO 200 MW SALE IN 1998 AND DEFERRAL OF RIEL STATION.

THIS ITEM PROVIDES FOR INCREASED TRANSFORMATION TO 115KV NETWORK AT ST. VITAL, TERMINATION OF NEW 230 KV LINE TO RIDGEWAY, AND INITIAL STAGE OF UPGRADING OF OLD 230 KV FACILITIES.

REFERENCE:
PSPD TM 94-6, 'WINNIPEG AND INTERLAKE TRANSMISSION CHANGES FOR 1994 IFF'.
PSPD TM 95-7, 'RECOMMENDED CHANGES TO ST. VITAL STATION DEVELOPMENT'.
PSPD TM 95-14, 'RIDGEWAY STATION - 1998 IMPROVEMENTS'.
MEMO, S.M. INNES TO W. ZURBA, 1997 10 22, 'PROTECTION UPGRADES'.

REVISION:
REFLECTS REVISED ACTIVITY & OVERHEAD RATES. PROJECT COST INCREASED IN PART DUE TO THE INCLUSION OF A FP&P DELUGE SYSTEM FOR TRANSFORMER BANKS 7 & 8, NOT PREVIOUSLY IDENTIFIED. ADDITIONAL SITE IMPORVEMENTS WERE REQUIRED FOR ACCESS WITHIN THE SWITCHYARD DUE TO DETERIORATED DRAINAGE CONDITIONS. ADDITIONAL COSTS WERE INCURRED TO TRANSFER CONTROL AND METERING FOR EXISTING 115 KV LINES TO THE NEW CONTROL SYSTEM AND TO FACILITATE ADDITION OF THE 3RD 115/230 KV TRANSFORMER IN 2001.

IN SERVICE DATES			Base estimate
1999 03 31	14 084		199903 L4
1999 04 30	419		Work start date
1999 07 31	299		1994 09 01
1999 12 31	193		

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:	12 805		1 280	-2		14 083
1999/00	- 970					- 970
TOTAL	11 835		1 280	-2		13 113
REV. AMOUNTS:						
Authorized to date:	12 805		1 280	-2		14 083
Over(under)expend:						
Auth 1999/00	895	16	-1			910
Req.:						
TOTAL	13 700	16	1 279	-2		14 993

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 03-00-6361

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1985 12	16 707	NEW ITEM.
1986 12	14 330	BASE DATE AND EST. REMAIN UNCHGED. REVISED INT. & ESC RATES.
1987 11	26 932	BASE DATE REVISED FROM 1985 TO 1987, START DATE FROM 94 04 01 TO 95 01 20 AND ISD DEF. FROM 1997 TO 1999. CONCEPT CHNG:'ST. VITAL-230 KV T/L TERM.' HAS BEEN INCORP. INTO THIS ITEM SINCE BOTH NOW HAVE SAME ISD. THERFORE NO. OF NEW 230KV BREAKERS INCREASED FROM 3 TO 5 AS WELL AS ONE BRK. REPL.
1988 11	32 044	BASE DATE REVISED FROM 1987 TO 1988, START DATE FR. 95 01 20TO 95 05 01. 80% OF THE COST INCREASE DUE TO APPARATUS COST (TRANFSORMERBREAKERS, & SWITCHES). NO SLD AVAILABLE. REFLECTS REV. INT & ESC RATES.
1989 10	36 906	EXCLUDING INT, EST. INCRS. DUE TO TRANSF.PRICE INCREASES. CAPITALIZATION DATES TO COINCIDE WITH CONAWAPA G.S. CAUSING INTRST INCRS
1990 05	18 663	REFLECTS O.H. 200 MW SALE.
1990 10	21 587	PREV. EST. USED FOR PLANNING. PRESENT EST. HAS CONCEPT CHNG.
1991 10	19 341	FST REMOVED FROM ALL MATERIAL. DECREASE IN ESCLTN RATES.
1992 10	21 168	TERM OF RICHER LINE REPLACES TERM OF RIEL LINE. ADD 1 BAY. USE HEAVY DUTY BUS/HARDWARE/INSULATORS & BREAKERS FOR HIGH FAULT LEVELS.ENV. INTELLIGENT SUBSTATION' COSTS NOW INCLUDED.
1993 10	19 302	DC POWER ORDER REDUCTION FOR ST. VITAL-RICHER LINE ADDED. ENVRNMNTL. ACTIVITIES ADDED. LOWER BUDGET PRICE QUOTATION FOR TRNSFRMR.
1994 10	14 958	TERM. OF RICHER 230KV LINE, BREAKR, & DC P.O. RDCTN. DELETED
1995 10	16 249	ADDED ONE 230KV BREAKER, ENHANCED DEVELOPMENT OF 230KV BAYS 2 & 3, SALVAGE OF BAY 1 AND INCREASED AUTO TRANSFORMER COST.
1996 10	11 909	A DETAILED REVIEW OF THE ESTIMATE RESULTED IN A DECREASE TO ENGINEERING, MATERIAL, AND LABOUR.
1997 10	12 779	SCOPE UNCHANGED, ESTIMATE REFLECTS REVISED COSTING METHODOLOGY IMPLEMENTED WITH THE NEW FINANCIAL REPORTING SYSTEM. INCREASE BASED ON PRELIMINARY ENGINEERING, INCREASED CONTINGENCY & APPROVED PROTECTION REPORT. IT ALSO REFLECTS REVISED INTEREST AND ESCALATION RATES. SALVAGE MATERIALS CREDIT REMOVED DUE TO UNCERTAINTY ABOUT REUSE OF SALVAGED APPARATUS.
1998 10	13 114	CASHFLOW ADJUSTED DUE TO CAPITAL CONSTRAINTS. ESTIMATE REVISED TO 1998 BASE AND FINAL DESIGN. CONTINGENCY REDUCED.

ASSOCIATED PROJECTS

Budget reference number	Description
02-00-3201	RIDGEWAY - ST. VITAL & RIDGEWAY - RICHER 230 KV T/L
03-00-8330	RIDGEWAY STATION - UPGRADE COMPRESSED AIR SYSTEM
03-00-8493	RIDGEWAY - TERMINATE ST. VITAL AND RICHER 230 KV T/L
05-00-3205	RIDGEWAY-ST. VITAL-RICHER 230 KV TELECONTROL REQUIREMENTS

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	174	3				177	177
May	161	2	-2			161	338
Jun	157	3	-1			159	497
Jul	116	1	1			118	615
Aug	83	2	-1			84	699
Sep	54	2				56	755
Oct	54	2				56	811
Nov	54	1	1			56	867
Dec	42		1			43	910
Jan							910
Feb							910
Mar							910
TOTAL	895	16	-1			910	910
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item ___ Domestic Item 170

Title
RIDGEWAY - TERMINATE ST. VITAL AND RICHER 230 KV T/L

Budget reference number
03-00-8493

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	60041

DESCRIPTION:
RE-TERMINATE RIDGEWAY - RICHER 230KV LINE R49R ON 230KV STATION BUS A1 IN NEW BAY 3. TERMINATE NEW ST. VITAL 230KV LINE ON BUS B1 IN BAY 3. REPLACE R32V LINE PROTECTION AT RIDGEWAY. INSTALLATION TO INCLUDE 1 - 230 KV CIRCUIT BREAKER, LINE R49R PROTECTION MODIFICATIONS, ASSOCIATED EQUIPMENT, AND STATION EXPANSION WITH DEVELOPMENT OF 230KV BAY 3. NOTE: BAY 3 FACILITIES TO BE INSTALLED BY 1998 04 30 TO PERMIT RE-TERMINATION OF R49R.

JUSTIFICATION:
ELSEWHERE IN THE BUDGET JUSTIFICATION IS GIVEN FOR CONSTRUCTION OF A SECOND 230KV RIDGEWAY- ST. VITAL LINE. THIS ITEM PROVIDES FOR TERMINATION OF NEW LINE AT RIDGEWAY AND REQUIRED RE-TERMINATION OF RICHER LINE R49R.

REFERENCE:
PSPD TM 94-6,' WINNIPEG AND INTERLAKE TRANSMISSION CHANGES FOR 1994 IFF'. PSPD TM 95-14, 'RIDGEWAY STATION - 1998 IMPROVEMENTS'.
MEMO, S.M. INNES TO W. ZURBA, 1997 10 22, 'PROTECTION UPGRADES'.

REVISION:
ACTUAL COSTS HIGHER THAN ESTIMATE DUE TO CONSTRUCTION COSTS BEING GREATER THAN ORIGINALLY ESTIMATED.

CONTINGENCY: $5000

IN SERVICE DATES				Base estimate
1998 10 31	3 610	1999 02 28	20	199804 L4
1998 11 30	71	1999 03 31	10	
1998 12 31	49	1999 10 31	91	Work start date
1999 01 31	27			1997 04 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:	3 482		313	-26		3 769
1999/00	-23					-23
TOTAL	3 459		313	-26		3 746
REV. AMOUNTS:						
Authorized to date:	3 482		313	-26		3 769
Over(under)expend:						
Auth Req.: 1999/00	80	2	1			83
TOTAL	3 562	2	314	-26		3 852

Prepared by: yy mm dd COORDINATOR Approved by: yy mm dd Approved by:
Estimated by: ORIGINATOR COORDINATING MANAGER ORIGINATING MANAGER

1999-08-21 05:26 PM

CAPITAL EXPENDITURE REVISION

Budget reference number 03-00-8493

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1987 11	773	NEW ITEM.
1988 11	781	BASE DATE REVISED FROM 1987 TO 1988, START DATE FROM 96 06 10 TO 96 10 01. NO SLD AVAILABLE. REFLECTS REVISED INTEREST AND ESCALATION RATES.
1989 10	854	CAPITALIZATION DATES CHANGED TO COINCIDE WITH THOSE OF CONAWAPA G.S. CAUSING AN INCREASE IN INTEREST COSTS.
1990 05	541	REFLECTS O.H. SALES.
1990 10	722	CONCEPT CHANGE FOR SECTIONALIZED LINE.
1991 10	631	F.S.T. REMOVED FROM ALL MATERIAL. START DATE DEFERRED ONE YEAR. DECREASE IN INTEREST AND ESCALATION RATES.
1992 10	567	SOUTHERN SECTION OF RIDGEWAY - RICHER LINE R49R TO BE TERMINATED AT ST. VITAL INSTEAD OF RIEL. DECREASE IN ESCALATION RATES.
1993 10	560	DECREASE IN INTEREST AND ESCALATION RATES.
1994 10	3 656	RETERMINATION OF RICHER LINE AT RIDGEWAY WITH 1-230 KV BRKR ADDED. STATION EXPANDED FOR3RD 230 KV BAY. START DATE ADVANCE 23 MONTHS
1995 10	4 039	COST INCREASE DUE TO CONCEPT CHANGE INVOLVING RELOCATION OF ST. VITAL T/L TERMINATION FROM BAY 2 TO BAY 3. IN-SERVICE ADVANCED 4 MONTHS TO 1998 06 30.
1996 10	2 959	IN-SERVICE DATE OF R49R RETERMINATION ADVANCED 2 MONTHS TO 1998 04 30. A DETAILED REVIEW OF THE ESTIMATE RESULTED IN DECREASES TO ENGINEERING AND LABOUR COSTS. CONCEPT CHANGED TO CONNECT NEW BAY 3 TO BAY 2 INSTEAD OF ALSO REBUILDING BAY 2, WHICH RESULTED IN A SIGNIFICANT REDUCTION AS REBUILDING WAS VERY LABOUR INTENSIVE.
1997 10	3 310	ESTIMATE REFLECTS REVISED COSTING METHODOLOGY IMPLEMENTED WITH THE NEW FINANCIAL REPORTING SYSTEM. IT ALSO REFLECTS REVISED INTEREST AND ESCALATION RATES.
1998 10	3 745	R32V LINE PROTECTION AT RIDGEWAY UPGRADE ADDED.

ASSOCIATED PROJECTS

Budget reference number	Description
02-00-3201	RIDGEWAY - ST. VITAL & RIDGEWAY - RICHER 230 KV T/L
03-00-6361	ST. VITAL TRANSFORMER ADDITION & LINE TERMINATIONS
03-00-8330	RIDGEWAY STATION - UPGRADE COMPRESSED AIR SYSTEM
05-00-3205	RIDGEWAY-ST. VITAL-RICHER 230 KV TELECONTROL REQUIREMENTS

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	11	1				12	12
May	11	1				12	24
Jun	11	1				12	36
Jul	11	1				12	48
Aug	11	1				12	60
Sep	11	1				12	72
Oct	14	-4	1			11	83
Nov							83
Dec							83
Jan							83
Feb							83
Mar							83
TOTAL	80	2	1			83	83
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item __ Domestic Item

171

Title
RIDGEWAY STATION - UPGRADE COMPRESSED AIR SYSTEM

Budget reference number
03-00-8330

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Power Planning & Operations	Operating & Maintenance	74101

DESCRIPTION:
UPGRADE THE STATION HIGH PRESSURE AIR SYSTEM TO MEET CURRENT PERFORMANCE REQUIREMENTS:

- INSTALL 3 NEW CONTINUOUS DUTY AIR COMPRESSORS
- INSTALL 2 NEW FULLY AUTOMATIC DESSICANT-TYPE AIR DRYERS
- UPGRADE CONTROLS AND REPLACE THE EXISTING HYGROMETER

JUSTIFICATION:
THE EXISTING COMPRESSED AIR SYSTEM IS 25 YEARS OLD AND UNABLE TO MATCH SPECIFICATION PERFORMANCE, LACKS REDUNDANCY AND SUFFERS A HIGH NUMBER OF MAINTENANCE CALLS.
THIS ITEM PROVIDES FOR THE REPLACEMENT OF MAJOR AIR SYSTEM COMPONENTS IN ORDER TO IMPROVE RELIABILITY, MAINTAINABILITY AND PERFORMANCE.

REFERENCE:
REPORT PP&O 97/6 'RIDGEWAY STATION - STUDY OF ALTERNATIVES FOR THE HIGH PRESSURE AIR SYSTEM'

REVISION:
INCREASE IS DUE TO THE FOLLOWING: HIGHER MATERIAL COSTS, INSTRUMENTATION COSTS HAD BEEN ADDED, AND CONSTRUCTION COSTS INCREASED TO COMPLY WITH NEW QUALITY ASSURANCE PROGRAM.

CONTINGENCY: $39,000

1999 09 30	727	IN SERVICE DATES		Base estimate 199904 L2
				Work start date 1998 04 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:	235		2			237
1999/00	288	5	17			310
TOTAL	523	5	19			547
REV. AMOUNTS:						
Authorized to date:	235		2			237
Over(under)expend:						
Auth Req.: 1999/00	468	2	20			490
TOTAL	703	2	22			727

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

1999-08-21 05:25 PM

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 03-00-8330

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1998 10	547	New Item.

ASSOCIATED PROJECTS

Budget reference number	Description
02-00-3201	RIDGEWAY - ST. VITAL & RIDGEWAY - RICHER 230 KV T/L
03-00-6361	ST. VITAL TRANSFORMER ADDITION & LINE TERMINATIONS
03-00-8493	RIDGEWAY - TERMINATE ST. VITAL AND RICHER 230 KV T/L
05-00-3205	RIDGEWAY-ST. VITAL-RICHER 230 KV TELECONTROL REQUIREMENTS

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	100		2			102	102
May	102	1	2			105	207
Jun	102	1	3			106	313
Jul	87	1	4			92	405
Aug	8		4			12	417
Sep	8	-1	5			12	429
Oct	8					8	437
Nov	8					8	445
Dec	45					45	490
Jan							490
Feb							490
Mar							490
TOTAL	468	2	20			490	490
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item ___ Domestic Item 172

Title: RIDGEWAY-ST. VITAL-RICHER 230 KV TELECONTROL REQUIREMENTS

Budget reference number: 05-00-3205

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Planning & Control	Construction	70168

DESCRIPTION:
DESIGN, INSTALL AND COMMISSION REQUIRED TELECONTROL FACILITIES FOR NEW 230 KV LINE FROM RIDGEWAY TO ST. VITAL AND RETERMINATED LINE R49R FROM RIDGEWAY TO RICHER. REPLACE COMMUNICATIONS EQUIPMENT ASSOCIATED WITH R32V LINE PROTECTION AT RIDGEWAY AND ST. VITAL STATIONS.

JUSTIFICATION:
ELSEWHERE IN THE BUDGET JUSTIFICATION IS GIVEN FOR CONSTRUCTION OF A 2ND 230KV RIDGEWAY - ST. VITAL 230KV LINE. THIS ITEM PROVIDES FOR NECESSARY TELECONTROL FACILITIES FOR NEW LINE AND RETERMINATION OF EXISTING RIDGEWAY - RICHER LINE R49R.

REFERENCE:
PSPD TM 94-6, WINNIPEG AND INTERLAKE TRANSMISSION CHANGES FOR 1994 IFF. PSPD TM 95-14, RIDGEWAY STATION - 1998 IMPROVEMENTS.
MEMO, S.M. INNES TO W. ZURBA, 1997 10 22, 'PROTECTION UPGRADES'.

REVISION:
INSERVICE DATE DEFERRED ONE YEAR. INCREASE DUE TO ADDITIONAL PHONE LINES AND DATA LINES.

CONTINGENCY: $13,000

IN SERVICE DATES: 1999 06 30 | 471

Base estimate: 199901 L2

Work start date: 1997 05 01

	PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:		311		19			330
1999/00		-26					-26
TOTAL		285		19			304
REV. AMOUNTS:							
Authorized to date:		311		19			330
Over(under)expend:							
Auth Req.: 1999/00		132	1	8			141
TOTAL		443	1	27			471

Prepared by: yy mm dd COORDINATOR — Approved by: yy mm dd — Approved by: yy mm dd

Estimated by: ORIGINATOR — COORDINATING MANAGER — ORIGINATING MANAGER

CAPITAL EXPENDITURE REVISION

Budget reference number: 05-00-3205

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1992 10	670	NEW ITEM.
1993 10	652	DECREASE IN INTEREST AND ESCALATION RATES.
1994 10	198	RIDGEWAY - RICHER LINE REPLACES ST. VITAL - RICHER LINE. SCOPE CHANGED - ESTIMATE FOR MUX CHANNELS, RFI MEASUREMENTS AND DC REDUCTION REMOVED.
1995 10	347	REVISED TO INCLUDE FUNDS FOR ADDITIONAL R32V TONE REPLACEMENT WORK NOT INCLUDED IN ORIGINAL ESTIMATE.
1996 10	329	ISD ADVANCED 4 MONTHS FROM 98 10 31 TO 98 06 30 BY SYSTEM PLANNING & ENVIRONMENT DIVISION.
1997 10	299	START DATE ADVANCED FROM 1998 01 TO 1997 04.
1998 10	303	ESTIMATE AND SCHEDULE UNCHANGED.

ASSOCIATED PROJECTS

Budget reference number	Description
02-00-3201	RIDGEWAY - ST. VITAL & RIDGEWAY - RICHER 230 KV T/L
03-00-6361	ST. VITAL TRANSFORMER ADDITION & LINE TERMINATIONS
03-00-8330	RIDGEWAY STATION - UPGRADE COMPRESSED AIR SYSTEM
03-00-8493	RIDGEWAY - TERMINATE ST. VITAL AND RICHER 230 KV T/L

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	40		2			42	42
May	53		3			56	98
Jun	39	1	3			43	141
Jul							141
Aug							141
Sep							141
Oct							141
Nov							141
Dec							141
Jan							141
Feb							141
Mar							141
TOTAL	132	1	8			141	141
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

COMPLEX STATUS: ☐ Planned ☒ In progress

Complex no. 64

REVISION STATUS: ☐ New complex ☒ In service change ☐ Concept change ☐ Estimate change only

COMPLEX: ST. VITAL TRANSFORMER ADDITION

Proposal

Design and construct terminal facilities at St. Vital as follows:

Terminations: Extend 230 and 115 KV facilities at St. Vital station, including a 3rd 230-115 KV 250 MVA transformer and associated 230 KV circuit breakers.

JUSTIFICATION

☒ Load ☐ Service
☐ Safety ☐ Efficiency
☒ Reliability ☐ Other

Explanation

The transformer is required in 2001 to supply increased Winnipeg load.

Estimate Level	COMPLEX START (yyyy mm)
L2	1997 10

IN SERVICE DATES AND AMOUNTS

2002 04	$8990			

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	6				6	304	-298	-98
Year 99/00	306	12	6		324	3,270	-2,946	-90
00/01	3,304	198	134		3,636	2,777	859	31
01/02	3,252	253	479		3,984	349	3,635	NA
02/03	960	24	56		1,040	2,062	-1,022	-50
03/04								
04/05								
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	7,828	487	675		8,990	8,762	228	3

REVISION: Deferred one year 2002 04 30 due to capital constraint reasons.

Reviewed by ORIGINATOR	yyyy mm dd 99 11 03	Reviewed by COORDINATOR	yyyy mm dd 99 11 03
Reviewed by CONSTRUCTOR	yyyy mm dd 99 11 03	Approved by VICE-PRESIDENT	yyyy mm dd 99 11 [illegible]

H2856/r Rev 99 03

Complex no. 64

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Advance or deferral impact

Deferral will decrease supply reliability in the St. Vital area in case of outage of an existing St. Vital 230-115 KV transformer.

Factors affecting timing or viability

Manitoba Load.
Ontario Hydro 200 MW Sale.
Supply to TCPL.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
St. Vital 230 KV Transformer Addition		7,707	7,861	7,828	-33	-0
TOTAL		7,707	7,861	7,828	-33	-0

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
9510	9,520	Retermination of 230 KV line R32V deleted. Transformer price increase, 1-230KV circuit brkr add'd (from Dorsey-St. Vital 230KV Trnsmssn cmplx), and add'l stn facil adj.
9610	8,198	Retermination of 2 - 115 kV lines and installation of 1 - 115 kV circuit breaker deleted. Reduced material cost based on recent autotransformer quote.
1997 10	8,885	In service date deferred 6 months to 2001 04 30 to coincide with Dorsey - St. Vital line addition at St. Vital Station. Also reflects revised interest and escalation rates.
1998 10	8,762	Scope unchanged.
1999 10	8,989	Deferred one year 2002 04 30 due to capital constraint reasons.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION
Complex 78	Ridgeway-St. Vital 230 KV Transmission
Complex 27	Dorsey - St. Vital 230 KV Transmission

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item

173

Title
ST. VITAL 230KV TRANSFORMER ADDITION

Budget reference number
03-00-1672

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	71009

DESCRIPTION:
RE-TERMINATE 115KV LINE XV39 AT FORMER LINE VJ50 CIRCUIT BREAKER AT ST. VITAL. RE-TERMINATE 115KV SIDE OF 230-115KV TRANSFORMER BANK #7 (230KV BAY 2) AT VACATED LINE XV39 CIRCUIT BREAKER. INSTALL A 230-115KV TRANSFORMER RATED 150/200/250 MVA WITH +/- 10% OLTC TAP RANGE IN 230KV BAY 1 AND TERMINATE 115KV SIDE AT VACATED BANK #7 CIRCUIT BREAKER. INSTALLATION WILL INCLUDE 2 - 230KV CIRCUIT BREAKERS, ASSOCIATED EQUIPMENT, AND RECONSTRUCTION OF PREVIOUSLY SALVAGED 230KV BAY 1.

JUSTIFICATION:
TRANSFORMER IS REQUIRED TO MEET INCREASED WINNIPEG AREA LOAD.

REFERENCE:
1) PSPD TM 94-6, WINNIPEG AND INTERLAKE TRANSMISSION CHANGES FOR 1994 IFF.
2) MEMO, W.N. ZURBA TO C.V. THIO, 1997 07 25, 'WINNIPEG AREA TRANSMISSION ISD CHANGES FOR 1997'.

REVISION:
ISD DEFERRED ONE YEAR FROM 2001 04 30 TO 2002 04 30 FOR CAPITAL CONSTRAINT REASONS. REFLECTS REVISED ACTIVITY AND OVERHEAD RATES.

CONTINGENCY: $696,000

IN SERVICE DATES

2002 04 30 | 8 989

Base estimate
199707 L2

Work start date
1998 04 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:	6					6
1999/00	3 306	143	119			3 568
2000/01	2 069	222	487			2 778
2001/02	282	21	45			348
2002/03	2 062					2 062
TOTAL	7 725	386	651			8 762
REV. AMOUNTS:						
Authorized to date:	6					6
Over(under)expend:						
Auth 1999/00	306	12	6			324
Req. 2000/01	3 304	198	134			3 636
2001/02	3 252	253	479			3 984
2002/03	960	23	56			1 039
TOTAL	7 828	486	675			8 989

Prepared by: yy mm dd COORDINATOR — Approved by: yy mm dd — Approved by: yy mm dd

Estimated by: ORIGINATOR — COORDINATING MANAGER — ORIGINATING MANAGER

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 03-00-1672

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1990 10	15 827	INCREASED APPARATUS COSTS.
1991 10	13 667	FEDERAL SALES TAX REMOVED FROM ALL MATERIAL. DECREASE IN INTEREST AND ESCALATION RATES. THE ESTIMATE FOR THE TRANSFORMER IS BASED ON 1991 SUPPLIERS' PRICES AND IS HIGHER THAN LAST YEAR'S ESTIMATE.
1992 10	12 254	DECREASE IN ESCALATION RATES.
1993 02	10 475	ISD ADVANCED 4 YEARS TO 2000 10 31 BY OH 1000 MW SALE CANCEL
1993 10	10 028	ITEM ADVANCED FOR ADJUSTED WINNIPEG SUPPLY REQUIREMNTS AFTERCANCELLATION OF ONT. HYDRO 1000 MW SALE. ISD ADVANCE 4 YRS TO 2000 10 31
1994 10	6 431	RETERMINATION OF LINE R32V ADDED. DEVELOPMENT OF 230KV BAY 3REDUCED. REVISED INTEREST AND ESCALATION RATES.
1995 10	9 520	RECONSTRUCTION OF BAY 1, RETERMINATION OF BAY 2 TRANSFORMER,AND 1-230 KV BREAKER ADDED. RETERMINATION OF LINE R32V DELETED. RELOCATION OF TERMINATIONS FOR 3-115KV LINES ADDED AND INCREASED AUTO TRANSFORMER COST.
1996 10	8 198	RE-TERMINATION OF 115KV LINE VH2 AND VJ50 DELETED. 1-115KV CIRCUIT BREAKER DELETED. REDUCED MATERIAL COSTS BASED ON RECENT AUTOTRANSFORMER BUDGET QUOTE.
1997 10	8 887	ISD DEFERRED FROM 2000 10 31 TO 2001 04 30 TO COINCIDE WITH DORSEY-ST. VITAL LINE ADDITION AT ST. VITAL STATION.
1998 10	8 762	NO CHANGE.

ASSOCIATED PROJECTS

Budget reference number	Description

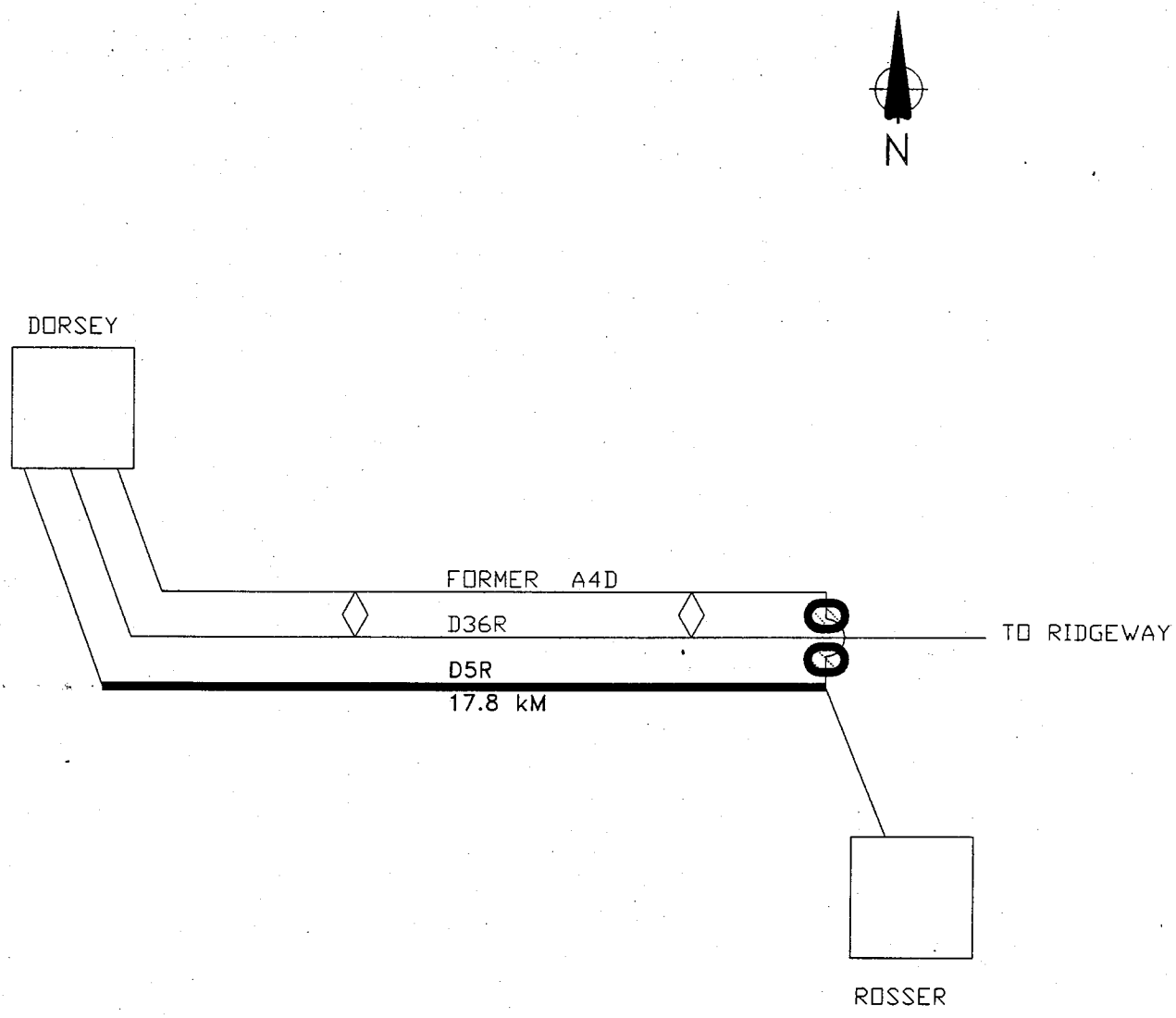
Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	13					13	13
May	11					11	24
Jun	11					11	35
Jul	11	1				12	47
Aug	11	1				12	59
Sep	11	1				12	71
Oct	11		1			12	83
Nov	11		1			12	95
Dec	11		1			12	107
Jan	11		1			12	119
Feb	11		1			12	131
Mar	183	9	1			193	324
TOTAL	306	12	6			324	324
2000/01 Apr	141	7	2			150	150
May	129	7	3			139	289
Jun	129	7	4			140	429
Jul	129	8	5			142	571
Aug	129	8	6			143	714
Sep	371	22	7			400	1 11
Oct	371	22	10			403	1 5
Nov	371	22	13			406	1 92
Dec	371	23	16			410	2 333
Jan	388	24	19			431	2 764
Feb	387	25	22			434	3 198
Mar	388	23	27			438	3 636
TOTAL	3 304	198	134			3 636	3 636

CAPITAL BUDGET COMPLEX CONCEPTUAL DIAGRAM

DORSEY – ROSSER 230KV TRANSMISSION IMPROVEMENTS

REVISED: 1999 - 10 - 01	ISSUED BY: WNZ

COMPLEX NO. 42



LEGEND

PROPOSED

EXISTING

SALVAGE

DOUBLE CIRCUIT TOWERS

manitoba hydro

PLANNING AND CONTROL DIVISION

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

COMPLEX STATUS: ☐ Planned ☒ In progress

Complex no. 42

REVISION STATUS: ☐ New complex ☐ In service change ☐ Concept change ☒ Estimate change only

COMPLEX: DORSEY - ROSSER 230 KV TRANSMISSION IMPROVEMENTS

Proposal

Perform environmental assessments and obtain licences, design and construct transmission and terminal facilities to refurbish Dorsey - Rosser 230 KV line D5R as follows:

Transmission: Reconductor 17.8 km of line D5R. Open temporary bypass of Dorsey - Rosser line D5R (former A4D). Restore reconductored D5R line by reconnecting at Dorsey and at Rosser.

Terminations: Modify line protection equipment at Dorsey and Rosser.

JUSTIFICATION

☒ Load ☐ Service
☐ Safety ☐ Efficiency
☒ Reliability ☐ Other

Explanation

Reconductoring of line D5R is part of the development of Winnipeg area 230 KV transmission. It will upgrade the line to the same current carrying capacity as all other 230 KV network lines in the Winnipeg area and prevent D5R overloads during transmission contingency outages.

Estimate Level	COMPLEX START (yyyy mm)
L2	1998 04

IN SERVICE DATES AND AMOUNTS

2001 04	$1816			

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	13		1		14	30	-16	-53
Year 99/00	46	1	2		49	33	16	48
00/01	1,290	42	38		1,370	1,310	60	5
01/02	355	18	10		383	349	34	10
02/03								
03/04								
04/05								
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	1,704	61	51		1,816	1,722	94	5

REVISION: Reflects addition of protection channels for transmission line D5R.

Reviewed by ORIGINATOR	yyyy mm dd 99 11 08	Reviewed by COORDINATOR	yyyy mm dd 99 11 03
Reviewed by CONSTRUCTOR	yyyy mm dd 99 11 03	Approved by VICE-PRESIDENT	yyyy mm dd 99 11 16

H2856/r Rev 99 03

Complex no. 42

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Advance or deferral impact

Deferral will cause overloading of D5R (which has smaller conductors than parallel lines) during contingency outages. It will also delay construction of the Dorsey - St. Vital 230 KV line required for firm supply of east Winnipeg and Ontario Hydro 200 MW Sale.

Factors affecting timing or viability

Manitoba Load.
Ontario Hydro 200 MW Sale.
Ashern - Dorsey 230 KV Transmission Improvements.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Reconductor & Reconnect 230 KV T/L D5R		1,396	1,424	1,366	-58	-4
Dorsey - Line D5R Protection Changes		118	120	131	11	9
Rosser - Line D5R Protection Changes		64	65	70	5	8
D5R Protection Channels				136	136	
TOTAL		1,578	1,609	1,703	94	6

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
9510	1,498	Reflects cost increase for line tower modifications.
9610	1,499	Revised interest rates.
1997 10	1,583	In service date advanced 6 months to 2001 04 30 to accommodate TCPL load addition at Ile des Chenes. Also reflects revised interest and escalation rates.
1998 10	1,722	Contingency added.
1999 10	1,816	Reflects addition of protection channels for transmission line D5R.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION
Complex 51	Ashern - Dorsey 230 KV Line Changes
Complex 27	Dorsey - St. Vital 230 KV Transmission

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item ___ Domestic Item

174

Title
RECONDUCTOR & RECONNECT 230KV T/L D5R

Budget reference number
02-00-5962

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
...ning & Control	Design	Construction	70306

DESCRIPTION:
CONDUCT ENVIRONMENTAL IMPACT ASSESSMENT AND OBTAIN LICENCING, AND RECONDUCTOR 17.8 KM OF UNUSED 230KV DORSEY-ROSSER LINE D5R FROM 795 MCM TO 1113 MCM ACSS CONDUCTOR. OPEN TEMPORARY D5R REPLACEMENT LINE (FORMER A4D) 0.85 KM NORTH OF ROSSER. RECONNECT RECONDUCTORED D5R LINE TO EXISTING D5R 1272 MCM LINE SECTIONS 0.80 KM FROM DORSEY AND 0.85 KM FROM ROSSER TO RE-ESTABLISH PRE-1997 D5R LINE ROUTE FROM DORSEY TO ROSSER.

JUSTIFICATION:
LOW CAPACITY 795 MCM ACSR CONDUCTOR ON DORSEY - ROSSER LINE D5R BECOMES OVERLOADED DURING WINNIPEG AREA TRANSMISSION OUTAGES. RECONDUCTORING TO 1113 MCM ACSS RAISES CURRENT CARRYING CAPACITY OF D5R TO SAME LEVEL AS ALL OTHER WINNIPEG 230KV CIRCUITS. TEMPORARY D5R REPLACEMENT USING FORMER A4D LINE SECTION IS RELEASED (AFTER RECONDUCTORED D5R IS RE-ESTABLISHED) TO FORM PART OF DORSEY-ST. VITAL 230KV LINE REQUIRED FOR WINNIPEG AREA TRANSMISSION DEVELOPMENT.

REFERENCE:
1) PSPD TM 94-6, 'WINNIPEG AND INTERLAKE TRANSMISSION CHANGES FOR 1994 IFF'.
2) SPED 95-4. 'DORSEY-ROSSER 230KV TRANSMISSION IMPROVEMENTS'.
3) MEMO, W.N. ZURBA TO C.V. THIO, 1997 07 25, 'WINNIPEG AREA TRANSMISSION ISD CHANGES FOR 1997'.

REVISION:
REFLECTS REVISED ACTIVITY AND OVERHEAD RATES.

CONTINGENCY: $125,000

IN SERVICE DATES

2001 04 30 | 1 448

Base estimate
199803 L3

Work start date
1997 04 01

• PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date	13		1			14
1999/00	44	1	4			49
2000/01	1 092	59	35			1 186
2001/02	248	15	9			272
TOTAL	1 397	75	49			1 521
REV. AMOUNTS.						
Authorized to date:	13		1			14
Over(under)expend:						
Auth 1999/00	46		2			48
Req.: 2000/01	1 039	30	29			1 098
2001/02	268	12	8			288
TOTAL	1 366	42	40			1 448

Prepared by yy mm dd COORDINATOR Approved by yy mm dd Approved by yy mm dd

Estimated by ORIGINATOR COORDINATING MANAGER ORIGINATING MANAGER

1999-08-21 05:17 PM

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 02-00-5962

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1994 10	924	NEW ITEM.
1995 10	1 302	ADDED COST OF EXISTING TOWER MODIFICATIONS AND REPLACEMENTS TO SUPPORT NEW CONDUCTOR.
1996 10	1 302	REVISED INTEREST RATES.
1997 10	1 390	ISD ADVANCED FROM 2001 10 31 TO 2001 04 30 TO ACCOMODATE TCPL LOAD ADDITION AT ILE DES CHENES.
1998 10	1 520	CONTINGENCY ADDED.

ASSOCIATED PROJECTS

Budget reference number	Description
03-00-5916	DORSEY LINE D5R PROTECTION CHANGES
03-00-5917	ROSSER LINE D5R PROTECTION CHANGES

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	1					1	1
May	1					1	2
Jun	2					2	4
Jul	2					2	6
Aug	2					2	8
Sep	2					2	10
Oct	4					4	14
Nov	4					4	18
Dec	4					4	22
Jan	9					9	31
Feb	9					9	40
Mar	6		2			8	48
TOTAL	46		2			48	48
2000/01 Apr	9	1				10	10
May	9		1			10	20
Jun	14		1			15	35
Jul	14		1			15	50
Aug	14		1			15	65
Sep	53	1	1			55	120
Oct	63	2	1			66	186
Nov	236	6	2			244	430
Dec	274	8	3			285	715
Jan	113	4	5			122	837
Feb	118	4	6			128	965
Mar	122	4	7			133	1 098
TOTAL	1 039	30	29			1 098	1 098

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item

175

Title: DORSEY LINE D5R PROTECTION CHANGES

Budget reference number: 03-00-5916

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	70307

DESCRIPTION:
MODIFY PROTECTION EQUIPMENT AS REQUIRED AT DORSEY IN CO-ORDINATION WITH RECONDUCTORING 230KV DORSEY - ROSSER LINE D5R AND RE-ESTABLISHING PRE-1997 D5R ROUTE AND STATION TERMINATIONS.

JUSTIFICATION:
ELSEWHERE IN THE BUDGET, JUSTIFICATION IS GIVEN FOR TEMPORARY REPLACEMENT OF LINE D5R WITH FORMER A4D LINE SECTION TO PERMIT RECONDUCTORING AND RE-ESTABLISHMENT OF D5R. THIS ITEM PROVIDES FOR NECESSARY PROTECTION CHANGES AT DORSEY TO CONVERT D5R FROM TEMPORARY DUTY TO NORMAL DUTY WITH RECONDUCTORED LINE.

REFERENCE:
1) PSPD TM 94-6, 'WINNIPEG AND INTERLAKE TRANSMISSION CHANGES FOR 1994 IFF'.
2) SPED 95-4, 'DORSEY-ROSSER 230KV TRANSMISSION IMPROVEMENTS'.
3) MEMO, W.N. ZURBA TO C.V. THIO, 1997 07 25, 'WINNIPEG AREA TRANSMISSION ISD CHANGES FOR 1997'

REVISION:
REFLECTS REVISED ACTIVITY AND OVERHEAD RATES.

CONTINGENCY: $10,000

IN SERVICE DATES: 2001 04 30 — 144

Base estimate: 199706 L2

Work start date: 2000 04 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:						
2000/01	75	5	3			83
2001/02	43	3	1			47
TOTAL	118	8	4			130
REV. AMOUNTS:						
Authorized to date:						
Over(under)expend:						
Auth 2000/01	86	5	4			95
Req. 2001/02	45	3	1			49
TOTAL	131	8	5			144

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR		COORDINATING MANAGER		ORIGINATING MANAGER

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 03-00-5916

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1995 10	127	REFLECTS NEW ESCALATION AND INTEREST RATES
1996 06	126	REVISED INTEREST RATES. CONTINGENCY AMOUNT $11,000.
1997 10	126	ISD ADVANCED FROM 2001 10 31 TO 2001 04 30 TO ACCOMMODATE TCPL LOAD ADDITION AT ILE DES CHENES. ALSO REFLECTS REVISED INTEREST AND ESCALATION RATES.
1998 10	130	NO CHANGE

ASSOCIATED PROJECTS

Budget reference number	Description
02-00-5962	RECONDUCTOR & RECONNECT 230KV T/L D5R
03-00-5917	ROSSER LINE D5R PROTECTION CHANGES

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr	7	1				8	8
May	7	1				8	16
Jun	7	1				8	24
Jul	7	1				8	32
Aug	7	1				8	40
Sep	7	1				8	48
Oct	7	1				8	56
Nov	7	1				8	64
Dec	7	1				8	72
Jan	7	1				8	80
Feb	7		1			8	88
Mar	9	-5	3			7	95
TOTAL	86	5	4			95	95

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item

176

Title
ROSSER LINE D5R PROTECTION CHANGES

Budget reference number
03-00-5917

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	70308

DESCRIPTION:
MODIFY PROTECTION EQUIPMENT AS REQUIRED AT ROSSER IN CO-ORDINATION WITH RECONDUCTORING 230KV DORSEY - ROSSER LINE D5R AND RE-ESTABLISHING PRE-1997 D5R ROUTE AND STATION TERMINATIONS.

JUSTIFICATION:
ELSEWHERE IN THE BUDGET, JUSTIFICATION IS GIVEN FOR TEMPORARY REPLACEMENT OF LINE D5R WITH FORMER A4D LINE SECTION TO PERMIT RECONDUCTORING AND RE-ESTABLISHMENT OF D5R. THIS ITEM PROVIDES FOR NECESSARY PROTECTION CHANGES AT ROSSER TO CONVERT D5R FROM TEMPORARY DUTY TO NORMAL DUTY WITH RECONDUCTORED LINE.

REFERENCE:
1) PSPD TM 94-6, 'WINNIPEG AND INTERLAKE TRANSMISSION CHANGES FOR 1994 IFF'.
2) SPED 95-4, 'DORSEY-ROSSER 230KV TRANSMISSION IMPROVEMENTS'
3) MEMO, W.N. ZURBA TO C.V. THIO, 1997 07 25, 'WINNIPEG AREA TRANSMISSION ISD CHANGES FOR 1997'

REVISION:
REFLECTS REVISED ACTIVITY AND OVERHEAD RATES.

CONTINGENCY: $5,000

This BRN contains Deleted, Blocked, or Closed Orders.

IN SERVICE DATES

2001 04 30	76

Base estimate
199706 L2

Work start date
2000 04 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:						
2000/01	37	2	2			41
2001/02	27	2				29
TOTAL	64	4	2			70
REV. AMOUNTS:						
Authorized to date:						
Over(under)expend:						
Auth 2000/01	42	2	2			46
Req. 2001/02	28	2				30
TOTAL	70	4	2			76

Prepared by — yy mm dd — COORDINATOR
Approved by — yy mm dd — COORDINATING MANAGER
Approved by — yy mm dd — ORIGINATING MANAGER
Estimated by — ORIGINATOR

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 03-00-5917

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1994 10	67	NEW ITEM.
1995 10	69	REFLECTS NEW ESCALATION AND INTEREST RATES
1996 06	71	REVISED INTEREST RATES.
1997 10	68	ISD ADVANCED FROM 2001 10 31 TO 2001 04 30 TO ACCOMMODATE TCPL LOAD ADDITION AT ILE DES CHENES. ALSO REFLECTS REVISED INTEREST AND ESCALATION RATES.
1998 10	70	NO CHANGE

ASSOCIATED PROJECTS

Budget reference number	Description
02-00-5962	RECONDUCTOR & RECONNECT 230KV T/L D5R
03-00-5916	DORSEY LINE D5R PROTECTION CHANGES

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr	4					4	4
May	4					4	8
Jun	4					4	12
Jul	4					4	16
Aug	4					4	20
Sep	4					4	24
Oct	4					4	28
Nov	3	1				4	32
Dec	3	1				4	36
Jan	3	1				4	40
Feb	3	1				4	44
Mar	2	-2	2			2	46
TOTAL	42	2	2			46	46

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item 177

Title			Budget reference number
D5R PROTECTION CHANNELS			05-00-8595
Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Planning & Control	Planning & Control	70590

DESCRIPTION:
PROVIDE PROTECTION CHANNELS FOR TRANSMISSION LINE D5R.

JUSTIFICATION:
COMMUNICATIONS MAINTENANCE INDICATED 96 02 16 IN A MEMO G. J. FRASER TO R. HAMLIN THAT THIS EQUIPMENT SHOULD BE REPLACED WHEN THE LINE WAS MODIFIED. THE PROTECTION ENGINEER, S. INNES, INDICATED IN A MEMO 97-10-22 TO W. ZURBA, THAT THE EQUIPMENT MUST BE REPLACED TO BE COMPATIBLE WITH THE NEW PROTECTION EQUIPMENT.

REVISION:
NEW ITEM.

CONTINGENCY: $10 000

IN SERVICE DATES				Base estimate
2001 04 30	147			199806 L2
				Work start date 2000 04 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:						
TOTAL						
REV. AMOUNTS:						
Authorized to date:						
Over(under)expend:						
Auth 2000/01	122	6	3			131
Req.: 2001/02	14	1	1			16
TOTAL	136	7	4			147

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 05-00-8595

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS

ASSOCIATED PROJECTS

Budget reference number	Description
02-00-5962	RECONDUCTOR & RECONNECT 230KV T/L D5R
03-00-5916	DORSEY LINE D5R PROTECTION CHANGES
03-00-5917	ROSSER LINE D5R PROTECTION CHANGES

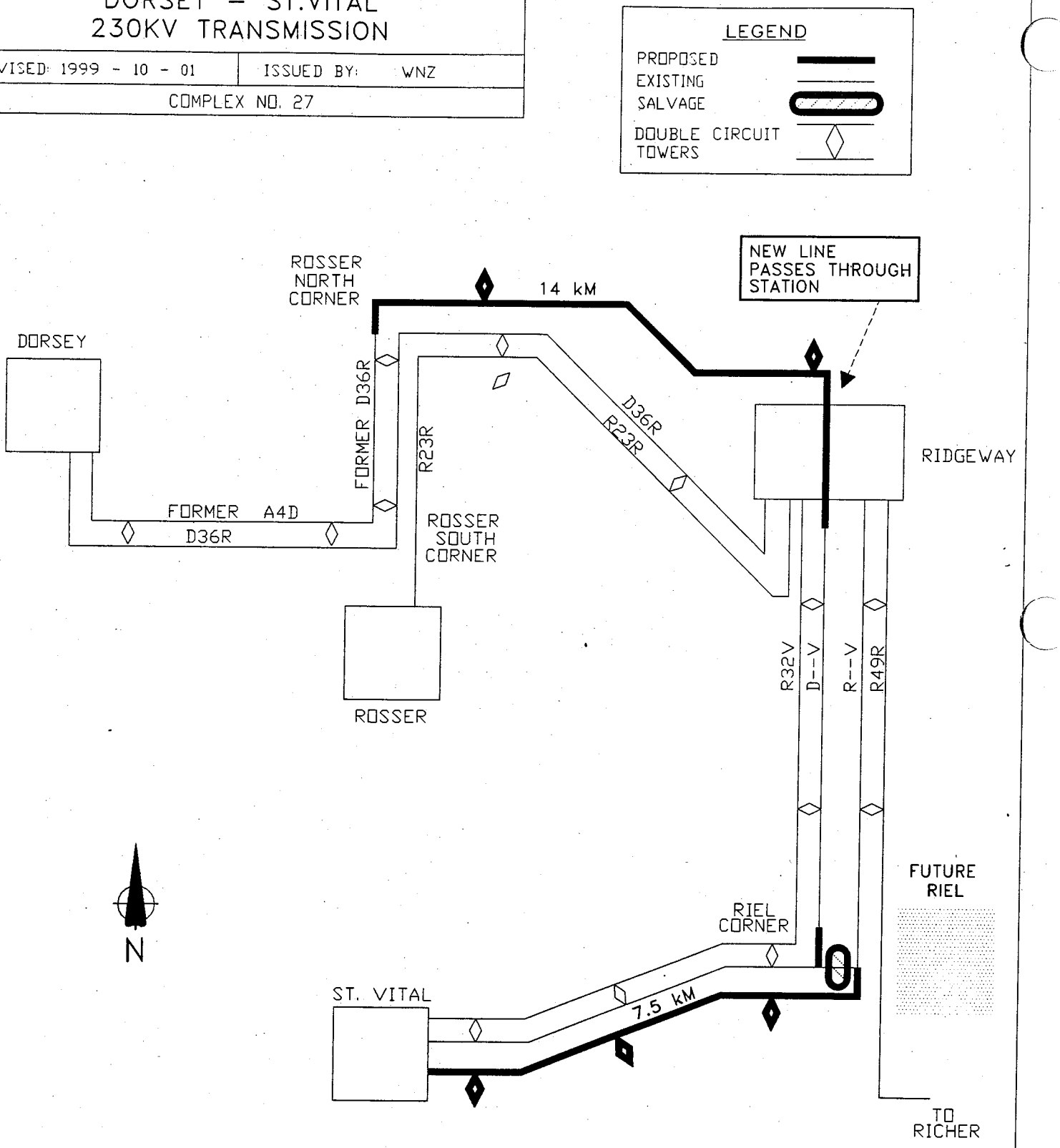
Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr	2					2	2
May	2					2	4
Jun	2					2	6
Jul	2					2	8
Aug	2					2	10
Sep	2					2	12
Oct	2					2	14
Nov	28	2				30	44
Dec	28	2				30	74
Jan	38	2	1			41	115
Feb	6		1			7	122
Mar	8		1			9	131
TOTAL	122	6	3			131	131

CAPITAL BUDGET COMPLEX CONCEPTUAL DIAGRAM

DORSEY – ST.VITAL 230KV TRANSMISSION

REVISED: 1999 - 10 - 01 | ISSUED BY: WNZ

COMPLEX NO. 27



manitoba hydro

PLANNING AND CONTROL DIVISION

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

COMPLEX STATUS	Complex no.	REVISION STATUS
☐ Planned ☒ In progress	27	☐ New complex ☒ In service change ☐ Concept change ☐ Estimate change only

COMPLEX	DORSEY - ST. VITAL 230 KV TRANSMISSION

Proposal

Perform environmental assessments and route selection, design and construct transmission and terminal facilities to firm up supply to stations in east Winnipeg as follows: Transmission: 230 KV line double circuit strung one side only, 14 km from Ridgeway along D36R/R23R R.O.W towards Rosser, 7.5 km from St. Vital along R32V R.O.W to Riel Corner. Open 2nd Ridgeway-St. Vital 230KV line at Riel Corner and re-establish line by connecting Ridgeway section to new 7.5 km circuit to St. Vital. Connect remaining St. Vital section of previous Ridgeway- St. Vital 230KV line, unused Ridgeway-Riel Corner line, new 14 km line, and unused former lines D36R & A4D north of Rosser to create Dorsey - St. Vital 230 KV circuit (passing through Ridgeway station). Terminations: Extend 230 KV facilities at St. Vital station. Install line protection changes at Dorsey. Communications: Integrated with existing Dorsey & St. Vital facilities.

JUSTIFICATION		Explanation
☒ Load	☐ Service	This line is required to provide firm supply to east Winnipeg stations from Dorsey via St. Vital station.
☐ Safety	☐ Efficiency	
☒ Reliability	☐ Other	

Estimate Level	COMPLEX START (yyyy mm)
L2	1998 04

IN SERVICE DATES AND AMOUNTS				
2002 04	$8136			

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	375		18		393	557	-164	-29
Year 99/00			34		34	5,143	-5,109	-99
00/01	1,136	56	72		1,264	1,489	-225	-15
01/02	4,665	344	325		5,334	457	4,877	NA
02/03	1,015	41	49		1,105		1,105	
03/04	5				5		5	
04/05								
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	7,196	441	498		8,135	7,646	489	6

REVISION	Deferred one year 2002 04 30 due to capital constraint reasons.

Reviewed by ORIGINATOR	yyyy mm dd 99 11 08	Reviewed by COORDINATOR	yyyy mm dd 99 11 03
Reviewed by CONSTRUCTOR	yyyy mm dd 99 11 03	Approved by VICE PRESIDENT	yyyy mm dd 99 11 16

H2856/r Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Complex no. 27

Advance or deferral impact

This transmission is required for supply to stations in east Winnipeg . Deferral will result in overloads or curtailment of load or Ontario Hydro 200 MW export during outages of Winnipeg area AC lines.

Factors affecting timing or viability

Manitoba Load.
Ontario Hydro 200 MW Sale.
Ashern - Dorsey - Rosser 230 KV Transmission Improvements.
Supply to TCPL.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Dorsey - St. Vital 230 KV T/L		5,769	5,884	5,857	-27	-0
St. Vital - Termination of Dorsey 230 KV Line		791	807	837	30	4
Dorsey-Protection Changes for St. Vital Line Term		279	285	300	15	5
Telecontrol for Dorsey-St. Vital 230 KV T/L		199	203	202	-1	-0
TOTAL		7,038	7,179	7,196	17	0

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
9510	10,110	Concept chg to different unused Ridgeway-Riel Corner line section, passing line through Ridgeway Stn. New St. Vital 230KV circuit brkr trnsf'd to Complex 64.
9610	10,062	Reflects concept change using former line D36R to replace 1.4 km of 230 KV line construction.
1997 10	7,948	In service date advanced 6 months to 2001 04 30 to accommodate TCPL load addition at Ile des Chenes. Also reflects revised interest and escalation rates.
1998 10	7,646	ISD of transmission line advanced one year from 2001 to 2000.
1999 10	8,135	Deferred one year 2002 04 30 due to capital constraint reasons.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION
Complex 78	Ridgeway - St. Vital 230 KV Transmission
Complex 64	St. Vital Transformer Addition
Complex 51	Ashern - Dorsey 230 KV Line Changes
Complex 42	Dorsey - Rosser 230 kV Transmission Improvements

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item ___ Domestic Item 178

Title: DORSEY - ST. VITAL 230 KV T/L

Budget reference number: 02-00-5963

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	70309

DESCRIPTION:
Conduct environmental impact assessment, select a route, acquire property for R.O.W. and obtain licencing. Design and construct 21.5 km of double circuit 230kV line strung on one side only with 1272 MCM ACSR conductor in following sections:
South side of double cct. towers 14.0 KM along D36R/R23R R.O.W. west from Ridgeway. North side of double cct. towers 7.5 KM along R32R R.O.W. from St Vital to 'Riel Corner'. Connect new and existing line sections as follows to create Dorsey-St Vital 230kV line: Rosser end of former A4D Dorsey-Rosser T/L to unused former D36R at 'Rosser South Corner'; north end of former D36R T/L at 'Rosser North Corner' to west end of new 14.0 KM T/L; Ridgeway end of new 14.0 KM line to end of unused east side of double circuit line R32R (by crossing through Ridgeway 230 kV station north to south); sectionalize 230kV Ridgeway-St Vital line on west side of line R49R double circuit towers at 'Riel Corner', connect unused east side of double cct. R32R to St Vital end of former Ridgeway-St Vital line. Reconnect Ridgeway end of sectionalized former Ridgeway-St Vital line to new 7.5 KM line at 'Riel Corner' to re-establish 2nd Ridgeway- St Vital circuit.
Open 230kV lines D36R and R23R at Rosser North and Rosser South Corners north of Rosser station. Connect unused portion of former A4D to Rosser end of opened R23R at Rosser South Corner to establish Rosser-Silver 230kV line. Connect Ridgeway end of opened D36R to Rosser end of opened R23R at Rosser North Corner, and connect Dorsey end of opened D36R to Ridgeway end of opened R23R of former D36R to tower 47 on west side of Rosser South Corner for future construction of Dorsey-St Vital line. Design and construct 2 KM of single circuit 230kV line using 1272 MCM ASCR and connect to Ridgeway end of opened R23R at Rosser North Corner to re-establish line R23R.
Note: Environmental assessment & route selection to include route for Dorsey - St Vital T/L along southern Wpg loop (Dorsey - Laverendrye - Floodway - St Vital).

JUSTIFICATION:
This item provides for part of system changes to transmit power from Dorsey to eastern half of Winnipeg. It is required to accommodate Winnipeg area load growth (including Winnipeg Hydro), Ontario Hydro 200 MW sale, and deferral of Riel Station. Construction of 230kV circuit is more economical than advancing Dorsey - Riel 500kV line to operate as part of Dorsey - St. Vital 230kV circuit due to delay of HVDC bipole 3 stages 2 & 3 which require 500kV line for DC paralleling.

REFERENCE:
1) PSPD TM 94-6, 'Winnipeg and Interlake Transmission Changes in 1994 IFF'.
2) Memo, W.N. Zurba to C.V. Thio, 1997 07 25, 'Winnipeg Area Transmission ISD Changes for 1997'.

REVISION:
ISD deferred two years from 2000 04 30 to 2002 04 for capital constraint reasons. Reflects revised activity and overhead rates. D36R and R23R line changes transfered from BRN 02-00-5961 due to deferral of Rosser-Silver T/L.
CONTINGENCY: $ 586,000

IN SERVICE DATES

2002 04 30	6 635	

Base estimate: 199704 L2

Work start date: 1997 09 01

	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
PREV. AUTHORITY						
Authorized to date	375		18			393
1999/00	4 797	172	219			5 188
2000/01	611	1	40			652
2001/02	7					7
TOTAL	5 790	173	277			6 240
REV. AMOUNTS:						
Authorized to date	375		18			393
Over(under)expend:						
Auth 1999/00			34			34
Req.: 2000/01	1 016	48	70			1 134
2001/02	3 868	280	285			4 433
2002/03	593	1	42			636
2003/04	5					5
TOTAL	5 857	329	449			6 635

Prepared by: ____ yy mm dd COORDINATOR Approved by: ____ yy mm dd Approved by: ____ yy mm dd

Estimated by: ____ ORIGINATOR COORDINATING MANAGER ORIGINATING MANAGER

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 02-00-5963

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1994 10	8 822	NEW ITEM. REPLACES BRN --02-00-6153 IN COMPLEX.
1995 10	8 804	RIDGEWAY-ST. VITAL SECTION OF LINE USES R32V DOUBLE CIRCUIT TOWERS INSTEAD OF LINE R49R & NEW 7.5 KM LINE DOUBLE CIRCUIT TOWERS.
1996 10	8 760	FORMER D36R LINE SECTION REPLACES NEW 1.4 KM LINE CONSTRUCTION.
1997 10	6 448	ISD ADVANCED FROM 2001 10 31 TO 2001 04 30 TO ACCOMMODATE TCPL LOAD ADDITION AT ILE DES CHENES. ESTIMATE REDUCED AS A RESULT OF CHANGE FROM UNIT COST ESTIMATE TO DETAILED ESTIMATE, RESULTING IN REFLECTION OF CURRENT MATERIAL AND CONSTRUCTION COSTS.
1998 10	6 240	ISD ADVANCED FROM 2001 04 30 TO 2000 04 30.

ASSOCIATED PROJECTS

Budget reference number	Description
03-00-3311	ST. VITAL TERMINATION OF DORSEY 230KV LINE
03-00-3314	DORSEY PROTECTION CHANGES FOR ST. VITAL LINE TERMINATION
05-00-5532	TELECONTROL FOR DORSEY-ST. VITAL 230KV T/L

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr			3			3	3
May			3			3	6
Jun			3			3	9
Jul			3			3	12
Aug			3			3	15
Sep			3			3	18
Oct			3			3	21
Nov			3			3	24
Dec			3			3	27
Jan			3			3	30
Feb			3			3	33
Mar			1			1	34
TOTAL			34			34	34
2000/01 Apr	57	3	3			63	63
May	28	1	3			32	95
Jun	28	1	4			33	128
Jul	19	1	4			24	152
Aug	19	1	4			24	176
Sep	25	1	4			30	206
Oct	192	9	4			205	411
Nov	192	9	6			207	618
Dec	192	10	7			209	827
Jan	192	10	9			211	1 038
Feb	27	1	10			38	1 076
Mar	45	1	12			58	1 134
TOTAL	1 016	48	70			1 134	1 134

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item ___ Domestic Item 179

Title: DORSEY PROTECTION CHANGES FOR ST. VITAL LINE TERMINATION

Budget reference number: 03-00-3314

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
anning & Control	Design	Construction	70310

DESCRIPTION:
MODIFY PROTECTION EQUIPMENT AS REQUIRED AT DORSEY IN CO-ORDINATION WITH TERMINATION OF A 230KV LINE TO ST. VITAL IN BAY 2 BREAKER POSITION PREVIOUSLY USED FOR ASHERN LINE A4D PRE-1997.

JUSTIFICATION:
ELSEWHERE IN THE BUDGET JUSTIFICATION IS GIVEN FOR CONSTRUCTION OF A 230 KV LINE FROM DORSEY TO ST. VITAL. THIS ITEM PROVIDES FOR REQUIRED PROTECTION CHANGES ASSOCIATED WITH TERMINATION OF THE NEW LINE IN BREAKER POSITION PREVIOUSLY USED BY LINE A4D AT DORSEY.

REFERENCE:
1) PSPD TM 94-6, 'WINNIPEG AND INTERLAKE TRANSMISSION CHANGES FOR 1994 IFF'.
2) MEMO, W.N. ZURBA TO C.V. THIO, 1997 07 25, 'WINNIPEG AREA TRANSMISSION ISD CHANGES FOR 1997'

REVISION:
ISD DEFERRED ONE YEAR FROM 2001 04 30 TO 2002 04 30 FOR CAPITAL CONSTRAINT REASONS.
REFLECTS REVISED ACTIVITY AND OVERHEAD RATES.

CONTINGENCY AMMOUNT $25,000

IN SERVICE DATES: 2002 04 30 | 340

Base estimate: 199707 L2

Work start date: 2000 09 01

PREV. AUTHORITY Authorized to date.	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
1999/00	71	3	2			76
2000/01	160	11	12			183
2001/02	48	3	2			53
TOTAL	279	17	16			312
REV. AMOUNTS: Authorized to date: Over(under)expend:						
Auth 2000/01	77	5	2			84
Req 2001/02	173	14	13			200
2002/03	50	4	2			56
TOTAL	300	23	17			340

Prepared by: yy mm dd COORDINATOR — Approved by: yy mm dd — Approved by: yy mm dd

Estimated by: ORIGINATOR — COORDINATING MANAGER — ORIGINATING MANAGER

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 03-00-3314

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1992 10	2 846	NEW ITEM.
1993 02	2 634	ITEM TRANSFERRED FROM ANOTHER COMPLEX. ISD ADVANCED 2 YEARSTO 2000 10 31.
1993 10	2 522	DECREASE IN INTEREST AND ESCALATION RATES.
1994 10	310	500KV LINE TERMINATION WITH ONE 230KV BREAKER REPLACED BY 230KV LINE TERMINATION IN PREVIOUS LINE A4D POSITION ELIMINATING NEED FOR A NEW BREAKER. ISD DEFERRED 1 YEAR TO 2001 10 31.
1995 10	311	REVISED ESCALATION AND INTEREST RATES.
1996 10	309	REVISED INTEREST RATES
1997 10	313	ISD ADVANCED FROM 2001 10 31 TO 2001 04 30 TO ACCOMMODATE TCPL LOAD ADDITION AT ILE DES CHENES.
1998 10	312	NO CHANGE

ASSOCIATED PROJECTS

Budget reference number	Description
02-00-5963	DORSEY - ST. VITAL 230 KV T/L
03-00-3311	ST. VITAL TERMINATION OF DORSEY 230KV LINE
05-00-5532	TELECONTROL FOR DORSEY-ST. VITAL 230KV T/L

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep	9	1				10	10
Oct	9	1				10	20
Nov	9	1				10	30
Dec	9	1				10	40
Jan	20	1				21	61
Feb	10	1				11	72
Mar	11	-1	2			12	84
TOTAL	77	5	2			84	84

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item 180

Title			Budget reference number
ST. VITAL TERMINATION OF DORSEY 230KV LINE			03-00-3311
Originating division: Planning & Control	Coordinating division: Design	Constructing division: Construction	Project Order Group (Range): 70311

DESCRIPTION:
RETERMINATE RIDGEWAY 230KV LINE R32V IN UNUSED BREAKER POSITION IN BAY 1. TERMINATE NEW DORSEY 230KV LINE IN BAY 2 POSITION PREVIOUSLY USED FOR LINE R32V.

NOTE: LINE TERMINATION BREAKER IN BAY 1 INSTALLED IN ST. VITAL TRANSFORMER ADDITION COMPLEX.

JUSTIFICATION:
ELSEWHERE IN THE BUDGET, JUSTIFICATION IS GIVEN FOR A DORSEY - ST. VITAL 230 KV LINE. THIS ITEM PROVIDES FOR TERMINATION OF NEW LINE AT ST. VITAL.

REFERENCE:
1) PSPD TM 94-6, 'WINNIPEG AND INTERLAKE TRANSMISSION CHANGES FOR 1994 IFF'.
2) MEMO, W.N. ZURBA TO C.V. THIO, 1997 07 25, 'WINNIPEG AREA TRANSMISSION ISD CHANGES FOR 1997'

REVISION:
ISD DEFERRED ONE YEAR FROM 2001 04 30 TO 2002 04 30 FOR CAPITAL CONSTRAINT REASONS. REFLECTS REVISED ACTIVITY AND OVERHEAD RATES.

CONTINGENCY AMOUNT $71,000

IN SERVICE DATES				Base estimate
2002 04 30	933			199707 L2
				Work start date 2000 04 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:						
1999/00	16		1			17
2000/01	446	29	18			493
2001/02	329	27	4			360
TOTAL	791	56	23			870
REV. AMOUNTS:						
Authorized to date:						
Over(under)expend:						
Auth 2000/01	17	1	1			19
Req. 2001/02	480	39	19			538
2002/03	340	32	4			376
TOTAL	837	72	24			933

Prepared by yy mm dd COORDINATOR — Approved by yy mm dd COORDINATING MANAGER — Approved by yy mm dd ORIGINATING MANAGER

Estimated by ORIGINATOR

1999-08-21 05:19 PM

CAPITAL EXPENDITURE REVISION

Budget reference number 03-00-3311

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1992 10	2 656	NEW ITEM.
1993 02	2 656	ITEM TRANSFERRED FROM RIEL - WPG. AC TRANSM. COMPLEX.
1993 10	2 545	DECREASE IN INTEREST AND ESCALATION RATES.
1994 10	1 877	IN-SERVICE DATE DEFERRED 1 YEAR TO 2001 10 31. BREAKER RATING REDUCED FROM 63KA TO 50KA. REVISED INTEREST AND ESCALATION RATES.
1995 10	812	BREAKER INSTALLATION DELETED AND TRANSFERRED TO ST. VITAL TRANSFORMER COMPLEX. LINE R32V RETERMINATION ADDED.
1996 10	807	REVISED INTEREST RATES. CORRECTION TO CALCULATED ESCALATION.
1997 10	885	ISD ADVANCED FROM 2001 10 31 TO 2001 04 30 TO ACCOMMODATE TCPL LOAD ADDITION AT ILE DES CHENES.
1998 10	870	NO CHANGE.

ASSOCIATED PROJECTS

Budget reference number	Description
02-00-5963	DORSEY - ST. VITAL 230 KV T/L
03-00-3314	DORSEY PROTECTION CHANGES FOR ST. VITAL LINE TERMINATION
05-00-5532	TELECONTROL FOR DORSEY-ST. VITAL 230KV T/L

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr	1	1				2	2
May	1	1				2	4
Jun	1	1				2	6
Jul	1	1				2	8
Aug	1	1				2	10
Sep	1	1				2	12
Oct	1	1				2	14
Nov	1	1				2	16
Dec	1	1				2	18
Jan	1	1				2	20
Feb	1	1				2	22
Mar	6	-10	1			-3	19
TOTAL	17	1	1			19	19

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item

181

Title			Budget reference number
TELECONTROL FOR DORSEY-ST. VITAL 230KV T/L			05-00-5532
Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Planning & Control	Construction	70312

DESCRIPTION:
DESIGN, INSTALL AND COMMISSION REQUIRED TELECONTROL FACILITIES FOR OPERATION OF DORSEY - ST. VITAL 230KV LINE.

JUSTIFICATION:
ELSEWHERE IN THE BUDGET JUSTIFICATION IS GIVEN FOR CONSTRUCTION OF DORSEY-ST. VITAL 230KV LINE. THIS ITEM PROVIDES FOR NECESSARY TELECONTROL FACILITIES FOR OPERATION OF NEW LINE.

REFERENCE:
1) PSPD TM 94-6, 'WINNIPEG AND INTERLAKE TRANSMISSION CHANGES FOR 1994 IFF'
2) MEMO, W.N. ZURBA TO C.V. THIO, 1997 07 25, 'WINNIPEG AREA TRANSMISSION ISD CHANGES FOR 1997'

REVISION:
ISD DEFERRED ONE YEAR FROM 2001 04 30 TO 2002 04 30 DUE TO FINANCIAL CONSTRAINTS AND ALSO REFLECTS REVISED ACTIVITY AND OVERHEAD RATES.

CONTINGENCY: $15,000

IN SERVICE DATES			Base estimate
2002 04 30	228		199704 L2
			Work start date
			2001 01 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date						
1999/00	24	2				26
2000/01	143	9	8			160
2001/02	32	3	1			36
TOTAL	199	14	9			222
REV. AMOUNTS:						
Authorized to date:						
Over(under)expend:						
Auth 2000/01	25	2				27
Req 2001/02	144	12	8			164
2002/03	33	3	1			37
TOTAL	202	17	9			228

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR		COORDINATING MANAGER		ORIGINATING MANAGER

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 05-00-5532

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1994 10	183	NEW ITEM REPLACES BRN --05-00-7170 IN COMPLEX.
1995 10	183	REVISED INTEREST AND ESCALATION RATES.
1996 10	186	REVISED INTEREST RATES.
1997 10	304	ISD ADVANCED FROM 2001 10 31 TO 2001 04 30 TO ACCOMMODATE TCPL LOAD ADDITION AT ILE DES
1998 10	222	REVISED TO MATCH ORIGINAL SUBMISSION

ASSOCIATED PROJECTS

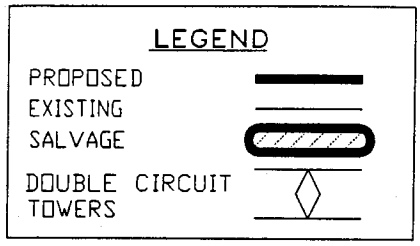
Budget reference number	Description
02-00-5963	DORSEY - ST. VITAL 230 KV T/L
03-00-3311	ST. VITAL TERMINATION OF DORSEY 230KV LINE
03-00-3314	DORSEY PROTECTION CHANGES FOR ST. VITAL LINE TERMINATION

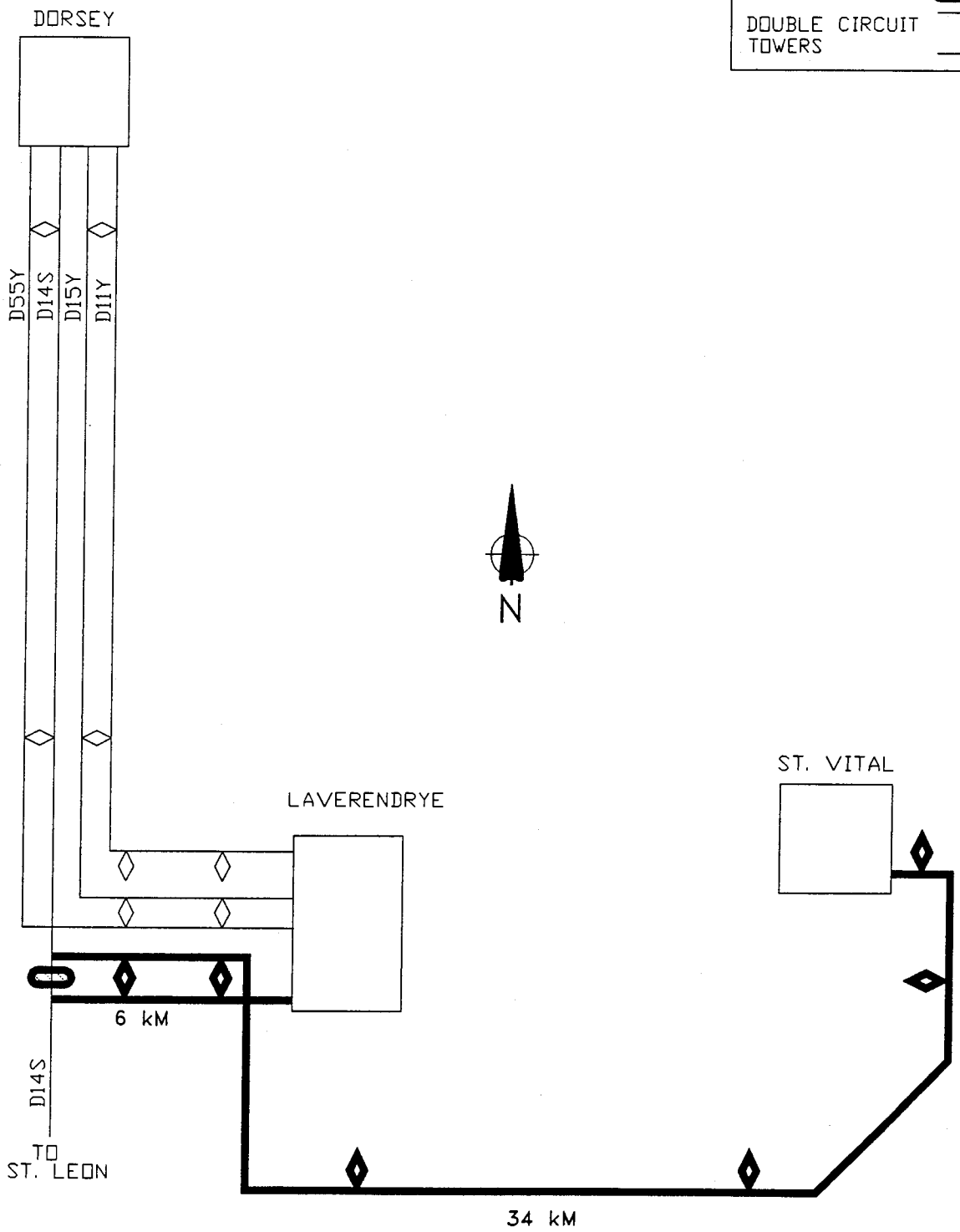
Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan	8	1				9	9
Feb	8	1				9	18
Mar	9					9	27
TOTAL	25	2				27	27

CAPITAL BUDGET COMPLEX CONCEPTUAL DIAGRAM

DORSEY–LA VERENDRYE–ST.VITAL 230KV TRANSMISSION

REVISED: 1999 - 10 - 01	ISSUED BY: WNZ
COMPLEX NO. 96	





manitoba hydro

PLANNING AND CONTROL DIVISION

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

COMPLEX STATUS	Complex no.	REVISION STATUS
☒ Planned ☐ In progress	96	☐ New complex ☐ In service change ☐ Concept change ☒ Estimate change only

COMPLEX	DORSEY - LA VERENDRYE - ST. VITAL 230KV TRANSMISSION

Proposal

Perform environmental assessments, acquire property along south Winnipeg loop and obtain licences; design and construct transmission and terminal facilities to firm up supply to stations in east Winnipeg as follows:
Transmission: 230 KV line double circuit strung one side only, 34.0 km from La Verendrye to St. Vital; 230 KV line double circuit strung both sides 6.0 km La Verendrye to La Verendrye Corner. Open Dorsey-St. Leon 230 KV line D14S at La Verendyre corner and join St. Leon open end to south side of double circuit to create La Verendrye - St. Leon 230 KV line. Join north side to Dorsey open end and new St. Vital line to create Dorsey - St. Vital south loop circuit. Terminations: Extend 230 KV facilities at St. Vital and La Verendrye stations. Install line protection changes at Dorsey and St. Leon.
Communications: Integrated with existing facilities at Dorsey, St. Vital, La Verendrye and St. Leon.

JUSTIFICATION		Explanation
☒ Load	☐ Service	The Dorsey - St. Vital line is required to provide firm supply to east Winnipeg stations from Dorsey via St. Vital station. Reterminating St. Leon line at La Verendrye permits use of high capacity line section from Dorsey to La Verendrye corner as part of Dorsey - St. Vital circuit.
☐ Safety	☐ Efficiency	
☒ Reliability	☐ Other	

Estimate Level	COMPLEX START (yyyy mm)
L2	2012 04

IN SERVICE DATES AND AMOUNTS			
2015 10 $25859			

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend								
Year 99/00								
00/01								
01/02								
02/03								
03/04								
04/05								
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13	1,190	401	102		1,693	1,613	80	5
13/14	2,275	830	354		3,459	3,284	175	5
14/15	6,854	2652	1,220		10,726	10,690	36	0
15/16	6,277	2528	1,176		9,981	9,961	20	0
16/17								
17/18								
18/19								
Beyond								
TOTAL	16,596	6,411	2,852		25,859	25,548	311	1

REVISION	Scope unchanged.

Reviewed by ORIGINATOR	yyyy mm dd 99 11 08	Reviewed by COORDINATOR	yyyy mm dd 99 11 03
Reviewed by CONSTRUCTOR	yyyy mm dd 99 11 03	Approved by VICE PRESIDENT	yyyy mm dd 99 11 [illegible]

H2856/r Rev 99 03

Complex no. 96

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Advance or deferral impact

Deferral will cause overloading or curtailment of loads during outages of Winnipeg area AC lines.

Factors affecting timing or viability

Manitoba Load.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Dorsey-St. Vital & LaVerendrye-St. Leon 230KV T/L		10,884	11,102	10,884	-218	-2
Dorsey-Protctn Changes for Term of St. Vital T/L		179	183	193	10	5
St. Vital-Term. of Dorsey South Loop 230KV T/L		2,792	2,848	2,936	88	3
LaVerendrye-Termination of St. Leon 230KV T/L		2,097	2,139	2,228	89	4
St. Leon-Protctn Change for LaVerendrye 230KV T/L		71	72	79	7	10
Tlcntrl for Dorsey-St.Vtl & LaVrndrye-St. Ln T/L		262	267	274	7	3
TOTAL		16,285	16,611	16,594	-17	-0

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
9510	30,225	Reflects added completion of 230KV Bay 3 at St. Vital. Revised escalation and interest rates.
9610	30,192	Revised escalation and interest rates.
1997 10	27,945	Scope unchanged, estimate reflects revised costing methodology implemented with the new financial reporting system. Also reflects revised interest and escalation rates.
1998 10	25,548	Revised to reflect current transmission line costs.
1999 10	25,859	Scope unchanged.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION
Complex 41	Metro Winnipeg Loop
Complex 27	Dorsey - St. Vital 230 KV Transmission

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item

182

Title			Budget reference number
DORSEY - ST. VITAL & LA VERENDRYE - ST. LEON 230KV T/L			02-00-5964
Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	70313

DESCRIPTION:
CONDUCT ENVIRONMENTAL IMPACT ASSESSMENT, OBTAIN LICENSING AND ACQUIRE RIGHT-OF WAY PROPERTY FOR SOUTH CORRIDOR LINE. DESIGN AND CONSTRUCT 6.0 KM OF DOUBLE CIRCUIT 230KV LINE STRUNG ON BOTH SIDES WITH 1272 MCM ACSR FROM LA VERENDRYE CORNER TO LA VERENDRYE. DESIGN AND CONSTRUCT 34.0 KM OF DOUBLE CIRCUIT 230KV LINE STRUNG ONLY ON SOUTHERN SIDE WITH 1272 MCM ACSR FROM LA VERENDRYE TO ST. VITAL. OPEN DORSEY-ST. LEON 230KV LINE D14S AT LA VERENDRYE CORNER. CONNECT DORSEY OPEN END OF D14S TO NORTH SIDE OF 6.0KM DOUBLE CIRCUIT LINE AND ST. LEON OPEN END TO SOUTH SIDE OF LA VERENDRYE CORNER. EXTEND SOUTH SIDE OF 6.0KM DOUBLE CIRCUIT INTO LA VERENDRYE TO CREATE LA VERENDRYE - ST. LEON 230KV LINE. CONNECT NORTH SIDE OF 6.0 KM LINE AT LA VERENDRYE TO 24.0 KM LINE END NEAR LA VERENDRYE TO CREATE DORSEY - ST. VITAL 230KV SOUTH CORRIDOR LINE.

NOTE: PROPERTY ACQUISITION ACTIVITIES COVERED IN BRN 02-00-5136 'METRO WPG LOOP DORSEY TO RIEL PROPERTY REQUIREMENTS'.

JUSTIFICATION:
THIS ITEM PROVIDES FOR PART OF SYSTEM CHANGES TO TRANSMIT POWER FROM DORSEY TO EASTERN HALF OF WINNIPEG TO ACCOMMODATE WINNIPEG AREA LOAD GROWTH. CONSTRUCTION OF LINE ALONG SOUTH CORRIDOR IMPROVES WINNIPEG TRANSMISSION RELIABILITY BY DIVERSIFYING SUPPLY ROUTES TO ST. VITAL BY ESTABLISHING INITIAL SOUTH CORRIDOR LINE, AND REDUCING NUMBER OF LINES ALONG NORTH WINNIPEG CORRIDOR.
RE-TERMINATION OF ST. LEON 230KV LINE AT LA VERENDRYE PERMITS USE OF HIGH CAPACITY LINE SECTION OF D14S FROM DORSEY TO LA VERENDRYE CORNER (1272 MCM) AS PART OF DORSEY - ST. VITAL LINE.

REFERENCE:
PSPD TM 94-6, 'WINNIPEG AND INTERLAKE TRANSMISSION CHANGES FOR 1994 IFF'

REVISION:
REFLECTS REVISED ACTIVITY AND OVERHEAD RATES.

CONTINGENCY: $907,000.

2015 10 31	17 071	IN SERVICE DATES				Base estimate 199706 L2 Work start date 2012 04 01
PREV. AUTHORITY Authorized to date:	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
2012/13	700	239	84			1 023
2013/14	907	334	211			1 452
2014/15	4 870	1 927	842			7 639
2015/16	4 407	1 880	797			7 084
TOTAL	10 884	4 380	1 934			17 198
REV AMOUNTS Authorized to date: Over(under)expend:						
Auth 2012/13	700	231	88			1 019
Req. 2013/14	907	323	215			1 445
2014/15	4 870	1 866	838			7 574
2015/16	4 407	1 824	802			7 033
TOTAL	10 884	4 244	1 943			17 071

Prepared by	yy mm dd	Approved by	yy mm dd	Approved by	yy mm dd
COORDINATOR					
Estimated by					
ORIGINATOR		COORDINATING MANAGER		ORIGINATING MANAGER	

CAPITAL EXPENDITURE REVISION

Budget reference number 02-00-5964

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1994 10	21 124	NEW ITEM.
1995 10	21 794	REVISED INTEREST AND ESCALATION RATES.
1996 10	21 798	REVISED INTEREST RATES.
1997 10	19 710	SCOPE UNCHANGED, ESTIMATE REFLECTS REVISED COSTING METHODOLOGY IMPLEMENTED WITH THE NEW FINANCIAL REPORTING SYSTEM. IT ALSO REFLECTS REVISED INTEREST AND ESCALATION RATES.
1998 10	17 198	ESTIMATE REVISION DUE TO UPDATED CURRENT TRANSMISSION LINE COSTS.

ASSOCIATED PROJECTS

Budget reference number	Description
03-00-5918	DORSEY PROTECTION CHANGES FOR TERMINATION OF ST. VITAL T/L
03-00-5919	ST. VITAL TERMINATION OF DORSEY SOUTH LOOP 230KV T/L
03-00-5920	LA VERENDRYE TERMINATION OF ST. LEON 230KV T/L
03-00-5921	ST. LEON PROTECTION CHANGES FOR LA VERENDRYE 230KV T/L
05-00-5533	TELECONTROL FOR DORSEY - ST. VITAL & LA VERENDRYE - ST. LEON

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item ___ Domestic Item

Title
DORSEY PROTECTION CHANGES FOR TERMINATION OF ST. VITAL T/L

Budget reference number
03-00-5918

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	70314

DESCRIPTION:
MODIFY PROTECTION EQUIPMENT AS REQUIRED AT DORSEY IN CO-ORDINATION WITH TERMINATION OF A 230KV LINE TO ST. VITAL IN BAY 5 BREAKER POSITION PREVIOUSLY USED TO TERMINATE LINE D14S TO ST. LEON.

JUSTIFICATION:
ELSEWHERE IN THE BUDGET JUSTIFICATION IS GIVEN FOR CONSTRUCTION OF DORSEY -ST. VITAL 230KV LINE ALONG SOUTH WINNIPEG CORRIDOR. THIS ITEM PROVIDES FOR REQUIRED PROTECTION CHANGES ASSOCIATED WITH TERMINATION OF NEW LINE IN BREAKER POSITION PREVIOUSLY USED BY LINE D14S AT DORSEY.

REFERENCE:
PSPD TM 94-6, 'WINNIPEG AND INTERLAKE TRANSMISSION CHANGES FOR 1994 IFF'

REVISION:
REFLECTS REVISED ACTIVITY AND OVERHEAD RATES.

CONTINGENCY: $17 000

IN SERVICE DATES		Base estimate
2015 10 31	287	199704 L2
		Work start date
		2014 04 01

PREV AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:						
2014/15	68	28	4			100
2015/16	111	49	8			168
TOTAL	179	77	12			268
REV. AMOUNTS:						
Authorized to date:						
Over(under)expend:						
Auth 2014/15	75	29	5			109
Req 2015/16	118	51	9			178
TOTAL	193	80	14			287

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number: 03-00-5918

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1994 10	251	NEW ITEM
1996 10	250	REVISED INTEREST RATES.
1997 10	269	SCOPE UNCHANGED, ESTIMATE RELFLECTS REVISED COSTING METHODOLOGY IMPLEMENTED WITH THE NEW FINANCIAL REPORTING SYSTEM.
1998 10	268	NO CHANGE

ASSOCIATED PROJECTS

Budget reference number	Description
02-00-5964	DORSEY - ST. VITAL & LA VERENDRYE - ST. LEON 230KV T/L
03-00-5919	ST. VITAL TERMINATION OF DORSEY SOUTH LOOP 230KV T/L
03-00-5920	LA VERENDRYE TERMINATION OF ST. LEON 230KV T/L
03-00-5921	ST. LEON PROTECTION CHANGES FOR LA VERENDRYE 230KV T/L
05-00-5533	TELECONTROL FOR DORSEY - ST. VITAL & LA VERENDRYE - ST. LEON

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — 184 Domestic Item

Title
ST. VITAL TERMINATION OF DORSEY SOUTH LOOP 230KV T/L

Budget reference number
03-00-5919

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	70315

DESCRIPTION:
TERMINATE DORSEY 230KV SOUTH LOOP LINE AT ST. VITAL. INSTALLATION WILL INCLUDE EXPANSION OF 3RD 230KV BAY STRUCTURE, 1-230KV CIRCUIT BREAKER AND ASSOCIATED EQUIPMENT.

JUSTIFICATION:
ELSEWHERE IN THE BUDGET JUSTIFICATION IS GIVEN FOR CONSTRUCTION OF DORSEY - ST. VITAL 230KV SOUTH LOOP LINE. THIS ITEM PROVIDES FOR TERMINATION OF NEW LINE AT ST. VITAL.

REFERENCE:
PSPD TM 94-6, 'WINNIPEG AND INTERLAKE TRANSMISSION CHANGES FOR 1994 IFF'

REVISION:
REFLECTS REVISED ACTIVITY AND OVERHEAD RATES.

CONTINGENCY: $246 000

IN SERVICE DATES

2015 10 31 — 4 583

Base estimate
199706 L2

Work start date
2012 10 01

PREV AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:						
2012/13	218	79	6			303
2013/14	757	290	67			1 114
2014/15	991	406	198			1 595
2015/16	826	357	187			1 370
TOTAL	2 792	1 132	458			4 382
REV AMOUNTS:						
Authorized to date:						
Over(under)expend:						
Auth 2012/13	251	88	7			346
Req 2013/14	823	305	77			1 205
2014/15	1 020	403	213			1 636
2015/16	842	355	199			1 396
TOTAL	2 936	1 151	496			4 583

Prepared by — yy mm dd — COORDINATOR — Approved by — yy mm dd — Approved by — yy mm dd

Estimated by — ORIGINATOR — COORDINATING MANAGER — ORIGINATING MANAGER

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 03-00-5919

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1994 10	3 284	NEW ITEM.
1995 10	4 428	COMPLETE 230KV BAY 3 BUSWORK ADDED.
1996 10	4 407	REVISED INTEREST RATES. CORRECTION TO CALCULATED ESCALATION.
1997 10	4 328	SCOPE UNCHANGED, ESTIMATE REFLECTS REVISED COSTING METHODOLOGY IMPLEMENTED WITH THE NEW FINANCIAL REPORTING SYSTEM. ALSO, REFELCTS REVISED INTEREST AND ESCALATION RATES.
1998 10	4 382	NO CHANGE.

ASSOCIATED PROJECTS

Budget reference number	Description
02-00-5964	DORSEY - ST. VITAL & LA VERENDRYE - ST. LEON 230KV T/L
03-00-5918	DORSEY PROTECTION CHANGES FOR TERMINATION OF ST. VITAL T/L
03-00-5920	LA VERENDRYE TERMINATION OF ST. LEON 230KV T/L
03-00-5921	ST. LEON PROTECTION CHANGES FOR LA VERENDRYE 230KV T/L
05-00-5533	TELECONTROL FOR DORSEY - ST. VITAL & LA VERENDRYE - ST. LEON

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item

185

Title
LA VERENDRYE TERMINATION OF ST. LEON 230KV T/L

Budget reference number
03-00-5920

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	70316

DESCRIPTION:
TERMINATE ST. LEON 230KV CIRCUIT AT LA VERENDRYE. INSTALLATION WILL INCLUDE 1-230KV CIRCUIT BREAKER AND ASSOCIATED EQUIPMENT.

JUSTIFICATION:
ELSEWHERE IN THE BUDGET JUSTIFICATION IS PROVIDED FOR CONSTRUCTION OF A DORSEY -ST. VITAL 230KV SOUTH LOOP LINE AND ASSOCIATED LA VERENDRYE - ST. LEON 230KV LINE. THIS ITEM PROVIDES FOR TERMINATION OF NEW ST. LEON LINE AT LA VERENDRYE.

REFERENCE:
PSPD TM 94-6, 'WINNIPEG AND INTERLAKE TRANSMISSION CHANGES FOR 1994 IFF'

REVISION:
REFLECTS REVISED ACTIVITY AND OVERHEAD RATES.

CONTINGENCY AMOUNT: $187,000

IN SERVICE DATES

2015 10 31 — 3 400

Base estimate
199706 L2

Work start date
2012 10 01

PREV AUTHORITY Authorized to date	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
2012/13	207	74	6			287
2013/14	480	183	54			717
2014/15	772	315	145			1 232
2015/16	638	195	139			972
TOTAL	2 097	767	344			3 208
REV. AMOUNTS:						
Authorized to date:						
Over(under)expend:						
Auth 2012/13	238	83	7			328
Req.: 2013/14	545	201	63			809
2014/15	794	314	159			1 267
2015/16	651	194	151			996
TOTAL	2 228	792	380			3 400

Prepared by: yy mm dd COORDINATOR — Approved by: yy mm dd — Approved by: yy mm dd

Estimated by: ORIGINATOR — COORDINATING MANAGER — ORIGINATING MANAGER

1999-08-21 05:20 PM

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 03-00-5920

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1994 10	3 289	NEW ITEM
1997 10	3 154	SCOPE UNCHANGED, ESTIMATE REFLECTS REVISED COSTING METHODOLOGY IMPLEMENTED WITH THE NEW FINANCIAL REPORTING SYSTEM. REFLECTS REVISED INTEREST AND ESCALATION RATES.
1998 10	3 208	NO CHANGE.

ASSOCIATED PROJECTS

Budget reference number	Description
02-00-5964	DORSEY - ST. VITAL & LA VERENDRYE - ST. LEON 230KV T/L
03-00-5918	DORSEY PROTECTION CHANGES FOR TERMINATION OF ST. VITAL T/L
03-00-5919	ST. VITAL TERMINATION OF DORSEY SOUTH LOOP 230KV T/L
03-00-5921	ST. LEON PROTECTION CHANGES FOR LA VERENDRYE 230KV T/L
05-00-5533	TELECONTROL FOR DORSEY - ST. VITAL & LA VERENDRYE - ST. LEON

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item 186

Title
ST. LEON PROTECTION CHANGES FOR LA VERENDRYE 230KV T/L

Budget reference number
03-00-5921

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	70317

DESCRIPTION:
MODIFY PROTECTION EQUIPMENT AS REQUIRED AT ST. LEON IN CO-ORDINATION WITH RETERMINATION OF 230KV LINE D14S FROM DORSEY INTO LA VERENDRYE

JUSTIFICATION:
ELSEWHERE IN THE BUDGET JUSTIFICATION IS GIVEN FOR CONSTRUCTION OF A DORSEY -ST. VITAL 230KV SOUTH LOOP LINE AND ASSOCIATED LA VERENDRYE - ST. LEON 230KV LINE. THIS ITEM PROVIDES FOR REQUIRED PROTECTION CHANGES AT ST. LEON ASSOCIATED WITH TERMINATION OF NEW LA VERENDRYE LINE.

REFERENCE:
PSPD TM 94-6, 'WINNIPEG AND INTERLAKE TRANSMISSION CHANGES FOR 1994 IFF'

REVISION:
REFLECTS REVISED ACTIVITY AND OVERHEAD RATES.

CONTINGENCY: $6 000

IN SERVICE DATES

2015 10 31 117

Base estimate
199706 L2

Work start date
2014 04 01

PREV. AUTHORITY Authorized to date.	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
2014/15	44	18	3			65
2015/16	27	9	4			40
TOTAL	71	27	7			105
REV AMOUNTS: Authorized to date: Over(under)expend:						
Auth 2014/15	51	20	3			74
Req 2015/16	28	10	5			43
TOTAL	79	30	8			117

Prepared by: yy mm dd COORDINATOR — Approved by: yy mm dd Approved by: yy mm dd

Estimated by: ORIGINATOR — COORDINATING MANAGER — ORIGINATING MANAGER

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 03-00-5921

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1996 10	110	REVISED INTEREST RATES.
1997 10	101	SCOPE UNCHANGED, ESTIMATE REFLECTS REVISED COSTING METHODOLOGY IMPLEMENTED WITH THE NEW FINANCIAL REPORTING SYSTEM. REFLECTS REVISED INTEREST AND ESCALATION RATES.
1998 10	105	NO CHANGE.

ASSOCIATED PROJECTS

Budget reference number	Description
02-00-5964	DORSEY - ST. VITAL & LA VERENDRYE - ST. LEON 230KV T/L
03-00-5918	DORSEY PROTECTION CHANGES FOR TERMINATION OF ST. VITAL T/L
03-00-5919	ST. VITAL TERMINATION OF DORSEY SOUTH LOOP 230KV T/L
03-00-5920	LA VERENDRYE TERMINATION OF ST. LEON 230KV T/L
05-00-5533	TELECONTROL FOR DORSEY - ST. VITAL & LA VERENDRYE - ST. LEON

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item

187

Title: TELECONTROL FOR DORSEY - ST. VITAL & LA VERENDRYE - ST. LEON

Budget reference number: 05-00-5533

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Planning & Control	Construction	70318

DESCRIPTION:
DESIGN, INSTALL AND COMMISSION REQUIRED TELECONTROL FACILITIES FOR OPERATION OF DORSEY - ST. VITAL 230KV SOUTH LOOP LINE AND ASSOCIATED LA VERENDRYE - ST. LEON 230 KV LINE.

JUSTIFICATION:
ELSEWHERE IN THE BUDGET, JUSTIFICATION IS PROVIDED FOR CONSTRUCTION OF A DORSEY - ST. VITAL 230KV SOUTH LOOP LINE AND ASSOCIATED LA VERENDRYE - ST. LEON 230KV LINE. THIS ITEM PROVIDES FOR NECESSARY TELECONTROL FOR OPERATION OF THESE NEW LINES.

REFERENCE:
PSPD TM 94-6 'WINNIPEG AND INTERLAKE TRANSMISSION CHANGES FOR 1994 IFF'.

REVISION:
REFLECTS REVISED ACTIVITY AND OVERHEAD RATES.

CONTINGENCY: $25 OOO

IN SERVICE DATES: 2015 10 31 — 402

Base estimate: 199704 L2

Work start date: 2014 04 01

	PREV. AUTHORITY Authorized to date:	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
	2014/15	40	18	2			60
	2015/16	222	97	9			328
	TOTAL	262	115	11			388
	REV. AMOUNTS: Authorized to date: Over(under)expend:						
Auth	2014/15	44	18	3			65
Req.	2015/16	230	98	9			337
	TOTAL	274	116	12			402

Prepared by: yy mm dd COORDINATOR — Approved by: yy mm dd Approved by: yy mm dd

Estimated by: ORIGINATOR — COORDINATING MANAGER — ORIGINATING MANAGER

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number: 05-00-5533

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1994 10	342	NEW ITEM.
1995 10	341	REVISED INTEREST AND ESCALATION RATES.
1996 10	342	REVISED INTEREST RATES.
1997 10	384	SCOPE UNCHANGED, ESTIMATE REFLECTS REVISED COSTING METHODOLOGY IMPLEMENTED WITH THE NEW FINANCIAL REPORTING SYSTEM. REFLECTS REVISED INTEREST AND ESCALATION RATES.
1998 10	388	REFLECTS REVISED ACTIVITY AND OVERHEAD RATES.

ASSOCIATED PROJECTS

Budget reference number	Description
02-00-5964	DORSEY - ST. VITAL & LA VERENDRYE - ST. LEON 230KV T/L
03-00-5918	DORSEY PROTECTION CHANGES FOR TERMINATION OF ST. VITAL T/L
03-00-5919	ST. VITAL TERMINATION OF DORSEY SOUTH LOOP 230KV T/L
03-00-5920	LA VERENDRYE TERMINATION OF ST. LEON 230KV T/L
03-00-5921	ST. LEON PROTECTION CHANGES FOR LA VERENDRYE 230KV T/L

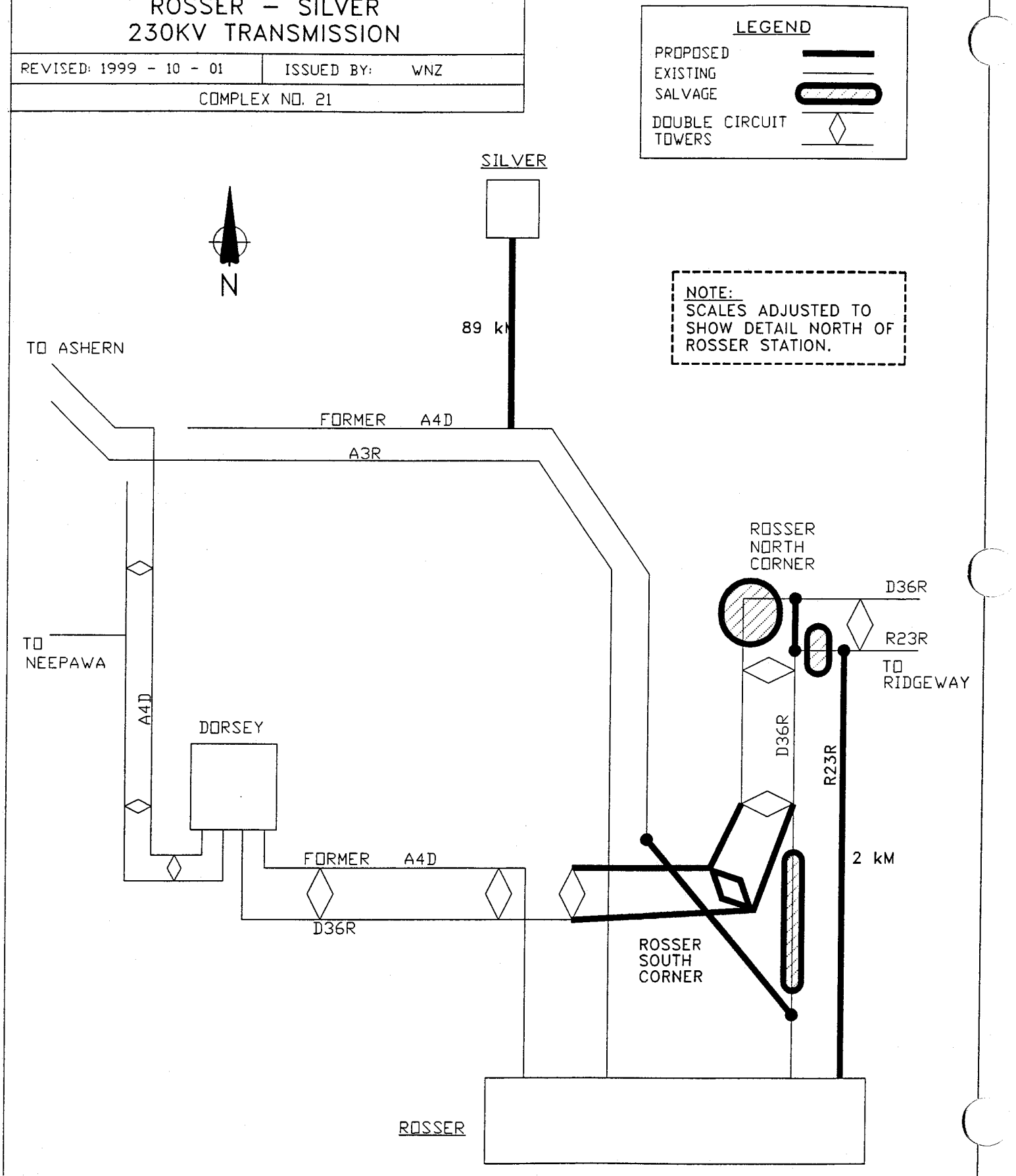
Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

CAPITAL BUDGET COMPLEX CONCEPTUAL DIAGRAM

ROSSER – SILVER 230KV TRANSMISSION

REVISED: 1999 - 10 - 01	ISSUED BY: WNZ

COMPLEX NO. 21



manitoba hydro

PLANNING AND CONTROL DIVISION

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

COMPLEX STATUS: ☐ Planned ☒ In progress

Complex no. 21

REVISION STATUS: ☐ New complex ☒ In service change ☐ Concept change ☐ Estimate change only

COMPLEX: ROSSER - SILVER 230 KV TRANSMISSION

Proposal

Perform environmental assessments and route selection, design and construct transmission and terminal facilities to provide firm supply to Silver stn as follows: Transmission: Construct 230kV line 89 km Silver to Wpg. Connect to unused former line A4D 15 km north of Rosser. Open 230kV lines D36R & R23R at Rosser North & South Corners. Connect end of former A4D to Rosser end of former R23R at Rosser S Corner to create Rosser-Silver circuit. Construct 2.0 km 230kV line from Rosser and connect to Ridgeway end of R23R at Rosser N Corner to re-establish Rosser-Ridgeway line R23R. Connect open ends of D36R to former R23R at Rosser N & S Corners to re-establish Dorsey-Ridgeway line D36R. Terminations: Extend 230kV facilities at Rosser and Silver. Extend 66kVfacilities at Silver to terminate previously installed spare 230-66kV transformer #1 Replace line protection at Ashern. Communications: Integrate with existing facilities at Rosser and Silver.

JUSTIFICATION		Explanation
☒ Load	☐ Service	This complex provides transmission system improvements for firm supply to Silver station.
☐ Safety	☐ Efficiency	
☒ Reliability	☐ Other	

Estimate Level	COMPLEX START (yyyy mm)
L2	95 04 0

IN SERVICE DATES AND AMOUNTS					
1999 03	$1388	2000 10	$1964	2004 10	$27767

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	3,125		418	2	3,541	2,771	770	28
Year 99/00	3,158	52	359		3,569	2,979	590	20
00/01		0	433		433	4,008	-3,575	-89
01/02	92	6	364		462	11,120	-10,658	-96
02/03	2,658	91	510		3,259	7,436	-4,177	-56
03/04	8,210	806	863		9,879		9,879	
04/05	7,907	948	1,120		9,975		9,975	
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	25,150	1,903	4,067	2	31,118	28,314	2,804	10

REVISION: ISD deferred two years to October 2004 due to financial constraints.

Reviewed by ORIGINATOR	yyyy mm dd 99 11 08	Reviewed by COORDINATOR	yyyy mm dd 99 11 03
Reviewed by CONSTRUCTOR	yyyy mm dd 99 11 03	Approved by VICE PRESIDENT	yyyy mm dd 99 11 3[illegible]

H2856/r Rev 99 03

Complex no. 21

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Advance or deferral impact

Deferral will limit firm supply to the Silver area and affect timing of Dorsey - St. Vital 230 KV Transmission improvements.

Factors affecting timing or viability

Manitoba Load.
Ashern - Dorsey 230 KV Transmission Improvements.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Rosser - Silver 230 KV T/L	13,269	15,456	15,765	16,103	338	2
Silver-Terminate Rosser 230KV T/L & 230-66KV Tfr.	4,832	4,319	4,405	4,736	331	8
Rosser-Terminate Silver 230KV T/L & Reterm. R23R	2,206	2,285	2,331	2,465	134	6
Ashern - Line A3R Protection Changes	254	271	276	290	14	5
Rosser-Silver 230KV T/L Telecontrol Facilities	1,436	1,494	1,524	1,554	30	2
TOTAL	21,997	23,825	24,301	25,148	847	3

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
9510	25,500	Reflects increases for material, engineering, line construction unit costs and added contingency.
9610	25,490	T/L work ISD defer 1 yr to 2000. Line modifctn optimized. Rosser-Silver line incrs 9 km. Ln R23R construct'n incrs 1.2 km. Ashern line prtctn rplc. Silver stn costs dcrs
1997 10	25,338	Scope unchanged, estimate reflects revised costing methodology implemented with the new financial reporting system. Also reflects revised interest and escalation rates.
1998 10	28,314	ISD deferred two years to October 2002.
1999 10	31,118	ISD deferred two years to October 2004 due to financial constraints.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION
Complex 51	Ashern - Dorsey 230 KV Line Changes

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item

188

Title			Budget reference number
ROSSER - SILVER 230 KV T/L			02-00-5961
Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	60026

DESCRIPTION:
CONDUCT ENVIRONMENTAL IMPACT ASSESSMENT, SELECT A ROUTE, ACQUIRE PROPERTY FOR RIGHT-OF-WAY AND OBTAIN LICENCING, DESIGN AND CONSTRUCT APPROXIMATELY 86 KM OF 230 KV WOOD/STEEL POLE LINE USING 954 MCM ACSR FROM SILVER TO WINNIPEG. CONNECT WINNIPEG END TO UNUSED FORMER LINE A4D SECTION 15 KM NORTH OF ROSSER.

JUSTIFICATION:
CONTINUED LOAD GROWTH IN INTERLAKE AREA REQUIRES FIRM SUPPLY TO BE PROVIDED AT SILVER STATION. A SECOND 230KV LINE CONSTRUCTED FROM ROSSER PROVIDES BEST ALTERNATIVE FOR FIRMING SILVER SUPPLY AS WELL AS CO-ORDINATING WITH REQUIRED WINNIPEG AREA TRANSMISSION DEVELOPMENTS.

REFERENCE:
PSPD TM 94-6, WINNIPEG AND INTERLAKE TRANSMISSION CHANGES FOR 1994 IFF. PSPD REPORT 95-2, FIRM 230KV SUPPLY TO SILVER STATION.
MEMO, C.V. THIO TO A. STAUDZS, 1995 11 13, ROSSER - SILVER 230KV TRANSMISSION.

REVISION:
ISD DEFERRED ONE YEAR FROM 2002 10 31 TO 2004 10 31 DUE TO FINANCIAL CONSTRAINTS. D36R AND R23R LINE CHANGES TRANSFERRED TO BRN 02-00-5963 DUE TO DEFERRAL OF ROSSER-SILVER T/L. INCREASE IS DUE TO ISD DEFERRAL THAT CAUSED ADDITIONAL WORK FOR PROPERTY APPRAISAL AND SURVEYS.

CONTINGENCY: $1,500,000

IN SERVICE DATES				Base estimate
2004 10 31	20 594			199903 L3
				Work start date 1995 04 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:	1 794		334			2 128
1999/00	637	44	195			876
2000/01	3 032	181	345			3 558
2001/02	6 587	335	1 039			7 961
2002/03	3 393	300	792			4 485
TOTAL	15 443	860	2 705			19 008
REV. AMOUNTS:						
Authorized to date:	1 794		334			2 128
Over(under)expend:						
Auth 1999/00	1 451	14	233			1 698
Req.: 2000/01			337			337
2001/02	50	3	361			414
2002/03	2 201	46	484			2 731
2003/04	5 705	539	692			6 936
2004/05	4 902	581	867			6 350
TOTAL	16 103	1 183	3 308			20 594

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 02-00-5961

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1994 10	11 566	NEW ITEM.
1995 10	13 711	ESTIMATE REFLECTS DETAILED COSTS FOR MATERIAL AND ENGINEERING AND INCREASED UNIT COSTS FOR CONSTRUCTION. CONTINGENCY ADDED.
1996 10	15 575	ISD DEFERRED 1 YEAR TO 2000 10 31. TRANSMISSION MODIFICATIONS NORTH OF ROSSER OPTIMIZED. LENGTH OF 230KV LINE INCREASED BY 9KM BY LATEST EIA DATA. SINGLE CIRCUIT R23R LINE CONSTRUCTION INCREASED BY 1.2 KM.
1997 10	16 667	SCOPE UNCHANGED. ESTIMATE REFLECTS REVISED COSTING METHODOLOGY IMPLEMENTED WITH THE NEW FINANCIAL REPORTING SYSTEM. IT ALSO REFLECTS REVISED INTEREST AND ESCALATION RATES.
1998 10	19 008	ISD DEFERRED TWO YEARS FROM 2000 10 31 TO 2002 10 31 DUE TO FINANCIAL CONSTRAINTS. ESTIMATE INCREASED DUE TO USE OF TUBULAR STEEL INSTEAD OF WOOD POLE STRUCTURES ON 19KM LONG SECTION EAST OF TEULON.

ASSOCIATED PROJECTS

Budget reference number	Description
03-00-5912	SILVER - TERMINATE ROSSER 230 KV T/L & 230-66KV TRANSFORMER
03-00-5914	ROSSER TERMINATE SILVER 230KV T/L & RETERMINATE R23R
03-00-5915	ASHERN LINE A3R PROTECTION CHANGES
05-00-5531	ROSSER - SILVER 230KV T/L TELECONTROL FACILITIES

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	47		15			62	62
May	275	1	15			291	353
Jun	69		17			86	439
Jul	31		18			49	488
Aug	30	1	18			49	537
Sep	240	1	19			260	797
Oct	27		20			47	844
Nov	27		21			48	892
Dec	17		21			38	930
Jan	233	3	21			257	1 187
Feb	226	3	23			252	1 439
Mar	229	5	25			259	1 698
TOTAL	1 451	14	233			1 698	1 698
2000/01 Apr			27			27	27
May			27			27	54
Jun			27			27	81
Jul			28			28	109
Aug			28			28	137
Sep			28			28	165
Oct			28			28	19
Nov			28			28	22
Dec			29			29	250
Jan			29			29	279
Feb			29			29	308
Mar			29			29	337
TOTAL			337			337	337

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item

189

Title			Budget reference number
SILVER - TERMINATE ROSSER 230 KV T/L & 230-66KV TRANSFORMER			03-00-5912
Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	70509:71042

DESCRIPTION:
TERMINATE PREVIOUSLY INSTALLED SYSTEM SPARE 230-66KV TRANSFORMER #1 AT SILVER STATION ONTO 66KV BUS. INSTALLATION WILL INCLUDE EXTENSION OF 66KV BUS STRUCTURES, 2 - 66KV CIRCUIT BREAKERS AND ASSOCIATED EQUIPMENT.
TERMINATE ROSSER 230KV LINE AT SILVER STATION. INSTALLATION WILL INCLUDE EXTENSION OF 230KV BAY FOR RING OPERATION, 2 - 230KV CIRCUIT BREAKERS, AND ASSOCIATED EQUIPMENT.

NOTE:
COMMISSIONING DATE FOR CONNECTION OF SPARE BANK AND 66KV FACILITIES - 1998 10 31
COMMISSIONING DATE FOR 230KV FACILITIES - 2001 10 21

JUSTIFICATION:
FIRM LOAD SUPPLY IS REQUIRED AT SILVER 230KV STATION. THIS ITEM PROVIDES FOR TERMINATION OF A SECOND 230KV LINE AND CONNECTION OF SYSTEM SPARE 230-66KV TRANSFORMER (BANK #1) TO 66 KV BUS AT SILVER TO ACCOMMODATE FIRM SUPPLY REQUIREMENTS.

REFERENCE:
PSPD TM 94-6, WINNIPEG AND INTERLAKE TRANSMISSION CHANGES FOR 1994 IFF.
PSPD REPORT 95-2, FIRM 230KV SUPPLY TO SILVER STATION.

REVISION:
ISD DEFERRED FROM 2002 10 TO 2004 10.

CONTINGENCY: $395,000

IN SERVICE DATES				Base estimate
1999 03 31	1 388			199803 L3
2000 10 31	1 964			Work start date
2004 10 31	2 048			1995 11 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:	1 328		84	-2		1 410
1999/00	1 292	37	1			1 330
2000/01	132	7	7			146
2001/02	1 470	71	85			1 626
2002/03	50	5	71			126
TOTAL	4 272	120	248	-2		4 638
REV. AMOUNTS:						
Authorized to date:	1 328		84	-2		1 410
Over(under)expend:						
Auth 1999/00	1 706	38	126			1 870
Req.: 2000/01			96			96
2001/02	37	3	3			43
2002/03	142	13	11			166
2003/04	1 074	113	92			1 279
2004/05	449	7	78			534
TOTAL	4 736	174	490	-2		5 398

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number: 03-00-5912

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1994 10	7 386	NEW ITEM.
1995 10	7 405	REVISED INTEREST AND ESCALATION RATES
1996 10	5 374	ESTIMATE REDUCED SIGNIGICANTLY; COSTS FOR ENGINEERING AND LABOUR FOR CONNECTION OF SPARE BANK AND 66KV FACILITIES REDUCED BASED ON A RECENT VIRDEN WORK ORDER (45161). ISD FOR 230KV LINE TERMINATION DEFERRED 2 YEARS TO 2000 10 31.
1997 10	4 176	NO CHANGE.
1998 10	4 636	COMMISSIONING DATE FOR 230KV FACILITIES DEFERRED TWO YEARS FROM 2000 10 31 TO 2002 10 31. GENERAL INCREASE DUE TO ENGINEERING AND CONSTRUCTION COSTS.

ASSOCIATED PROJECTS

Budget reference number	Description
02-00-5961	ROSSER - SILVER 230 KV T/L
03-00-5914	ROSSER TERMINATE SILVER 230KV T/L & RETERMINATE R23R
03-00-5915	ASHERN LINE A3R PROTECTION CHANGES
05-00-5531	ROSSER - SILVER 230KV T/L TELECONTROL FACILITIES

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	14					14	14
May	1 621	38				1 659	1 673
Jun	14		12			26	1 699
Jul	14		12			26	1 725
Aug	14	1	12			27	1 752
Sep	14	1	12			27	1 779
Oct	14		13			27	1 806
Nov			13			13	1 819
Dec			13			13	1 832
Jan			13			13	1 845
Feb			13			13	1 858
Mar	1	-2	13			12	1 870
TOTAL	1 706	38	126			1 870	1 870
2000/01 Apr			13			13	13
May			13			13	26
Jun			14			14	40
Jul			14			14	54
Aug			14			14	68
Sep			14			14	82
Oct			14			14	96
Nov							96
Dec							96
Jan							96
Feb							96
Mar							96
TOTAL			96			96	96

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item 190

Title			Budget reference number
ROSSER TERMINATE SILVER 230KV T/L & RETERMINATE R23R			03-00-5914
Originating division: Planning & Control	Coordinating division: Design	Constructing division: Construction	Project Order Group (Range): 71038

DESCRIPTION:
RETERMINATE ROSSER - RIDGEWAY 230KV T/L R23R AT ROSSER IN NEW BREAKER POSITION IN BAY 2. DESIGN AND INSTALL PROTECTION CHANGES AND TERMINATE NEW SILVER 230KV LINE IN FORMER LINE R23R POSITION IN BAY 2. DESIGN AND INSTALL PROTECTION CHANGES FOR LINE A3R IN CONJUNCTION WITH ADDITION OF NEW 230KV ROSSER LINE AT SILVER. INSTALLATION WILL INCLUDE 1 - 230 KV CIRCUIT BREAKER AND ASSOCIATED EQUIPMENT.

JUSTIFICATION:
ELSEWHERE IN THE BUDGET JUSTIFICATION IS GIVEN FOR CONSTRUCTION OF ROSSER - SILVER 230KV LINE FOR FIRM SUPPLY TO SILVER. THIS ITEM PROVIDES FOR REQUIRED FACILITIES TO TERMINATE NEW LINE AT ROSSER, INCLUDING SHIFTING LINE R23R TERMINATION AND LINE A3R PROTECTION CHANGES.

REFERENCE:
PSPD TM 94-6, WINNIPEG AND INTERLAKE TRANSMISSION CHANGES FOR 1994 IFF.
PSPD REPORT 95-2, FIRM 230KV SUPPLY TO SILVER STATION.

REVISION:
ISD DEFERRED FROM 2002 10 31 TO 2004 10 31 DUE TO FINANCIAL CONSTRAINTS.

CONTINGENCY: $205,000

IN SERVICE DATES				Base estimate
2004 10 31	2 946			199704 L2
				Work start date 1995 10 01

	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
PREV. AUTHORITY						
Authorized to date:	3		1			4
1999/00	4	-1	1			4
2000/01	273	19	12			304
2001/02	1 073	79	59			1 211
2002/03	932	98	96			1 126
TOTAL	2 285	195	169			2 649
REV. AMOUNTS:						
Authorized to date:	3		1			4
Over(under)expend:						
Auth 1999/00						
Req.: 2000/01						
2001/02	4		1			5
2002/03	315	31	15			361
2003/04	1 118	114	67			1 299
2004/05	1 025	143	109			1 277
TOTAL	2 465	288	193			2 946

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number: 03-00-5914

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1994 10	2 721	NEW ITEM.
1995 10	2 727	REVISED INTEREST AND ESCALATION RATES.
1996 10	2 629	IN-SERVICE DATE DEFERRED 1 YEAR TO 2000 10 31.
1997 10	2 554	SCOPE UNCHANGED, ESTIMATE REFLECTS REVISED COSTING AND METHODOLOGY IMPLEMENTED WITH THE NEW FINANCIAL REPORTING SYSTEM. ALSO REFLECTS REVISED INTEREST AND ESC RATES.
1998 10	2 649	ISD DEFERRED TWO YEARS FROM 2000 10 31 TO 2002 10 31. 205,397

ASSOCIATED PROJECTS

Budget reference number	Description
02-00-5961	ROSSER - SILVER 230 KV T/L
03-00-5912	SILVER - TERMINATE ROSSER 230 KV T/L & 230-66KV TRANSFORMER
03-00-5915	ASHERN LINE A3R PROTECTION CHANGES
05-00-5531	ROSSER - SILVER 230KV T/L TELECONTROL FACILITIES

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item

191

Title			Budget reference number
ASHERN LINE A3R PROTECTION CHANGES			03-00-5915
Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	70319

DESCRIPTION:
DESIGN AND INSTALL PROTECTION CHANGES FOR LINES A3R AND A4D IN CO-ORDINATION WITH CONSTRUCTION OF ROSSER - SILVER 230 KV LINE.

JUSTIFICATION:
ELSEWHERE IN THE BUDGET JUSTIFICATION IS GIVEN FOR CONSTRUCTION OF ROSSER-SILVER 230KV LINE. THIS ITEM PROVIDES FOR REQUIRED PROTECTION CHANGES ON LINE A3R AT ASHERN TO ACCOMMODATE THE NEW LINE INTO SILVER

REFERENCE:
PSPD TM 94-6, 'WINNIPEG AND INTERLAKE TRANSMISSION CHANGES FOR 1994 IFF'.
PSPD REPORT 95-2, 'FIRM 230KV SUPPLY TO SILVER STATION'.
MEMO, S.M. INNES TO W. ZURBA, 1997 10 22, 'PROTECTION UPGRADES'.

REVISION:
ISD DEFERRED FROM 2002 10 31 TO 2004 10 31 DUE TO FINANCIAL CONSTRAINTS.

CONTINGENCY AMOUNT: $24,000

IN SERVICE DATES				Base estimate
2004 10 31	346			199704 L2
				Work start date
				2002 04 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL-NET COST
Authorized to date:						
2001/02	168	15	6			189
2002/03	103	11	11			125
TOTAL	271	26	17			314
REV. AMOUNTS:						
Authorized to date:						
Over(under)expend:						
Auth 2003/04	182	22	7			211
Req.: 2004/05	108	14	13			135
TOTAL	290	36	20			346

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

CAPITAL EXPENDITURE REVISION

Budget reference number: 03-00-5915

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1994 10	72	NEW ITEM.
1995 10	72	REVISED INTEREST AND ESCALATION RATES.
1996 10	289	IN-SERVICE DEFERRED 1 YEAR TO 2000 10 31. SCOPE CHANGED TO REPLACMENT OF LINE PROTECTION RATHER THAN SIMPLY ADJUSTMENTS TO EXISTING LINE PROTECTION.
1997 10	302	SCOPE UNCHANGED, ESTIMATE REFLECTS REVISED COSTING METHODOLOGY IMPLEMENTED WITH THE NEW FINANCIAL REPORTING SYSTEM. ALSO, REFLECTS REVISED INTEREST AND ESC RATES.
1998 10	314	ISD DEFERRED TWO YEARS FROM 2000 10 31 TO 2002 10 31.

ASSOCIATED PROJECTS

Budget reference number	Description
02-00-5961	ROSSER - SILVER 230 KV T/L
03-00-5912	SILVER - TERMINATE ROSSER 230 KV T/L & 230-66KV TRANSFORMER
03-00-5914	ROSSER TERMINATE SILVER 230KV T/L & RETERMINATE R23R
05-00-5531	ROSSER - SILVER 230KV T/L TELECONTROL FACILITIES

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item

192

Title			Budget reference number
ROSSER - SILVER 230KV T/L TELECONTROL FACILITIES			05-00-5531
Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Planning & Control	Construction	70320

DESCRIPTION:
DESIGN, INSTALL AND COMMISSION TELECONTROL FACILITIES REQUIRED FOR THE ADDITION OF A 230 KV LINE FROM ROSSER TO SILVER. UPGRADE COMMUNICATIONS EQUIPMENT ASSOCIATED WITH LINES A3R AND A4D AT ASHERN AND LINE A3R AT ROSSER.

JUSTIFICATION:
ELSEWHERE IN THE BUDGET, JUSTIFICATION IS GIVEN FOR CONSTRUCTION OF A ROSSER - SILVER 230KV LINE. THIS ITEM PROVIDES FOR NECESSARY TELECONTROL FACILITIES TO CONNECT THE NEW LINE TO THE 230KV NETWORK.

REFERENCE:
PSPD TM94-6, 'WINNIPEG INTERLAKE TRANSMISSION CHANGES FOR 1994 IFF'.
PSPD REPORT 95-2, 'FIRM 230KV SUPPLY TO SILVER STATION'.
MEMO, S.M. INNES TO W. ZURBA, 1997 10 22, 'PROTECTION UPGRADES'.

REVISION:
ISD DEFERRED FROM 2002 10 31 TO 2004 10 31 DUE TO FINANCIAL CONSTRAINTS.

CONTINGENCY: $150 000

IN SERVICE DATES				Base estimate
2004 10 31	1 831			199704 L2
				Work start date 2003 04 01

	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
PREV. AUTHORITY Authorized to date:						
2001/02	118	12	4			134
2002/03	1 376	148	49			1 573
TOTAL	1 494	160	53			1 707
REV. AMOUNTS: Authorized to date: Over(under)expend:						
Auth 2003/04	130	17	5			152
Req.: 2004/05	1 424	201	54			1 679
TOTAL	1 554	218	59			1 831

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 05-00-5531

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1994 10	1 587	NEW ITEM.
1995 10	1 585	REFLECTS NEW ESCALATION AND INTEREST RATES.
1996 10	1 623	REVISED INTEREST RATES. ISD DEFERRED FROM 1999 10 31 TO 2000 10 31.
1997 10	1 637	SCOPE UNCHANGED. ESTIMATE RELECTS REVISED COSTING METHODOLOGY IMPLEMENTED WITH THE NEW FINANCIAL REPORTING SYSTEM.
1998 10	1 707	ISD DEFERRED TWO YEAR FROM 2000 10 31 TO 2002 10 31. 150 000

ASSOCIATED PROJECTS

Budget reference number	Description
02-00-5961	ROSSER - SILVER 230 KV T/L
03-00-5912	SILVER - TERMINATE ROSSER 230 KV T/L & 230-66KV TRANSFORMER
03-00-5914	ROSSER TERMINATE SILVER 230KV T/L & RETERMINATE R23R
03-00-5915	ASHERN LINE A3R PROTECTION CHANGES

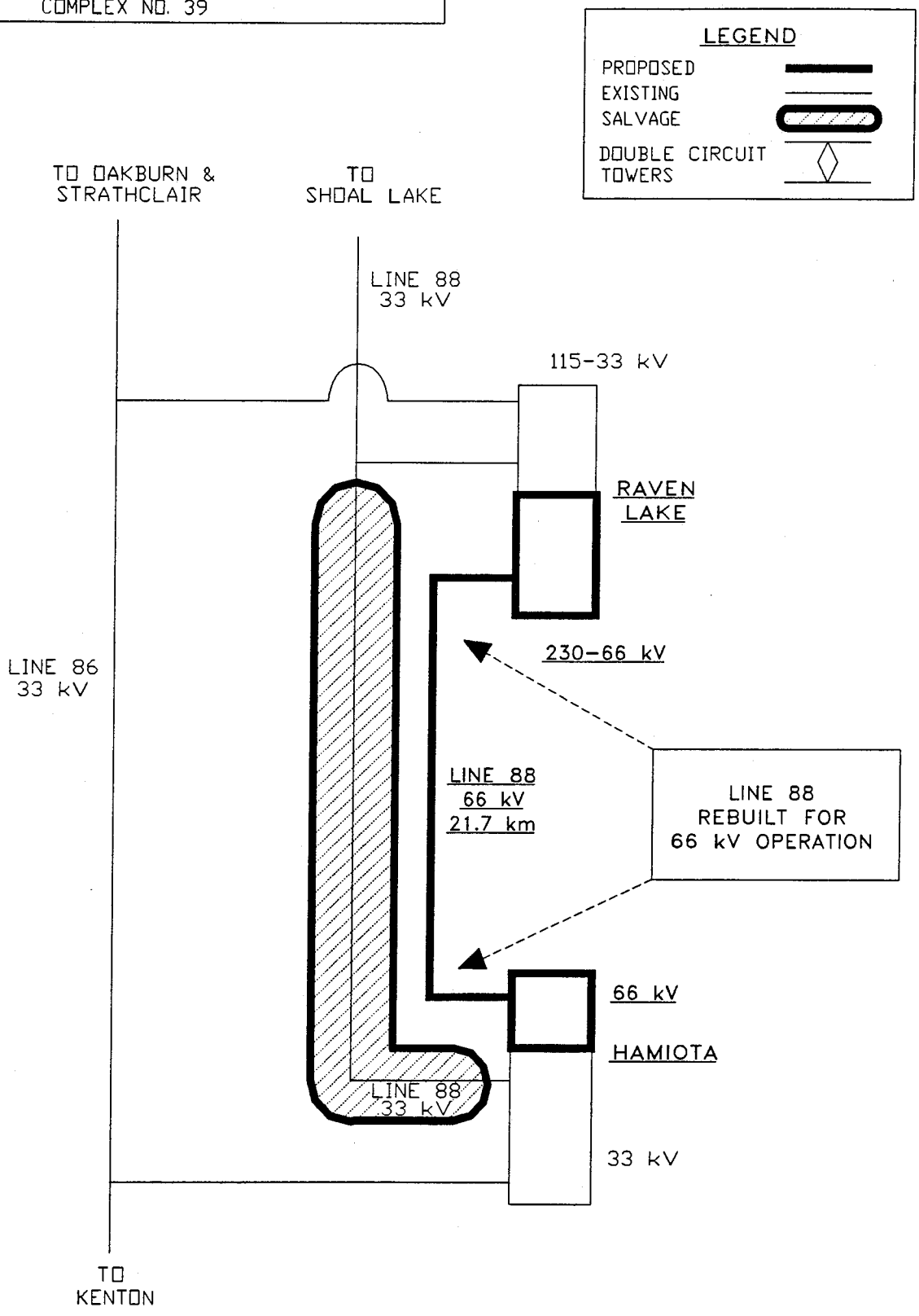
Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

CAPITAL BUDGET COMPLEX CONCEPTUAL DIAGRAM

RAVEN LAKE STATION
230–66 KV TRANSFORMATION

REVISED: 1999 - 10 - 01 | ISSUED BY: WNZ

COMPLEX NO. 39



manitoba hydro

PLANNING AND CONTROL DIVISION

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

COMPLEX STATUS: [X] Planned [ ] In progress

Complex no. 39

REVISION STATUS: [ ] New complex [ ] In service change [ ] Concept change [X] Estimate change only

COMPLEX: RAVEN LAKE 230-66 KV TRANSFORMATION

Proposal

Design and construct transmission and terminal facilities for supply at Raven Lake and Hamiota as follows:

Transmission: Rebuild 33 KV line 88 Raven Lake - Hamiota for 66 KV operation.

Terminations: Extend 230 and 66 KV facilities at Raven Lake station, including addition of a 230-66 KV 50 MVA transformer and associated 66 KV circuit breaker and 40 MVA grounding bank. Reconnect Hamiota 33-25 KV Bank 2 for 66-25 KV operation.

JUSTIFICATION

[X] Load [ ] Service
[ ] Safety [ ] Efficiency
[X] Reliability [ ] Other

Explanation

This transformer is required to supply increased load at Raven Lake. Loading on the Raven Lake 115-33 KV system will be reduced by transferring part of the 33 KV load at Raven Lake and Hamiota to 66 KV supply.

Estimate Level	COMPLEX START (yyyy mm)
L2	2014 04

IN SERVICE DATES AND AMOUNTS			
2017 10	$8321		

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend								
Year 99/00								
00/01								
01/02								
02/03								
03/04								
04/05								
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15	396	156	24		576	505	71	14
15/16	956	408	97		1,461	1,388	73	5
16/17	1,837	828	327		2,992	2,927	65	2
17/18	1,972	940	369	20	3,261	3,231	30	1
18/19								
Beyond								
TOTAL	5,161	2,332	817	20	8,290	8,051	239	3

REVISION: Scope unchanged.

Reviewed by ORIGINATOR	yyyy mm dd 99 11 05	Reviewed by COORDINATOR	yyyy mm dd 99 11 03
Reviewed by CONSTRUCTOR	yyyy mm dd 99 11 03	Approved by VICE-PRESIDENT	yyyy mm dd 99 11 3[illegible]

H2856/r Rev 99 03

Complex no. 39

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Advance or deferral impact

Deferral will decrease supply reliability in the Raven Lake area in case of an outage of an existing Raven Lake 115-33 KV transformer and will overload 33 KV facilities during peak load conditions.

Factors affecting timing or viability

Manitoba Load.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Raven Lake Station 230-66 KV Transformation		4,451	4,540	4,619	79	2
Hamiota Stn.-Reconnect Bank 2 for 66 KV Operation		60	61	61	0	0
Line 88 Conversion to 66 KV Operation		487	497	481	-16	-3
TOTAL		4,998	5,098	5,161	63	1

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
1995 10	3,737	Reflects revised escalation and interest rates.
1996 10	8,061	In-service date deferred 19 years to 2017. Conversion of Hamiota 33 KV line and transformer to 66 KV operation added.
1997 10	7,993	Estimate reflects revised costing methodology implemented with the new financial reporting system. Also reflects revised insterest and escalation rates.
1998 10	8,051	Scope unchanged
1999 10	8,290	Scope unchanged.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item

193

Title
RAVEN LAKE STATION 230-66KV TRANSFORMATION

Budget reference number
03-00-5898

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	70324

DESCRIPTION:
INSTALL A 30/40/50/MVA 230-66 KV +/- 15% LTC TRANSFORMER C/W 1 - 66KV CIRCUIT BREAKER, 1-40 MVA GROUNDING BANK AND ASSOCIATED EQUIPMENT.

JUSTIFICATION:
THE LOADING ON THE 115-33KV TRANSFORMERS AT RAVEN LAKE IS EXPECTED TO EXCEED THEIR FIRM CAPACITY (25 MVA) DURING THE 2017/18 WINTER PEAK. IT IS PLANNED TO ADD 230-66KV TRANSFORMATION IN THE RAVEN LAKE STATION AND CONVERT HAMIOTA STATION FROM 33KV TO 66KV SUPPLY TO RELIEVE THE 33KV SYSTEM OF LOAD.

REFERENCE:
1. H&TPD REPORT 86-11 'WESTERN MANITOBA AC TRANSMISSION 1986-2006' RECOMMENDATION #12
2.G&TP REPORT 87-15 'MID-WEST SUBTRANSMISSION IMPROVEMENTS'
3. TP REPORT 'MINITONAS 66KV SYSTEM IMPROVEMENTS 1990-1999'
4.TP REPORT 'RE-EVALUATION OF TRANSMISSION REQUIREMENTS BETWEEN DAUPHIN AND VIRDEN'
5. SPED REPORT 96-4 'BIRTLE SOUTH AND RAVEN LAKE SYSTEMS'

REVISION:
REFLECTS REVISED ACTIVITY AND OVERHEAD RATES.

CONTINGENCY: $402,000.

IN SERVICE DATES		Base estimate
2017 10 31	7 471	199707 L2
		Work start date
		2014 04 01

PREV AUTHORITY Authorized to date	GROSS	ESCALATION	INT CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
2014/15	344	140	21			505
2015/16	905	397	86			1 388
2016/17	1 767	819	299			2 885
2017/18	1 435	700	304			2 439
TOTAL	4 451	2 056	710			7 217
REV. AMOUNTS:						
Authorized to date:						
Over(under)expend:						
Auth 2014/15	396	156	24			576
Req 2015/16	956	409	97			1 462
2016/17	1 808	815	325			2 948
2017/18	1 459	693	333			2 485
TOTAL	4 619	2 073	779			7 471

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number: 03-00-5898

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1994 10	3 729	NEW ITEM (TRANSFERRED FROM DOMESTIC 9503-00-7054). IN-SERVICE DATE DEFERRED 1 YEAR TO 1998 10 31.
1995 10	3 737	REFLECTS CURRENT REVISED ESCALATION AND INTEREST RATES.
1996 10	7 273	DEFERRED ISD FROM 1998 10 31 TO 2017 10 31. POWER TRANSFORMER NEW PURCHASE INSTEAD OF EXISTING UNIT FROM MINITONAS.
1997 10	7 176	SCOPE UNCHANGED, ESTIMATE REFLECTS REVISED COSTING METHODOLOGY IMPLEMENTED WITH THE NEW FINANCIAL REPORTING SYSTEM. ALSO REFLECTS REVISED INTEREST AND ESCALATION RATES.
1998 10	7 217	NO CHANGE.

ASSOCIATED PROJECTS

Budget reference number	Description
03-00-6187	HAMIOTA STATION RECONNECT BANK2 FOR 66KV OPERATION
04-00-6543	LINE 88 CONVERSION TO 66KV OPERATION

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item 194

Title			Budget reference number
HAMIOTA STATION RECONNECT BANK2 FOR 66KV OPERATION			03-00-6187
Originating division: Planning & Control	Coordinating division: Design	Constructing division: Construction	Project Order Group (Range): 70326

DESCRIPTION:
RECONNECT BANK 2 FROM 33-25KV TO 66-25KV OPERATION. REPLACE THE HIGH SIDE FUSE, UPGRADE LIGHTNING ARRESTORS, AND REMOVE THE HIGH SIDE JUMPER CONNECTING BANK 2 TO BANK 1.

JUSTIFICATION:
THIS IS REQUIRED IN CONJUNCTION WITH THE INSTALLATION OF 230-66KV TRANSFORMATION AT RAVEN LAKE STATION AND THE TRANSFER OF THE HAMIOTA LOAD FROM 33KV TO 66KV SUPPLY.

REFERENCE:
SPED REPORT 96-4'BIRTLE SOUTH AND RAVEN LAKE SYSTEMS'

REVISION:
REFLECTS REVISED ACTIVITY AND OVERHEAD RATES.

CONTINGENCY: $5,000

IN SERVICE DATES				Base estimate
2017 10 31	95			199706 L2
				Work start date 2016 04 01

PREV AUTHORITY Authorized to date:	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
2016/17	21	9	1			31
2017/18	39	19	3			61
TOTAL	60	28	4			92
REV AMOUNTS. Authorized to date: Over(under)expend:						
Auth 2016/17	21	10	1			32
Req. 2017/18	40	20	3			63
TOTAL	61	30	4			95

Prepared by yy mm dd COORDINATOR — Approved by yy mm dd COORDINATING MANAGER — Approved by yy mm dd ORIGINATING MANAGER

Estimated by ORIGINATOR

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 03-00-6187

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1996 10	92	NEW ITEM
1997 10	91	SCOPE UNCHANGED. ESTIMATE REFLECTS REVISED COSTING METHODOLOGY IMPLEMENTED WITH THE NEW FINANCIAL REPORTING SYSTEM. REVISED INTEREST AND ESCALATION RATES.
1998 10	92	NO CHANGE.

ASSOCIATED PROJECTS

Budget reference number	Description
03-00-5898	RAVEN LAKE STATION 230-66KV TRANSFORMATION
04-00-6543	LINE 88 CONVERSION TO 66KV OPERATION

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item ___ Domestic Item 195

Title
LINE 88 CONVERSION TO 66KV OPERATION

Budget reference number
04-00-6543

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	94206

DESCRIPTION:
REBUILD LINE 88 BETWEEN RAVEN LAKE STATION AND HAMIOTA STATION 21.7 KM FOR 66KV OPERATION.

JUSTIFICATION:
THIS IS REQUIRED IN CONJUNCTION WITH THE INSTALLATION OF 230-66KV TRANSFORMATION AT RAVEN LAKE STATION AND THE TRANSFER OF THE HAMIOTA LOAD TO 66KV SUPPLY. THIS LINE REBUILD IS REQUIRED DUE TO THE ADOPTION OF 100 DEGREE CELSIUS STANDARDS. THE PRESENT LINE IS BUILT TO PRE 1990 66KV STANDARDS.

REFERENCE:
SPED REPORT 96-4 'BIRTLE SOUTH AND RAVEN LAKE SYSTEMS'

REVISION:
REVISED TO INCLUDE INTEREST.

Contingency Amount: $0

IN SERVICE DATES

2017 10 31	755

Base estimate
199805 L2

Work start date
2016 11 01

PREV. AUTHORITY Authorized to date:	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
2016/17	7	4				11
2017/18	480	238	33	-20		731
TOTAL	487	242	33	-20		742
REV. AMOUNTS: Authorized to date: Over(under)expend:						
Auth 2016/17	8	4				12
Req.: 2017/18	473	227	33	-20		713
TOTAL	481	231	33	-20		725

Prepared by ___ yy mm dd COORDINATOR Approved by ___ yy mm dd Approved by ___ yy mm dd

Estimated by ___ ORIGINATOR COORDINATING MANAGER ORIGINATING MANAGER

1999-08-21 05:27 PM

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number: 04-00-6543

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1997 04	0	New Item.
1997 04	711	Revised to reflect the increase for SAP.
1998 06	759	Revised to include interest.

ASSOCIATED PROJECTS

Budget reference number	Description
03-00-5898	RAVEN LAKE STATION 230-66KV TRANSFORMATION
03-00-6187	HAMIOTA STATION RECONNECT BANK2 FOR 66KV OPERATION

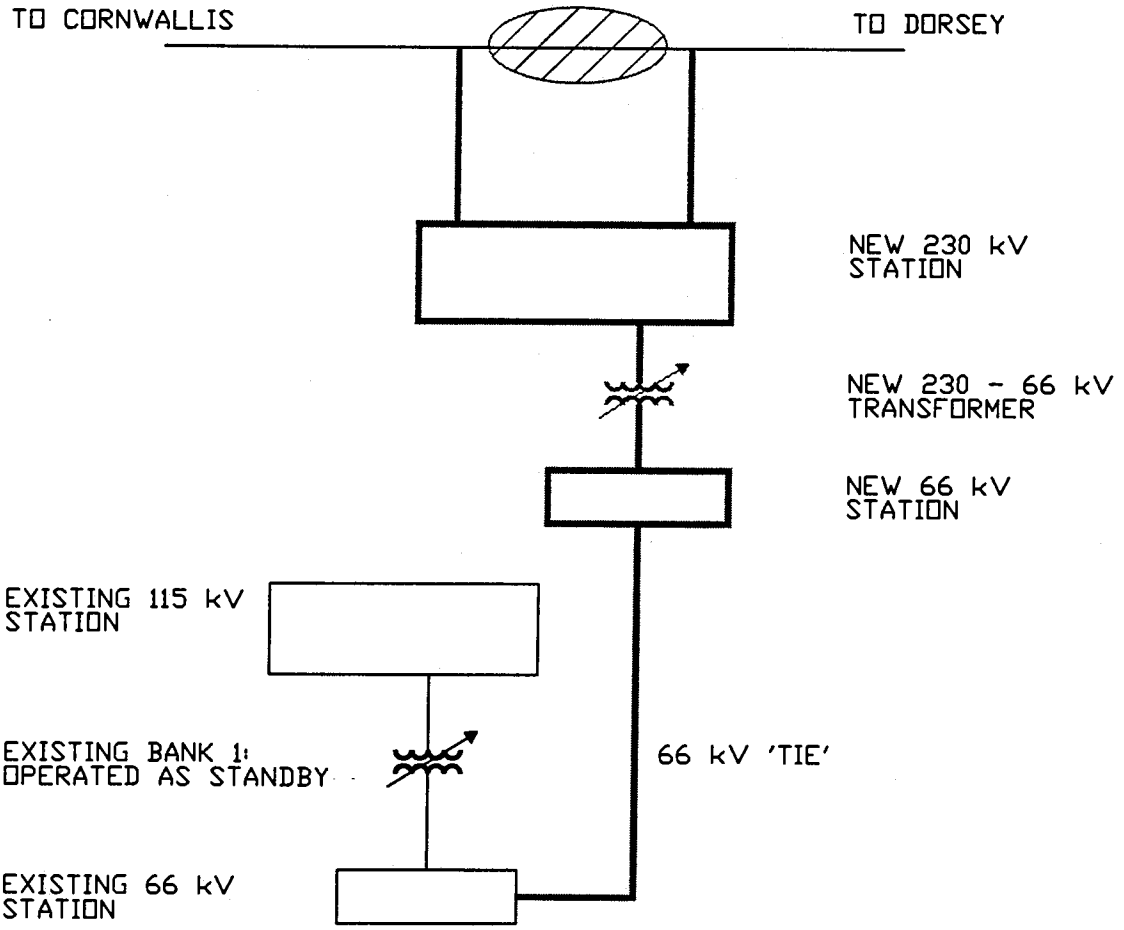
Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

1999-08-21 05:27 PM

CAPITAL BUDGET COMPLEX CONCEPTUAL DIAGRAM

NEEPAWA 230 - 66 kV STATION

REVISED: 1999 10 01	ISSUED BY: CS
COMPLEX NO. 18	



LEGEND

PROPOSED

EXISTING

SALVAGE

manitoba hydro

PLANNING AND CONTROL DIVISION

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

COMPLEX STATUS	Complex no.	REVISION STATUS
☒ Planned ☐ In progress	18	☐ New complex ☒ In service change ☒ Concept change ☐ Estimate change only

COMPLEX	NEEPAWA 230-66KV STATION

Proposal

Perform environmental assessments and route selection, design and construct terminal facilities to provide firm supply to Neepawa as follows:
Transmission: Sectionalize 230KV T/L D54C into Neepawa 230kV Stn, creating Dorsey-Neepawa and Neepawa -Cornwallis 230kV circuits. Build a 66KV tie line between the new 66KV terminal and the Existing 115/66/kV Station
Terminations: Establish Neepawa 230-66KV station, including three 230kV circuit breakers, a 50/66/83.3/93.3 MVA, 230-66KV LTC transformer, six 66KV circuit breakers and associated equipment. Adjust line protection equipment at Dorsey and Cornwallis 230KV stations. Terminate two 230kV transmission lines to Dorsey and Cornwallis.
Communications: Integrate with existing facilities at Neepawa , Dorsey, and Cornwallis 230KV stations.

JUSTIFICATION		Explanation
☒ Load	☐ Service	These facilities provide transmission improvements required by 2006 to supply Neepawa and related Western Region future load growth.
☐ Safety	☐ Efficiency	
☒ Reliability	☐ Other	

Estimate Level	COMPLEX START (yyyy mm)
L2	1999 04

IN SERVICE DATES AND AMOUNTS				
2006 10	$17689			

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend								
Year 99/00						325	-325	-100
00/01						416	-416	-100
01/02						1,007	-1,007	-100
02/03						10,109	-10,109	-100
03/04	54	7	1		62	10,513	-10,451	-99
04/05	872	118	33		1,023		1,023	
05/06	6,035	999	324		7,358		7,358	
06/07	7,325	1323	597	153	9,092		9,092	
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	14,286	2,447	955	153	17,535	22,370	-4,835	-22

REVISION	Concept changed from 230-115kV to 230-66kV project, eliminating 115kv improvements to existing stn. ISD deferred 3 years to 2006 10 31.

Reviewed by ORIGINATOR	yyyy mm dd 99 11 08	Reviewed by COORDINATOR	yyyy mm dd 99 11 03
Reviewed by CONSTRUCTOR	yyyy mm dd 99 11 03	Approved by VICE PRESIDENT	yyyy mm dd 99 11 16

H2856/r Rev 99 03

Complex no. 18

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Advance or deferral impact

Delays will reduce firm supply to Neepawa load.

Factors affecting timing or viability

Manitoba Load.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Neepawa Sectionalize 230kV T/L D54C		764	883	780	-103	-12
Neepawa - Establish 230-66kV Station		9,706	11,443	10,019	-1,424	-12
Neepawa 115 KV Station Upgrade (cancelled)		7,045	7,186	0	-7,186	-100
Dorsey - Protection Changes for Neepawa 230KV T/L		62	71	67	-4	-6
Cornwallis-Protectn Changes for Neepawa 230KV T/L		46	53	50	-3	-6
Telecontrol for Neepawa 230-115KV Station Addtn.		1,357	1,161	1,485	324	28
Neepawa Terminate 66kV from New 230/66kV Stn				1,414	1,414	
Neepawa 66kV Subtransmission				470	470	
TOTAL		18,980	20,797	14,285	-6,512	-31

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy mm	TOTAL AMOUNT	AMENDMENT
95 10	22,752	New complex.
96 10	22,689	Revised escalation and interest rates.
1997 10	22,245	Scope unchanged, estimate reflects revised costing methodology implemented with the new financial reporting system. Also reflects revised interest and escalation rates.
1998 10	22,370	ISD deferred one year to Octobr 2003.
1999 10	17,535	Concept changed from 230-115kV to 230-66kV project, eliminating 115kv improvements to existing stn. ISD deferred 3 years to 2006 10 31.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION
Complex 57	Dorsey-Neepawa-Cornwallis 230 KV Line

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item

196

Title
NEEPAWA SECTIONALIZE 230 kV TRANSMISSION LINE D54C

Budget reference number
02-00-6970

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	70327

DESCRIPTION:
SECTIONALIZE 230 kV TRANSMISSION LINE D54C INTO NEEPAWA 230 kV STATION, CREATING DORSEY-NEEPAWA AND NEEPAWA-CORNWALLIS 230 kV CIRCUITS

JUSTIFICATION:
ELSEWHERE IN THE BUDGET, JUSTIFICATION IS GIVEN FOR THE CONSTRUCTION OF A 230/66 kV STATION AT NEEPAWA. THIS ITEM PROVIDES THE TRANSMISSION ADDITIONS REQUIRED TO CONNECT THE STATION TO THE 230 kV NETWORK.

REFERENCE:
REPORT SPD 99/7, 'SYSTEM EXPANSION AT NEEPAWA'

REVISION:
CONCEPT CHANGED FROM 230-115KV TO 230-66KV PROJECT. ISD DEFERRED 3 YRS FROM 2003 10 31 TO 2006 10 31. REFLECTS REVISED ACTIVITY AND OVERHEAD RATES

CONTINGENCY: $0.

IN SERVICE DATES		Base estimate
2006 10 31	949	199707 L2
		Work start date
		2003 04 01

	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
PREV. AUTHORITY						
Authorized to date						
2000/01	12	1	1			14
2001/02	16	2	2			20
2002/03	25	2	4			31
2003/04	711	91	16			818
TOTAL	764	96	23			883
REV. AMOUNTS:						
Authorized to date						
Over(under)expend:						
Auth 2003/04	15	1	1			17
Req. 2004/05	20	3	2			25
2005/06	29	5	5			39
2006/07	716	133	19			868
TOTAL	780	142	27			949

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 02-00-6970

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1995 10	949	NEW ITEM.
1996 10	949	REVISED INTEREST RATES.
1997 10	864	ADJUSTED CASH FLOWS. REFLECTS REVISED INTEREST AND ESCALATION RATES.
1998 10	883	ISD DEFERRED ONE YEAR FROM 2002 10 31 TO 2003 10 31.

ASSOCIATED PROJECTS

Budget reference number	Description
03-00-6990	NEEPAWA ESTABLISH 230/66 kV TERMINAL STATION
03-00-6991	NEEPAWA 115KV STATION UPGRADE
03-00-6992	DORSEY PROTECTION CHANGES FOR NEEPAWA 230KV T/L
03-00-6993	CORNWALLIS PROTECTION CHANGES FOR NEEPAWA 230KV T/L
03-00-8406	NEEPAWA TERMINATE 66 KV SUPPLY FROM NEW 230/66 KV STATION
04-00-8621	NEEPAWA 66KV SUBTRANSMISSION
05-00-6553	TELECONTROL FOR NEEPAWA 230/66 kV TERMINAL STATION

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item

197

Title	Budget reference number
NEEPAWA ESTABLISH 230/66 kV TERMINAL STATION	03-00-6990

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	70328

DESCRIPTION:
DESIGN AND CONSTRUCT A 230/66 kV STATION INCLUDING THREE (3) 230 kV CIRCUIT BREAKERS, A 50/66/83.3//93.3 MVA, 230 TO 66 kV LTC TRANSFORMER, SIX (6) 66 kV CIRCUIT BREAKERS AND ASSOCIATED EQUIPMENT. TERMINATE TWO (2) 230 kV TRANSMISSION LINES TO DORSEY AND CORNWALLIS.
NOTE: ENVIRONMENTAL IMPACT ASSESSMENT, LICENCING AND PROPERTY ACQUISITION FOR STATION SITE COVERED BY BRN 03-00-1661, 'NEEPAWA STATION - LAND PURCHASE' IN DORSEY-NEEPAWA-CORNWALLIS 230KV LINE COMPLEX.

JUSTIFICATION:
THIS ITEM IS REQUIRED TO SUPPLY PROJECTED FIRM LOAD GROWTH IN THE AREA.

REFERENCE:
REPORT SPD 99/7, 'SYSTEM EXPANSION AT NEEPAWA'

REVISION:
CONCEPT CHANGED FROM 230-115KV TO 230-66KV PROJECT. ISD DEFERRED 3 YRS FROM 2003 10 31 TO 2006 10 31. REFLECTS REVISED ACTIVITY AND OVERHEAD RATES.

CONTINGENCY: $886,000.

IN SERVICE DATES		Base estimate
2006 10 31	12 462	199707 L2
		Work start date
		2003 10 01

PREV. AUTHORITY Authorized to date	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
2000/01	36	3	1			40
2001/02	386	34	20			440
2002/03	4 605	512	193			5 310
2003/04	4 679	595	379			5 653
TOTAL	9 706	1 144	593			11 443
REV. AMOUNTS:						
Authorized to date:						
Over(under)expend:						
Auth 2003/04	39	5	1			45
Req.: 2004/05	423	62	23			508
2005/06	4 796	811	221			5 828
2006/07	4 761	887	433			6 081
TOTAL	10 019	1 765	678			12 462

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR		COORDINATING MANAGER		ORIGINATING MANAGER

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 03-00-6990

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1995 10	12 372	NEW ITEM.
1996 10	12 273	REVISED INTEREST RATES. CORRECTION TO CALCULATED ESCALATION. START DATE DEFERRED FOR ONE YEAR, BUT ISD REMAINS THE SAME.
1997 10	11 403	POWER TRANSFORMER PRICE DECREASED. REFLECTS REVISED INTEREST AND ESCALATION RATES.
1998 10	11 443	ISD DEFERRED ONE YEAR FROM 2002 10 31 TO 2003 10 31.

ASSOCIATED PROJECTS

Budget reference number	Description
02-00-6970	NEEPAWA SECTIONALIZE 230 kV TRANSMISSION LINE D54C
03-00-6991	NEEPAWA 115KV STATION UPGRADE
03-00-6992	DORSEY PROTECTION CHANGES FOR NEEPAWA 230KV T/L
03-00-6993	CORNWALLIS PROTECTION CHANGES FOR NEEPAWA 230KV T/L
03-00-8406	NEEPAWA TERMINATE 66 KV SUPPLY FROM NEW 230/66 KV STATION
04-00-8621	NEEPAWA 66KV SUBTRANSMISSION
05-00-6553	TELECONTROL FOR NEEPAWA 230/66 kV TERMINAL STATION

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item 198

Title
NEEPAWA 115KV STATION UPGRADE

Budget reference number
03-00-6991

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	70329

DESCRIPTION:
SALVAGE 115 KV RING BUS EQUIPMENT AND REPLACE WITH UPGRADED EQUIPMENT RATED FOR 1200 AMP CAPACITY, INCLUDING REBUILD OF STEEL AND FOUNDATION STRUCTURES AND REPLACEMENT OF 6-115 KV CIRCUIT BREAKERS. TERMINATE 115 KV TIE LINE TO NEEPAWA 230 KV STATION IN BREAKER POSITION PREVIOUSLY USED FOR LINE CN9 TO PARKDALE. FACILITIES WILL INCLUDE ASSOCIATED EQUIPMENT AND A NEW CONTROL BUILDING.

JUSTIFICATION:
ELSEWHERE IN THE BUDGET, JUSTIFICATION IS GIVEN FOR ADDING 230-115 KV TRANSFORMATION AT A NEW NEEPAWA 230 KV STATION. THIS ITEM PROVIDES FOR NECESSARY UPGRADES AT EXISTING NEEPAWA 115 KV STATION TO ACCOMMODATE CONNECTION TO NEW HIGH POWER CAPACITY 230KV STATION

REFERENCE:
TPD REPORT 89-3, 'WESTERN MANITOBA SYSTEM DEVELOPMENT ALTERNATIVES'.
PSPD TM 95-12, 'NEEPAWA 230-115KV TRANSFORMER ADDITION'.

REVISION:
ITEM CANCELLED.

IN SERVICE DATES

Base estimate
199707 L2

Work start date
2002 04 01

PREV. AUTHORITY Authorized to date:	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
1999/00	299	13	13			325
2000/01	301	20	42			363
2001/02	301	26	74			401
2002/03	3 455	375	245			4 075
2003/04	2 689	340	302	- 185		3 146
TOTAL	7 045	774	676	- 185		8 310
REV. AMOUNTS:						
Authorized to date:						
Over(under)expend:						
Auth Req.:						
TOTAL						

Prepared by: yy mm dd COORDINATOR — Approved by: yy mm dd — Approved by: yy mm dd

Estimated by: ORIGINATOR — COORDINATING MANAGER — ORIGINATING MANAGER

1999-08-21 05:23 PM

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 03-00-6991

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1995 10	8 059	NEW ITEM
1996 10	7 803	WORK START DATE DEFERRED ONE YEAR FROM 1997 04 01 TO 1998 04 01 TO ASSIST IN ACHIEVINGTHE CORPORATE CAPITAL TARGET.
1997 10	8 305	SCOPE UNCHANGED, ESTIMATE REFLECTS REVISED COSTING METHODOLOGY IMPLEMENTED WTIH THE NEW FINANCIAL REPORTING SYSTEM. ALSO REFLECTS REVISED INTEREST AND ESCALATION RATES.
1998 10	8 310	ISD DEFERRED ONE YEAR FROM 2002 10 31 TO 2003 10 31.

ASSOCIATED PROJECTS

Budget reference number	Description
02-00-6970	NEEPAWA SECTIONALIZE 230 kV TRANSMISSION LINE D54C
03-00-6990	NEEPAWA ESTABLISH 230/66 kV TERMINAL STATION
03-00-6992	DORSEY PROTECTION CHANGES FOR NEEPAWA 230KV T/L
03-00-6993	CORNWALLIS PROTECTION CHANGES FOR NEEPAWA 230KV T/L
03-00-8406	NEEPAWA TERMINATE 66 KV SUPPLY FROM NEW 230/66 KV STATION
04-00-8621	NEEPAWA 66KV SUBTRANSMISSION
05-00-6553	TELECONTROL FOR NEEPAWA 230/66 kV TERMINAL STATION

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item ___ Domestic Item 199

Title: DORSEY PROTECTION CHANGES FOR NEEPAWA 230KV T/L

Budget reference number: 03-00-6992

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	70330

DESCRIPTION:
MODIFY PROTECTION EQUIPMENT AS REQUIRED AT DORSEY IN CO-ORDINATION WITH SECTIONALIZATION OF DORSEY - NEEPAWA - CORNWALLIS 230KV LINE AT NEEPAWA AND RETERMINATION AT NEEPAWA 230KV STATION.

JUSTIFICATION:
ELSEWHERE IN THE BUDGET JUSTIFICATION IS GIVEN FOR SECTIONALIZING 230KV DORSEY - NEEPAWA - CORNWALLIS LINE AND RETERMINATION OF LINE ENDS AT NEEPAWA 230KV STATION. THIS ITEM PROVIDES FOR REQUIRED PROTECTION CHANGES ASSOCIATED WITH CREATION OF DORSEY-NEEPAWA LINE.

REFERENCE:
TPD REPORT 89-3, 'WESTERN MANITOBA SYSTEM DEVELOPMENT ALTERNATIVES'. PSPD TM 95-12, 'NEEPAWA 230-115KV TRANSFORMER ADDITION'

REVISION:
CONCEPT CHANGED FROM 230-115KV TO 230-66KV PROJECT. ISD DEFERRED 3 YRS FROM 2003 10 31 TO 2006 10 31. REFLECTS REVISED ACTIVITY AND OVERHEAD RATES.

CONTINGENCY: $5,535

IN SERVICE DATES: 2006 10 31 — 82

Base estimate: 199706 L2

Work start date: 2005 10 01

	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
PREV. AUTHORITY Authorized to date:						
2002/03	24	3				27
2003/04	38	4	2			44
TOTAL	62	7	2			71
REV. AMOUNTS:						
Authorized to date:						
Over(under)expend:						
Auth 2005/06	27	5	1			33
Req.: 2006/07	40	6	3			49
TOTAL	67	11	4			82

Prepared by: yy mm dd COORDINATOR — Approved by: yy mm dd — Approved by: yy mm dd

Estimated by: ORIGINATOR — COORDINATING MANAGER — ORIGINATING MANAGER

CAPITAL EXPENDITURE REVISION

Budget reference number 03-00-6992

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1995 10	65	NEW ITEM
1996 10	64	REVISED INTEREST RATES.
1997 06	70	SCOPE UNCHANGED, ESTIMATE REFLECTS REVISED COSTING METHODOLOGY IMPLEMENTED WITH THE NEW FINANCIAL REPORTING SYSTEM.
1998 10	71	ISD DEFERRED ONE YEAR FROM 2002 10 31 TO 2003 10 31.

ASSOCIATED PROJECTS

Budget reference number	Description
02-00-6970	NEEPAWA SECTIONALIZE 230 kV TRANSMISSION LINE D54C
03-00-6990	NEEPAWA ESTABLISH 230/66 kV TERMINAL STATION
03-00-6991	NEEPAWA 115KV STATION UPGRADE
03-00-6993	CORNWALLIS PROTECTION CHANGES FOR NEEPAWA 230KV T/L
03-00-8406	NEEPAWA TERMINATE 66 KV SUPPLY FROM NEW 230/66 KV STATION
04-00-8621	NEEPAWA 66KV SUBTRANSMISSION
05-00-6553	TELECONTROL FOR NEEPAWA 230/66 kV TERMINAL STATION

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item 200

Title: CORNWALLIS PROTECTION CHANGES FOR NEEPAWA 230KV T/L

Budget reference number: 03-00-6993

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	70331

DESCRIPTION:
MODIFY PROTECTION EQUIPMENT AS REQUIRED AT CORNWALLIS IN CO-ORDINATION WITH SECTIONALIZATION OF 230KV DORSEY - NEEPAWA - CORNWALLIS LINE AT NEEPAWA AND RETERMINATION AT NEEPAWA 230KV STATION.

JUSTIFICATION:
ELSEWHERE IN THE BUDGET JUSTIFICATION IS GIVEN FOR SECTIONALIZING 230KV DORSEY - NEEPAWA - CORNWALLIS LINE AND RETERMINATION OF LINE ENDS AT NEEPAWA 230KV STATION. THIS ITEM PROVIDES FOR REQUIRED PROTECTION CHANGES ASSOCIATED WITH CREATION OF NEEPAWA - CORNWALLIS 230KV LINE.

REFERENCE:
TPD REPORT 89-3, 'WESTERN MANITOBA SYSTEM DEVELOPMENT ALTERNATIVES'. PSPD TM 95-12, 'NEEPAWA 230-115KV TRANSFORMER ADDITION'.

REVISION:
CONCEPT CHANGED FROM 230-115KV TO 230-66KV PROJECT. ISD DEFERRED 3 YRS FROM 2003 10 31 TO 2006 10 31. REFLECTS REVISED ACTIVITY AND OVERHEAD RATES.

CONTINGENCY: $4,026

IN SERVICE DATES

2006 10 31 — 62

Base estimate: 199706 L2

Work start date: 2005 10 01

PREV AUTHORITY Authorized to date	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
2002/03	19	3				22
2003/04	27	2	2			31
TOTAL	46	5	2			53
REV. AMOUNTS:						
Authorized to date:						
Over(under)expend:						
Auth 2005/06	21	5				26
Req 2006/07	29	5	2			36
TOTAL	50	10	2			62

Prepared by yy mm dd COORDINATOR — Approved by yy mm dd Approved by yy mm dd

Estimated by ORIGINATOR — COORDINATING MANAGER — ORIGINATING MANAGER

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 03-00-6993

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1996 10	49	REVISED INTEREST RATES.
1997 10	51	SCOPE UNCHANGED ESTIMATE REFLECT REVISED COSTING METHODOLOGY IMPLEMENTED WITH THE NEW FINANCIAL REPORTING SYSTEM.
1998 10	53	ISD DEFERRED ONE YEAR FROM 2002 10 31 TO 2003 10 31.

ASSOCIATED PROJECTS

Budget reference number	Description
02-00-6970	NEEPAWA SECTIONALIZE 230 kV TRANSMISSION LINE D54C
03-00-6990	NEEPAWA ESTABLISH 230/66 kV TERMINAL STATION
03-00-6991	NEEPAWA 115KV STATION UPGRADE
03-00-6992	DORSEY PROTECTION CHANGES FOR NEEPAWA 230KV T/L
03-00-8406	NEEPAWA TERMINATE 66 KV SUPPLY FROM NEW 230/66 KV STATION
04-00-8621	NEEPAWA 66KV SUBTRANSMISSION
05-00-6553	TELECONTROL FOR NEEPAWA 230/66 kV TERMINAL STATION

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item 20/

Title			Budget reference number
NEEPAWA TERMINATE 66 KV SUPPLY FROM NEW 230/66 KV STATION			03-00-8406
Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	70637

DESCRIPTION:
TERMINATE THE NEW 66 KV 'TIE' LINE BETWEEN THE NEW 230/66 KV TERMINAL STATION AND THE EXISTING 115/66 KV STATION. REPLACE EXISTING 66KV SWITCHES AND BUSWORK AS REQUIRED. SALVAGE 115 KV BREAKERS R12, R17 AND R19, 66 KV BREAKER B20, B50, 810 AND 570 AND ASSOCIATED 115 KV AND 66 KV EQUIPMENT.

JUSTIFICATION:
ELSEWHERE IN THE BUDGET, JUSTIFICATION IS GIVEN FOR THE CONSTRUCTION OF A 230/66 KV STATION AT NEEPAWA. THIS ITEM IS REQUIRED TO SUPPLY THE EXISTING 66 KV SYSTEM IN THE AREA.

REFERENCE:
REPORT SPD 99/7, 'SYSTEM EXPANSION AT NEEPAWA'.

REVISION:
NEW ITEM.

CONTIGENCY $124 000

IN SERVICE DATES				Base estimate
2006 10 31	1 725			199903 L2
				Work start date 2004 10 01

	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
PREV. AUTHORITY Authorized to date:						
TOTAL						
REV. AMOUNTS:						
Authorized to date:						
Over(under)expend:						
Auth Req.: 2004/05	293	33	6			332
2005/06	587	75	57			719
2006/07	534	77	63	- 143		531
TOTAL	1 414	185	126	- 143		1 582

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 03-00-8406

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS

ASSOCIATED PROJECTS

Budget reference number	Description
02-00-6970	NEEPAWA SECTIONALIZE 230 kV TRANSMISSION LINE D54C
03-00-6990	NEEPAWA ESTABLISH 230/66 kV TERMINAL STATION
03-00-6991	NEEPAWA 115KV STATION UPGRADE
03-00-6992	DORSEY PROTECTION CHANGES FOR NEEPAWA 230KV T/L
03-00-6993	CORNWALLIS PROTECTION CHANGES FOR NEEPAWA 230KV T/L
04-00-8621	NEEPAWA 66KV SUBTRANSMISSION
05-00-6553	TELECONTROL FOR NEEPAWA 230/66 kV TERMINAL STATION

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item 202

Title: NEEPAWA 66KV SUBTRANSMISSION

Budget reference number: 04-00-8621

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	94327

DESCRIPTION:
BUILD NEW 66 KV CIRCUITS EMANATING FROM THE 230/66 KV STATION AND CONNECT TO EXISTING FEEDERS. BUILD A 66 KV 'TIE' LINE BETWEEN THE NEW 66 KV TERMINAL AND THE EXISTING 115/66 KV STATION. MOVE ICE MELTING EQUIPMENT OVER TO THE 230/66 KV TERMINAL.

JUSTIFICATION:
ELSEWHERE IN THE BUDGET, JUSTIFICATION IS GIVEN FOR THE CONSTRUCTION OF A 230/66 KV STATION AT NEEPAWA. THIS ITEM PROVIDES THE SUBTRANSMISSION ADDITIONS REQUIRED TO CONNECT THE STATION TO THE 66 KV FEEDERS.

REFERENCE:
REPORT SPD 99/7, 'SYSTEM EXPANSION AT NEEPAWA'.

REVISION:
NEW ITEM.

IN SERVICE DATES: 2006 10 31 — 556

Base estimate: 199903 L2

Work start date: 1999 03 01

	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
PREV. AUTHORITY Authorized to date:						
TOTAL						
REV. AMOUNTS:						
Authorized to date:						
Over(under)expend:						
Auth 2005/06	9	1				10
Req. 2006/07	461	64	19	-9		535
TOTAL	470	65	19	-9		545

Prepared by: yy mm dd COORDINATOR

Approved by: yy mm dd COORDINATING MANAGER

Approved by: yy mm dd ORIGINATING MANAGER

Estimated by: ORIGINATOR

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 04-00-8621

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS

ASSOCIATED PROJECTS

Budget reference number	Description
02-00-6970	NEEPAWA SECTIONALIZE 230 kV TRANSMISSION LINE D54C
03-00-6990	NEEPAWA ESTABLISH 230/66 kV TERMINAL STATION
03-00-6991	NEEPAWA 115KV STATION UPGRADE
03-00-6992	DORSEY PROTECTION CHANGES FOR NEEPAWA 230KV T/L
03-00-6993	CORNWALLIS PROTECTION CHANGES FOR NEEPAWA 230KV T/L
03-00-8406	NEEPAWA TERMINATE 66 KV SUPPLY FROM NEW 230/66 KV STATION
05-00-6553	TELECONTROL FOR NEEPAWA 230/66 kV TERMINAL STATION

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item

203

Title
TELECONTROL FOR NEEPAWA 230/66 kV TERMINAL STATION

Budget reference number
05-00-6553

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Planning & Control	Construction	70393

DESCRIPTION:
DESIGN, INSTALL AND COMMISSION TELECONTROL FACILITIES FOR THE OPERATION OF THE DORSEY-NEEPAWA AND NEEPAWA-CORNWALLIS 230 kV TRANSMISSION LINES AND THE NEW 230/66 kV STATION.

JUSTIFICATION:
ELSEWHERE IN THE BUDGET, JUSTIFICATION IS GIVEN FOR THE CONSTRUCTION OF A NEW 230/66 kV STATION AT NEEPAWA INCLUDING SECTIONALIZING AND TERMINATING 230 kV TRANSMISSION LINE D54C. THIS ITEM PROVIDES FOR THE TELECONTROL FACILITIES REQUIRED TO OPERATE THE NEW STATION AND ITS ASSOCIATED TRANSMISSION LINES.

REFERENCE:
REPORT SPD 99, 'SYSTEM EXPANSION AT NEEPAWA'.

REVISION:
CONCEPT CHANGED FROM 230-115KV TO 230-66KV PROJECT. ISD DEFERRED 3 YRS FROM 2003 10 31 TO 2006 10 31. REFLECTS REVISED ACTIVITY AND OVERHEAD RATES.

CONTINGENCY $100,000.

IN SERVICE DATES		Base estimate
2006 10 31	1 853	199704 L2
		Work start date
		2004 01 01

PREV. AUTHORITY Authorized to date.	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
2001/02	132	13	1			146
2002/03	546	63	36			645
2003/04	679	90	51			820
TOTAL	1 357	166	88			1 611
REV. AMOUNTS:						
Authorized to date:						
Over(under)expend:						
Auth 2004/05	136	21	1			158
Req. 2005/06	566	97	40			703
2006/07	783	150	59			992
TOTAL	1 485	268	100			1 853

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

1999-08-21 05:29 PM

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 05-00-6553

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1995 10	1 259	NEW ITEM.
1996 10	1 259	REVISED INTEREST RATES.
1997 04	1 570	SCOPE UNCHANGED, ESTIMATE REFLECTS REVISED COSTING METHODOLOGY IMPLEMENTED WITH THE NEW FINANCIAL REPORTING SYSTEM
1998 10	1 611	ISD DEFERRED ONE YEAR FROM 2002 10 31 TO 2003 10 31.

ASSOCIATED PROJECTS

Budget reference number	Description
02-00-6970	NEEPAWA SECTIONALIZE 230 kV TRANSMISSION LINE D54C
03-00-6990	NEEPAWA ESTABLISH 230/66 kV TERMINAL STATION
03-00-6991	NEEPAWA 115KV STATION UPGRADE
03-00-6992	DORSEY PROTECTION CHANGES FOR NEEPAWA 230KV T/L
03-00-6993	CORNWALLIS PROTECTION CHANGES FOR NEEPAWA 230KV T/L
03-00-8406	NEEPAWA TERMINATE 66 KV SUPPLY FROM NEW 230/66 KV STATION
04-00-8621	NEEPAWA 66KV SUBTRANSMISSION

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

1999-08-21 05:29 PM

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

COMPLEX STATUS: ☐ Planned ☒ In progress

Complex no. 201

REVISION STATUS: ☐ New complex ☐ In service change ☐ Concept change ☒ Estimate change only

COMPLEX	ASSINIBOINE WILKES AVE. 115-24 KV BANK 1 ADDITION

Proposal

Design and construct transmission and terminal facilities to firm supply to Assiniboine Wilkes Avenue as follows:

Transmission: 4.4 KM 115 KV line Assiniboine Wilkes - Line YV5 Tap.

Terminations: Extend 115-24.9 KV distribution station facilities at Assiniboine Wilkes, including new 115-24 KV 100 MVA transformer bank #1 and 3-24 KV additional feeder lines.

Communications: Expand and integrate with existing Assiniboine Wilkes facilities.

JUSTIFICATION

☒ Load ☐ Service
☐ Safety ☐ Efficiency
☒ Reliability ☐ Other

Explanation

The facilities are required to firm 115-24 KV supply at Assiniboine Wilkes and provide for future area load growth. Additional feeders are required to supply load and increase feeder tie capacities in the St. James and Kirkfield station areas.

Estimate Level	COMPLEX START (yyyy mm)
L2	1996 04

IN SERVICE DATES AND AMOUNTS							
1999 02	$26	1999 04	$418	1999 05	$4823	1999 10	$2315
1999 12	$5341	2000 09	$571				

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	5,831		392	4	6,219	7,625	-1,406	-18
Year 99/00	6,775	71	368	74	7,140	5,866	1,274	22
00/01	33	1	24		58	1,258	-1,200	-95
01/02								
02/03								
03/04								
04/05								
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	12,639	72	784	78	13,417	14,749	-1,332	-9

REVISION	Labour costs were lower than estimated.

Reviewed by	ORIGINATOR	yyyy mm dd 99 11 08	Reviewed by	COORDINATOR	yyyy mm dd 99 11 03
Reviewed by	CONSTRUCTOR	yyyy mm dd 99 11 03	Approved by	VICE PRESIDENT	yyyy mm dd 99 11 16

H2856/r Rev 99 03

Complex no. 201

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Advance or deferral impact

Deferral will decrease supply reliability in the Assiniboine Wilkes, St James and Kirkfield areas in case of outage of the existing 115-24 KV transformer or 115 KV tap supply line.

Factors affecting timing or viability

Assiniboine-Wilkes area load growth.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Assiniboine Wilkes Ave-YV5 115KV T/L Tap	490	447	456	490	34	7
Assiniboine Wilkes Ave-W65 24KV Breaker Addtn.	213	245	250	205	-45	-18
Assiniboine Wilkes Ave-W62 24KV Breaker Addtn.	219	219	223	219	-4	-2
Assiniboine Wilkes Ave- 115-24KV Trnsfmr. Addtn.	5,565	5,367	5,474	5,565	91	2
Assiniboine Wilkes Ave-W71 24KV Breaker Addtn.	216	250	255	168	-87	-34
Assiniboine Wilkes Ave-W65 24KV Feeder Addtn.	4,759	4,421	4,509	3,169	-1,340	-30
Assiniboine Wilkes Ave-W62 24KV Feeder Addtn.		559	570	1,114	544	95
Assiniboine Wilkes Ave-W71 24KV Feeder Addtn.	2,285	2,186	2,230	1,293	-937	-42
Assiniboine Wilkes Ave-Bank 1 Addtn.-Communictn.	417	287	293	417	124	42
TOTAL	14,164	13,981	14,260	12,640	-1,620	-11

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
96 10	12,265	New complex.
1997 10	14,445	W65 & W7 breakers deferred 4 months, W65 feeder deferred 5 months, W71 feeder deferred 8 months and W62 feeder and breaker advanced 1 year to 1998 06 30
1998 10	14,749	Reflects 97/98 underexpend 0.8M,W62 feeder and breaker deferred one year to Oct 1999, to coincide with voltage conversion in Wilkes station area by Distribution Planning Wpg.
1999 10	13,417	Labour costs were lower than estimated.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item

204

Title	Budget reference number
ASSINIBOINE WILKES YV5 115KV TRANSMISSION LINE TAP	02-00-6985

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	70143

DESCRIPTION:
TAP 115KV LINE YV5 USING 4.4KM OF 795 KCMIL CONDUCTOR IN THE SECOND CIRCUIT POSITION ON THE EXISTING DOUBLE CIRCUIT YX47 TAP TOWERS NORTH TO ASSINIBOINE WILKES AVE STATION. TERMINATE AT BANK 1 POSITION.

JUSTIFICATION:
ELSEWHERE IN THE BUDGET, JUSTIFICATION IS GIVEN FOR THE INSTALLATION OF BANK 1 AT ASSINIBOINE WILKES AVE. THIS ITEM PROVIDES PRIMARY SUPPLY FOR BANK 1.

REFERENCE:
MEMO, W. PYL TO C.V. THIO, 1996 10 10 ,CENTRAL REGION 24KV STUDY REQUIREMENTS.
MEMO, L.A. MILLER TO W. PYL, 1996 01 09, REPLY TO AUGIER 12KV FEEDER STUDY CR92-27.
MEMO, W. PYL TO J.N. ROIK, 1995 05 25, 12KV SUPPLY TO WESTFAIR FOODS ON SCHOOL ROAD, ST JAMES W.O.#32730.

REVISION:
REFLECTS REVISED ACTIVITY AND OVERHEAD RATES.

CONTINGENCY: $ 48,000

IN SERVICE DATES			Base estimate
1999 10 31	516		199903 L3
			Work start date 1998 04 01

	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
PREV. AUTHORITY Authorized to date:	60		3			63
1999/00	389	15	10			414
TOTAL	449	15	13			477
REV. AMOUNTS:						
Authorized to date:	60		3			63
Over(under)expend:						
Auth Req.: 1999/00	430	15	8			453
TOTAL	490	15	11			516

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number: 02-00-6985

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1996 10	555	NEW ITEM
1997 10	472	ESTIMATE RAISED TO A DETAILED LEVEL III, RESULTING IN A DECREASE.
1998 10	477	ISD DEFERRED FROM 1999 03 31 TO 1999 10 31, TO COINCIDE WITH BANK ADDITION.

ASSOCIATED PROJECTS

Budget reference number	Description
03-00-6154	ASSINIBOINE WILKES W65 24KV BREAKER ADDITION
03-00-6155	ASSINIBOINE WILKES W62 24KV BREAKER ADDITION
03-00-6157	ASSINIBOINE WILKES 115-24KV TRANSFORMER ADDITION
03-00-6158	ASSINIBOINE WILKES W71 24KV BREAKER ADDITION
04-00-6532	ASSINIBOINE WILKES W65 24KV FEEDER ADDITION
04-00-6533	ASSINIBOINE WILKES W62 24KV FEEDER ADDITION
04-00-6534	ASSINIBOINE WILKES AVE W71 24KV FEEDER ADDITION
05-00-6571	ASSINIBOINE WILKES BANK 1 ADDITION COMMUNICATION

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	7					7	7
May	7					7	14
Jun	8	-1	1			8	22
Jul	71	2	1			74	96
Aug	103	4	1			108	204
Sep	115	5	2			122	326
Oct	68	3	3			74	400
Nov	3					3	403
Dec							403
Jan							403
Feb							403
Mar	48	2				50	453
TOTAL	430	15	8			453	453
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item

205

Title			Budget reference number
ASSINIBOINE WILKES W65 24KV BREAKER ADDITION			03-00-6154
Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	71018

DESCRIPTION:
TERMINATE 24KV W65 FEEDER LINE AT ASSINIBOINE WILKES AVE STATION. INSTALL 1-25KV 1500 MVA CIRCUIT BREAKER AND ASSOCIATED EQUIPMENT.

JUSTIFICATION:
ELSEWHERE IN THE BUDGET, JUSTIFICATION IS GIVEN FOR THE CONSTRUCTION OF W65 FEEDER LINE FROM ASSINIBOINE WILKES AVE STATION. THIS ITEM PROVIDES FOR THE TERMINATION OF W65 FEEDER LINE.

REFERENCE:
MEMO, W. PYL TO C.V. THIO, 1996 01 10, CENTRAL REGION 24KV STUDY REQUIREMENTS.
MEMO, L.A. MILLER TO W. PYL, 1996 01 09, REPLY TO AUGIER 12KV FEEDER STUDY CR92-27.
MEMO, W. PYL TO J.N. ROIK, 1996 05 25, 12KV SUPPLY TO WESTFAIR FOODS ON SCHOOL ROAD, ST JAMES WORK ORDER #32730.
SYSTEM PLANNING REPORT SPD 97/5 'WINNIPEG SUBURBAN WEST AREA SYSTEM IMPROVEMENTS'.

REVISION:
COST DECREASED BECAUSE TWO BREAKER ADDITION PROJECTS WERE DESIGNED AND INSTALLED TO THE SAME ISD RESULTING IN DECREASED LABOR COSTS.

IN SERVICE DATES				Base estimate
1999 04 30	228			199610 L2
				Work start date 1996 12 01

	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
PREV. AUTHORITY Authorized to date:	205		21			226
1999/00	35					35
TOTAL	240		21			261
REV. AMOUNTS:						
Authorized to date:	205		21			226
Over(under)expend:						
Auth 1999/00 Req.:			2			2
TOTAL	205		23			228

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number: 03-00-6154

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1996 10	213	NEW ITEM
1997 10	241	ISD DEFERRED FROM 97 07 31 TO 98 06 30.
1998 10	262	ISD DEFERRED FROM 1998 06 30 TO 1998 10 31.

ASSOCIATED PROJECTS

Budget reference number	Description
02-00-6985	ASSINIBOINE WILKES YV5 115KV TRANSMISSION LINE TAP
03-00-6155	ASSINIBOINE WILKES W62 24KV BREAKER ADDITION
03-00-6157	ASSINIBOINE WILKES 115-24KV TRANSFORMER ADDITION
03-00-6158	ASSINIBOINE WILKES W71 24KV BREAKER ADDITION
04-00-6532	ASSINIBOINE WILKES W65 24KV FEEDER ADDITION
04-00-6533	ASSINIBOINE WILKES W62 24KV FEEDER ADDITION
04-00-6534	ASSINIBOINE WILKES AVE W71 24KV FEEDER ADDITION
05-00-6571	ASSINIBOINE WILKES BANK 1 ADDITION COMMUNICATION

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr			2			2	2
May							2
Jun							2
Jul							2
Aug							2
Sep							2
Oct							2
Nov							2
Dec							2
Jan							2
Feb							2
Mar							2
TOTAL			2			2	2
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item

206

Title			Budget reference number
ASSINIBOINE WILKES W62 24KV BREAKER ADDITION			03-00-6155
Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	70333

DESCRIPTION:
TERMINATE 24KV W62 FEEDER LINE AT ASSINIBOINE WILKES AVE STATION. INSTALL 1-25KV 1500 MVA CIRCUIT BREAKER AND ASSOCIATED EQUIPMENT.

JUSTIFICATION:
ELSEWHERE IN THE BUDGET, JUSTIFICATION IS GIVEN FOR THE CONSTRUCTION OF W62 FEEDER LINE FROM ASSINIBOINE WILKES AVE STATION. THIS ITEM PROVIDES FOR THE TERMINATION OF W62 FEEDER LINE.

REFERENCE:
MEMO, W. PYL TO C.V. THIO, 1996 01 10, 'CENTRAL REGION 24KV STUDY REQUIREMENTS'.
MEMO, L.A. MILLER TO W. PYL, 1996 01 09, 'REPLY TO AUGIER 12KV FEEDER STUDY CR92-27'.
MEMO, W. PYL TO J.N. ROIK, 1995 05 25, '12KV SUPPLY TO WESTFAIR FOODS ON SCHOOL ROAD, ST JAMES W.O. #32730.
SYSTEM PLANNING REPORT SPD 97/5 'WINNIPEG SUBURBAN WEST AREA SYSTEM IMPROVEMENTS'.

REVISION:
REFLECTS REVISED ACTIVITY AND OVERHEAD RATES.

CONTINGENCY: $20,000

IN SERVICE DATES				Base estimate
1999 10 31	236			199704 L2
				Work start date 1997 08 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:	106		6			112
1999/00	107	9	3			119
2000/01						
TOTAL	213	9	9			231
REV. AMOUNTS:						
Authorized to date:	106		6			112
Over(under)expend:						
Auth 1999/00	113	5	6			124
Req.: 2000/01						
TOTAL	219	5	12			236

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

CAPITAL EXPENDITURE REVISION

Budget reference number 03-00-6155

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1996 10	221	NEW ITEM.
1997 10	223	ISD ADVANCED 1 YEAR FROM 1999. ESTIMATE REFLECTS REVISED COSTING METHODOLOGY IMPLEMENTED WITH THE NEW FINANCIAL REPORTING SYSTEM. ALSO REFLECTS REVISED INTEREST AND ESCALATION RATES.
1998 10	232	ISD DEFERRED FROM 1998 06 30 TO 1999 10 31.

ASSOCIATED PROJECTS

Budget reference number	Description
02-00-6985	ASSINIBOINE WILKES YV5 115KV TRANSMISSION LINE TAP
03-00-6154	ASSINIBOINE WILKES W65 24KV BREAKER ADDITION
03-00-6157	ASSINIBOINE WILKES 115-24KV TRANSFORMER ADDITION
03-00-6158	ASSINIBOINE WILKES W71 24KV BREAKER ADDITION
04-00-6532	ASSINIBOINE WILKES W65 24KV FEEDER ADDITION
04-00-6533	ASSINIBOINE WILKES W62 24KV FEEDER ADDITION
04-00-6534	ASSINIBOINE WILKES AVE W71 24KV FEEDER ADDITION
05-00-6571	ASSINIBOINE WILKES BANK 1 ADDITION COMMUNICATION

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr			1			1	1
May			1			1	2
Jun			1			1	3
Jul	-8	-1	1			-8	-5
Aug	34	1	1			36	31
Sep	34	1	1			36	67
Oct	53	3	1			57	124
Nov							124
Dec							124
Jan							124
Feb							124
Mar		1	-1				124
TOTAL	113	5	6			124	124
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item

207

Title			Budget reference number
ASSINIBOINE WILKES W71 24KV BREAKER ADDITION			03-00-6158
Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	71020

DESCRIPTION:
TERMINATE 24KV W71 FEEDER LINE AT ASSINIBOINE WILKES AVE STATION. INSTALL 1-25KV 1500 MVA CIRCUIT BREAKER AND ASSOCIATED EQUIPMENT.

JUSTIFICATION:
ELSEWHERE IN THE BUDGET, JUSTIFICATION IS GIVEN FOR THE CONSTRUCTION OF W71 FEEDER LINE FROM ASSINIBOINE WILKES AVE STATION. THIS ITEM PROVIDES FOR THE TERMINATION OF W71 FEEDER LINE.

REFERENCE:
MEMO, W. PYL TO C.V. THIO, 1996 01 10, CENTRAL REGION 24KV STUDY REQUIREMENTS.
MEMO, L.A. MILLER TO W. PYL, 1996 01 09, REPLY TO AUGIER 12KV FEEDER STUDY CR92-27.
MEMO, W. PYL TO J.N. ROIK, 1995 05 25, 12KV SUPPLY TO WESTFAIR FOODS ON SCHOOL ROAD, ST JAMES W.O.#32730.

REVISION:
COST DECREASED BECAUSE TWO BREAKER ADDITION PROJECTS WERE DESIGNED AND INSTALLED TO THE SAME ISD RESULTING IN DECREASED LABOR COSTS.

IN SERVICE DATES				Base estimate
1999 04 30	189			199610 L2
				Work start date 1996 12 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:	168		20			188
1999/00	80					80
TOTAL	248		20			268
REV. AMOUNTS:						
Authorized to date:	168		20			188
Over(under)expend:						
Auth 1999/00 Req.:			1			1
TOTAL	168		21			189

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

CAPITAL EXPENDITURE REVISION

Budget reference number: 03-00-6158

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1997 10	242	ISD DEFERRED FROM 97 07 31 TO 98 06 30
1998 10	268	ISD DEFERRED FROM 1998 06 30 TO 1998 10 31.
		19,000

ASSOCIATED PROJECTS

Budget reference number	Description
02-00-6985	ASSINIBOINE WILKES YV5 115KV TRANSMISSION LINE TAP
03-00-6154	ASSINIBOINE WILKES W65 24KV BREAKER ADDITION
03-00-6155	ASSINIBOINE WILKES W62 24KV BREAKER ADDITION
03-00-6157	ASSINIBOINE WILKES 115-24KV TRANSFORMER ADDITION
04-00-6532	ASSINIBOINE WILKES W65 24KV FEEDER ADDITION
04-00-6533	ASSINIBOINE WILKES W62 24KV FEEDER ADDITION
04-00-6534	ASSINIBOINE WILKES AVE W71 24KV FEEDER ADDITION
05-00-6571	ASSINIBOINE WILKES BANK 1 ADDITION COMMUNICATION

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr			1			1	1
May							1
Jun							1
Jul							1
Aug							1
Sep							1
Oct							1
Nov							1
Dec							1
Jan							1
Feb							1
Mar							1
TOTAL			1			1	1
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item

208

Title			Budget reference number
ASSINIBOINE WILKES 115-24KV TRANSFORMER ADDITION			03-00-6157
Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	70646:71019

DESCRIPTION:
INSTALL ONE 80/90/100/112 MVA, 114.3-24/13.8KV, DUAL SECONDARY WINDING, TRANSFORMER IN BANK 1 POSITION AT ASSINIBOINE WILKES AVE STATION TO MATCH THE EXIXTING BANK #2 UNIT. INSTALL 7-24KV BREAKERS TO CONNECT THE TRANSFORMER AND FACILITATE SWITCHING AND PROTECTION

JUSTIFICATION:
THE SECOND BANK AT ASSINIBOINE WILKES AVE STATION IS REQUIRED TO SUPPORT THE LOAD GROWTH IN THE AREA AND TO PROVIDE BACKUP TO OTHER 24KV STATIONS NEARBY.

REFERENCE:
MEMO, W. PYL TO C.V. THIO, 1996 01 10, CENTRAL REGION 24KV STUDY REQUIREMENTS.
MEMO, L.A. MILLER TO W. PYL, 1996 01 09, REPLY TO AUGIER 12KV STUDY CR92-27.
MEMO, W. PYL TO J.N. ROIK, 1996 01 03, FUTURE PLANS FOR CHARLESWOOD AREA DISTRIBUTION.
SYSTEM PLANNING REPORT SPD 97/5 'WINNIPEG SUBURBAN WEST AREA SYSTEM IMPROVEMENTS'

REVISION:
INCREASE DUE TO THE ADDITION OF LINE PROTECTION. REFLECTS REVISED ACTIVITY AND OVERHEAD RATES.

CONTINGENCY: $349,000

IN SERVICE DATES				Base estimate
1999 12 31	5 341			199903 L3
2000 09 30	572			Work start date
				1997 04 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:	1 026		18			1 044
1999/00	3 104	28	174			3 306
2000/01	1 258					1 258
TOTAL	5 388	28	192			5 608
REV. AMOUNTS:						
Authorized to date:	1 026		18			1 044
Over(under)expend:						
Auth 1999/00	4 506	38	267			4 811
Req.: 2000/01	33	1	24			58
TOTAL	5 565	39	309			5 913

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

-MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number: 03-00-6157

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1996 10	4 630	NEW ITEM
1997 10	4 975	BREAKERS INCREASED FROM 5 TO 7 TO PROVIDE FOR OEPRATING FLEXIBILITY.
1998 10	5 608	ESTIMATE REVISED TO A DETAILED LEVEL RESULTING IN AN INCREASE.

ASSOCIATED PROJECTS

Budget reference number	Description
02-00-6985	ASSINIBOINE WILKES YV5 115KV TRANSMISSION LINE TAP
03-00-6154	ASSINIBOINE WILKES W65 24KV BREAKER ADDITION
03-00-6155	ASSINIBOINE WILKES W62 24KV BREAKER ADDITION
03-00-6158	ASSINIBOINE WILKES W71 24KV BREAKER ADDITION
04-00-6532	ASSINIBOINE WILKES W65 24KV FEEDER ADDITION
04-00-6533	ASSINIBOINE WILKES W62 24KV FEEDER ADDITION
04-00-6534	ASSINIBOINE WILKES AVE W71 24KV FEEDER ADDITION
05-00-6571	ASSINIBOINE WILKES BANK 1 ADDITION COMMUNICATION

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	1 226	4	7			1 237	1 237
May	1 141	6	16			1 163	2 400
Jun	865	8	24			897	3 297
Jul	366	8	30			404	3 701
Aug	180	3	33			216	3 917
Sep	184	3	35			222	4 139
Oct	96	3	36			135	4 274
Nov	73	2	37			112	4 386
Dec	10	1	38			49	4 435
Jan			4			4	4 439
Feb			4			4	4 443
Mar	365		3			368	4 811
TOTAL	4 506	38	267			4 811	4 811
2000/01 Apr	17		4			21	21
May	17		4			21	42
Jun			4			4	46
Jul			4			4	50
Aug			4			4	54
Sep	-1	1	4			4	58
Oct							58
Nov							58
Dec							58
Jan							58
Feb							58
Mar							58
TOTAL	33	1	24			58	58

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item

209

Title			Budget reference number
ASSINIBOINE WILKES W65 24KV FEEDER ADDITION			04-00-6532
Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	93392

DESCRIPTION:
CONSTRUCT 2.56KM OF DUCTLINE FROM ROBLIN BLVD TO PORTAGE AVE, ON MORAY AND LAKE STREETS; ON PORTAGE AVE FROM LAKE ST. TO STURGEON RD; INSTALL 5.6KM OF 3-750 KCMIL COPPER DUCTLINE CABLE FROM WILKES ASSINIBOINE AVE TO CAVALIER DR; REBUILD OAKDALE DRIVE APPROXIMATELY 2.5KM OF DOUBLE CIRCUIT 335 ACSR OVERHEAD.

JUSTIFICATION:
ADDITIONAL FEEDER LINES ARE REQUIRED TO SUPPLY LOAD GROWTH IN THE ST JAMES AND KIRKFIELD STATION AREAS AND TO INCREASE THE FEEDER TIE CAPACITY IN THE AREA.

REFERENCE:
MEMO, W. PYL TO C.V. THIO, 1996 01 10, 'CENTRAL REGION 24KV STUDY REQUIREMENTS'.
MEMO, L.A. MILLER TO W. PYL, 1996 01 09, 'REPLY TO AUGIER 12KV FEEDER STUDY CR92-27'.
MEMO, W. PYL TO J.N. ROIK, 1995 05 25, '12KV SUPPLY TO WESTFAIR FOODS ON SCHOOL ROAD', ST JAMES W.O.#32730.

REVISION:
CONSTRUCTION MANHOURS ARE SIGNIFICANTLY LESS THAN PREVIOUSLY ESTIMATED. CONTRACTOR COSTS FOR DUCTLINE WORK ARE $500,000 LESS THAN ESTIMATED. ALUMINIUM CABLE USED INSTEAD OF COPPER AND DIRECT-BURIED WHICH IS MORE COST EFFECTIVE. 500M OF WORK ON CAVALIER DRIVE WAS NOT REQUIRED.

IN SERVICE DATES				Base estimate
1999 05 31	3 451			199707 L4
				Work start date 1997 08 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:	3 062		235	-2		3 295
1999/00	1 391					1 391
TOTAL	4 453		235	-2		4 686
REV. AMOUNTS:						
Authorized to date:	3 062		235	-2		3 295
Over(under)expend:						
Auth 1999/00 Req.:	107		47			154
TOTAL	3 169		282	-2		3 449

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number: 04-00-6532

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1996 10	3 860	NEW ITEM
1997 10	5 009	ESTIMATE REFLECTS COSTING METHODDOLOGY IMPLEMENTED WITH THE NEW FINANCIAL REPORTING SYSTEM. IT ALSO REFLECTS REVISED INTEREST AND ESCALATION. IN-SERVICE DATE REVISED DUE TO CAPITAL BUDGET CONSTRAINTS.
1998 10	4 692	ISD DEFERRED FROM 1998 06 30 TO 1998 10 31. REVISED ACTIVITY AND OVERHEAD RATES.
1999 10	3 393	CONSTRUCTION MANHOURS SIGNIFICANTLY LESS THAN EXPECTED. DUCTLINE COSTS LESS THAN ANTICIPATED. ALUMINUM CABLE USED INSTEAD OF COPPER AND DIRECT-BURIED WHICH IS MORE COST EFFECTIVE. 500M OF WORK ON CAVALIER DRIVE NOT REQUIRED.

ASSOCIATED PROJECTS

Budget reference number	Description
02-00-6985	ASSINIBOINE WILKES YV5 115KV TRANSMISSION LINE TAP
03-00-6154	ASSINIBOINE WILKES W65 24KV BREAKER ADDITION
03-00-6155	ASSINIBOINE WILKES W62 24KV BREAKER ADDITION
03-00-6157	ASSINIBOINE WILKES 115-24KV TRANSFORMER ADDITION
03-00-6158	ASSINIBOINE WILKES W71 24KV BREAKER ADDITION
04-00-6533	ASSINIBOINE WILKES W62 24KV FEEDER ADDITION
04-00-6534	ASSINIBOINE WILKES AVE W71 24KV FEEDER ADDITION
05-00-6571	ASSINIBOINE WILKES BANK 1 ADDITION COMMUNICATION

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	107		23			130	130
May			24			24	154
Jun							154
Jul							154
Aug							154
Sep							154
Oct							154
Nov							154
Dec							154
Jan							154
Feb							154
Mar							154
TOTAL	107		47			154	154
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item

210

Title			Budget reference number
ASSINIBOINE WILKES W62 24KV FEEDER ADDITION			04-00-6533
Originating division: Planning & Control	Coordinating division: Design	Constructing division: Construction	Project Order Group (Range): 93391

DESCRIPTION:
CONSTRUCT ABOUT 0.5 KM OF 750 KCMIL SINGLE CIRCUIT 25 KV UNDERGROUND FEEDER LINE FROM ASSINIBOINE WILKES AVENUE STATION TO WILKES AVENUE AND FAIRMONT ROAD. CONTINUE FOR 3.25 KM WITH 336 ACSR CONDUCTOR USING DOUBLE CIRCUIT 25 KV OVERHEAD FEEDER LINE CONSTRUCTION TO COMMUNITY ROW AND RANNOCK AVENUE. CONTINUE APPROXIMATELY 2.4 KM WITH A SINGLE CIRCUIT 336 ACSR OVERHEAD LINE TO AN EXISTING DISTRIBUTION CENTRE DC 052 NEAR ROBLIN BOULEVARD.

JUSTIFICATION:
ADDITIONAL FEEDER LINES ARE REQUIRED TO SUPPLY LOAD GROWTH IN THE ST JAMES AND KIRKFIELD STATION AREAS AND TO INCREASE THE FEEDER TIE CAPACITY IN THE AREA.

REFERENCE:
MEMO, W.PYL TO C.V. THIO, 1996 01 10, 'CENTRAL REGION 24KV STUDY REQUIREMENTS'.
MEMO, L.A. MILLER TO W. PYL, 1996 01 09, 'REPLY TO AUGIER 12KV FEEDER STUDY CR92-27'.
MEMO, W. PYL TO J.N. ROIK, 1995 05 25, '12KV SUPPLY TO WESTFAIR FOODS ON SCHOOL ROAD', ST JAMES W.O.#32730
REPORT SPD 97/5, 'WINNIPEG SUBURBAN WEST AREA SYSTEM IMPROVEMENTS, 1998 04 14.
DRAFT REPORT DPW 99-01, 'RANNOCK 12 KV STATION AREA, CABLE REPLACEMENT AND 24 KV CONVERSION, 1999 02 01'.

REVISION:
CIRCUIT LENGTH INCREASED (FROM 3.45 TO 5.9 KM) TO INTEGRATE WITH DISTRIBUTION PLANNING - WINNIPEG'S SYSTEM IMPROVEMENTS IN THE AREA.

IN SERVICE DATES				Base estimate
1999 10 31	1 135			199704 L2
				Work start date: 1997 12 01

	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
PREV. AUTHORITY Authorized to date: 1999/00	563	20	21			604
TOTAL	563	20	21			604
REV. AMOUNTS: Authorized to date: Over(under)expend: Auth Req.: 1999/00	1 114	8	13	-66	-8	1 061
TOTAL	1 114	8	13	-66	-8	1 061

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

CAPITAL EXPENDITURE REVISION

Budget reference number 04-00-6533

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1996 10	480	NEW ITEM
1997 10	603	IN SERVICE DATE ADVANCED ONE YEAR. ESTIMATE REFLECTS REVISED COSTING METHODOLOGY IMPLEMENTED WITH THE NEW FINANCIAL REPORTING SYSTEM. IT ALSO REFLECTS REVISED INTEREST AND ESCALATION. PROJECT SCOPE REMAINS UNCHANGED.
1998 10	646	ISD DEFERRED FROM 1998 06 30 TO 1999 10 31.
1999 10	1 061	CIRCUIT LENGTH INCREASED (FROM 3.45 TO 5.9 KM) TO INTEGRATE WITH DISTRIBUTION PLANNING - WINNIPEG'S SYSTEM IMPROVEMENTS IN THE AREA.

ASSOCIATED PROJECTS

Budget reference number	Description
02-00-6985	ASSINIBOINE WILKES YV5 115KV TRANSMISSION LINE TAP
03-00-6154	ASSINIBOINE WILKES W65 24KV BREAKER ADDITION
03-00-6155	ASSINIBOINE WILKES W62 24KV BREAKER ADDITION
03-00-6157	ASSINIBOINE WILKES 115-24KV TRANSFORMER ADDITION
03-00-6158	ASSINIBOINE WILKES W71 24KV BREAKER ADDITION
04-00-6532	ASSINIBOINE WILKES W65 24KV FEEDER ADDITION
04-00-6534	ASSINIBOINE WILKES AVE W71 24KV FEEDER ADDITION
05-00-6571	ASSINIBOINE WILKES BANK 1 ADDITION COMMUNICATION

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	15	1				16	16
May	15	1				16	32
Jun	15	1				16	48
Jul	15	1				16	64
Aug	661	2				663	727
Sep	192	2	5			199	926
Oct	201		8	-8	-66	135	1 061
Nov							1 061
Dec							1 061
Jan							1 061
Feb							1 061
Mar							1 061
TOTAL	1 114	8	13	-8	-66	1 061	1 061
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item

214

Title			Budget reference number
ASSINIBOINE WILKES AVE W71 24KV FEEDER ADDITION			04-00-6534
Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	93331

DESCRIPTION:
INSTALL 1.15KM OF 3.-750KCMIL COPPER DUCTLINE CABLE FROM WILKES ASSINIBOINE STATION TO OAKDALE AND RIDGEWOOD BLVD. INSTALL 2.064KM OF 750KCMIL COPPER DUCTLINE CABLE FROM ROBLIN BLVD AND MORAY TO STURGEON RD AND PORTAGE AVE. DIRECT BURY 1.6KM OF 750KCMIL ALUMINUM CABLE FROM STURGEON RD AND PORTAGE AVE TO STURGEON AVE AND NESS AVE COMPLETE WITH 5 SWITCHING CUBICLES.

JUSTIFICATION:
ADDITIONAL FEEDER LINES ARE REQUIRED TO SUPPLY LOAD GROWTH IN THE ST JAMES AND KIRKFIELD STATION AREAS AND TO INCREASE THE FEEDER TIE CAPACITY IN THE AREA.

REFERENCE:
MEMO, W. PYL TO C.V. THIO, 1996 01 10,'CENTRAL REGION 24KV STUDY REQUIREMENTS'.
MEMO, L.A. MILLER TO W. PYL, 1996 01 09, 'REPLY TO AUGIER 12KV FEEDER STUDY CR92-27'.
MEMO, W. PYL TO J.N. ROIK, 1995 05 25, '12KV SUPPLY TO WESTFAIR FOODS ON SCHOOL ROAD', ST JAMES W.O.#32730.

REVISION:
CONSTRUCTION LABOUR HOURS WERE SIGNIFICANTLY LESS THAN PREVIOUSLY ESTIMATED. CONSTRUCTION DISTANCES WERE NOT AS GREAT AS PREVIOUSLY PLANNED. MORE ALUMINUM CABLE WAS USED INSTEAD OF COPPER ALLOWING FOR DIRECT-BURIAL OF CONDUCTOR WHICH IS MORE COST-EFFECTIVE.

IN SERVICE DATES				Base estimate
1999 02 28	26			199707 L3
1999 05 31	1 373			Work start date
				1997 06 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:	1 189		88	-2		1 275
1999/00	1 032					1 032
TOTAL	2 221		88	-2		2 307
REV. AMOUNTS:						
Authorized to date:	1 189		88	-2		1 275
Over(under)expend:						
Auth 1999/00	104		18			122
Req.:						
TOTAL	1 293		106	-2		1 397

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

CAPITAL EXPENDITURE REVISION

Budget reference number: 04-00-6534

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1996 10	1 843	NEW ITEM
1997 10	2 398	ESTIMATE REFLECTS REVISED COSTING METHODOLOGY IMPLEMENTED WITH THE NEW FINANCIAL REPORTING SYSTEM. IT ALSO REFLECTS REVISED INTEREST AND ESCALATION. PROJECT SCOPE REMAINS UNCHANGED. IN-SERVICE DATE REVISED DUE TO CAPITAL BUDGET CONSTRAINTS.
1998 10	2 411	ISD DEFERRED FROM 1998 06 30 TO 1998 10 31.
1999 10	1 310	CONSTRUCTION HOURS LESS THAN ESTIMATED. FEEDER DISTANCE LESS THAN PLANNED. MORE ALUMINUM CABLE USED THAN COPPER CABLE ALLOWING FOR DIRECT-BURIAL WHICH IS MORE COST-EFFECTIVE.

ASSOCIATED PROJECTS

Budget reference number	Description
02-00-6985	ASSINIBOINE WILKES YV5 115KV TRANSMISSION LINE TAP
03-00-6154	ASSINIBOINE WILKES W65 24KV BREAKER ADDITION
03-00-6155	ASSINIBOINE WILKES W62 24KV BREAKER ADDITION
03-00-6157	ASSINIBOINE WILKES 115-24KV TRANSFORMER ADDITION
03-00-6158	ASSINIBOINE WILKES W71 24KV BREAKER ADDITION
04-00-6532	ASSINIBOINE WILKES W65 24KV FEEDER ADDITION
04-00-6533	ASSINIBOINE WILKES W62 24KV FEEDER ADDITION
05-00-6571	ASSINIBOINE WILKES BANK 1 ADDITION COMMUNICATION

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	52		9			61	61
May	52		9			61	122
Jun							122
Jul							122
Aug							122
Sep							122
Oct							122
Nov							122
Dec							122
Jan							122
Feb							122
Mar							122
TOTAL	104		18			122	122
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item

2/2

Title			Budget reference number
ASSINIBOINE WILKES BANK 1 ADDITION COMMUNICATION			05-00-6571
Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Planning & Control	Construction	70334

DESCRIPTION:
INSTALL COMMUNICATION TO UPGRADE THE PROTECTION OF ASSINIBOINE WILKES AVE STATION IN CONJUNCTION WITH THE BANK 1 ADDITION.

JUSTIFICATION:
ELSEWHERE IN THE BUDGET, JUSTIFICATION IS GIVEN FOR THE INSTALLATION OF BANK 1 AT ASSINIBOINE WILKES AVE. THIS ITEM PROVIDES COMMUNICATION DEVICES FOR THE PROTECTION OF BANK 1 AND ASSOCIATED EQUIPMENT.

REFERENCE:
MEMO, W. PYL TO C.V. THIO, 1996 01 10, 'CENTRAL REGION 24KV STUDY REQUIREMENTS'.
MEMO, L.A. MILLER TO W. PYL, 1996 01 09, 'REPLY TO AUGIER 12KV FEEDER STUDY CR92-27'.
MEMO, W. PYL TO J.N. ROIK, 1995 05 25, '12KV SUPPLY TO WESTFAIR FOODS ON SCHOOL ROAD,ST JAMES W.O.#32730'.
MEMO, H.E. WICHERT TO W.J. TISHINSKI, 1992 06 29, 'WINNIPEG 115KV SYSTEM'.
MEMO, D.W. GUNTER TO W.J. TISHINSKI, 1992 06 04, 'WINNIPEG 115KV SYSTEM'.

REVISION:
YV5 & XV47 PROTECTION CHANGES ADDED. LEASED CIRCUIT ADDED

CONTINGENCY $12,000

IN SERVICE DATES				Base estimate
1999 10 31	428			199901 L2
				Work start date 1999 01 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:	15					15
1999/00	274	12	7			293
TOTAL	289	12	7			308
REV. AMOUNTS:						
Authorized to date:	15					15
Over(under)expend:						
Auth 1999/00 Req.:	402	4	7			413
TOTAL	417	4	7			428

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

CAPITAL EXPENDITURE REVISION

Budget reference number: 05-00-6571

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1996 10	250	NEW ITEM.
1997 10	296	ESTIMATE RELECTS REVISED COSTING METHODOLOGY IMPLEMENTED WITH THE NEW FINANCIAL REPORTING SYSTEM. ALSO REFLECTS REVISED INTEREST AND ESCALATION RATES.
1998 10	307	ISD DEFERRED FROM 1999 03 31 TO 1999 10 31, TO COINCIDE WITH BANK ADDITION.

ASSOCIATED PROJECTS

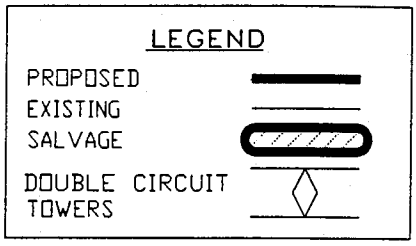
Budget reference number	Description
02-00-6985	ASSINIBOINE WILKES YV5 115KV TRANSMISSION LINE TAP
03-00-6154	ASSINIBOINE WILKES W65 24KV BREAKER ADDITION
03-00-6155	ASSINIBOINE WILKES W62 24KV BREAKER ADDITION
03-00-6157	ASSINIBOINE WILKES 115-24KV TRANSFORMER ADDITION
03-00-6158	ASSINIBOINE WILKES W71 24KV BREAKER ADDITION
04-00-6532	ASSINIBOINE WILKES W65 24KV FEEDER ADDITION
04-00-6533	ASSINIBOINE WILKES W62 24KV FEEDER ADDITION
04-00-6534	ASSINIBOINE WILKES AVE W71 24KV FEEDER ADDITION

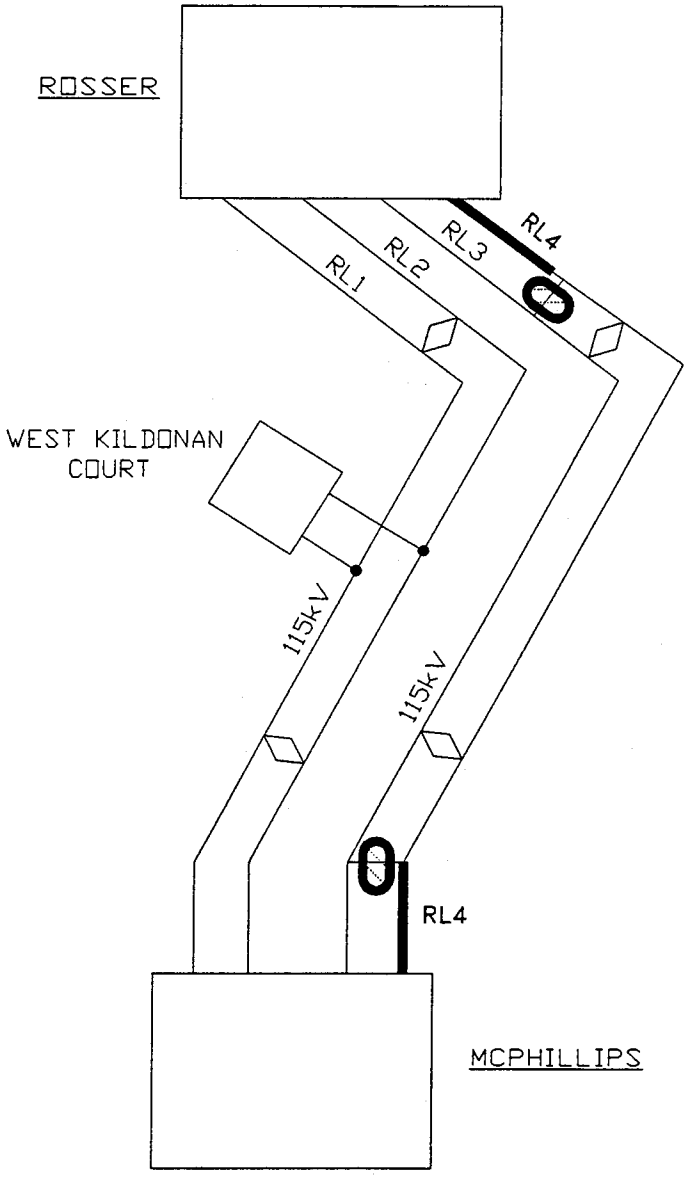
Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	26					26	26
May	42	1				43	69
Jun	47		1			48	117
Jul	47		1			48	165
Aug	47	1	1			49	214
Sep	47		2			49	263
Oct	59		2			61	324
Nov	46	1				47	371
Dec	41	1				42	413
Jan							413
Feb							413
Mar							413
TOTAL	402	4	7			413	413
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

CAPITAL BUDGET COMPLEX CONCEPTUAL DIAGRAM

ROSSER – MCPHILLIPS 115KV TRANSMISSION IMPROVEMENTS

REVISED: 1999 - 10 - 01	ISSUED BY: WNZ
COMPLEX NO. 202	





manitoba hydro

PLANNING AND CONTROL DIVISION

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

COMPLEX STATUS: [X] Planned [ ] In progress

Complex no. 202

REVISION STATUS: [ ] New complex [X] In service change [ ] Concept change [ ] Estimate change only

COMPLEX: ROSSER - MCPHILLIPS 115 KV TRANSMISSION IMPROVEMENTS

Proposal

Design and construct transmission and terminal facilities for supply to McPhillips station as follows:

Transmission: Remove jumpers at both ends of paralleled double circuit 115 KV line RL3 and extend open line ends into Rosser and McPhillips to create 115 KV line RL4.

Terminations: Extend 115 KV facilities at Rosser and McPhillips stations.

Communications: Integrated with existing facilities at Rosser and McPhillips.

JUSTIFICATION: [X] Load [ ] Service [ ] Safety [ ] Efficiency [X] Reliability [ ] Other

Explanation

Addition of a second transformer bank at West Kildonan Court station and upgrade of Winnipeg Hydro phase shifters at McPhillips station requires a transmission capacity increase between Rosser and McPhillips for load support.

Estimate Level	COMPLEX START yyyy mm
L2	1998 10

IN SERVICE DATES AND AMOUNTS

2002 10	$2367			

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	4				4	32	-28	-88
Year 99/00	7	0	1		8	72	-64	-89
00/01	82	5	4		91	372	-281	-76
01/02	374	30	22		426	1,744	-1,318	-76
02/03	1,623	155	60		1,838		1,838	
03/04								
04/05								
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	2,090	190	87		2,367	2,220	147	7

REVISION: ISD deferred one year to October 2002 due to financial constraints.

Reviewed by ORIGINATOR	yyyy mm dd 99 11 08	Reviewed by COORDINATOR	yyyy mm dd 99 11 03
Reviewed by CONSTRUCTOR	yyyy mm dd 99 11 03	Approved by VICE-PRESIDENT	yyyy mm dd 99 11 16

H2856/r Rev 99 03

Complex no. 202

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Advance or deferral impact

Deferral will cause overloading of two remaining Rosser - McPhillips 115 KV lines during an outage of double circuit line RL3.

Factors affecting timing or viability

Winnipeg Hydro Phase Shifter Upgrade.
West Kildonan Court 2nd transformer installation.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Rosser - McPhillips 115 KV T/L		53	54	54	0	0
Rosser - Terminate New McPhillips 115 KV Line		849	866	884	18	2
McPhillips - Terminate New Rosser 115 KV Line		853	870	910	40	5
Rosser - McPhillips 115 KV T/L Telecontrol		227	232	242	10	4
TOTAL		1,982	2,022	2,090	68	3

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
96 10	2,255	New complex.
1997 10	2,267	Scope unchanged, estimate reflects revised costing methodology implemented with the new financial reporting system. Also reflects revised interest and escalation rates.
1998 10	2,220	Scope unchanged.
1999 10	2,367	ISD deferred one year to October 2002 due to financial constraints.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item

213

Title	Budget reference number
ROSSER - MCPHILLIPS 115KV T/L	02-00-6986

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	70336

DESCRIPTION:
CREATE A NEW 115KV TRANSMISSION LINE BETWEEN ROSSER AND MCPHILLIPS STATIONS BY REMOVING JUMPERS ON DOUBLE CIRCUIT LINE RL3. EXTEND UNUSED CIRCUIT INTO ROSSER AND MCPHILLIPS STATIONS CREATING A NEW 115KV TRANSMISSION LINE.

JUSTIFICATION:
THE ADDITION OF A SECOND BANK AT WEST KILDONAN COURT STATION AND THE UPGRADE OF WINNIPEG HYDRO PHASE SHIFTERS AT MCPHILLIPS STATION NECESSITATES A CAPACITY INCREASE BETWEEN ROSSER AND MCPHILLIPS STATIONS.

REFERENCE:
MEMO, W.N. ZURBA TO C.V. THIO, 1996 04 23, 'ROSSER-MCPHILLIPS 115KV TRANSMISSION'.

REVISION:
ISD DEFERRED FROM 2001 10 31 TO 2002 10 31.

CONTINGENCY: $9,000

IN SERVICE DATES				Base estimate
2002 10 31	59			199704 L3
				Work start date 2001 10 01

	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
PREV. AUTHORITY						
Authorized to date:						
2000/01	4					4
2001/02	49	3	1			53
TOTAL	53	3	1			57
REV. AMOUNTS:						
Authorized to date:						
Over(under)expend:						
Auth 2001/02	4	1				5
Req.: 2002/03	50	3	1			54
TOTAL	54	4	1			59

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

1999-09-28 11:41 AM

CAPITAL EXPENDITURE REVISION

Budget reference number 02-00-6986

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1996 10	87	NEW ITEM.
1997 10	60	DETAILED ESTIMATE PREPARED FOR THIE YEAR'S SUBMISSION. ESTIMATE REFLECTS REVISED COSTING METHODOLOGY IMPLEMENTED WITH THE NEW FINANCIAL REPORTING SYSTEM. IT ALSO REFLECTS REVISED INTEREST AND ESCALATION RATES.
1998 10	57	NO CHANGE.

ASSOCIATED PROJECTS

Budget reference number	Description
03-00-6176	MCPHILLIPS: TERMINATE NEW ROSSER 115KV LINE
03-00-6177	ROSSER TERMINATION OF MCPHILLIPS 115KV LINE
05-00-6576	ROSSER - MCPHILLIPS 115KV T/L TELECONTROL

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item

214

Title			Budget reference number
MCPHILLIPS: TERMINATE NEW ROSSER 115KV LINE			03-00-6176
Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	70337

DESCRIPTION:
TERMINATE NEW 115KV LINE FROM ROSSER AT MCPHILLIPS STATION. FACILITIES WILL INCLUDE A 115KV BREAKER, ASSOCIATED EQUIPMENT, AND PROTECTION CHANGES ON EXISTING LINE RL3 AS REQUIRED.

JUSTIFICATION:
ELSEWHERE IN THE BUDGET, JUSTIFICATION IS GIVEN FOR A 115KV CIRCUIT FROM ROSSER TO MCPHILLIPS STATION. THIS ITEM PROVIDES FOR TERMINATION OF THAT LINE AT MCPHILLIPS STATION.

REFERENCE:
MEMO, W.N. ZURBA TO C.V. THIO, 1996 04 23, 'ROSSER-MCPHILLIPS 115KV TRANSMISSION'.

REVISION:
ISD DEFERRED FROM 2001 10 31 TO 2002 10 31.

CONTINGENCY: $78 000

IN SERVICE DATES				Base estimate
2002 10 31	1 034			199707 L2
				Work start date
				1998 09 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:	4					4
1999/00	44	1	3			48
2000/01	152	11	10			173
2001/02	654	54	25			733
TOTAL	854	66	38			958
REV. AMOUNTS:						
Authorized to date:	4					4
Over(under)expend:						
Auth 1999/00						
Req.: 2000/01	55	3	3			61
2001/02	172	13	12			197
2002/03	679	65	28			772
TOTAL	910	81	43			1 034

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 03-00-6176

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1996 10	984	NEW ITEM.
1997 10	981	SCOPE UNCHANGED, ESTIMATE REFLECTS REVISED COSTING METHODOLOGY IMPLEMENTED WITH THE NEW FINANCIAL REPORTING SYSTEM. ALSO REFLECTS REVISED INTEREST AND ESCALATION RATES.
1998 10	958	NO CHANGE.

ASSOCIATED PROJECTS

Budget reference number	Description
02-00-6986	ROSSER - MCPHILLIPS 115KV T/L
03-00-6177	ROSSER TERMINATION OF MCPHILLIPS 115KV LINE
05-00-6576	ROSSER - MCPHILLIPS 115KV T/L TELECONTROL

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr	4					4	4
May	4					4	8
Jun	4					4	12
Jul	4					4	16
Aug	4					4	20
Sep	5					5	25
Oct	5	1				6	31
Nov	5	1				6	37
Dec	5	1				6	43
Jan	5	1				6	49
Feb	5	1				6	55
Mar	5	-2	3			6	61
TOTAL	55	3	3			61	61

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item

215

Title			Budget reference number
ROSSER TERMINATION OF MCPHILLIPS 115KV LINE			03-00-6177
Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	70338

DESCRIPTION:
TERMINATE NEW 115KV LINE FROM MCPHILLIPS AT ROSSER STATION. FACILITIES WILL INCLUDE A 115KV CIRCUIT BREAKER AND ASSOCIATED EQUIPMENT, AND PROTECTION CHANGES ON EXISTING LINE RL3 AS REQUIRED.

JUSTIFICATION:
ELSEWHERE IN THE BUDGET, JUSTIFICATION IS GIVEN FOR A 115KV CIRCUIT FROM ROSSER TO MCPHILLIPS STATION. THIS ITEM PROVIDES FOR TERMINATION OF THAT LINE AT ROSSER STATION.

REFERENCE:
MEMO, W.N. ZURBA TO C.V. THIO, 1996 04 23, 'ROSSER-MCPHILLIPS 115KV TRANSMISSION'.

REVISION:
ISD DEFERRED FROM 2001 10 31 TO 2002 10 31.

CONTINGENCY: $78 000

IN SERVICE DATES		Base estimate
2002 10 31	1 002	199707 L2
		Work start date
		2000 04 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:						
1999/00	48	1	3			52
2000/01	148	10	10			168
2001/02	654	54	25			733
TOTAL	850	65	38			953
REV. AMOUNTS:						
Authorized to date:						
Over(under)expend:						
Auth 2000/01	34	3	1			38
Req.: 2001/02	170	14	9			193
2002/03	680	65	26			771
TOTAL	884	82	36			1 002

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

CAPITAL EXPENDITURE REVISION

Budget reference number: 03-00-6177

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1996 10	984	NEW ITEM.
1997 10	975	SCOPE UNCHANGED, ESTIMATE REFLECTS REVISED COSTING METHODOLOGY IMPLEMENTED WITH THE NEW FINANCIAL REPORTING SYSTEM. ALSO REFLECTS REVISED INTEREST AND ESCALATION RATES.
1998 10	953	NO CHANGE.

ASSOCIATED PROJECTS

Budget reference number	Description
02-00-6986	ROSSER - MCPHILLIPS 115KV T/L
03-00-6176	MCPHILLIPS: TERMINATE NEW ROSSER 115KV LINE
05-00-6576	ROSSER - MCPHILLIPS 115KV T/L TELECONTROL

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr	2					2	2
May	2					2	4
Jun	2					2	6
Jul	2					2	8
Aug	2					2	10
Sep	3	1				4	14
Oct	3	1				4	18
Nov	3	1				4	22
Dec	3	1				4	26
Jan	3	1				4	30
Feb	3	1				4	34
Mar	6	-3	1			4	38
TOTAL	34	3	1			38	38

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item

216

Title			Budget reference number
ROSSER - MCPHILLIPS 115KV T/L TELECONTROL			05-00-6576
Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Planning & Control	Construction	70339

DESCRIPTION:
DESIGN, INSTALL, AND COMMISSION REQUIRED TELECONTROL FACILITIES FOR OPERATION OF NEW ROSSER - MCPHILLIPS 115KV LINE.

JUSTIFICATION:
ELSEWHERE IN THE BUDGET, JUSTIFICATION IS GIVEN FOR SEPARATION OF PARALLELED DOUBLE CIRCUIT CONDUCTORS ON 115KV RL3 TO CREATE A NEW ROSSER - MCPHILLIPS 115KV LINE RL4. THIS ITEM PROVIDES FOR NECESSARY TELECONTROL FACILITIES FOR OPERATION OF THE NEW LINE.

REFERENCE:
MEMO, W.N. ZURBA TO C.V. THIO, 1996 94 23, 'ROSSER - MCPHILLIPS 115KV TRANSMISSION'.

REVISION:
ISD DEFERRED FROM 2001 10 31 TO 2002 10 31.

CONTINGENCY: $10 000

IN SERVICE DATES				Base estimate
2002 10 31	272			199704 L2
				Work start date 2001 08 01

	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
PREV. AUTHORITY Authorized to date:						
2000/01	25	3				28
2001/02	202	19	5			226
TOTAL	227	22	5			254
REV. AMOUNTS: Authorized to date:						
Over(under)expend:						
Auth 2001/02	28	3				31
Req.: 2002/03	214	22	5			241
TOTAL	242	25	5			272

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number: 05-00-6576

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1996 10	200	NEW ITEM.
1997 10	251	ESTIMATE REFLECTS REVISED COSTING METHODOLOGY IMPLEMENTED WITH THE NEW FINANCIAL REPORTING SYSTEM. IT ALSO REFLECTS REVISED INTEREST AND ESCALATION RATES.
1998 10	254	NO CHANGE.

ASSOCIATED PROJECTS

Budget reference number	Description
02-00-6986	ROSSER - MCPHILLIPS 115KV T/L
03-00-6176	MCPHILLIPS: TERMINATE NEW ROSSER 115KV LINE
03-00-6177	ROSSER TERMINATION OF MCPHILLIPS 115KV LINE

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

COMPLEX STATUS	Complex no.	REVISION STATUS
[X] Planned [ ] In progress	204	[ ] New complex [ ] In service change [ ] Concept change [X] Estimate change only

COMPLEX	RICHER SOUTH 230-66 KV TRANSFORMER ADDITION

Proposal

Design and construct terminal facilities at Richer South as follows:

Terminations: Extend 230 and 66 KV facilities at Richer station, including a 2nd 230-66 KV 93.3 MVA OLTC transformer and associated 66 KV circuit breaker and 40 MVA grounding bank.

JUSTIFICATION		Explanation
[X] Load	[ ] Service	The second 230-66 KV transformer is required to provide firm supply to distribution station load in the Richer area.
[ ] Safety	[ ] Efficiency	
[X] Reliability	[ ] Other	

Estimate Level	COMPLEX START (yyyy mm)
L2	2002 04

IN SERVICE DATES AND AMOUNTS				
2005 10	$4938			

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend								
Year 99/00								
00/01								
01/02								
02/03	328	33	14		375	328	47	14
03/04	328	40	48		416	364	52	14
04/05	1,892	275	157		2,324	2,300	24	1
05/06	1,454	180	188		1,822	1,807	15	1
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	4,002	528	407		4,937	4,799	138	3

REVISION	Scope unchanged.

Reviewed by	yyyy mm dd	Reviewed by	yyyy mm dd
ORIGINATOR	99 11 03	COORDINATOR	99 11 05
Reviewed by	yyyy mm dd	Approved by	yyyy mm dd
CONSTRUCTOR	99 11 03	VICE PRESIDENT	99 11 16

H2856/r Rev 99 03

Complex no. 204

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Advance or deferral impact

Deferral will decrease supply reliability in the Richer area during an outage of the existing Richer 230-66 KV transformer.

Factors affecting timing or viability

Richer area load.
Transmission improvements from St. Vital to Randolph / Hanover.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Richer South 230-66 KV Transformer Addition		3,872	3,949	4,002	53	1
TOTAL		3,872	3,949	4,002	53	1

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
96 10	4,832	New complex.
1997 10	4,788	Scope unchanged, estimate reflects revised costing methodology implemented with the new financial reporting system. Also reflects revised interest and escalation rates.
1998 10	4,799	Scope unchanged.
1999 10	4,937	Scope unchanged.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item

217

Title
RICHER SOUTH 230-66KV TRANSFORMER ADDITION

Budget reference number
03-00-6164

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
anning & Control	Design	Construction	70340

DESCRIPTION:
INSTALL A 50/66.7/83.3//93.3 MVA, 230-66KV, +/- 15% LTC TRANSFORMER AT RICHER SOUTH STATION C/W 2 72.5KV 2500 A BREAKER, A 40 MVA GROUNDING BANK, AND ASSOCIATED EQUIPMENT.

JUSTIFICATION:
PRESENTLY RICHER SOUTH STATION HAS A 50/66.7/83.3 MVA TRANSFORMER. CONTINGENCY SUPPLY IS PROVIDED BY THE ST VITAL - HANOVER 66KV SYSTEM WHICH HAS 150 MVA OF FIRM 66KV CAPACITY. THE 1995/96 WINTER LOADING OF THE RICHER SOUTH, ST VITAL - HANOVER 66KV SYSTEM WAS 149.6 MVA. PROPOSED LOAD TRANSFERS TO THE LETELLIER 66KV SYSTEM WILL DEFER REQUIREMENTS FOR ADDITIONAL 66KV CAPACITY UNTIL 2005/06. THIS ADDITIONAL CAPACITY WILL BE PROVIDED BY THE ADDITION OF A SECOND 230-66KV TRANSFORMER AT RICHER SOUTH STATION. THERE IS ALSO A PENDING LOAD TRANSFER OF HADASHVILLE STATION FROM THE WHITESHELL 33KV SYSTEM TO RICHER SOUTH.

REFERENCE:
MEMO, 'C.V. THIO TO E.T. FLOYDE, 1996 02 19',

ST VITAL - RICHER 66KV SYSTEMS'.

REVISION:
REFLECTS REVISED ACTIVITY AND OVERHEAD RATES.

CONTINGENCY: $349,000

IN SERVICE DATES		Base estimate
2005 10 31	4 938	199706 L2
		Work start date
		2002 04 01

PREV AUTHORITY Authorized to date	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
2002/03	285	32	12			329
2003/04	285	38	41			364
2004/05	1 864	290	146			2 300
2005/06	1 438	189	180			1 807
TOTAL	3 872	549	379			4 800
REV. AMOUNTS: Authorized to date: Over(under)expend:						
Auth 2002/03	328	33	14			375
Req.: 2003/04	328	40	48			416
2004/05	1 892	275	157			2 324
2005/06	1 454	181	188			1 823
TOTAL	4 002	529	407			4 938

Prepared by: yy mm dd	Approved by: yy mm dd	Approved by: yy mm dd
COORDINATOR		
Estimated by:		
ORIGINATOR	COORDINATING MANAGER	ORIGINATING MANAGER

CAPITAL EXPENDITURE REVISION

Budget reference number 03-00-6164

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1996 10	4 832	NEW ITEM
1997 10	4 789	SCOPE UNCHANGED. ESTIMATE REFLECTS REVISED COSTING METHODOLOGY IMPLEMENTED WITH THE NEW FINANCIAL REPORTING SYSTEM. REVISED INTEREST AND ESCALATION RATES.
1998 10	4 800	NO CHANGE.

ASSOCIATED PROJECTS

Budget reference number	Description

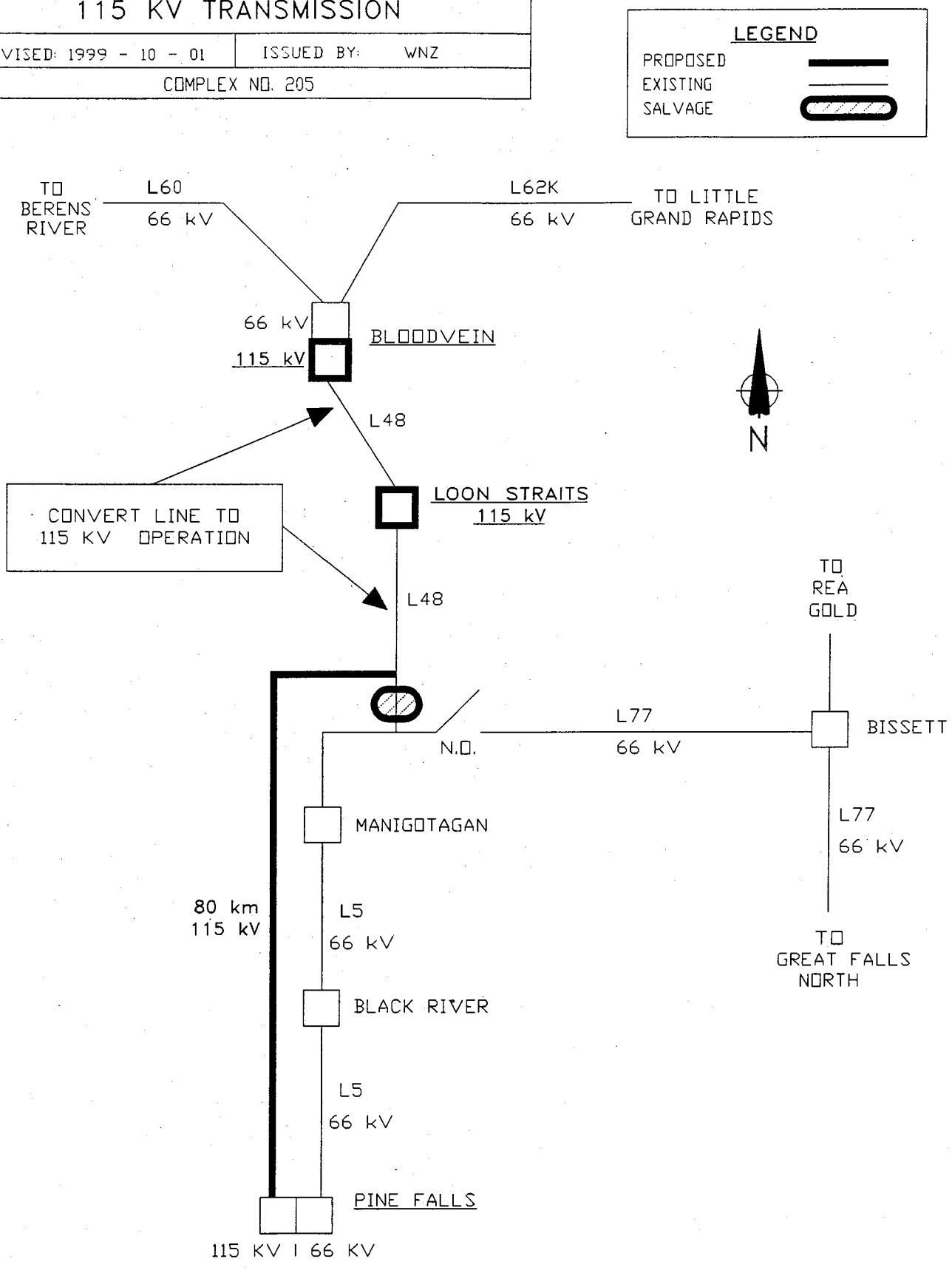
Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

CAPITAL BUDGET COMPLEX CONCEPTUAL DIAGRAM

PINE FALLS – BLOODVEIN 115 KV TRANSMISSION

REVISED: 1999 - 10 - 01 | ISSUED BY: WNZ

COMPLEX NO. 205



manitoba hydro

PLANNING AND CONTROL DIVISION

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

COMPLEX STATUS	Complex no.	REVISION STATUS
☒ Planned ☐ In progress	205	☐ New complex ☒ In service change ☐ Concept change ☐ Estimate change only

COMPLEX	PINE FALLS - BLOODVEIN 115 KV TRANSMISSION

Proposal

Perform environmental assessments and route selection, design and construct transmission and terminal facilities to provide 115 KV supply to Bloodvein station as follows:
Transmission: Construct 115 KV line 80 km Pine Falls-L48 to L5 Tap near Manigotagan. Disconnect L48 from L5 at tap location and connect L48 to new line, converting L48 from 66 KV to 115 KV operation up to Bloodvein.
Terminations: Extend 115 KV facilities at Pine Falls. Replace 66 KV transformers at Loon Straits with 2 - 115-7.2 KV 500 KVA transformers and modify station for 115 KV supply. Construct 115-66 KV station at Bloodvein, including 2 - 115-66 KV 28 MVA transformers.

JUSTIFICATION		Explanation
☒ Load	☐ Service	This complex provides increased transmission capacity required to supply Lake Winnipeg East area load increases.
☐ Safety	☐ Efficiency	
☒ Reliability	☐ Other	

Estimate Level	COMPLEX START (yyyy mm)
L2	1999 04

IN SERVICE DATES AND AMOUNTS			
2011 10 $29100			

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend								
Year 99/00						131	-131	-100
00/01						145	-145	-100
01/02						775	-775	-100
02/03						1,417	-1,417	-100
03/04						5,312	-5,312	-100
04/05						13,878	-13,878	-100
05/06						29	-29	-100
06/07	126	23	6		155		155	
07/08	126	26	20		172		172	
08/09	734	169	66		969		969	
09/10	1,218	315	201		1,734		1,734	
10/11	5,005	1440	585		7,030		7,030	
11/12	12,153	2768	696	4	15,613		15,613	
12/13	2,585	836			3,421		3,421	
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	21,947	5,577	1,574	4	29,094	21,687	7,407	34

REVISION	ISD deferred seven years to 2011 10 31

Reviewed by ORIGINATOR	yyyy mm dd 99 11 08	Reviewed by COORDINATOR	yyyy mm dd 99 11 03
Reviewed by CONSTRUCTOR	yyyy mm dd 99 11 03	Approved by VICE-PRESIDENT	yyyy mm dd 99 11 16

H2856/r Rev 99 03

Complex no. 205

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Advance or deferral impact

Deferral will reduce reliability of supply and require load curtailments in the Lake Winnipeg East area during peak load periods.

Factors affecting timing or viability

Lake Winnipeg East load growth.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Pine Falls - Bloodvein 115 KV Line		14,083	14,365	14,156	-209	-1
Pine Falls Stn. Termination of Bloodvein 115 KV Line		278	284	286	2	1
Bloodvein 115-66 KV Transformer Additions		6,452	6,581	7,173	592	9
Loon Straits Station Transformer Replacement		322	328	330	2	1
TOTAL		21,135	21,558	21,945	387	2

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy mm	TOTAL AMOUNT	AMENDMENT
96 10	19,123	New complex.
1997 10	18,190	Scope unchanged, estimate reflects revised costing methodology implemented with the new financial reporting system. Also reflects revised interest and escalation rates.
1998 10	24,646	Revised design concept - a sub standard wishbone type of transmission line was used in the previous estimate. Cursory review of the terrain also indicated that it is rougher than assumed.
1999 10	29,094	ISD deferred seven years to 2011 10 31

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item

218

Title
PINE FALLS - BLOODVEIN 115KV T/L

Budget reference number
02-00-6984

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
lanning & Control	Design	Construction	70342

DESCRIPTION:
PERFORM ROUTE ENGINEERING, ENVIRONMENTAL ASSESSMENTS, OBTAIN LICENCES, ACQUIRE PROPERTY FOR 80 KM OF NEW 115KV T/L AND CONVERSION OF 88.4 KM OF 115KV T/L (OPERATING AT 66KV) FROM PINE FALLS TO BLOODVEIN.

CONSTRUCT 80 KM OF 115KV LINE FROM PINE FALLS TO BLOODVEIN TAP. INCLUDE A 115KV RIVER CROSSING OF THE WINNIPEG RIVER AT PINE FALLS

CONVERT 88.4 KM OF 115KV (OPERATING AT 66KV) FROM BLOODVEIN TAP TO BLOODVEIN TO 115KV OPERATION.

JUSTIFICATION:
IN 1984-88 CENTRAL STATION SUPPLY WAS EXTENDED TO THE DIESEL-ELECTRIC SUPPLIED LAKE WINNIPEG EAST COMMUNITIES AT 66KV. BASED UPON PREVIOUS STUDIES THIS SYSTEM IS LIMITED TO 18 MVA LOAD SUPPLIED FROM PINE FALLS. THE 1995/96 LOADING IS 13.5 MVA. IT IS EXPECTED THAT THE LOAD LIMIT OF THIS SYSTEM WILL BE REACHED BY 2004/05.

REFERENCE:
LAKE WINNIPEG EAST COMMUNITIES DIESEL ELECTRIC VS CENTRAL SUPPLY 80-06

NOTE: COMPLETION DATE FOR PROPERTY ACQUISITION: 2009 03 31

REVISION:
ISD DEFERRED FROM 2004 10 31TO 2011 10 31. REFLECTS REVISED ACTIVITY AND OVERHEAD RATES.

CONTINGENCY: $2,340,000

IN SERVICE DATES		Base estimate
2011 10 31	18 263	199804 L2
		Work start date
		2006 04 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:						
1999/00	122	5	5			132
2000/01	121	7	17			145
2001/02	449	32	43			524
2002/03	338	31	87			456
2003/04	349	40	127			516
2004/05	10 122	1 078	136			11 336
2005/06	2 582	406				2 988
TOTAL	14 083	1 599	415			16 097
REV. AMOUNTS:						
Authorized to date:						
Over(under)expend:						
Auth 2006/07	126	24	6			156
Req.: 2007/08	126	27	20			173
2008/09	491	111	54			656
2009/10	373	94	121			588
2010/11	373	102	183			658
2011/12	10 083	2 336	193			12 612
2012/13	2 584	836				3 420
TOTAL	14 156	3 530	577			18 263

Prepared by (yy mm dd) COORDINATOR	Approved by (yy mm dd)	Approved by (yy mm dd)
Estimated by ORIGINATOR	COORDINATING MANAGER	ORIGINATING MANAGER

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 02-00-6984

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1996 10	9 754	NEW ITEM
1997 04	9 277	REVISED INTEREST AND ESCALATION RATES
1998 10	16 097	REVISED DESIGN CONCEPT - A SUB STANDARD WISHBONE TYPE OF TRANSMISSION LINE WAS USED IN THE PREVIOUS ESTIMATE. CURSORY REVIEW OF THE TERRAIN ALSO INDICATED THAT IT IS ROUGHER THAN THAT ASSUMED. THE 1997 UNIT COST WAS REFINED TO REFLECT THE ABOVE INFORMATION.

ASSOCIATED PROJECTS

Budget reference number	Description
03-00-6168	PINE FALLS TERMINATION OF BLOODVEIN 115KV LINE
03-00-6169	BLOODVEIN 115-66KV TRANSFORMER ADDITIONS
03-00-6170	LOON STRAITS TRANSFORMER REPLACEMENT

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item ___ Domestic Item 219

Title
PINE FALLS TERMINATION OF BLOODVEIN 115KV LINE

Budget reference number
03-00-6168

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	70341

DESCRIPTION:
ESTABLISH A 115KV LINE TERMINATION AT PINE FALLS TO EXTEND 115KV SUPPLY TO THE LAKE WINNIPEG EAST COMMUNITIES.

JUSTIFICATION:
ELSEWHERE IN THE BUDGET, JUSTIFICATION IS GIVEN FOR CONVERTING THE 66KV LAKE WINNIPEG EAST SYSTEM UP TO BLOODVEIN TO 115KV SUPPLY.

REFERENCE:
LAKE WINNIPEG EAST COMMUNITIES DIESEL ELECTRIC VS CENTRAL SUPPLY 80-06.

REVISION:
ISD DEFERRED FROM 2004 10 31 TO 2011 10 31 BY SYSTEM PLANNING. REFLECTS REVISED ACTIVITY AND OVERHEAD RATES.

CONTINGENCY: $24,000

IN SERVICE DATES

2011 10 31	394

Base estimate
199706 L2

Work start date
2009 10 01

	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
PREV. AUTHORITY Authorized to date						
2002/03	47	6	1			54
2003/04	95	13	9			117
2004/05	136	18	11			165
TOTAL	278	37	21			336
REV. AMOUNTS Authorized to date: Over(under)expend:						
Auth 2009/10	48	14	1			63
Req. 2010/11	97	29	12			138
2011/12	141	36	16			193
TOTAL	286	79	29			394

Prepared by: yy mm dd COORDINATOR Approved by: yy mm dd Approved by: yy mm dd

Estimated by: ORIGINATOR COORDINATING MANAGER ORIGINATING MANAGER

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 03-00-6168

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1996 10	323	NEW ITEM
1997 10	321	SCOPE UNCHANGED. ESTIMATE REFLECTS REVISED COSTING METHODOLOGY IMPLEMENTED WITH THE NEW FINANCIAL REPORTING SYSTEM. REFLECTS REVISED INTEREST AND ESCALATION RATES.
1998 10	336	NO CHANGE

ASSOCIATED PROJECTS

Budget reference number	Description
02-00-6984	PINE FALLS - BLOODVEIN 115KV T/L
03-00-6169	BLOODVEIN 115-66KV TRANSFORMER ADDITIONS
03-00-6170	LOON STRAITS TRANSFORMER REPLACEMENT

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item ___ Domestic Item 220

Title: BLOODVEIN 115-66KV TRANSFORMER ADDITIONS

Budget reference number: 03-00-6169

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	70343

DESCRIPTION:
PERFORM ENVIRONMENTAL ASSESSMENTS, OBTAIN LICENCES, AND ACQUIRE PROPERTY FOR A 115-66KV ANNEX AT THE EXISTING BLOODVEIN STATION.

INSTALL 3 - 7.5/10/12.5//14 MVA THREE PHASE 15-66KV, +/- 15% LTC EQUIPPED TRANSFORMERS AT BLOODVEIN STATION. INCLUDE 1 - 115KV AND 1- 66KV BREAKERS, GROUNDING BANK, PT'S, STRUCTUES, AUXILIARY EQUIPMENT, LINE TERMINATIONS AND SITE IMPROVEMENTS.

JUSTIFICATION:
ELSEWHERE IN THE BUDGET, JUSTIFICATION IS GIVEN FOR CONVERTING THE 66KV LAKE WINNIPEG EAST SYSTEM UP TO BLOODVEIN TO 115KV SUPPLY. THIS 115-66KV STATION WILL PROVIDE 66KV SUPPLY TO BLOODVEIN, BERENS RIVER, POPLAR RIVER AND LITTLE GRAND RAPIDS STATIONS.

REFERENCE:
LAKE WINNIPEG EAST COMMUNITIES DIESEL ELECTRIC VS CENTRAL SUPPLY 80-06

REVISION:
ISD DEFERRED FROM 2004 10 31TO 2011 10 31 BY SYSTEM PLANNING. REFLECTS REVISED ACTIVITY AND OVERHEAD RATES.

CONTINGENCY: $ 643,000

IN SERVICE DATES: 2011 10 31 — 9 976

Base estimate: 199707 L2

Work start date: 2008 04 01

PREV. AUTHORITY Authorized to date:	GROSS	ESCALATION	INT CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
2001/02	223	20	9			252
2002/03	697	75	55			827
2003/04	3 770	499	236			4 505
2004/05	1 762	167	309			2 238
TOTAL	6 452	761	609			7 822
REV. AMOUNTS:						
Authorized to date:						
Over(under)expend:						
Auth 2008/09	243	57	12			312
Req.: 2009/10	725	190	75			990
2010/11	4 390	1 267	372			6 029
2011/12	1 815	362	468			2 645
TOTAL	7 173	1 876	927			9 976

Prepared by: yy mm dd — COORDINATOR
Approved by: yy mm dd — COORDINATING MANAGER
Approved by: yy mm dd — ORIGINATING MANAGER
Estimated by: — ORIGINATOR

CAPITAL EXPENDITURE REVISION

Budget reference number: 03-00-6169

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1996 10	8 668	NEW ITEM
1997 10	8 203	SCOPE UNCHANGED. ESTIMATE REFLECTS REVISED COSTING METHODOLOGY IMPLEMENTED WITH THE NEW FINANCIAL REPORTING SYSTEM. REFLECTS REVISED INTEREST AND ESCALATION RATES.
1998 10	7 822	DELAYED ISD FROM 2004 04 30 TO 2004 10 31, DELAYS WORK START BY 2 YEARS TO 2001 04 01.

ASSOCIATED PROJECTS

Budget reference number	Description
02-00-6984	PINE FALLS - BLOODVEIN 115KV T/L
03-00-6168	PINE FALLS TERMINATION OF BLOODVEIN 115KV LINE
03-00-6170	LOON STRAITS TRANSFORMER REPLACEMENT

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item 221

Title
LOON STRAITS TRANSFORMER REPLACEMENT

Budget reference number
03-00-6170

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
nning & Control	Design	Construction	70344

DESCRIPTION:
REPLACE THE LOON STRAITS 2 X 333KVA, 66 -7.2KV SINGLE PHASE TRANSFORMERS WITH 2 X 500 KVA,115 - 7.2KV UNITS AND MODIFY THE STATION FOR 115KV SUPPLY.

JUSTIFICATION:
ELSEWHERE IN THE BUDGET, JUSTIFICATION IS GIVEN FOR CONVERTING THE 66KV LAKE WINNIPEG EAST SYSTEM UP TO BLOODVEIN TO 115KV SUPPLY. THIS WILL REQUIRE CONVERSION OF LOON STRAITS STATION FROM 66KV TO 115KV SUPPLY.

REFERENCE:
LAKE WINNIPEG EAST COMMUNITIES DIESEL ELELCTRIC VS CENTRAL SUPPLY 80-06

REVISION:
ISD DEFERRED FROM 2004 10 31 TO 2011 10 31. REFLECTS REVISED ACTIVITY AND OVERHEAD RATES.

CONTINGENCY: $29,000

IN SERVICE DATES

		Base estimate
2011 10 31	466	199706 L2
		Work start date
		2009 04 01

PREV. AUTHORITY Authorized to date.	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
2002/03	69	7	3			79
2003/04	141	19	13			173
2004/05	112	16	15	-4		139
TOTAL	322	42	31	-4		391
REV. AMOUNTS:						
Authorized to date:						
Over(under)expend:						
Auth 2009/10	71	18	4			93
Req. 2010/11	145	41	18			204
2011/12	114	34	20	-4		164
TOTAL	330	93	42	-4		461

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR		COORDINATING MANAGER		ORIGINATING MANAGER

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 03-00-6170

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1996 10	378	NEW ITEM
1997 10	389	SCOPE UNCHANGED. ESTIMATE REFLECTS REVISED COSTING METHODOLOGY IMPLEMENTED WITH THE NEW FINANCIAL REPORTING SYSTEM. REFLECTS REVISED INTEREST AND ESCALATION RATES.
1998 10	391	NO CHANGE

ASSOCIATED PROJECTS

Budget reference number	Description
02-00-6984	PINE FALLS - BLOODVEIN 115KV T/L
03-00-6168	PINE FALLS TERMINATION OF BLOODVEIN 115KV LINE
03-00-6169	BLOODVEIN 115-66KV TRANSFORMER ADDITIONS

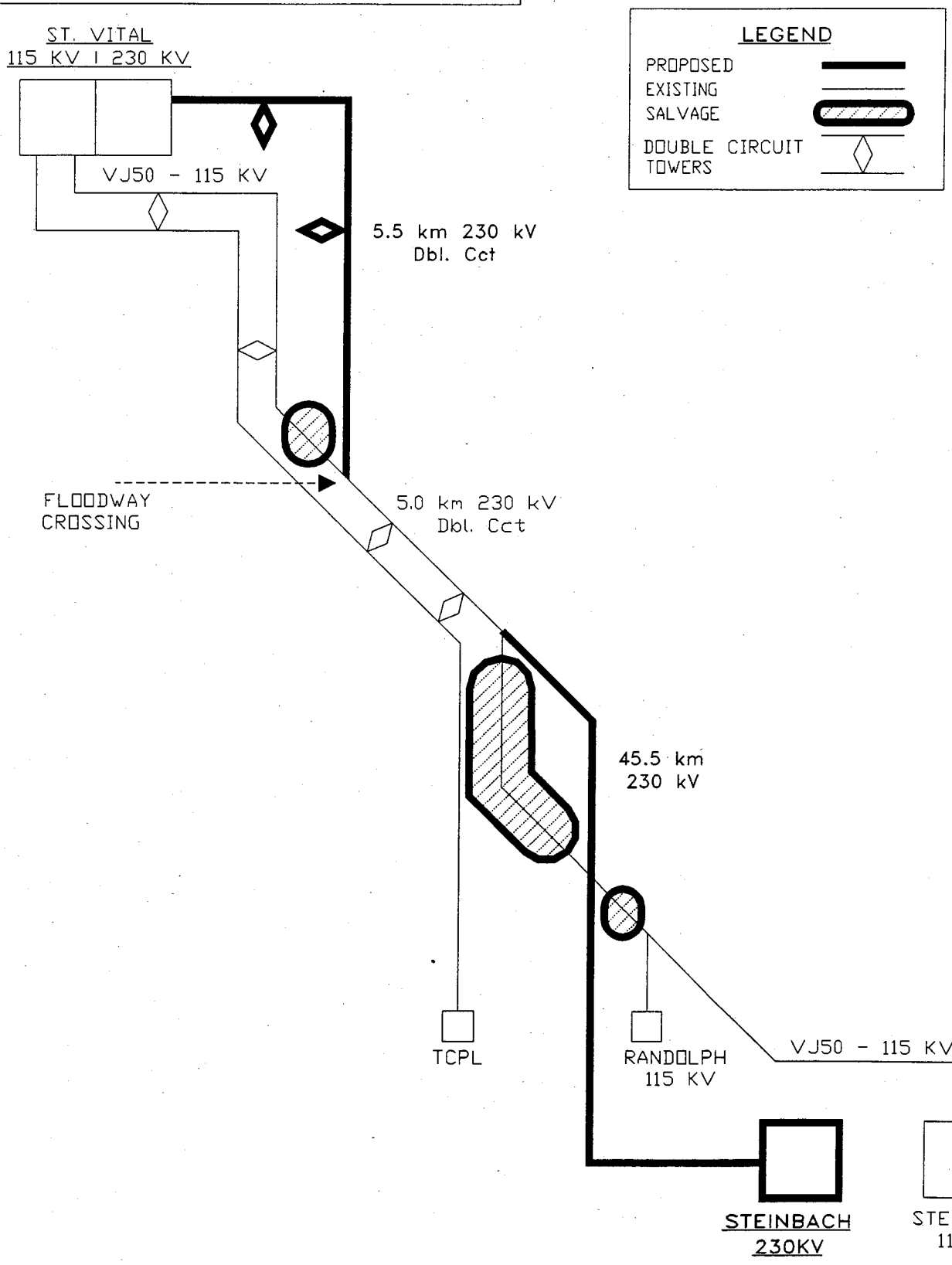
Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

CAPITAL BUDGET COMPLEX CONCEPTUAL DIAGRAM

ST. VITAL – STEINBACH 230KV TRANSMISSION

REVISED: 1999 - 10 - 01 | ISSUED BY: WNZ

COMPLEX NO. 207



manitoba hydro

PLANNING AND CONTROL DIVISION

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

COMPLEX STATUS	Complex no.	REVISION STATUS
☒ Planned ☐ In progress	207	☐ New complex ☐ In service change ☐ Concept change ☒ Estimate change only

COMPLEX: ST. VITAL - STEINBACH 230 KV TRANSMISSION

Proposal

Perform environmental assessments and route selection, acquire property and obtain licences, design and construct transmission and terminal facilities to provide support to Steinbach as follows:
Transmission: Construct 230 KV double cct. line strung one side only along 115 KV line VJ50 r.o.w. to location 5.5 km south of St.Vital. Construct 230 KV single cct. line 45.5 km north from Steinbach and connect to south end of double cct. line. Salvage 26.5 km of 115 KV line VJ50 from Ile des Chenes tap to Randolph station tap.
Terminations: Construct 230-66 KV station at Steinbach, including 230-66 KV 83 MVA transformer and associated 230 KV and 66 KV circuit breakers. Extend 230 KV facilities at St. Vital.
Communications: Integrate with existing facilities at St. Vital.

JUSTIFICATION		Explanation
☒ Load	☐ Service	This complex provides a 230 KV supply into the Steinbach area for support of load growth in south eastern Manitoba.
☐ Safety	☐ Efficiency	
☒ Reliability	☐ Other	

Estimate Level	COMPLEX START (yyyy mm)
L2	2004 04

IN SERVICE DATES AND AMOUNTS			
2009 10	$22259		

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend								
Year 99/00								
00/01								
01/02								
02/03								
03/04								
04/05	237	34	11		282	246	36	15
05/06	260	44	37		341	296	45	15
06/07	465	89	79		633	551	82	15
07/08	2,489	536	239		3,264	3,143	121	4
08/09	2,898	694	570		4,162	3,991	171	4
09/10	10,165	2628	784		13,577	13,441	136	1
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	16,514	4,025	1,720		22,259	21,668	591	3

REVISION: Scope unchanged.

Reviewed by	yyyy mm dd	Reviewed by	yyyy mm dd
ORIGINATOR	99 11 08	COORDINATOR	99 11 03
Reviewed by	yyyy mm dd	Approved by	yyyy mm dd
CONSTRUCTOR	99 11 16	VICE PRESIDENT	99 11 16

H2856/r Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Complex no. 207

Advance or deferral impact

Deferral will reduce reliability of supply to the Steinbach /Randolph area 66 KV and 115 KV systems.

Factors affecting timing or viability

Steinbach / Randolph area load growth.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
St. Vital - Steinbach 230 KV T/L		7,731	7,886	7,882	-4	-0
Steinbach - New 230-66 KV Station		5,566	5,677	5,769	92	2
St. Vital - Terminate Steinbach 230 KV T/L		2,058	2,099	2,179	80	4
St. Vital - Steinbach Communications Complex		654	667	684	17	3
TOTAL		16,009	16,329	16,514	185	1

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
96 10	26,352	New complex.
1997 10	21,593	5.0 km dbl cct line section btwn the floodway & Ile des Chenes tap, & VJ50 line salvage cmpltd on 97 07 24 under complex #212. Also reflects revised interest and escalation rates.
1998 10	21,668	Scope unchanged.
1999 10	22,259	Scope unchanged.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item ___ Domestic Item 222

Title: ST. VITAL - STEINBACH 230KV T/L

Budget reference number: 02-00-6987

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	70345

DESCRIPTION:
CONDUCT ENVIRONMENTAL IMPACT ASSESSMENT, SELECT A ROUTE, OBTAIN LICENCING AND ACQUIRE PROPERTY FOR RIGHT-OF-WAY. DESIGN AND CONSTRUCT 51 KM OF NEW 230KV LINE BETWEEN ST VITAL AND STEINBACH STATIONS CONSISTING OF THE FOLLOWING SECTIONS: 5.5 KM OF 1272 MCM ASCR ON ONE SIDE OF NEW DOUBLE CIRCUIT BETWEEN ST VITAL AND THE FLOODWAY. THIS LINE SECTION WILL BE CONNECTED TO THE EXISTING 5 KM LONG DOUBLE CIRCUIT BETWEEN THE FLOODWAY AND ILE DES CHENES TAP. 45.5 KM OF 954 MCM ASCR SINGLE CIRCUIT BETWEEN ILE DES CHENES TAP AND STEINBACH. SALVAGE 26.5 KM OF 115KV VJ50 BETWEEN ILE DES CHENES TAP AND RANDOLPH STATION.

NOTE: COMPLETION DATE FOR PROPERTY ACQUISITION: 2006 03 01.

JUSTIFICATION:
THIS ITEM PROVIDES A 230KV SUPPLY INTO THE STEINBACH AREA WHICH WILL SUPPORT LOAD GROWTH IN SOUTH EASTERN MANITOBA.

ILE DES CHENES TAP AND VJ50 LINE SALVAGE COMPLETED ON 1997 07 24 UNDER 'ST VITAL TO TCPL 115KV LINE ' COMPLEX # 212.

REFERENCE:
MEMO, B.C. JOROWSKI TO J.K. CHAN,1997 07 04, 'CAPITAL BUDGET CHANGE AND RE-ESTIMATE REQUEST: ST. VITAL-STEINBACH 230KV TRANSMISSION'.

REVISION:
REFLECTS REVISED ACTIVITY AND OVERHEAD RATES.

IN SERVICE DATES		Base estimate
2009 10 31	10 257	199707 L2
		Work start date: 2004 04 01

	PREV. AUTHORITY Authorized to date.	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
	2004/05	33	5	2			40
	2005/06	53	9	6			68
	2006/07	67	13	13			93
	2007/08	100	23	23			146
	2008/09	170	43	39			252
	2009/10	7 308	1 959	252			9 519
	TOTAL	7 731	2 052	335			10 118
	REV. AMOUNTS: Authorized to date: Over(under)expend:						
Auth	2004/05	40	5	2			47
Req.	2005/06	63	10	7			80
	2006/07	79	16	15			110
	2007/08	119	25	28			172
	2008/09	202	48	47			297
	2009/10	7 379	1 899	273			9 551
	TOTAL	7 882	2 003	372			10 257

Prepared by: yy mm dd COORDINATOR — Approved by: yy mm dd — Approved by: yy mm dd

Estimated by: ORIGINATOR — COORDINATING MANAGER — ORIGINATING MANAGER

CAPITAL EXPENDITURE REVISION

Budget reference number: 02-00-6987

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1996 05	15 007	NEW ITEM
1997 10	10 079	CONSTRUCTION OF THE 5 KM LONG DOUBLE CIRCUIT LINE SELECTION BETWEEN THE FLOODWAY, IDE DES CHENES TAP AND VJ50 LINE SALVAGE COMPLETED ON 1997 07 24 UNDER 'ST VITAL TO TCPL 115 KV LINE' COMPLEX #212. WORK START ADVANCED TO APR. 20004 TO ALLOW FOR ROW SELECTION.
1998 10	10 118	NO CHANGE

ASSOCIATED PROJECTS

Budget reference number	Description
03-00-6178	STEINBACH NEW 230-66KV STATION
03-00-6179	ST. VITAL TERMINATE STEINBACH 230KV T/L
05-00-6572	ST. VITAL - STEINBACH COMMUNICATION COMPLEX

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item

223

Title: STEINBACH NEW 230-66KV STATION

Budget reference number: 03-00-6178

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
nning & Control	Design	Construction	70346

DESCRIPTION:
CONDUCT ENVIRONMENTAL IMPACT ASSESSMENT, SELECT A SITE, OBTAIN LICENSING AND ACQUIRE LICENSING, DESIGN AND CONSTRUCT A NEW 230-66KV STATION LOCATED NEAR STEINBACH. INSTALL A 230-66KV, 50/66.7/83.3 MVA TRANSFORMER WITH OLTC (WITH PROVISION FOR FUTURE REPLACEMENT WITH 125 MVA BANK). TERMINATE 1-230KV LINE TO ST. VITAL AND 2-66KV LINES. FACILITIES WILL INCLUDE 1-230KV AND 2-66KV CIRCUIT BREAKERS AND ASSOCIATED EQUIPMENT.

JUSTIFICATION:
ELSEWHERE IN THE BUDGET, JUSTIFICATION IS GIVEN FOR A ST. VITAL - STEINBACH 230KV LINE. THIS ITEM PROVIDES FACILITIES TO TERMINATE THE LINE AT STEINBACH AND ESTABLISH A CONNECTION INTO THE 66KV NETWORK.

REFERENCE:
MEMO, W.N. ZURBA TO C.V. THIO, 1996 03 28, 'ST. VITAL - STEINBACH 230KV TRANSMISSION'.

REVISION:
REFLECTS REVISED ACTIVITY AND OVERHEAD RATES.

CONTINGENCY: $505 000

IN SERVICE DATES		Base estimate
2009 10 31	8 112	199706 L2
		Work start date
		2004 04 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:						
2004/05	171	27	8			206
2005/06	171	31	26			228
2006/07	171	35	47			253
2007/08	1 832	413	153			2 398
2008/09	1 746	437	377			2 560
2009/10	1 475	402	328			2 205
TOTAL	5 566	1 345	939			7 850
REV. AMOUNTS:						
Authorized to date:						
Over(under)expend:						
Auth 2004/05	197	29	9			235
Req.: 2005/06	197	33	30			260
2006/07	197	37	55			289
2007/08	1 891	407	166			2 464
2008/09	1 793	428	398			2 619
2009/10	1 494	390	361			2 245
TOTAL	5 769	1 324	1 019			8 112

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

CAPITAL EXPENDITURE REVISION

Budget reference number: 03-00-6178

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1996 06	7 714	New Item.
1997 10	7 855	SCOPE UNCHANGED, ESTIMATE REFLECTS REVISED COSTING METHODOLOGY IMPLEMENTED WITH THE NEW FINANCIAL REPORTING SYSTEM. ALSO REFLECTS REVISED INTEREST AND ESCALATION RATES.
1998 10	7 850	NO CHANGE.

ASSOCIATED PROJECTS

Budget reference number	Description
02-00-6987	ST. VITAL - STEINBACH 230KV T/L
03-00-6179	ST. VITAL TERMINATE STEINBACH 230KV T/L
05-00-6572	ST. VITAL - STEINBACH COMMUNICATION COMPLEX

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item

224

Title
ST. VITAL TERMINATE STEINBACH 230KV T/L

Budget reference number
03-00-6179

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	70347

DESCRIPTION:
TERMINATE 230KV LINE TO STEINBACH AT ST. VITAL . FACILITIES WILL INCLUDE 1-230KV CIRCUIT BREAKER, PARTIAL DEVELOPMENT OF 1-230KV BAY AND ASSOCIATED EQUIPMENT.

JUSTIFICATION:
ELSEWHERE IN THE BUDGET, JUSTIFICATION IS GIVEN FOR A ST. VITAL - STEINBACH 230KV LINE. THIS ITEM PROVIDES FACILITIES TO TERMINATE THE LINE AT ST. VITAL.

REFERENCE:
MEMO, W.N. ZURBA TO C.V. THIO, 1996 03 28, 'ST. VITAL - STEINBACH 230KV TRANSMISSION'.

REVISION:
REFLECTS REVISED ACTIVITY AND OVERHEAD RATES.

CONTINGENCY: $184 000

IN SERVICE DATES		Base estimate
2009 10 31	3 004	199706 L2
		Work start date
		2006 04 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:						
2006/07	164	33	8			205
2007/08	455	103	41			599
2008/09	792	199	115			1 106
2009/10	647	176	115			938
TOTAL	2 058	511	279			2 848
REV. AMOUNTS.						
Authorized to date:						
Over(under)expend:						
Auth. 2006/07	188	37	9			234
Req.: 2007/08	479	104	45			628
2008/09	838	201	124			1 163
2009/10	674	176	129			979
TOTAL	2 179	518	307			3 004

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR		COORDINATING MANAGER		ORIGINATING MANAGER

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 03-00-6179

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1996 10	2 788	NEW ITEM.
1997 10	2 813	SCOPE UNCHANGED, ESTIMATE REFLECTS REVISED COSTING METHODOLOGY IMPLEMENTHED WITH THE NEW FINANCIAL REPORTING SYSTEM. ALSO, REFLECTS INTEREST AND ESCALATION RATES.
1998 10	2 848	NO CHANGE.

ASSOCIATED PROJECTS

Budget reference number	Description
02-00-6987	ST. VITAL - STEINBACH 230KV T/L
03-00-6178	STEINBACH NEW 230-66KV STATION
05-00-6572	ST. VITAL - STEINBACH COMMUNICATION COMPLEX

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item 225

Title: ST. VITAL - STEINBACH COMMUNICATION COMPLEX

Budget reference number: 05-00-6572

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
anning & Control	Planning & Control	Construction	70348

DESCRIPTION:
DESIGN, INSTALL, AND COMMISSION TELECOMMUNICATION FACILITIES REQUIRED FOR OPERATION OF THE ST. VITAL - STEINBACH 230KV LINE AND STEINBACH 230 KV STATION.

JUSTIFICATION:
ELSEWHERE IN THE BUDGET, JUSTIFICATION IS GIVEN FOR BUILDING A ST. VITAL - STEINBACH 230KV LINE. THIS ITEM PROVIDES FOR THE COMMUNICATIONS, PROTECTION, AND CONTROL REQUIREMENTS FOR THE PROJECT.

REFERENCE:
MEMO, W.N. ZURBA TO C.V. THIO, 1996 03 28, 'ST. VITAL - STEINBACH 230KV TRANSMISSION'.

REVISION:
REFLECTS REVISED ACTIVITY AND OVERHEAD RATES.

CONTINGENCY: $50,000

IN SERVICE DATES: 2009 10 31 | 886

Base estimate: 199704 L2

Work start date: 2008 04 01

PREV. AUTHORITY Authorized to date	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
2008/09	58	14	2			74
2009/10	596	164	20			780
TOTAL	654	178	22			854
REV. AMOUNTS:						
Authorized to date:						
Over(under)expend:						
Auth 2008/09	65	16	2			83
Req. 2009/10	619	162	22			803
TOTAL	684	178	24			886

Prepared by (yy mm dd) COORDINATOR	Approved by (yy mm dd)	Approved by	
Estimated by ORIGINATOR	COORDINATING MANAGER	ORIGINATING MANAGER	

CAPITAL EXPENDITURE REVISION

Budget reference number 05-00-6572

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1996 10	848	New item.
1997 10	846	SCOPE UNCHANGED, ESTIMATE REFLECTS REVISED COSTING METHODOLOGY IMPLEMENTED WITH THE NEW FINANCIAL REPORTING SYSTEM.
1998 10	854	NO CHANGE.

ASSOCIATED PROJECTS

Budget reference number	Description
02-00-6987	ST. VITAL - STEINBACH 230KV T/L
03-00-6178	STEINBACH NEW 230-66KV STATION
03-00-6179	ST. VITAL TERMINATE STEINBACH 230KV T/L

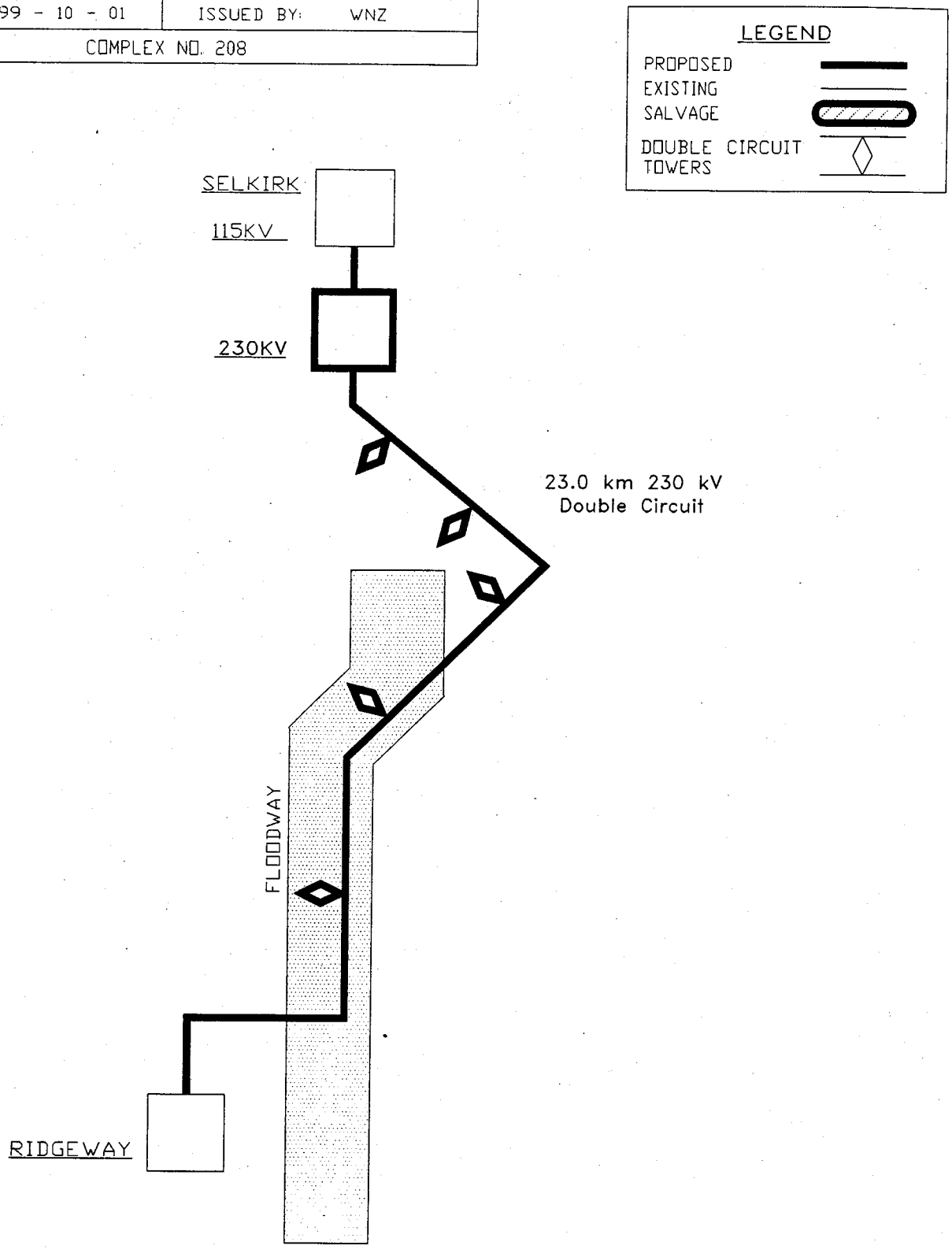
Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

CAPITAL BUDGET COMPLEX CONCEPTUAL DIAGRAM

RIDGEWAY – SELKRIK 230KV TRANSMISSION

REVISED: 1999 - 10 - 01	ISSUED BY: WNZ

COMPLEX NO. 208



manitoba hydro

PLANNING AND CONTROL DIVISION

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

COMPLEX STATUS: [X] Planned [ ] In progress

Complex no. 208

REVISION STATUS: [ ] New complex [ ] In service change [ ] Concept change [X] Estimate change only

COMPLEX: RIDGEWAY - SELKIRK 230 KV TRANSMISSION

Proposal

Perform environmental assessments and route selection, acquire property and obtain licences, design and construct transmission and terminal facilities to provide support to Selkirk station as follows:
Transmission: 230 KV double cct. line strung one side only 23 km Ridgeway to Selkirk.

Terminations: Construct 230 KV station at Selkirk G.S. 115 KV station site, including 230-115 KV 250 MVA OLTC transformer and associated 230 KV and 115 KV circuit breakers. Extend 230 KV facilities at Ridgeway.

Communications: Integrate with existing facilities at Ridgeway and Selkirk.

JUSTIFICATION

[X] Load [X] Service [ ] Safety [ ] Efficiency [X] Reliability [ ] Other

Explanation

This complex provides a 230 KV supply into the Selkirk area to alleviate customer voltage flicker problems and increase system support to the Rosser - Parkdale - Selkirk area.

Estimate Level	COMPLEX START yyyy mm
L2	2002 04

IN SERVICE DATES AND AMOUNTS

2007 10	$25099			

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend								
Year 99/00								
00/01								
01/02								
02/03	553	55	24		632	571	61	11
03/04	1,693	207	128		2,028	1,969	59	3
04/05	2,609	375	360		3,344	3,204	140	4
05/06	3,236	546	670		4,452	4,303	149	3
06/07	4,869	924	1,215		7,008	6,871	137	2
07/08	5,461	1156	1,018		7,635	7,554	81	1
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	18,421	3,263	3,415		25,099	24,472	627	3

REVISION: Scope unchanged.

Reviewed by ORIGINATOR	yyyy mm dd 99 11 03	Reviewed by COORDINATOR	yyyy mm dd 99 11 03
Reviewed by CONSTRUCTOR	yyyy mm dd 99 11 03	Approved by VICE-PRESIDENT	yyyy mm dd 99 11 16

H2856/r Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Complex no. 208

Advance or deferral impact

Deferral will cause continuation of Selkirk area industrial load customer voltage flicker difficulties and reduce reliability of supply to Selkirk - Parkdale area load.

Factors affecting timing or viability

Selkirk - Parkdale area load growth.
Winnipeg area transmission improvements.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Ridgeway - Selkirk 230 KV T/L		6,156	6,279	6,156	-123	-2
Selkirk - Establish 230-115 KV Station		9,131	9,314	9,514	200	2
Ridgeway - Terminate Selkirk 230 KV T/L		2,064	2,105	2,199	94	4
Ridgeway - Selkirk - Communications Complex		524	534	553	19	4
TOTAL		17,875	18,232	18,422	190	1

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
96 10	26,899	New complex.
1997 10	26,560	Scope unchanged, estimate reflects revised costing methodology implemented with the new financial reporting system. Also reflects revised interest and escalation rates.
1998 10	24,472	Revised to reflect current transmission line cost and advancement of start date to 2002 04 01.
1999 10	25,099	Scope unchanged.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item __ Domestic Item

226

Title
RIDGEWAY - SELKIRK 230KV T/L

Budget reference number
02-00-6988

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
anning & Control	Design	Construction	70349

DESCRIPTION:
CONDUCT ENVIRONMENTAL IMPACT ASSESSMENT, SELECT A ROUTE, ACQUIRE PROPERTY FOR RIGHT-OF-WAY AND OBTAIN LICENSING, DESIGN AND CONSTRUCT APPROX 23 KM OF 230KV DOUBLE CIRCUIT WITH ONE SIDE STRUNG USING 1272 MCM ACSR FROM RIDGEWAY TO SELKIRK STATION.

JUSTIFICATION:
THIS ITEM PROVIDES A 230KV SUPPLY INTO THE SELKIRK AREA WHICH WILL ALLEVIATE VOLTAGE FLICKER CONCERNS AND SUPPORT THE ROSSER-PARKDALE-SELKIRK 115KV SYSTEM.

REFERENCE:
MEMO, W.N. ZURBA TO C.V. THIO, 1996 04 10, 'RIDGEWAY-SELKIRK 230KV TRANSMISSION'.
NOTE: COMPLETION DATE FOR PROPERTY ACQUISITION IS 2005 04 01.

REVISION:
NO CHANGE

CONTINGENCY: $513,000.

IN SERVICE DATES		Base estimate
2007 10 31	8 100	199803 L2
		Work start date
		2002 04 01

PREV. AUTHORITY Authorized to date	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
2002/03	113	12	5			130
2003/04	300	41	21			362
2004/05	300	46	60			406
2005/06	678	126	90			894
2006/07	2 252	449	295			2 996
2007/08	2 513	559	300			3 372
TOTAL	6 156	1 233	771			8 160
REV. AMOUNTS:						
Authorized to date:						
Over(under)expend:						
Auth 2002/03	113	11	5			129
Req.: 2003/04	300	38	21			359
2004/05	300	43	60			403
2005/06	678	119	90			887
2006/07	2 252	425	298			2 975
2007/08	2 513	531	303			3 347
TOTAL	6 156	1 167	777			8 100

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 02-00-6988

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1996 05	0	NEW ITEM
1997 06	10 262	SCOPE UNCHANGED, ESTIMATE REFLECTS REVISED COSTING METHODOLOGY IMPLEMENTED WITH THE NEW FINANCIAL REPORTING SYSTEM. ALSO, REFLECTS REVISED INTEREST AND ESCALATION RATES.
1998 10	8 160	START DATE ADVANCED TO 2002 04 01 TO ALLOW FOR ROW SELECTION. ESTIMATE REVISION DUE TO UPDATE CURRENT TRANSMISSION LINE COSTS.

ASSOCIATED PROJECTS

Budget reference number	Description
03-00-6180	SELKIRK ESTABLISH 230-115KV STATION
03-00-6181	RIDGEWAY TERMINATE SELKIRK 230KV LINE
05-00-6573	RIDGEWAY-SELKIRK COMMUNICATION COMPLEX

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item ___ Domestic Item 227

Title: SELKIRK ESTABLISH 230-115KV STATION

Budget reference number: 03-00-6180

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
anning & Control	Design	Construction	70350

DESCRIPTION:
CONDUCT ENVIRONMENTAL IMPACT ASSESSMENT, AND OBTAIN LICENSING, DESIGN AND CONSTRUCT A NEW 230-115KV STATION WITHIN EXISTING SELKIRK G.S. BOUNDARIES. INSTALL 1-230-115KV 150/200/250 MVA TRANSFORMER WITH OLTC TAP RANGE +/- 10%. TERMINATE 230KV LINE TO RIDGEWAY. FACILITIES WILL INCLUDE 1-230KV CIRCUIT BREAKER, 2-115KV BREAKERS IN A NEW BAY AND ASSOCIATED EQUIPMENT.

JUSTIFICATION:
ELSEWHERE IN THE BUDGET JUSTIFICATION IS GIVEN FOR CONSTRUCTION OF RIDGEWAY-SELKIRK 230KV LINE. THIS ITEM PROVIDES FACILITIES REQUIRED TO TERMINATE THIS NEW LINE AT SELKIRK AND CONNECT THE STATION TO THE 115KV NETWORK.

REFERENCE:
MEMO, W.N. ZURBA TO C.V. THIO, 1996 04 10, 'RIDGEWAY-SELKIRK 230KV TRANSMISSION'.

REVISION:
REFLECTS REVISED ACTIVITY AND OVERHEAD RATES.

CONTINGENCY: $825 000

IN SERVICE DATES: 2007 10 31 | 13 410

Base estimate: 199707 L2

Work start date: 2002 04 01

PREV. AUTHORITY Authorized to date	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
2002/03	382	42	17			441
2003/04	1 336	175	97			1 608
2004/05	1 998	306	272			2 576
2005/06	1 998	352	506			2 856
2006/07	1 648	328	747			2 723
2007/08	1 769	393	551			2 713
TOTAL	9 131	1 596	2 190			12 917
REV. AMOUNTS: Authorized to date: Over(under)expend:						
Auth 2002/03	440	44	19			503
Req.: 2003/04	1 393	169	107			1 669
2004/05	2 097	301	290			2 688
2005/06	2 097	350	535			2 982
2006/07	1 694	321	796			2 811
2007/08	1 793	380	584			2 757
TOTAL	9 514	1 565	2 331			13 410

Prepared by: yy mm dd COORDINATOR Approved by: yy mm dd Approved by:

Estimated by: ORIGINATOR COORDINATING MANAGER ORIGINATING MANAGER

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 03-00-6180

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1996 05	12 064	NEW ITEM
1997 10	12 941	SCOPE UNCHANGED, ESTIMATE REFLECTS REVISED COSTING METHODOLOGY IMPLEMENTED WITH THE NEW FINANCIAL REPORTING SYSTEM. ALSO REFLECTS REVISED INTEREST AND ESCALATION RATES.
1998 10	12 917	NO CHANGE.

ASSOCIATED PROJECTS

Budget reference number	Description
02-00-6988	RIDGEWAY - SELKIRK 230KV T/L
03-00-6181	RIDGEWAY TERMINATE SELKIRK 230KV LINE
05-00-6573	RIDGEWAY-SELKIRK COMMUNICATION COMPLEX

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item ___ Domestic Item 228

Title: RIDGEWAY TERMINATE SELKIRK 230KV LINE

Budget reference number: 03-00-6181

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
anning & Control	Design	Construction	70351

DESCRIPTION:
TERMINATE THE NEW SELKIRK 230KV LINE AT RIDGEWAY. FACILITIES WILL INCLUDE 1-230KV CIRCUIT BREAKER AND ASSOCIATED EQUIPMENT.

JUSTIFICATION:
ELSEWHERE IN THE BUDGET JUSTIFICATION IS GIVEN FOR CONSTRUCTION OF RIDGEWAY-SELKIRK 230KV LINE. THIS ITEM PROVIDES FACILITIES REQUIRED TO TERMINATE THIS NEW LINE AT RIDGEWAY.

REFERENCE:
MEMO, W.N. ZURBA TO C.V. THIO, 1996 04 10, 'RIDGEWAY-SELKIRK 230KV TRANSMISSION'.

REVISION:
REFLECTS REVISED ACTIVITY AND OVERHEAD RATES.

CONTINGENCY: $183 000

IN SERVICE DATES

2007 10 31 — 2 900

Base estimate: 199706 L2

Work start date: 2004 04 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:						
2004/05	185	29	8			222
2005/06	434	78	40			552
2006/07	796	161	107			1 064
2007/08	649	144	107			900
TOTAL	2 064	412	262			2 738
REV. AMOUNTS:						
Authorized to date:						
Over(under)expend:						
Auth 2004/05	213	30	10			253
Req. 2005/06	462	77	45			584
2006/07	846	162	117			1 125
2007/08	678	144	116			938
TOTAL	2 199	413	288			2 900

Prepared by: yy mm dd COORDINATOR — Approved by: yy mm dd Approved by: yy mm dd

Estimated by: ORIGINATOR — COORDINATING MANAGER — ORIGINATING MANAGER

CAPITAL EXPENDITURE REVISION

Budget reference number: 03-00-6181

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1996 06	2 673	NEW ITEM.
1997 10	2 703	SCOPE UNCHANGED, ESTIMATE REFLECTS REVISED COSTING METHODOLOGY IMPLEMENTED WITH THE NEW FINANCIAL REPORTING SYSTEM. ALSO REFLECTS REVISED INTEREST AND ESCALATION RATES.
1998 10	2 738	NO CHANGE.

ASSOCIATED PROJECTS

Budget reference number	Description
02-00-6988	RIDGEWAY - SELKIRK 230KV T/L
03-00-6180	SELKIRK ESTABLISH 230-115KV STATION
05-00-6573	RIDGEWAY-SELKIRK COMMUNICATION COMPLEX

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item ___ Domestic Item 229

Title
RIDGEWAY-SELKIRK COMMUNICATION COMPLEX

Budget reference number
05-00-6573

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Planning & Control	Construction	70352

DESCRIPTION:
DESIGN, INSTALL, AND COMMISSION REQUIRED TELECONTROL FACILITIES FOR NEW 230KV LINE FROM RIDGEWAY TO SELKIRK.

JUSTIFICATION:
ELSEWHERE IN THE BUDGET, JUSTIFICATION IS GIVEN FOR BUILDING A RIDGEWAY TO SELKIRK 230KV LINE. THIS ITEM PROVIDES FOR THE COMMUNICATIONS, PROTECTION, AND CONTROL REQUIREMENTS FOR THE PROJECT.

REFERENCE:
MEMO, W.N. ZURBA TO C.V. THIO, 1996 04 10, 'RIDGEWAY - SELKIRK 230KV TRANSMISSION'.

REVISION:
REFLECTS REVISED ACTIVITY AND OVERHEAD RATES.

CONTINGENCY: $50 000

IN SERVICE DATES

2007 10 31 690

Base estimate
199704 L2

Work start date
2006 04 01

PREV. AUTHORITY Authorized to date:	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
2006/07	71	14	3			88
2007/08	453	102	15			570
TOTAL	524	116	18			658
REV. AMOUNTS:						
Authorized to date:						
Over(under)expend:						
Auth 2006/07	77	15	4			96
Req.: 2007/08	476	102	16			594
TOTAL	553	117	20			690

Prepared by yy mm dd COORDINATOR Approved by yy mm dd Approved by

Estimated by ORIGINATOR COORDINATING MANAGER ORIGINATING MANAGER

CAPITAL EXPENDITURE REVISION

Budget reference number 05-00-6573

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1996 10	627	New item.
1997 10	654	SCOPE UNCHANGED, ESTIMATE REFLECTS REVISED COSTING METHODOLOGY IMPLEMENTED WITH THE NEW FINANCIAL REPORTING SYSTEM. ALSO REFLECTS REVISED INTEREST AND ESCALATION RATES.
1998 10	658	NO CHANGE

ASSOCIATED PROJECTS

Budget reference number	Description
02-00-6988	RIDGEWAY - SELKIRK 230KV T/L
03-00-6180	SELKIRK ESTABLISH 230-115KV STATION
03-00-6181	RIDGEWAY TERMINATE SELKIRK 230KV LINE

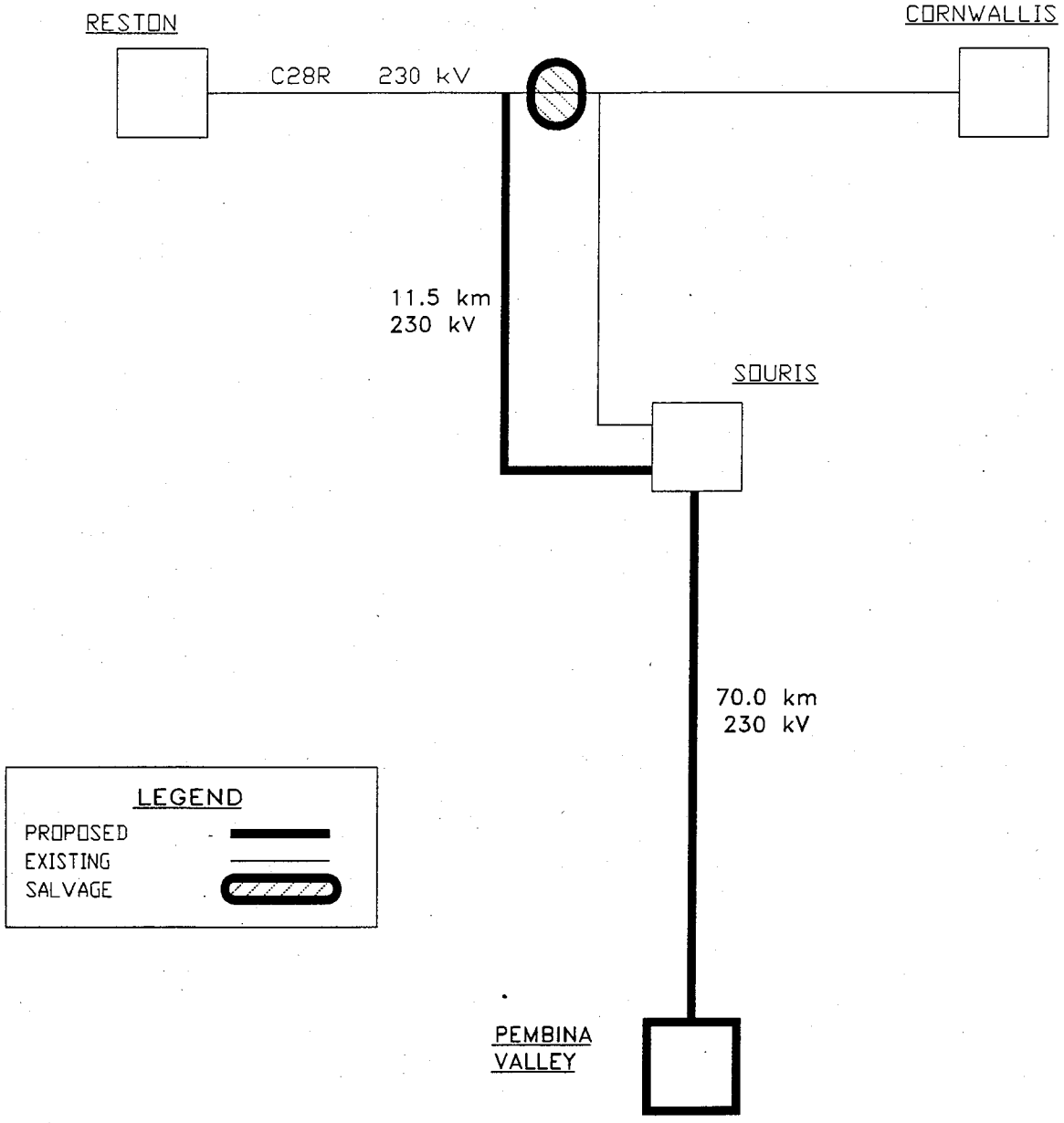
Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

CAPITAL BUDGET COMPLEX CONCEPTUAL DIAGRAM

SOURIS – PEMBINA VALLEY 230KV TRANSMISSION

REVISED: 1999 - 10 - 01	ISSUED BY: WNZ

COMPLEX NO. 210



manitoba hydro

PLANNING AND CONTROL DIVISION

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

COMPLEX STATUS: [X] Planned [ ] In progress

Complex no. 210

REVISION STATUS: [ ] New complex [ ] In service change [ ] Concept change [X] Estimate change only

COMPLEX: SOURIS - PEMBINA VALLEY 230 KV TRANSMISSION

Proposal

Perform environmental assessments and route selection, acquire property and obtain licences, design and construct transmission and terminal facilities to provide supply to Pembina Valley and firm supply to Souris as follows:
Transmission: 230 KV line 11.5 km Souris-line C28R Tap, 230 KV line 70.0 km Souris-Pembina Valley. Open line C28R west of Souris Tap to create Cornwallis-Souris 230 KV line. Connect open end of C28R to 11.5 km line to create Reston-Souris 230 KV line.
Terminations: Establish Pembina Valley 230-66 KV station, including 230-66 KV 83 MVA transformer and associated 230 KV & 66 KV circuit breakers. Extend 230 KV facilities at Souris. Modify line protection at Cornwallis and Reston.
Communications: Integrate with existing facilities at Souris, Cornwallis and Reston.

JUSTIFICATION

[X] Load [ ] Service
[ ] Safety [ ] Efficiency
[X] Reliability [ ] Other

Explanation

This complex provides a 230 KV supply into the Killarney/Boissevain area around Pembina Valley to support load growth in south-western Manitoba.

Estimate Level	COMPLEX START yyyy mm
L2	2006 04

IN SERVICE DATES AND AMOUNTS				
2011 10	$32570			

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend								
Year 99/00								
00/01								
01/02								
02/03								
03/04								
04/05								
05/06								
06/07	468	87	32		587	579	8	1
07/08	649	133	117		899	898	1	0
08/09	966	225	217		1,408	1,355	53	4
09/10	966	252	357		1,575	1,446	129	9
10/11	8,403	2385	1,192		11,980	11,759	221	2
11/12	11,476	3280	1,365		16,121	15,843	278	2
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	22,928	6,362	3,280		32,570	31,880	690	2

REVISION: Scope unchanged.

Reviewed by ORIGINATOR	yyyy mm dd 99 11 03	Reviewed by COORDINATOR	yyyy mm dd 99 11 03		
Reviewed by CONSTRUCTOR	yyyy mm dd 99 11 03	Approved by VICE PRESIDENT	yyyy mm dd 99 11 16		

H2856/r Rev 99 03

Complex no. 210

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Advance or deferral impact

Deferral will reduce reliability of supply to the Killarney / Boissevain area, and to the Souris area for an outage of 230 KV line C28R.

Factors affecting timing or viability

Load growth in south-west Manitoba.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Souris-Pembina Valley 230 KV T/L		11,317	11,543	11,317	-226	-2
Pembina Valley - New 230-66 KV Station		5,649	5,762	5,926	164	3
Souris - Terminate Pembina Valley 230KV T/L		3,689	3,763	3,884	121	3
Cornwallis - Protection Changes for C28R		213	217	228	11	5
Reston - Protection Changes for C28R		212	216	228	12	6
Souris-Pembina Valley Communications Complex		1,297	1,323	1,345	22	2
TOTAL		22,377	22,824	22,928	104	0

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
96 10	33,012	New complex.
1997 10	30,474	Pembina Valley line termination changed to new bay.
1998 10	31,880	Estimate revised to reflect current transmission line costs.
1999 10	32,570	Scope unchanged.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item 230

Title: SOURIS - PEMBINA VALLEY 230KV T/L

Budget reference number: 02-00-6983

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	70353

DESCRIPTION:
CONDUCT ENVIRONMENTAL IMPACT ASSESSMENT, SELECT A ROUTE, ACQUIRE PROPERTY FOR RIGHT-OF-WAY AND OBTAIN LICENCING, DESIGN AND CONSTUCT A 11.5 KM 230KV SINGLE CIRCUIT LINE FROM SOURIS STATION TO C28R USING 795 MCM ASCR AND A 70 KM 230KV SINGLE CIRCUIT LINE FROM SOURIS TO PEMBINA VALLEY (BETWEEN KILLARNEY AND BOISSEVAIN) USING 954 MCM ASCR. SECTIONALIZE LINE C28R AT SOURIS TAP POINT TO CREATE A SOURIS-CORNWALLIS 230KV AND A SOURIS-RESTON 230KV LINE.

JUSTIFICATION:
THIS ITEM PROVIDES A 230KV SUPPLY INTO THE KILLARNEY/BOISSEVAIN AREA WHICH WILL SUPPORT LOAD GROWTH IN SOUTH WESTERN MANITOBA.

REFERENCE:
MEMO, W.N. ZURBA TO C.V. THIO, 1996 04 26, 'SOURIS-PEMBINA VALLEY 230KV TRANSMISSION'.

NOTE: COMPLETION DATE FOR PROPERTY ACQUISITION IS 2009 01 01.

REVISION:
'REFLECTS REVISED ACTIVITY AND OVERHEAD RATES.

CONTINGENCY: $943,000.

IN SERVICE DATES		Base estimate
2011 10 31	16 649	199706 L2
		Work start date: 2006 04 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:						
2006/07	193	37	19			249
2007/08	600	129	82			811
2008/09	550	131	155			836
2009/10	343	91	213			647
2010/11	5 188	1 501	822			7 511
2011/12	4 443	1 413	768			6 624
TOTAL	11 317	3 302	2 059			16 678
REV. AMOUNTS.						
Authorized to date:						
Over(under)expend:						
Auth 2006/07	193	35	19			247
Req. 2007/08	600	122	83			805
2008/09	550	126	155			831
2009/10	343	87	224			654
2010/11	5 188	1 443	861			7 492
2011/12	4 443	1 361	816			6 620
TOTAL	11 317	3 174	2 158			16 649

Prepared by (yy mm dd) COORDINATOR	Approved by (yy mm dd)	Approved by	(yy mm dd)
Estimated by ORIGINATOR	COORDINATING MANAGER	ORIGINATING MANAGER	

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 02-00-6983

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1996 06	0	NEW ITEM
1997 06	15 051	CHANGE DUE TO REVISED CASH FLOWS AND INCREASED OVERHEAD AND LABOUR RATES.
1998 10	16 678	ESTIMATE REVISION DUE TO UPDATED CURRENT TRANSMISSION LINE COSTS.

ASSOCIATED PROJECTS

Budget reference number	Description
03-00-6166	PEMBINA VALLEY NEW 230-66KV STATION
03-00-6167	CORNWALLIS PROTECTION CHANGES FOR LINE C28R
03-00-6188	SOURIS TERMINATE PEMBINA VALLEY 230KV T/L
03-00-6189	RESTON PROTECTION CHANGES FOR LINE C28R
05-00-6574	SOURIS - PEMBINA VALLEY COMMUNICATION COMPLEX

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item ___ Domestic Item 231

Title: PEMBINA VALLEY NEW 230-66KV STATION

Budget reference number: 03-00-6166

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	70354

DESCRIPTION:
CONDUCT ENVIRONMENTAL IMPACT ASSESSMENT, SELECT A SITE, ACQUIRE PROPERTY AND OBTAIN LICENCING, DESIGN AND CONSTRUCT A NEW 230-66KV STATION AT PEMBINA VALLEY LOCATED BETWEEN KILLARNEY AND BOISSEVAIN. INSTALL A 230-66KV, 50/66.7/83.3 MVA TRANSFORMER WITH OLTC (WITH PROVISION FOR FUTURE REPLACEMENT WITH 125 MVA BANK). TERMINATE 1-230KV LINE TO SOURIS AND 2-66KV LINES. FACILITIES WILL INCLUDE 1-230KV AND 2-66KV CIRCUIT BREAKERS AND ASSOCIATED EQUIPMENT.

JUSTIFICATION:
ELSEWHERE IN THE BUDGET JUSTIFICATION IS GIVEN FOR A SOURIS-PEMBINA VALLEY 230KV LINE. THIS ITEM PROVIDES FACILITIES TO TERMINATE THE LINE AT PEMBINA VALLEY AND ESTABLISH A CONNECTION INTO THE 66KV NETWORK.

REFERENCE:
MEMO, W.N. ZURBA TO C.V. THIO, 1996 04 26, 'SOURIS-PEMBINA VALLEY 230KV TRANSMISSION.'

REVISION:
REFLECTS REVISED ACTIVITY AND OVERHEAD RATES.

CONTINGENCY : $519 000

IN SERVICE DATES: 2011 10 31 / 8 308

Base estimate: 199704 L2

Work start date: 2006 04 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:						
2006/07	265	53	13			331
2007/08	45	10	32			87
2008/09	351	87	57			495
2009/10	414	114	107			635
2010/11	2 079	636	220			2 935
2011/12	2 495	639	299			3 433
TOTAL	5 649	1 539	728			7 916
REV. AMOUNTS:						
Authorized to date:						
Over(under)expend:						
Auth 2006/07	275	53	13			341
Req.: 2007/08	49	10	34			93
2008/09	396	95	61			552
2009/10	489	128	125			742
2010/11	2 183	642	255			3 080
2011/12	2 534	627	339			3 500
TOTAL	5 926	1 555	827			8 308

Prepared by: yy mm dd COORDINATOR — Approved by: yy mm dd Approved by: yy mm dd

Estimated by: ORIGINATOR — COORDINATING MANAGER — ORIGINATING MANAGER

CAPITAL EXPENDITURE REVISION

Budget reference number 03-00-6166

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1996 10	8 108	NEW ITEM
1997 10	8 061	SCOPE UNCHANGED, ESTIMATE REFLECTS REVISED COSTING METHODOLOGY IMPLEMENTED WITH THE NEW FINANCIAL REPORTING SYSTERM. REVISED INTEREST AND ESCALATION RATES.
1998 10	7 916	NO CHANGE.

ASSOCIATED PROJECTS

Budget reference number	Description
02-00-6983	SOURIS - PEMBINA VALLEY 230KV T/L
03-00-6167	CORNWALLIS PROTECTION CHANGES FOR LINE C28R
03-00-6188	SOURIS TERMINATE PEMBINA VALLEY 230KV T/L
03-00-6189	RESTON PROTECTION CHANGES FOR LINE C28R
05-00-6574	SOURIS - PEMBINA VALLEY COMMUNICATION COMPLEX

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item 232

Title			Budget reference number
SOURIS TERMINATE PEMBINA VALLEY 230KV T/L			03-00-6188
Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	70355

DESCRIPTION:
TERMINATE 230KV LINES TO RESTON AND PEMBINA VALLEY AT SOURIS. FACILITIES WILL INCLUDE 3-230KV BREAKERS AND ASSOCIATED EQUIPMENT.

JUSTIFICATION:
ELSEWHERE IN THE BUDGET JUSTIFICATION IS GIVEN FOR A SOURIS-PEMBINA VALLEY 230KV LINE AND FOR SECTIONALIZING C28R INTO SOURIS. THIS ITEM PROVIDES FACILITIES TO TERMINATE THE THREE NEW 230KV LINES AT SOURIS.

REFERENCE:
MEMO,B.C. JOROWSKI TO D.A. ALLEN, 1997 07 15, 'CAPITAL BUDGET CHANGE AND RE-ESTIMATE REQUEST SOURIS - PEMBINA VALLEY 230KV T/L.'

REVISION:
REFLECTS REVISED ACTIVITY AND OVERHEAD RATES.

CONTINGENCY: $336 000

IN SERVICE DATES				Base estimate
2011 10 31	5 143			199704 L2
				Work start date
				2008 04 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:						
2008/09	18	5	1			24
2009/10	76	22	6			104
2010/11	319	97	30			446
2011/12	3 276	948	111			4 335
TOTAL	3 689	1 072	148			4 909
REV. AMOUNTS:						
Authorized to date:						
Over(under)expend:						
Auth Req.: 2008/09	20	5	1			26
2009/10	84	22	7			113
2010/11	365	106	35			506
2011/12	3 415	958	125			4 498
TOTAL	3 884	1 091	168			5 143

Prepared by yy mm dd COORDINATOR — Approved by yy mm dd COORDINATING MANAGER — Approved by yy mm dd ORIGINATING MANAGER

Estimated by ORIGINATOR

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 03-00-6188

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1997 10	4 991	PEMBINA VALLEY LINE TERMINATION CHANGED TO A SECOND 230KV BAY NORTH OF THE EXISTING BAY TO ACCOMMODATE THE IPL EXPANSION. PROVISIONS MADE TO MODIFY THE LINE BREAKER BYPASS TO A BREAKER DICONNECT.
1998 10	4 909	NO CHANGE.

ASSOCIATED PROJECTS

Budget reference number	Description
02-00-6983	SOURIS - PEMBINA VALLEY 230KV T/L
03-00-6166	PEMBINA VALLEY NEW 230-66KV STATION
03-00-6167	CORNWALLIS PROTECTION CHANGES FOR LINE C28R
03-00-6189	RESTON PROTECTION CHANGES FOR LINE C28R
05-00-6574	SOURIS - PEMBINA VALLEY COMMUNICATION COMPLEX

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item

233

Title
CORNWALLIS PROTECTION CHANGES FOR LINE C28R

Budget reference number
03-00-6167

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
nning & Control	Design	Construction	70357

DESCRIPTION:
MODIFY PROTECTION EQUIPMENT AS REQUIRED AT CORNWALLIS IN CO-ORDINATION WITH SECTIONALIZATION OF 230KV LINE C28R AT SOURIS.

JUSTIFICATION:
ELSEWHERE IN THE BUDGET JUSTIFICATION IS GIVEN FOR A SOURIS-PEMBINA VALLEY 230KV LINE. THIS ITEM PROVIDES PROTECTION CHANGES AT CORNWALLIS REQUIRED FOR THIS PROJECT.

REFERENCE:
MEMO, W.N. ZURBA TO C.V. THIO, 1996 04 26, 'SOURIS-PEMBINA VALLEY 230KV TRANSMISSION.'

REVISION:
REFLECTS REVISED ACTIVITY AND OVERHEAD RATES.

CONTINGENCY:$19 000

IN SERVICE DATES		Base estimate
2011 10 31	306	199704 L2
		Work start date
		2010 04 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:						
2010/11	68	21	4			93
2011/12	145	41	8			194
TOTAL	213	62	12			287
REV. AMOUNTS:						
Authorized to date:						
Over(under)expend:						
Auth 2010/11	77	22	5			104
Req.: 2011/12	151	41	10			202
TOTAL	228	63	15			306

Prepared by — yy mm dd — COORDINATOR
Approved by — yy mm dd — COORDINATING MANAGER
Approved by — yy mm dd — ORIGINATING MANAGER
Estimated by — ORIGINATOR

CAPITAL EXPENDITURE REVISION

Budget reference number: 03-00-6167

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1996 10	309	NEW ITEM
1997 10	287	SCOPE UNCHANGED, ESTIMATE REFLECTS REVISED COSTING METHODOLOGY IMPLEMENTED WITH THE NEW FINANCIAL REPORTING SYSTEM. REVISED INTEREST AND ESCALATION RATES.
1998 10	287	NO CHANGE.

ASSOCIATED PROJECTS

Budget reference number	Description
02-00-6983	SOURIS - PEMBINA VALLEY 230KV T/L
03-00-6166	PEMBINA VALLEY NEW 230-66KV STATION
03-00-6188	SOURIS TERMINATE PEMBINA VALLEY 230KV T/L
03-00-6189	RESTON PROTECTION CHANGES FOR LINE C28R
05-00-6574	SOURIS - PEMBINA VALLEY COMMUNICATION COMPLEX

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item

234

Title
RESTON PROTECTION CHANGES FOR LINE C28R

Budget reference number
03-00-6189

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
anning & Control	Design	Construction	70358

DESCRIPTION:
MODIFY PROTECTION EQUIPMENT AS REQUIRED AT RESTON IN CO-ORDINATION WITH SECTIONALIZATION OF 230KV LINE C28R AT SOURIS.

JUSTIFICATION:
ELSEWHERE IN THE BUDGET JUSTIFICATION IS GIVEN FOR A SOURIS-PEMBINA VALLEY 230KV LINE AND SECTIONALIZATION OF 230KV LINE C28R. THIS ITEM PROVIDES PROTECTION CHANGES AT RESTON REQUIRED FOR THIS PROJECT.

REFERENCE:
MEMO, W.N. ZURBA TO C.V. THIO, 1996 04 26, 'SOURIS-PEMBINA VALLEY 230KV TRANSMISSION.'

REVISION:
REFLECTS REVISED ACTIVITY AND OVERHEAD RATES.

CONTINGENCY: $19 000

IN SERVICE DATES		Base estimate
2011 10 31	314	199704 L2
		Work start date
		2010 04 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:						
2010/11	87	26	5			118
2011/12	125	41	10			176
TOTAL	212	67	15			294
REV. AMOUNTS						
Authorized to date:						
Over(under)expend:						
Auth 2010/11	96	29	5			130
Req. 2011/12	132	41	11			184
TOTAL	228	70	16			314

Prepared by — yy mm dd — COORDINATOR
Approved by — yy mm dd — COORDINATING MANAGER
Approved by — yy mm dd — ORIGINATING MANAGER
Estimated by — ORIGINATOR

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 03-00-6189

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1997 10	295	SCOPE UNCHANGED, ESTIMATE REFLECTS REVISED COSTING METHDOLOGY IMPLEMENTED WITH THE NEW FINANCIAL REPORTING SYSTEM.
1998 10	294	NO CHANGE.

ASSOCIATED PROJECTS

Budget reference number	Description
02-00-6983	SOURIS - PEMBINA VALLEY 230KV T/L
03-00-6166	PEMBINA VALLEY NEW 230-66KV STATION
03-00-6167	CORNWALLIS PROTECTION CHANGES FOR LINE C28R
03-00-6188	SOURIS TERMINATE PEMBINA VALLEY 230KV T/L
05-00-6574	SOURIS - PEMBINA VALLEY COMMUNICATION COMPLEX

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — 235 — Domestic Item

Title
SOURIS - PEMBINA VALLEY COMMUNICATION COMPLEX

Budget reference number
05-00-6574

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Planning & Control	Construction	70356

DESCRIPTION:
DESIGN, INSTALL, AND COMMISSION TELECOMMUNICATION FACILITIES REQUIRED FOR OPERATION OF THE SOURIS - PEMBINA VALLEY 230KV LINE, THE SOURIS - CORNWALLIS 230KV LINE, THE SOURIS - RESTON 230KV LINE, SOURIS STATION, AND PEMBINA VALLEY STATION.

JUSTIFICATION:
ELSEWHERE IN THE BUDGET, JUSTIFICATION IS GIVEN FOR BUILDING A SOURIS - PEMBINA VALLEY 230KV LINE. THIS ITEM PROVIDES FOR THE COMMUNICATIONS, PROTECTION, AND CONTROL REQUIREMENTS FOR THE PROJECT.

REFERENCE:
MEMO, W.N. ZURBA TO C.V. THIO, 1996 04 26, 'SOURIS - PEMBINA VALLY 230KV TRANSMISSION'.

REVISION:
REFLECTS REVISED ACTIVITY AND OVERHEAD RATES.

CONTINGENCY: $130 000.

IN SERVICE DATES		Base estimate
2011 10 31	1 851	199704 L2
		Work start date
		2009 10 01

	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
PREV. AUTHORITY Authorized to date.						
2009/10	45	13	1			59
2010/11	481	148	28			657
2011/12	771	253	58			1 082
TOTAL	1 297	414	87			1 798
REV. AMOUNTS: Authorized to date: Over(under)expend.						
Auth Req. 2009/10	50	14	1			65
2010/11	493	145	30			668
2011/12	802	253	63			1 118
TOTAL	1 345	412	94			1 851

Prepared by yy mm dd COORDINATOR — Approved by yy mm dd Approved by yy mm dd

Estimated by ORIGINATOR — COORDINATING MANAGER — ORIGINATING MANAGER

CAPITAL EXPENDITURE REVISION

Budget reference number 05-00-6574

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1996 10	2 012	NEW ITEM
1997 10	1 791	SCOPE UNCHANGED, ESTIMATE REFLECTS REVISED COSTING METHODOLOGY IMPLEMENTED WITH THE NEW FINANCIAL REPORTING SYSTEM.
1998 10	1 798	NO CHANGE.

ASSOCIATED PROJECTS

Budget reference number	Description
02-00-6983	SOURIS - PEMBINA VALLEY 230KV T/L
03-00-6166	PEMBINA VALLEY NEW 230-66KV STATION
03-00-6167	CORNWALLIS PROTECTION CHANGES FOR LINE C28R
03-00-6188	SOURIS TERMINATE PEMBINA VALLEY 230KV T/L
03-00-6189	RESTON PROTECTION CHANGES FOR LINE C28R

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

COMPLEX STATUS: ☐ Planned ☒ In progress

Complex no. 4

REVISION STATUS: ☐ New complex ☐ In service change ☐ Concept change ☒ Estimate change only

COMPLEX: WINNIPEG AREA TRANSMISSION REFURBISHMENT

Proposal

Refurbish 292.6 KM of double circuit and 120.7 KM of single circuit 230 and 110 KV transmission lines in the Winnipeg area. Refurbish 16.9 KM of double circuit and 49.2 KM of single circuit 63.5 KV subtransmission lines in the Winnipeg area. The refurbishment will correct insufficient ground clearances of line conductors. Using resagging, reconductoring, and tower extensions where required, the lines are to be upgraded to maintain safe ground clearances under thermal conductor loading.

JUSTIFICATION

☒ Load ☐ Service
☒ Safety ☐ Efficiency
☐ Reliability ☐ Other

Explanation

Lines in the Winnipeg area built pre-1970 cannot accommodate thermal conductor loading without violating required ground clearances. The refurbishment program will increase line to ground clearances to allow higher conductor temperatures under all potential heavy current line loads.

Estimate Level	COMPLEX START (yyyy mm)
L2-3	1991 03

IN SERVICE DATES AND AMOUNTS							
To 1997 12	$474	1998 01	$490	1998 12	$408	1999 01	$118
1999 07	$766	1999 09	$297	1999 10	$351	2000 03	$568
2000 09	$297	2001 03	$587	2001 09	$297	2002 on	$2212

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	2,254		299	9	2,544	3,031	-487	-16
Year 99/00	957	18	101		1,076	630	446	71
00/01	485	13	52		550	721	-171	-24
01/02	396	19	18		433	722	-289	-40
02/03	756	51	10		817	736	81	11
03/04	1,038	25	21		1,084	882	202	23
04/05	5	1			6		6	
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	5,891	127	501	9	6,510	6,722	-212	-3

REVISION: Reduced cost resulted from less than expected upgrade work on several lines.

Reviewed by ORIGINATOR	yyyy mm dd 99 11 08	Reviewed by COORDINATOR	yyyy mm dd 99 11 03
Reviewed by CONSTRUCTOR	yyyy mm dd 99 11 03	Approved by VICE PRESIDENT	yyyy mm dd 99 11 16

H2856/r Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Complex no. 4

Advance or deferral impact

Deferral would result in a continued safety hazard due to insufficient line to ground clearances under operation with high conductor temperatures.

Factors affecting timing or viability

Time required for line measurement and testing.
Evaluation and design for refurbishment of individual circuits.
Actual (undetermined) capacities of lines.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE	
					Amount	%
Winipeg 230 & 115 KV Network T/L Refurbishment	4,856	5,951	6,070	5,791	-279	-5
Winnipeg 63.5 KV Network T/L Refurbishment	477	102	104	100	-4	-4
TOTAL	5,333	6,053	6,174	5,891	-283	-5

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
9510	5,875	In-service dates for all 230 & 110KV lines deferred 4.5 years to 2003 09 30 and for 63.5KV lines to 1996 09 30 to accommodate other work priorities.
9610	6,209	In-service dates for 63.5 KV lines deferred 6 months to 1997 03 31 to accommodate other work priorities. Work schedule for 1998/99 deferred.
1997 10	6,596	Scope unchanged, estimate reflects revised costing methodology implemented with the new financial reporting system. Also reflects revised interest and escalation rates.
1998 10	6,722	Reflects 97/98 underexpenditure 0.7M, and revised estimate based on last four years cost data.
1999 10	6,510	Reduced cost resulted from less than expected upgrade work on several lines.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item ___ Domestic Item 236

Title
WINNIPEG 230 AND 100KV NETWORK T/L REFURBISHMENT (WPGTL&TL2)

Budget reference number
02-00-1259

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Operating & Maintenance	Construction	60017:74570

DESCRIPTION:
REFURBISH 14-230 AND 20-110KV NETWORK TRANSMISSION LINES IN WINNIPEG AREA (292.6 KM OF DOUBLE CIRCUIT AND 120.7 KM OF SINGLE CIRCUIT) WITH INSUFFICIENT GROUND CLEARANCES. INDIVIDUAL CIRCUIT REFURBISHMENT METHODS INCLUDE RE-SAGGING, RECONDUCTORING, TOWER HEIGHT EXTENSIONS, ETC. RECORD ALL LINE CHARACTERISTICS IN AN APPROPRIATE DATABASE FOR FUTURE REFERENCE. LINES ARE TO BE REFURBISHED IN ACCORDANCE WITH PRIORITIES SET BY THE 'TRANSMISSION FACILITIES OPTIMIZATION TASK FORCE'.

JUSTIFICATION:
TRANSMISSION LINES BUILT PRE-1970 IN THE WINNIPEG AREA WERE NOT DESIGNED TO CARRY CURRENTS PRESCRIBED BY EXPECTED LOADS WITHOUT VIOLATING MINIMUM GROUND CLEARANCES DURING ADVERSE WEATHER CONDITIONS IN SUMMER. THIS ITEM PROVIDES FOR REFURBISHMENT OF LINES TO ENSURE SAFE OPERATING GROUND CLEARANCES.

REFERENCE:
1) TPD REPORT 89-2 - RE-SAGGING OF 230KV, 110KV AND 63.5KV WINNIPEG NETWORK TRANSMISSION LINES.
2) TRANSMISSION FACILITIES OPTIMIZATION TASK FORCE - MEETING MINUTES OF MEETINGS 1 & 2 - 90 04 23 - FILE 2-15A-1.

3) E&C MEMO FILE 1-30000-00021 - 1991 08 20 D.W. MILLER TO V.J. STECIUK: 'WINNIPEG TRANSMISSION LINE REFURBISHMENT'.
4) ENG MEMO, 1995 05 15, S.S. CHEUNG TO J. KANE: 'WINNIPEG AND WINNIPEG RIVER 230KV/110KV TRANSMISSION LINE UPGRADE'. NOTE: RECONDUCTORING IS NOT ENVISIONED NOR INCLUDED IN THIS ESTIMATE.

REVISION:
REVISED ESTIMATE REFLECTS REMAINING DESIGN AND CONSTRUCTION WORK BASED ON COST DATA DERIVED SINCE THE INTRODUCTION OF THE SAP ACCOUNTING SYSTEM. THE REDUCED TOTAL COST RESULTED FROM LESS THAN EXPECTED UPGRADE WORK ON SEVERAL LINES.

CONTINGENCY: $750,000

IN SERVICE DATES						Base estimate
Prior Total	1 496	1999 10 31	232	2001 09 30	297	199706 L3
1999 04 30	41	2000 03 31	568	2002 03 31	411	
1999 07 31	766	2000 09 30	297	2002 09 30	297	Work start date
1999 09 30	297	2001 03 31	587	And On	1 110	1991 03 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date	2 238		286	-9		2 515
1999/00	934	15	70			1 019
2000/01	667	35	20			722
2001/02	656	47	19			722
2002/03	656	61	18			735
2003/04	829	36	17			882
TOTAL	5 980	194	430	-9		6 595
REV. AMOUNTS						
Authorized to date	2 238		286	-9		2 515
Over(under)expend:						
Auth 1999/00	873	15	97			985
Req. 2000/01	485	13	52			550
2001/02	396	19	18			433
2002/03	756	52	10			818
2003/04	1 038	25	21			1 084
2004/05	5					5
TOTAL	5 791	124	484	-9		6 390

Prepared by (yy mm dd) COORDINATOR	Approved by (yy mm dd)	Approved by (yy mm dd)
Estimated by ORIGINATOR	COORDINATING MANAGER	ORIGINATING MANAGER

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 02-00-1259

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1990 10	4 508	NEW ITEM.
1991 10	4 343	REFINED CASH FLOW.
1992 10	5 544	IN SERVICE DATES EXTENDED UP TO 5 YEARS. PROJECT SCOPE EXPANDED TO INCLUDE ENGINEERING STUDY AND FIELD MEASUREMENTS OF EXISTINGTRANSMISSION LINE GROUND CLEARANCES.
1993 10	5 575	UPDATED ESCALATION RATES
1994 10	5 517	CASH FLOW CHANGED TO REFLECT CURRENT WORK SCHEDULE. REVISEDINTEREST AND ESCALATION RATES.
1995 10	5 790	IN-SERVICE DATES EXTENDED 4.5 YEARS TO 2003 09 30.
1996 10	6 124	TOWER MODIFICATIONS TO 230KV LINES ALSO REQUIRED. CASH FLOWS REVISED TO REDUCE 98/99 CAPITAL EXPENDITURES TO ASSIST IN ACHIEVING CORPORATE CAPITAL TARGET.
1998 10	6 405	ESTIMATE REFLECTS REVISED COSTING METHODOLOGY IMPLEMENTED WITH THE NEW FINANCIAL REPORTING SYSTEM. IT ALSO REFLECTS REVISED INTEREST AND ESCALATION RATES.
1999 10	6 020	REVISED ESTIMATE REFLECTS REMAINING DESIGN AND CONSTRUCTION WORK BASED ON COST DATA DERIVED SINCE THE INTRODUCTION OF THE SAP ACCOUNTING SYSTEM. THE REDUCED TOTAL COST RESULTED FROM LESS THAN EXPECTED UPGRADE WORK ON SEVERAL LINES.

ASSOCIATED PROJECTS

Budget reference number	Description
04-00-1414	WINNIPEG 63.5 KV NETWORK TRANSMISSION LINE REFURBISHMENT

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Acoumulated
1999/00 Apr	116	1	10			127	127
May	107	2	10			119	246
Jun	107	2	11			120	366
Jul	107	2	12			121	487
Aug	62	1	8			71	558
Sep	62	1	8			71	629
Oct	62	1	7			70	699
Nov	51	2	5			58	757
Dec	51	1	6			58	815
Jan	50	1	6			57	872
Feb	50		7			57	929
Mar	48	1	7			56	985
TOTAL	873	15	97			985	985
2000/01 Apr	43		4			47	47
May	43	1	4			48	95
Jun	43	1	4			48	143
Jul	40		5			45	188
Aug	40	1	5			46	234
Sep	40	1	5			46	280
Oct	40	1	3			44	324
Nov	40	1	4			45	369
Dec	40	1	4			45	414
Jan	40	1	4			45	459
Feb	40	1	5			46	505
Mar	36	4	5			45	550
TOTAL	485	13	52			550	550

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item

237

Title
WINNIPEG 63.5 KV NETWORK TRANSMISSION LINE REFURBISHMENT

Budget reference number
04-00-1414

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	93410

DESCRIPTION:
REFURBISH ALL 63.5 KV NETWORK TRANSMISSION LINES IN THE WINNIPEG AREA (16.9 KM OF DOUBLE CIRCUIT AND 49.2 KM OF SINGLE CIRCUIT) WITH INSUFFICIENT GROUND CLEARANCES. INDIVIDUAL CIRCUIT REFURBISHMENT METHODS INCLUDE RESAGGING, RECONDUCTORING, TOWER HEIGHT EXTENSIONS ETC. RECORD ALL LINE CHARACTERISTICS IN AN APPROPRIATE DATABASE FOR FUTURE REFERENCE. LINES ARE TO BE REFURBISHED IN ACCORDANCE WITH PRIORITIES SET BY THE 'TRANSMISSION FACILITIES OPTIMIZATION TASK FORCE'.

JUSTIFICATION:
TRANSMISSION LINES BUILT PRE-1970 IN THE WINNIPEG AREA CANNOT CARRY ADEQUATE LINE CURRENT WITHOUT VIOLATING MINIMUM GROUND CLEARANCES DURING ADVERSE WEATHER CONDITIONS IN SUMMER. THIS ITEM PROVIDES FOR REFURBISHMENT OF LINES TO ENSURE SAFE OPERATING GROUND CLEARANCES.

REFERENCE:
TPD REPORT 89-2 - RE-SAGGING OF 230 KV, 110KV, AND 63.5 KV WINNIPEG NETWORK TRANSMISSION LINES
TRANSMISSION FACILITIES OPTIMIZATION TASK FORCE - MEETING MINUTES OF MEETINGS 1 & 2 - 90 04 23 - FILE 2-15A-1
REPORT CR.DES.93.01 63.5 KV WINNIPEG NETWORK SUBTRANSMISSION LINE CLEARANCE STUDY.

REVISION:
NO CHANGE IN PROJECT SCOPE OR IN-SERVICE DATE.

IN SERVICE DATES		Base estimate
1999 10 31	120	199707 L2
		Work start date
		1997 04 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:	16		13			29
1999/00	90	2	5			97
TOTAL	106	2	18			126
REV. AMOUNTS:						
Authorized to date.	16		13			29
Over(under)expend:						
Auth 1999/00 Req.:	84	3	4			91
TOTAL	100	3	17			120

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR		COORDINATING MANAGER		ORIGINATING MANAGER

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 04-00-1414

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1990 10	516	NEW ITEM
1991 10	542	IN-SERVICE DATES DEFERRED BY ONE YEAR.
1992 10	494	TO REFLECT DECREASE IN ESCALATION RATES.
1993 10	77	TO REFLECT DECREASE IN SCOPE OF THE PROJECT AND REVISED IN- SERVICE DATE.
1994 10	81	IN-SERVICE DATE DEFERRED 1 YEAR TO 1995 03 31 DUE TO OTHER WORK PRIORITIES.
1995 10	85	IN-SERVICE DATE DEFERRED 18 MONTHS TO 1996 09 30 DUE TO OTHER WORK PRIORITIES.
1996 10	85	IN-SERVICE DATES DEFERRED 6 MONTHS TO 1997 03 31 DUE TO OTHER WORK PRIORITIES.
1997 10	142	IN-SERVICE DATE DEFERRED FROM 1997 03 31 TO 1998 10 31 TO ACCOMMODATE OTHER HIGHER PRIORITY PROJECTS. CHANGE IN ESTIMATE IS EXPECTED IMPACT FROM NEW FRS ACCOUNTING SYSTEM. SCOPE OF THE PROJECT REMAINS UNCHANGED.
1998 10	125	INSERVICE DATE DEFERRED FROM 1998 10 31 TO 1999 10 31 TO ACCOMMODATE OTHER HIGHER PRIORITY PROJECTS.
1999 10	124	NO CHANGE IN PROJECT SCOPE OR IN-SERVICE DATE.

ASSOCIATED PROJECTS

Budget reference number	Description
02-00-1259	WINNIPEG 230 AND 100KV NETWORK T/L REFURBISHMENT (WPGTL&TL2)

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	20	1				21	21
May	20	2				22	43
Jun	9					9	52
Jul	9		1			10	62
Aug	9		1			10	72
Sep	9		1			10	82
Oct	8		1			9	91
Nov							91
Dec							91
Jan							91
Feb							91
Mar							91
TOTAL	84	3	4			91	91
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

COMPLEX STATUS	Complex no.	REVISION STATUS
☐ Planned ☒ In progress	28	☐ New complex ☐ In service change ☐ Concept change ☒ Estimate change only

COMPLEX	DORSEY STATION 230 KV BREAKER REPLACEMENT

Proposal

Replace 25 - 230 KV Dorsey breakers with gas insulated units of 63.5 KAMP fault current interrupting capacity.
Upgrade 5 - 230 KV breakers to 63.5 KAMP fault capacity. Replace 23 sets of underrated breaker current transformers (CT's).
Purchase 3 - 1 phase spare breaker heads and a gas cart for new breaker maintenance. Install resistors on 4KV secondary windings of station service transformers SST1 & SST2. Replacements are to be installed over a three year period.

JUSTIFICATION	Explanation
☐ Load ☐ Service ☒ Safety ☐ Efficiency ☒ Reliability ☐ Other	The specified Dorsey 230 KV breakers are underrated for the increasing short circuit levels in the Winnipeg area. The new breakers are rated to accommodate the increased fault levels.

Estimate Level	COMPLEX START (yyyy mm)
L4	1992 01

IN SERVICE DATES AND AMOUNTS					
1994 03	$7360	1996 06	$10045	1999 03	($538)	1999 12	$2279

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	15,666		1,915	344	17,237	19,097	-1,860	-10
Year 99/00	1,479	7	80		1,566	1,008	558	55
00/01								
01/02								
02/03								
03/04								
04/05								
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	17,145	7	1,995	344	18,803	20,105	-1,302	-6

REVISION	Decrease reflects settlement received from Square D.

Reviewed by ORIGINATOR	yyyy mm dd 99 11 08	Reviewed by COORDINATOR	yyyy mm dd 99 11 03
Reviewed by CONSTRUCTOR	yyyy mm dd 99 11 03	Approved by VICE PRESIDENT	yyyy mm dd 99 11 16

H2856/r Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Complex no. 28

Advance or deferral impact

Deferral would result in continued risk of equipment damage and personnel hazard due to insufficient circuit breaker fault clearing capacity.

Factors affecting timing or viability

Supply delays.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Dorsey Station Replacement of 230 KV Breakers	17,884	18,436	18,805	17,145	-1,660	-9
TOTAL	17,884	18,436	18,805	17,145	-1,660	-9

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
9510	16,912	Reflects contingency adj, CT retrofit and addition of SST resistors. Cost decrease due to application of experience from initial stages of breaker repl to later stages.
9610	18,216	Replacement of 2 breakers deferred 8 months to 1996 06 30. Completion of CT replacement defer 2 years to 1997 10 31. Cost increases for engineering, labour and material.
1997 10	18,627	Completion of CT replacement deferred from 97 10 30 to 98 11 30.
1998 10	20,105	Reflects 97/98 underexpenditure 0.5M. Contingency increased to allow for purchase of current transformers to replace existing faulty Square D CT'S.
1999 10	18,803	Decrease reflects settlement received from Square D.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item

238

Title
DORSEY STATION REPLACEMENT OF 230KV BREAKERS

Budget reference number
03-00-2338

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
anning & Control	Design	Construction	70037

DESCRIPTION:
REPLACE 25 DORSEY 230 KV BREAKERS WITH UNITS OF 63.5 KAMP FAULT CURRENT INTERRUPTING CAPACITY, INCLUDING ASSOCIATED EQUIPMENT AS REQUIRED. PURCHASE 3 - 1 PHASE SPARE BREAKER HEADS AND AN SF6 MAINTENANCE GAS CART. REPLACE 23 - 3 PHASE SETS OF BREAKER CT'S WITH INSUFFICIENT FAULT CURRENT CAPACITY. UPGRADE 5 ABB 230 KV ELF BREAKERS TO 63.5 KAMP FAULT CURRENT INTERRUPTING CAPACITY.
1994 03 11 - 10 BREAKERS, 7 CT SETS
** 1994 11 25 - 8 BREAKERS, UPGRADE 5 BREAKERS
** 1995 10 31 - 5 BREAKERS, 1 CT SETS
1996 06 30 - 2 BREAKERS
1997 10 31 - 15 CT SETS
** REPLACE ONE OF THE 1994 11 25 BREAKERS WITH 230 KV BREAKER NO. 42 SALVAGED FROM MMTU PROJECT (ITEM 9203-00-1810).
PURCHASE AND INSTALL RESISTORS ON 4 KV SECONDARY WINDINGS OF STATION SERVICE TRANSFORMERS SST1 AND SST2.

JUSTIFICATION:
TRANSMISSION ADDITIONS IN THE WINNIPEG AREA ARE INCREASING FAULT LEVELS AT THE DORSEY 230 KV BUS, SURPASSING THE FAULT INTERRUPTING CAPACITIES OF 23 OF THE 230 KV BREAKERS. BREAKER AND ASSOCIATED CT REPLACEMENTS ARE RECOMMENDED WITH UNITS CAPABLE OF ACCOMMODATING FUTURE FAULT LEVEL INCREASES AFTER ADDITION OF RIEL STATION. FIVE ELF BREAKERS MUST BE UPGRADED TO THE SAME FAULT CAPACITIES. BREAKERS 48 AND 50 ARE REPLACED DUE TO EXCESSIVE WEAR FROM HEAVY SWITCHING DUTY ON FILTER BANKS F7 & 8. THE SPARE HEADS AND GAS CART ARE REQUIRED FOR EFFICIENT MAINTENANCE. STATION SERVICE TRANSFORMER RESISTORS ARE REQUIRED TO ELIMINATE STATION FERRO-RESONANCE.

REFERENCE:
TPD REPORT 91-4,' DORSEY 230 KV FAULT LEVELS AND BREAKER UPGRADE'
TPD TM 92-8, 'ADDITIONAL REQUIREMENTS FOR DORSEY 230 KV BREAKER UPGRADE'
TPD TM 92-16, 'DORSEY 230 KV STATION BREAKER UPGRADE - BREAKER INFORMATION UPDATE'.

REVISION:
DECREASE DUE TO SETTLEMENT RECEIVED FROM SQUARE D, CONTINGENCY HAS BEEN REDUCED.

CONTINGENCY: $150 000

IN SERVICE DATES

1994 03 31	7 360
1996 06 30	10 045
1999 03 31	- 538
1999 12 31	2 280

Base estimate
199903 L4

Work start date
1992 01 01

	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
PREV AUTHORITY						
Authorized to date:	15 666		1 915	- 344		17 237
1999/00	2 868	1				2 869
TOTAL	18 534	1	1 915	- 344		20 106
REV. AMOUNTS						
Authorized to date:	15 666		1 915	- 344		17 237
Over(under)expend:						
Auth 1999/00	1 479	7	80			1 566
Req.:						
TOTAL	17 145	7	1 995	- 344		18 803

Prepared by — yy mm dd — COORDINATOR
Estimated by — ORIGINATOR
Approved by — yy mm dd — COORDINATING MANAGER
Approved by — ORIGINATING MANAGER — yy mm dd

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 03-00-2338

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1991 10	15 925	NEW ITEM.
1992 10	19 524	ADDED REPLACEMENT OF CT'S, BREAKERS 48 AND 50. ADDED UPGRADE OF FIVE ELF BREAKERS. ADDED SPARE HEADS AND GAS CART. REPLACEDONE NEW BREAKER WITH SALVAGED BREAKER NO. 42 FROM MMTU PROJECT.
1993 10	19 990	ESTIMATE INCREASED DUE TO INCREASE IN MAJOR EQUIPMENT COSTS,ADDITIONAL COSTS FOR CONSTRUCTION SITE SUPERVISION AND REQUIRED UPGRADE OF EXISTING ELF BREAKERS.
1994 10	18 060	COST OF PROJECT DECREASED DUE TO REVISED CONSTRUCTION AND COMMISSIONING ESTIMATES AND A REDUCTION TO THE CONTINGENCY.
1995 10	16 912	CONTINGENCY ADJUSTED AND ESTIMATE REVISED FOR CT RETROFIT AND INSTALLATION OF STATION SERVICE TRANSFORMER RESISTORS. ESTIMATE REDUCTIONS REFLECT INSTALLATION EXPERIENCE FROM INITIAL BREAKER REPLACEMENT STAGES APPLIED TO LATER STAGES.
1996 10	18 216	REPLACEMENT OF 2 BREAKERS DEFERRED 8 MONTHS TO 1996 06 30. COMPLETION OF CT REPLACEMENT DEFERRED 2 YEARS TO 1997 10 31. ESTIMATE REVISED BASED ON UPDATED COSTS RESULTING IN AN INCREASE TO ENGINEERING, MATERIAL, AND LABOUR.
1997 10	18 628	COMPLETION OF CT REPLACEMENT DEFERRED TO 1998 11 30.
1998 10	20 105	CONTINGENCY INCREASED TO ALLOW FOR PURCHASE OF CURRENT TRANSFORMERS TO REPLACE EXISTING FAULTY SQUARE D CT'S.

ASSOCIATED PROJECTS

Budget reference number	Description

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	111		3			114	114
May	111	1	3			115	229
Jun	552	2	4			558	787
Jul	400	2	8			410	1 197
Aug	96		11			107	1 304
Sep	95	1	12			108	1 412
Oct	95	2	12			109	1 521
Nov	19		13			32	1 553
Dec		-1	14			13	1 566
Jan							1 566
Feb							1 566
Mar							1 566
TOTAL	1 479	7	80			1 566	1 566
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

COMPLEX STATUS: ☐ Planned ☒ In progress

Complex no. 43

REVISION STATUS: ☐ New complex ☒ In service change ☐ Concept change ☒ Estimate change only

COMPLEX: DORSEY - US BORDER 500 KV T/L INSULATOR REPLACEMENT

Proposal

Purchase and install new 36-kip suspension insulators on the 500kv transmission line between Dorsey and the US border to replace the existing defective ones. The scope of the work includes a total of 475 suspension, and possibly 15 dead end, towers..

JUSTIFICATION

☒ Load ☐ Service ☐ Safety ☐ Efficiency ☒ Reliability ☐ Other

Explanation

A 1994/95 test program indicated that the existing 36-kip suspension insulators in this line are defective. This item provides for their replacement and full restoration of the lines integrity.

Estimate Level	COMPLEX START (yyyy mm)
L2	1995 12

IN SERVICE DATES AND AMOUNTS

1999 01	$3881	1999 12	$1897	2000 12	$607	2001 12	$607
2002 12	$683						

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	4,369		587		4,956	4,261	695	16
Year 99/00	1,103	9	109		1,221	792	429	54
00/01	401	10	43		454	763	-309	-40
01/02	402	17	29		448	928	-480	-52
02/03	551	26	18		595	1,195	-600	-50
03/04								
04/05								
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	6,826	62	786		7,674	7,939	-265	-3

REVISION: Reflects a schedule change to 120 towers in 99/00 (prev 60), and 40 towers per yr to 02/03 (prev 60).

Reviewed by COORDINATOR	yyyy mm dd 1999 11 09	Reviewed by COORDINATOR	yyyy mm dd 99 11 09
Reviewed by CONSTRUCTOR	yyyy mm dd 99 11 03	Approved by VICE PRESIDENT	yyyy mm dd 99 11 16

H2856/r Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Complex no. 43

Advance or deferral impact

Deferral increases chance of insulator failure.

Factors affecting timing or viability

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Dorsey - US border D602F 500kv T/L insulator repl	5,308	6,907	7,045	6,827	-218	-3
TOTAL	5,308	6,907	7,045	6,827	-218	-3

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
95 10	7,104	New Complex
96 10	6,899	COB insulator replacement at 60 towers at major crossings moved foreward to the fall of 1996 and 1997.
1997 10	7,395	Revised estimate based on all insulator replacement work being carried out by MH's work crews instead of contractors.
1998 10	7,939	In service deferred 1 year due to Oct 97 accident. Labour cost increase due to new safety procedures for equip mtce, replacing insulator strings and local weather checks.
1999 10	7,674	Reflects a schedule change to 120 towers in 99/00 (prev 60), and 40 towers per yr to 02/03 (prev 60).

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item ___ Domestic Item 239

Title
DORSEY - U.S. BORDER D602F 500KV T/L INSULATOR REPLACEMENTS

Budget reference number
02-00-6978

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Operating & Maintenance	Operating & Maintenance	Operating & Maintenance	70023

DESCRIPTION:
PURCHASE AND INSTALL NEW 36-KIP SUSPENSION INSULATORS ON THE 500KV TRANSMISSION LINE BETWEEN DORSEY AND THE U.S. BORDER TO REPLACE THE EXISTING DEFECTIVE ONES. THE SCOPE OF THE WORK INCLUDES A TOTAL OF 475 SUSPENSION, AND POSSIBLY 15 DEAD END, TOWERS.

JUSTIFICATION:
A 1994/95 TEST PROGRAM INDICATED THAT THE EXISTING 36-KIP SUSPENSION INSULATORS IN THIS LINE ARE DEFECTIVE. THIS ITEM PROVIDES FOR THEIR REPLACEMENT AND FULL RESTORATION OF THE LINE'S INTEGRITY.

REFERENCE:
ENGINEERING REPORT NO. 95-L2 36-KIP OHIO BRASS (OB) PORCELAIN SUSPENSION INSULATOR TESTING, DATED AUGUST 1995, BY S.S. CHEUNG.

REVISION:
LAST ESTIMATES ASSUMED CHANGING OUT EQUAL NUMBER OF TOWERS EACH YEAR,(IE, 60 TOWERS PER YEAR) FOR THE NEXT FOUR (4) YEARS.
LATEST ESTIMATES REVISED TO CHANGE OUT 120 TOWERS IN 1999/00 AND 40 TOWERS EACH YEAR FOR THE REMAINING THREE (3) YEARS.

CONTINGENCY: $150,000

		IN SERVICE DATES			Base estimate
1999 01 31	3 881	2002 12 31	682		199704 L2
1999 12 31	1 897				Work start date
2000 12 31	607				1995 12 01
2001 12 31	607				

PREV AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date	4 369		587			4 956
1999/00	-53	17	133			97
2000/01	642	30	91			763
2001/02	815	55	59			929
2002/03	1 128	42	26			1 196
TOTAL	6 901	144	896			7 941
REV. AMOUNTS:						
Authorized to date	4 369		587			4 956
Over(under)expend:						
Auth 1999/00	1 103	9	109			1 221
Req. 2000/01	401	10	43			454
2001/02	402	17	29			448
2002/03	552	25	18			595
TOTAL	6 827	61	786			7 674

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR		COORDINATING MANAGER		ORIGINATING MANAGER

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 02-00-6978

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1996 10	6 899	COB INSULATOR REPLACEMENT AT 60 TOWERS AT MAJOR CROSSINGS MOVED FORWARD TO THE FALL OF 1996 AND 1997 AS PER D.J. HOGG'S MEMO OF 1996 02 04 TO A. STAUDZS ACTUALS FROM TEMPORARY DOMESTIC ITEM 9502-5958 JOURNALLED INTO S/A 9000.
1998 10	7 941	INCREASE IN CONSTRUCTION LABOUR COST OFFSET BY A DECREASE IN MATERIALS, ENGINEERING AND INTEREST. MORE ISD'S ADDED TO CAPITALIZE MORE FREQUENT STAGES OF WORK COMPLETION.
1999 10	6 777	LAST ESTIMATES ASSUMED CHARGING OUT EQUAL NUMBER OF TOWERS EACH YEAR,IE, 60 TOWERS PER YEAR FOR THE NEXT 4 YEARS. LATEST ESTIMATES REVISED TO CHARGE OUT 120 TOWERS IN 1999/00 AND 40 TOWERS EACH YEAR FOR THE REMAINING 3 YEARS.

ASSOCIATED PROJECTS

Budget reference number	Description

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	123	1	7			131	131
May	123	1	8			132	263
Jun	123	1	9			133	396
Jul	123	1	10			134	530
Aug	123	1	11			135	665
Sep	122	2	12			136	801
Oct	122	2	13			137	938
Nov	122	2	14			138	1 076
Dec	122	1	15			138	1 214
Jan			3			3	1 217
Feb			3			3	1 220
Mar		-3	4			1	1 221
TOTAL	1 103	9	109			1 221	1 221
2000/01 Apr	45		3			48	48
May	45	1	3			49	97
Jun	45		4			49	146
Jul	45		4			49	195
Aug	45	1	4			50	245
Sep	44	1	5			50	295
Oct	44	2	5			51	346
Nov	44	2	5			51	397
Dec	44	1	6			51	448
Jan			2			2	450
Feb			2			2	452
Mar		2				2	454
TOTAL	401	10	43			454	454

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

COMPLEX STATUS: ☐ Planned ☒ In progress

Complex no. 7

REVISION STATUS: ☐ New complex ☐ In service change ☐ Concept change ☒ Estimate change only

COMPLEX: BIPOLE 1 & 2 LINE SPACER DAMPERS REPLACEMENT

Proposal

Design and install a new damping system for the 2 DC transmission lines Radisson/Dorsey (896 KM each) and the DC transmission line Henday/Radisson (42 KM) to restore their capacity to suppress aeolian vibration to the origional design level. The new damping system will either reuse the existing refurbished spacer dampers or use new dampers of the existing design.

JUSTIFICATION

☒ Load ☐ Service
☐ Safety ☐ Efficiency
☒ Reliability ☐ Other

Explanation

These transmission lines are experiencing fatigue failures in the cross arms of the suspension towers. The origin of these failures has been traced to deterioration and some failures of the spacer dampers after approximately 25 years of service. A rehabilitation program is necessary to prevent further failures and escalating consequential failures of conductores.

Estimate Level	COMPLEX START (yyyy mm)
L1	1995 12

IN SERVICE DATES AND AMOUNTS					
1999 01	$4400	2000 12	$5590	2001 12	$324

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	4,690		514		5,204	6,100	-896	-15
Year 99/00	601	1	84		686	3,674	-2,988	-81
00/01	2,381	11	140		2,532	3,710	-1,178	-32
01/02	1,915	4	-27		1,892	3,458	-1,566	-45
02/03	1	0			1		1	
03/04								
04/05								
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	9,588	16	711		10,315	16,942	-6,627	-39

REVISION: Reflects favourable actual damper costs, 1 yr deferral of damper refurbishment prog, and unfavourable cost of retro-fitting dampers refurbished in 1998.

Reviewed by ORIGINATOR	yyyy mm dd 99 11 09	Reviewed by COORDINATOR	yyyy mm dd 99 11 09
Reviewed by CONSTRUCTOR	yyyy mm dd 99 11 03	Approved by VICE PRESIDENT	yyyy mm dd 99 11 16

H2856/r Rev 99 03

Complex no. 7

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Advance or deferral impact

Escalating failures of conductors.

Factors affecting timing or viability

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Radisson/Dorsey & Henday/Radisson DC lines spacer dampers	16,656	15,403	15,711	9,588	-6,123	-39
TOTAL	16,656	15,403	15,711	9,588	-6,123	-39

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
95 10	19,825	NEW ITEM.
96 10	22,248	Scope change to include: end span stock bridge dampers, repl rubber bushing performance tests, as built span length measurement, const schedule moved forward to 1997.
1997 10	19,121	Project recalculated using activity rates as per the new accounting system. Further studies indicated that end-spand stockbridge dampers and span length surveys not required.
1998 10	16,942	Revised to reflect the 97/98 underexpenditure 1.6M , and that labour costs, and contingency have been moved from 97/98 to 01/02.
1999 10	10,315	Reflects favourable actual damper costs, 1 yr deferral of damper refurbishment prog, and unfavourable cost of retro-fitting dampers refurbished in 1998.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item __ Domestic Item 240

Title
RADISSON-DORSEY AND HENDAY-RADISSON DC LINES SPACER DAMPERS

Budget reference number
02-00-6977

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Operating & Maintenance	Operating & Maintenance	Construction	70031

DESCRIPTION:
DESIGN AND INSTALL A NEW DAMPING SYSTEM FOR THE 2 DC TRANSMISSION LINES BETWEEN RADISSON- DORSEY (896 KM EACH) AND THE DC TRANSMISSION LINE BETWEEN HENDAY-RADISSON (42 KM), TO RESTORE THEIR CAPACITY TO SUPPRESS AEOLIAN VIBRATION TO THE ORIGINAL DESIGN LEVEL. THE NEW DAMPING SYSTEM WILL EITHER REUSE THE EXISTING REFURBISHED SPACER DAMPERS OR USE NEW DAMPERS OF THE EXISTING DESIGN.

JUSTIFICATION:
THESE TRANSMISSION LINES ARE EXPERIENCING FATIGUE FAILURES IN THE CROSS ARMS OF THE SUSPENSION TOWERS. THE ORIGIN OF THESE FAILURES HAS BEEN TRACED TO THE DETERIORATION AND SOME FAILURES OF THE SPACER DAMPERS AFTER APPROXIMATELY 25 YEARS OF SERVICE. A REHABILITATION PROGRAM IS NECESSARY TO PREVENT FURTHER FAILURES AND ESCALATING CONSEQUENTIAL FAILURES OF CONDUCTORS.

REFERENCE:
MANITOBA HYDRO 500KV DC TRANSMISSION LINE VIBRATION STUDY BY HERBERT J. HUSTON & CO. INC., INDUSTRIAL TECHNOLOGY CENTRE, DATED APRIL, 1995.
TECHNICAL REVIEW COMMITTEE MINUTES OF MEETING #158, DECEMBER 10, 1996.

REVISION:
ORIGINAL CONTRACT ESTIMATE BASED ON $120/DAMPER, ACTUAL CHARGES ARE APPROXIMATING $62/DAMPER. REFURBISHING OF EXISTING DAMPERS DEFERRED FOR ONE YEAR SO THAT COLD TEMPERATURE RUBBER BUSHING SLIP PROBLEM CAN BE RECTIFIED. ADDITIONAL FUNDING IN THIS REVISION FOR RETRO-FITTING DAMPERS REFURBISHED AND INSTALLED ON THE LINES IN 1998.

CONTINGENCY: $750 000

IN SERVICE DATES		Base estimate
1999 01 31	4 400	199706 L3
2000 12 31	5 590	
2001 12 31	326	Work start date
		1997 04 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date	4 690		514			5 204
1999/00	4 243	88	239			4 570
2000/01	3 364	157	189			3 710
2001/02	3 115	211	132			3 458
TOTAL	15 412	456	1 074			16 942
REV. AMOUNTS						
Authorized to date	4 690		514			5 204
Over(under)expend:						
Auth 1999/00	601	1	84			686
Req. 2000/01	2 381	12	140			2 533
2001/02	1 915	4	-27			1 892
2002/03	1					1
TOTAL	9 588	17	711			10 316

Prepared by (yy mm dd)	Approved by (yy mm dd)	Approved by (yy mm dd)
COORDINATOR		
Estimated by		
ORIGINATOR	COORDINATING MANAGER	ORIGINATING MANAGER

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 02-00-6977

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1995 10	19 825	NEW ITEM
1996 10	22 248	CHANGE IN PROJECT SCOPE.
1997 10	19 105	PROJECT RECALCULATED USING ACTIVITY RATES AS PER THE NEW ACCOUNTING SYSTEM. END-SPAN STOCKBRIDGE DAMPERS & SPAN LENGTH SURVEYS NOT REQUIRED. IN-SERVICE DATES REVISED TO CAPITALIZE MORE FREQUENT STAGES OF WORK COMPLETION.
1998 10	16 940	CONTINGENCY OF $750,000 MOVED FROM 1997/98 TO 2001/02. REVISED CONSTRUCTION AND ENGINEERING LABOUR COSTS.
1999 10	10 123	DAMPER CHANGE-OUT COSTS ESTIMATED AT $120/DAMPER, ACTUAL COSTS APPROXIMATELY $62/DAMPER. DAMPER REFURBISHMENT DEFERRED 1 YR TO ALLOW FOR RUBBER BUSHING SLIP PROBLEM RECTIFICATION. ADDITIONAL FUNDING TO REFURBISH DAMPERS REFURBISHED AND INSTALLED IN 1998.

ASSOCIATED PROJECTS

Budget reference number	Description

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	7		6			13	13
May	7		6			13	26
Jun	9	-1	6			14	40
Jul	9		6			15	55
Aug	9		6			15	70
Sep	79		6			85	155
Oct	79		7			86	241
Nov	79	1	7			87	328
Dec	79		8			87	415
Jan	79	1	8			88	503
Feb	82		9			91	594
Mar	83		9			92	686
TOTAL	601	1	84			686	686
2000/01 Apr	157	1	11			169	169
May	451	1	12			464	633
Jun	451	1	15			467	1 100
Jul	365	1	18			384	1 484
Aug	11	1	21			33	1 517
Sep	89	3	21			113	1 630
Oct	448	2	22			472	2 102
Nov	375	1	25			401	2 503
Dec	9		28			37	2 540
Jan	9		-11			-2	2 538
Feb	9		-11			-2	2 536
Mar	7	1	-11			-3	2 533
TOTAL	2 381	12	140			2 533	2 533

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

COMPLEX STATUS: [X] Planned [ ] In progress

Complex no. 247

REVISION STATUS: [ ] New complex [ ] In service change [ ] Concept change [X] Estimate change only

COMPLEX: DORSEY BUS ENHANCEMENT

Proposal
Sectionalize Dorsey A and B busses with breaker and interconnecting bus. Installation will include 4 - 230kV breakers, an interconnecting bus, plus associated equipment.

JUSTIFICATION
[ ] Load [ ] Service
[X] Safety [X] Efficiency
[X] Reliability [ ] Other

Explanation
Sectionalizing Dorsey bus will minimize the chances of a complete Dorsey shutdown , and allow ent bus maintenance.

Estimate Level	COMPLEX START yyyy mm
L2	1999 04

IN SERVICE DATES AND AMOUNTS							
2002 05	$4009	2002 09	$4009	2003 05	$4009	2003 09	$4009

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend								
Year 99/00	377	9	18		404	371	33	9
00/01	764	34	64		862	750	112	15
01/02	2,839	182	222		3,243	2,658	585	22
02/03	6,239	528	200		6,967	6,412	555	9
03/04	4,056	416	88		4,560	4,393	167	4
04/05								
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	14,275	1,169	592		16,036	14,584	1,452	10

REVISION: Scope Unchanged

Reviewed by ORIGINATOR	yyyy mm dd 99 11 08	Reviewed by COORDINATOR	yyyy mm dd 99 11 03
Reviewed by CONSTRUCTOR	yyyy mm dd 99 11 03	Approved by VICE PRESIDENT	yyyy mm dd 99 11 16

H2856/r Rev 99 03

Complex no. 247

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Advance or deferral impact

System Planning report 98/2 recommended that bus enhancement be done A.S.A.P. due to the secutity risk. Deferral increases the risk of system collapse.

Factors affecting timing or viability

A detailed design study will be done due to the complexity of protection changes.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE	
					Amount	%
Dorsey bus enhancement		12,952	13,211	14,275	1,064	8
TOTAL		12,952	13,211	14,275	1,064	8

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
1998 06	14,584	NEW ITEM
1999 10	16,037	Scope Unchanged.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item Domestic Item

241

Title
DORSEY BUS ENHANCEMENT

Budget reference number
03-00-8339

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
anning & Control	Design	Construction	70557

DESCRIPTION:
SECTIONALIZE DORSEY A AND B BUSSES WTIH BREAKER AND INTERCONNECTING BUS. INSTALLATION WILL INCLUDE 4-230KV BREAKERS, AN INTERCONNECTING BUS, PLUS ASSOCIATED EQUIPMENT. WORK SCHEDULE IS AS FOLLOWS:
2002 05 31 - STAGE 1, 1 BREAKER
2002 09 30 - STAGE 2, 1 BREAKER
2003 05 31 - STAGE 3, 1 BREAKER
2003 09 30 - STAGE 4, 1 BREAKER

JUSTIFICATION:
SECTIONALIZING DORSEY BUS WILL MINIMIZE THE CHANCES OF A COMPLETE DORSEY SHUTDOWN PLUS ALLOW MORE THOROUGH AND CONVENIENT BUS MAINTENANCE.

REFERENCE:
SPD 98/2 'DORSEY BUS ENHANCEMENT'.

REVISION:
REFLECTS REVISED ACTIVITY AND OVERHEAD RATES.

CONTINGENCY: $2,000,000

IN SERVICE DATES

2002 05 31	4 009
2002 09 30	4 009
2003 05 31	4 009
2003 09 30	4 010

Base estimate
199805 L2

Work start date
1999 04 01

PREV. AUTHORITY Authorized to date	GROSS	ESCALATION	INT CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
1999/00	346	8	17			371
2000/01	659	32	59			750
2001/02	2 306	160	192			2 658
2002/03	5 739	517	156			6 412
2003/04	3 902	422	69			4 393
TOTAL	12 952	1 139	493			14 584
REV. AMOUNTS: Authorized to date: Over(under)expend:						
Auth 1999/00	377	9	18			404
Req. 2000/01	764	34	64			862
2001/02	2 839	183	222			3 244
2002/03	6 239	528	200			6 967
2003/04	4 056	416	88			4 560
TOTAL	14 275	1 170	592			16 037

Prepared by yy mm dd COORDINATOR
Estimated by ORIGINATOR
Approved by yy mm dd COORDINATING MANAGER
Approved by ORIGINATING MANAGER
yy mm dd

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 03-00-8339

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1998 10	14 584	NEW ITEM

ASSOCIATED PROJECTS

Budget reference number _____ Description _____

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	37					37	37
May	37	1				38	75
Jun	37		1			38	113
Jul	37		1			38	151
Aug	36	1	1			38	189
Sep	36	2	1			39	228
Oct	46	1	2			49	277
Nov	46	1	2			49	326
Dec	46	1	2			49	375
Jan	7		3			10	385
Feb	7		3			10	395
Mar	5	2	2			9	404
TOTAL	377	9	18			404	404
2000/01 Apr	62	2	3			67	67
May	62	2	3			67	134
Jun	62	2	4			68	202
Jul	61	3	4			68	270
Aug	61	3	5			69	339
Sep	61	3	5			69	408
Oct	44	1	6			51	459
Nov	43	3	6			52	511
Dec	43	3	6			52	563
Jan	43	2	7			52	615
Feb	43	3	7			53	668
Mar	179	7	8			194	862
TOTAL	764	34	64			862	862

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

COMPLEX STATUS: [X] Planned [ ] In progress

Complex no. 251

REVISION STATUS: [X] New complex [ ] In service change [ ] Concept change [ ] Estimate change only

COMPLEX: FLIN FLON AREA TRANSMISSION IMPROVEMENTS

Proposal

Perform environmental assessments and route selection, design and construct transmission and terminal facilities, and reconnect T/L in Flin Flon area to salvage Switch Tower #3, Mile 13 Stn, and Mile 13 - Sherridon section of HS15 and to enhance system reliability. Transmission: Construct115 kV line 6.0 km Herblet L Stn - Chisel L tap, 115 kV line 1.5 km Ross L Stn - Switch Tower #3 line 1. Upgrade 115 kV line 73 km HS15 Herblet L Stn - Sherridon Stn. Termination: Establish single line termination into Ross L Stn for lines I1F & I2F, terminate HBM&S line 1 & re-terminate HBM&S line 3 and re-terminate line RC56 into Ross L Stn, install former Ponton's 30/40/45 MVA transformer bank at Herblet L Stn, terminate the new line to Chisel L tap into Herblet L Stn, install a single phase station service power VT at Ponton Stn. Modify, upgrade and coordinate protection at Ross L, Herblet L, Sherridon and Ponton . Communications: Modify to accommodate 2-line supply to HBM&S and changes at Ross L and Herblet L.

JUSTIFICATION

[X] Load [ ] Service
[X] Safety [X] Efficiency
[X] Reliability [ ] Other

Explanation

Facilities are required to decommission crumbling Mile 13 Station and Switch Tower #3, to enhance reliability of transmission to HBM&S, to firm transformation at Herblet Lake Station, and to firm supply to Snow Lake area loads.

Estimate Level	COMPLEX START (yyyy mm)
L1-2	1998 06

IN SERVICE DATES AND AMOUNTS

2001 08	$7793	2004 10	$9738		

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	19		1		20		20	
Year 99/00	299	10	3		312		312	
00/01	2,002	86	70	192	1,966		1,966	
01/02	4,850	257	145	4	5,248		5,248	
02/03	1,472	128	47		1,647		1,647	
03/04	4,392	470	334		5,196		5,196	
04/05	2,333	219	385	37	2,900		2,900	
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	15,367	1,170	985	233	17,289		17,289	

REVISION: NEW ITEM

Reviewed by ORIGINATOR	yyyy mm dd 99 11 08	Reviewed by COORDINATOR	yyyy mm dd 99 11 07
Reviewed by CONSTRUCTOR	yyyy mm dd 99 11 03	Approved by VICE-PRESIDENT	yyyy mm dd 99 11 16

H2856/r Rev 99 03

Complex no. 251

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Advance or deferral impact

Delay of this complex will delay customer satisfaction in the HBM&S and Snow Lake area and will jeopardize personel safety due to an aging system with inadequate grounding and structures.

Factors affecting timing or viability

Environmental Licencing for new 6KM line from Herblet to Chisel L.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	%
Dedicated Lines > HBM&S & Paralleling R1F/R2F				3,043	3,043	
Transmission Line HS15 Salvage & Upgrade				6,321	6,321	
Herblet Lake>Chisel Lake Tap 115kV line				1,375	1,375	
Flin Flon-Ross L Salvage Switch Tower #3 & Reconfig				1,063	1,063	
Mile 13 Salvage 115kV Stn				205	205	
Herblet L Add Spare 230-115kVBank and 115kVT/L				2,983	2,983	
Ponton Convert Stn Service & Salvage Auto Transf				378	378	
TOTAL				15,368	15,368	

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
1999 10	17,289	NEW ITEM

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item 2 42

Title	Budget reference number
DEDICATED LINES TO HBM&S AND PARALLELING R1F / R2F	02-00-8004

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	70566

DESCRIPTION:
CONSTRUCT 1.5 KM SINGLE CIRCUIT 115KV LINE BETWEEN ROSS LAKE STATION AND SWITCH TOWER #3 LOCATION USING 477 MCM CONDUCTOR. INSTALL THE REQUIRED STRUCTURES, INCLUDING A DOUBLE CIRCUIT CORNER TOWER AT SWITCH TOWER #3 SITE TO CONNECT THE NEW ROSS LAKE LINE TO HBM&S LINE 1 AND ALSO TO CONNECT FR54 TO HBM&S LINE 3. INSTALL ONE SWITCHING STRUCTURE, TWO SETS OF MANUALLY OPERATED DISCONNECT SWITCHES, AND ALL THE REQUIRED TELECOMMUNICATION HARDWARE FOR PARALLELING ISLAND FALLS LINES I1F AND I2F AT SWITCH TOWER #3 LOCATION. ON THE NEW SWITCHING STRUCTURE, CONNECT FR55 TO THE PARALLELED I1F/I2F.

JUSTIFICATION:
TWO DEDICATED ROSS LAKE STATION - HBM&S LINES SEPARATE THE HBM&S LOAD FROM SASK POWER SYSTEM. NEW CONFIGURATION ENHANCES THE RELIABILITY OF SUPPLY TO HBM&S LOAD. PARALLELING I1F/I2F AT SWITCH TOWER #3 SAVES SPACE ON ROSS LAKE STATION 115KV RING BUS AND DEFERS INSTALLATION OF BREAKER R6.

REFERENCE:
REPORT SPD 98/3, 'FLIN FLON AREA IMPROVEMENTS'.

REVISION:
NEW ITEM

CONTINGENCY: $277 000

IN SERVICE DATES				Base estimate
2001 08 31	3 278			199805 L1
				Work start date 2000 04 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:						
TOTAL						
REV. AMOUNTS:						
Authorized to date:						
Over(under)expend:						
Auth 2000/01	346	15	14			375
Req.: 2001/02	2 697	157	49			2 903
TOTAL	3 043	172	63			3 278

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 02-00-8004

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS

ASSOCIATED PROJECTS

Budget reference number	Description
02-00-8005	TRANSMISSION LINE HS15 SALVAGE AND UPGRADE
02-00-8006	HERBLET LAKE - CHISEL LAKE TAP 115KV LINE
03-00-8352	FLIN FLON ROSS LAKE - SALVAGE SWITCHTOWER #3 AND RECONFIGURE
03-00-8353	MILE 13 - SALVAGE 115KV STATION
03-00-8354	HERBLET LAKE - ADD SPARE 230 - 115K BANK AND 115KV T/L
03-00-8355	PONTON-CONVERT STATION SERVICE AND SALVAGE AUTO TRANSFORMER

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr	29	1				30	30
May	29	1				30	60
Jun	29	1				30	90
Jul	29	1	1			31	121
Aug	29	1	1			31	152
Sep	29	1	1			31	183
Oct	29	1	1			31	21
Nov	29	1	2			32	24
Dec	29	1	2			32	278
Jan	29	1	2			32	310
Feb	29	1	2			32	342
Mar	27	4	2			33	375
TOTAL	346	15	14			375	375

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item

243

Title			Budget reference number
TRANSMISSION LINE HS15 SALVAGE AND UPGRADE			02-00-8005
Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	70567

DESCRIPTION:
SALVAGE 65 KM OF 115 KV LINE HS15 BETWEEN I1F/I2F TAP AND SHERRIDON STATION. UPGRADE 73 KM OF HS15 BETWEEN HERBLET LAKE AND SHERRIDON STATIONS . FIX TOWERS AND INSULATORS WHERE REQUIRED AND CLEAN UP THE RIGHT OF WAY.

JUSTIFICATION:
MILE 13 - SHERRIDON SECTION OF HS15 BECOMES REDUNDANT FOLLOWING THE SALVAGE OF MILE 13 STATION. HERBLET LAKE - SHERRIDON SECTION OF HS15 SHOULD BE UPGRADED TO SUPPLY SHERRIDON STATION AND TO PROVIDE FIRM SUPPLY TO SNOW LAKE AREA LOADS.

REFERENCE:
REPORT SPD 98/3 'FLIN FLON AREA IMPROVEMENTS'.

REVISION:
NEW ITEM.

CONTINGENCY: $575 000

IN SERVICE DATES				Base estimate
2004 10 31	7 543			199805 L1
				Work start date
				2002 06 01

	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
PREV. AUTHORITY Authorized to date:						
TOTAL						
REV. AMOUNTS:						
Authorized to date:						
Over(under)expend:						
Auth 2002/03	1 149	101	40			1 290
Req.: 2003/04	3 448	369	266			4 083
2004/05	1 724	144	302			2 170
TOTAL	6 321	614	608			7 543

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 02-00-8005

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS

ASSOCIATED PROJECTS

Budget reference number	Description
02-00-8004	DEDICATED LINES TO HBM&S AND PARALLELING R1F / R2F
02-00-8006	HERBLET LAKE - CHISEL LAKE TAP 115KV LINE
03-00-8352	FLIN FLON ROSS LAKE - SALVAGE SWITCHTOWER #3 AND RECONFIGURE
03-00-8353	MILE 13 - SALVAGE 115KV STATION
03-00-8354	HERBLET LAKE - ADD SPARE 230 - 115K BANK AND 115KV T/L
03-00-8355	PONTON-CONVERT STATION SERVICE AND SALVAGE AUTO TRANSFORMER

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11-

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item

244

Title			Budget reference number
HERBLET LAKE - CHISEL LAKE TAP 115KV LINE			02-00-8006
Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	70568

DESCRIPTION:
DESIGN, AND CONSTRUCT APPROXIMATELY 6.0 KM OF SINGLE CIRCUIT, 115KV, 266.8 MCM LINE BETWEEN HERBLET LAKE STATION AND CHISEL LAKE DISCONNECT SWITCH 1521.

JUSTIFICATION:
A SECOND LINE FROM HERBLET LAKE STATION TO CHISEL LAKE SWITCH 1521 PROVIDES A DEDICATED RADIAL SUPPLY TO SHERRIDON STATION AND FIRMS UP SUPPLY TO SNOW LAKE AREA LOADS.

REFERENCE:
REPORT SPD 98/3 'FLIN FLON AREA IMPROVEMENTS'.

REVISION:
NEW ITEM.

CONTINGENCY: $125 000

IN SERVICE DATES				Base estimate
2004 10 31	1 656			199805 L1
				Work start date 2002 06 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:						
TOTAL						
REV. AMOUNTS:						
Authorized to date:						
Over(under)expend:						
Auth 2002/03	250	21	9			280
Req.: 2003/04	750	80	58			888
2004/05	375	47	66			488
TOTAL	1 375	148	133			1 656

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number: 02-00-8006

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS

ASSOCIATED PROJECTS

Budget reference number	Description
02-00-8004	DEDICATED LINES TO HBM&S AND PARALLELING R1F / R2F
02-00-8005	TRANSMISSION LINE HS15 SALVAGE AND UPGRADE
03-00-8352	FLIN FLON ROSS LAKE - SALVAGE SWITCHTOWER #3 AND RECONFIGURE
03-00-8353	MILE 13 - SALVAGE 115KV STATION
03-00-8354	HERBLET LAKE - ADD SPARE 230 - 115K BANK AND 115KV T/L
03-00-8355	PONTON-CONVERT STATION SERVICE AND SALVAGE AUTO TRANSFORMER

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item

245

Title	Budget reference number
FLIN FLON ROSS LAKE - SALVAGE SWITCHTOWER #3 AND RECONFIGURE	03-00-8352

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	70561

DESCRIPTION:
SALVAGE SWITCH TOWER #3 AND ITS ASSOCIATED COMMUNICATION AND SWITCHING EQUIPMENT. UTILIZING A DOUBLE CIRCUIT DEAD END STRUCTURE TERMINATE THE NEW LINE TO SWITCH TOWER #3 LOCATION INTO ROSS LAKE STATION BETWEEN BREAKERS R7 AND R8. RE-TERMINATE LINE FR55 BETWEEN BREAKER R5 AND FUTURE BREAKER R6. RE-TERMINATE LINE RC56 BETWEEN BREAKER R3 AND R4. RE-TERMINATE LINE FR54 BETWEEN BREAKERS R4 AND R5. MAKE ALL THE NECESSARY PROTECTION AND COMMUNICATION CHANGES TO ACCOMMODATE TWO DEDICATED LINES FROM ROSS LAKE STATION TO HBM&S. TRANSFER CUSTOMER BILLING AND METERING EQUIPMENT FROM HBM&S TO ROSS LAKE STATION.

JUSTIFICATION:
SALVAGING OF SWITCH TOWER #3 IS DUE TO THE UNSAFE CONDITION OF THE STRUCTURE. CHANGES TO THE 115KV RING BUS ARE TO ENHANCE RELIABILITY OF SUPPLY TO HBM&S BY PROVIDING TWO DEDICATED LINES FROM ROSS LAKE STATION.

REFERENCE:
REPORT SPD 98/3 'FLIN FLON AREA IMPROVEMENTS'.

REVISION:
NEW ITEM

CONTINGENCY: $91,000

IN SERVICE DATES				Base estimate
2001 08 31	1 150			199805 L2
				Work start date 2000 06 01

	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
PREV. AUTHORITY Authorized to date:						
TOTAL						
REV. AMOUNTS: Authorized to date: Over(under)expend:						
Auth 2000/01	427	20	11			458
Req.: 2001/02	636	31	25	-4		688
TOTAL	1 063	51	36	-4		1 146

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 03-00-8352

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS

ASSOCIATED PROJECTS

Budget reference number	Description
02-00-8004	DEDICATED LINES TO HBM&S AND PARALLELING R1F / R2F
02-00-8005	TRANSMISSION LINE HS15 SALVAGE AND UPGRADE
02-00-8006	HERBLET LAKE - CHISEL LAKE TAP 115KV LINE
03-00-8353	MILE 13 - SALVAGE 115KV STATION
03-00-8354	HERBLET LAKE - ADD SPARE 230 - 115K BANK AND 115KV T/L
03-00-8355	PONTON-CONVERT STATION SERVICE AND SALVAGE AUTO TRANSFORMER

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun	20					20	20
Jul	4					4	24
Aug	4					4	28
Sep	4					4	32
Oct	151	7				158	190
Nov	48	2	1			51	241
Dec	48	2	2			52	293
Jan	48	2	2			52	345
Feb	48	2	2			52	397
Mar	52	5	4			61	458
TOTAL	427	20	11			458	458

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item

246

Title			Budget reference number
MILE 13 - SALVAGE 115KV STATION			03-00-8353
Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	70560

DESCRIPTION:
DE-COMMISSION AND SALVAGE THE MILE 13 STATION.

JUSTIFICATION:
MILE 13 STATION IS NO LONGER MAINTAINABLE AS IT IS 50 YEARS OLD AND NEARING THE END OF ITS USEFUL LIFE. REMEDIAL WORK IS VERY COSTLY.

REFERENCE:
REPORT SPD 98/3 'FLIN FLON AREA IMPROVEMENTS.'

REVISION:
NEW ITEM.

CONTINGENCY: $18 000

IN SERVICE DATES				Base estimate
2004 10 31	239			199805 L2
				Work start date
				2002 11 01

	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
PREV. AUTHORITY Authorized to date:						
TOTAL						
REV. AMOUNTS: Authorized to date: Over(under)expend:						
Auth 2002/03	33	3	1			37
Req.: 2003/04	20	2	4			26
2004/05	152	19	5	-37		139
TOTAL	205	24	10	-37		202

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 03-00-8353

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS

ASSOCIATED PROJECTS

Budget reference number	Description
02-00-8004	DEDICATED LINES TO HBM&S AND PARALLELING R1F / R2F
02-00-8005	TRANSMISSION LINE HS15 SALVAGE AND UPGRADE
02-00-8006	HERBLET LAKE - CHISEL LAKE TAP 115KV LINE
03-00-8352	FLIN FLON ROSS LAKE - SALVAGE SWITCHTOWER #3 AND RECONFIGURE
03-00-8354	HERBLET LAKE - ADD SPARE 230 - 115K BANK AND 115KV T/L
03-00-8355	PONTON-CONVERT STATION SERVICE AND SALVAGE AUTO TRANSFORMER

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item

247

Title			Budget reference number
HERBLET LAKE - ADD SPARE 230 - 115K BANK AND 115KV T/L			03-00-8354
Originating division	Coordinating division	Constructing division	Project Order Group (Range):
anning & Control	Design	Construction	70559

DESCRIPTION:
INSTALL 30/40/45 MVA 230-115-13.8 KV AUTO TRANSFORMER (FROM PONTON), TWO 230KV VERTICAL BREAK MOD'S RATED FOR INTERRUPTING THE MAGNETIZING CURRENT AND ONE NEW 115 KV BREAKER. CO-TERMINATE THE 230 KV SIDES OF NEW AND EXISTING TRANSFORMERS. TERMINATE THE NEW HERBLET LAKE - CHISEL LAKE TAP 115 KV LINE INTO HERBLET LAKE STATION UTILIZING A NEW 115KV BREAKER.

NOTE
ISD EXCEPT FOR THE TERMINATION 2000 10 31

ISD FOR LINE TERMINATION 2004 10 31

JUSTIFICATION:
115 KV OPERATION OF H59C AS A BACK UP TO HERBLET LAKE 30/40/50/56 MVA BANK WOULD COMPROMISE SUPPLY TO ROSS LAKE AND HBM&S AND WOULD REDUCE THE ABILITY TO TRANSFER POWER OUT OF THE NORTH. THE SECOND TRANSFORMER BANK FIRMS UP 230 - 115 KV TRANSFORMATION AT HERBLET LAKE STATION AND FREES H59C FOR 230 KV OPERATION.

REFERENCE:
REPORT SPD 98/3 'FLIN FLON AREA IMPROVEMENTS'.

REVISION:
NEW ITEM

CONTINGENCY $261 000

This BRN contains Deleted, Blocked, or Closed Orders.

IN SERVICE DATES				Base estimate
2001 08 31	2 950			199805 L2
2004 10 31	300			Work start date
				1998 10 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:	9					9
1999/00	-9					-9
TOTAL						
REV. AMOUNTS:						
Authorized to date:	9					9
Over(under)expend:						
Auth 1999/00	178	6	1			185
Req.: 2000/01	1 021	51	28			1 100
2001/02	1 480	68	65			1 613
2002/03	40	3	-2			41
2003/04	174	18	7			199
2004/05	81	10	12			103
TOTAL	2 983	156	111			3 250

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 03-00-8354

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS

ASSOCIATED PROJECTS

Budget reference number	Description
02-00-8004	DEDICATED LINES TO HBM&S AND PARALLELING R1F / R2F
02-00-8005	TRANSMISSION LINE HS15 SALVAGE AND UPGRADE
02-00-8006	HERBLET LAKE - CHISEL LAKE TAP 115KV LINE
03-00-8352	FLIN FLON ROSS LAKE - SALVAGE SWITCHTOWER #3 AND RECONFIGURE
03-00-8353	MILE 13 - SALVAGE 115KV STATION
03-00-8355	PONTON-CONVERT STATION SERVICE AND SALVAGE AUTO TRANSFORMER

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb	89	3				92	92
Mar	89	3	1			93	185
TOTAL	178	6	1			185	185
2000/01 Apr	89	4	1			94	94
May	2		2			4	98
Jun	2		2			4	102
Jul	2		2			4	106
Aug	1		2			3	109
Sep	1		2			3	112
Oct	1		2			3	115
Nov	1		2			3	118
Dec			2			2	120
Jan			2			2	122
Feb	457	24	2			483	605
Mar	465	23	7			495	1 100
TOTAL	1 021	51	28			1 100	1 100

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item

248

Title			Budget reference number
PONTON-CONVERT STATION SERVICE AND SALVAGE AUTO TRANSFORMER			03-00-8355
Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	70558

DESCRIPTION:
SALVAGE 230-115-13.8 KV, 30/40/45 MVA STATION SERVICE TRANSFORMER. CONVERT THE THREE PHASE STATION AIR CONDITIONING LOAD TO SINGLE PHASE. PURCHASE TWO SINGLE PHASE 138 KV-120/240 V POWER VT UNITS. INSTALL ONE POWER VT UNIT AS MAIN STATION SERVICE SUPPLY AND STORE THE SECOND UNIT AS SPARE.

JUSTIFICATION:
RELOCATING THE 30/40/45 MVA, 230/115/13.8 KV TRANSFORMER BANK FROM PONTON TO HERBLET LAKE STATION NECESSITATES AN ALTERNATIVE STATION SERVICE SUPPLY AT PONTON.

NOTE: ONE SPARE POWER VT TO BE PURCHASED TO STORES AT $145 000.

REFERENCE:
REPORT SPD 98/3, 'FLIN FLON AREA IMPROVEMENTS.'

REVISION:
NEW ITEM

CONTINGENCY: $31 000

This BRN contains Deleted, Blocked, or Closed Orders.

IN SERVICE DATES				Base estimate
2001 08 31	414			199805 L2
				Work start date 1998 10 01

PREV. AUTHORITY Authorized to date:	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
1999/00	-10					-10
TOTAL	-10					-10
REV. AMOUNTS:						
Authorized to date:	10					10
Over(under)expend:						
Auth 1999/00	122	4	1			127
Req.: 2000/01	209		16	- 192		33
2001/02	37	1	6			44
TOTAL	378	5	23	- 192		214

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 03-00-8355

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS

ASSOCIATED PROJECTS

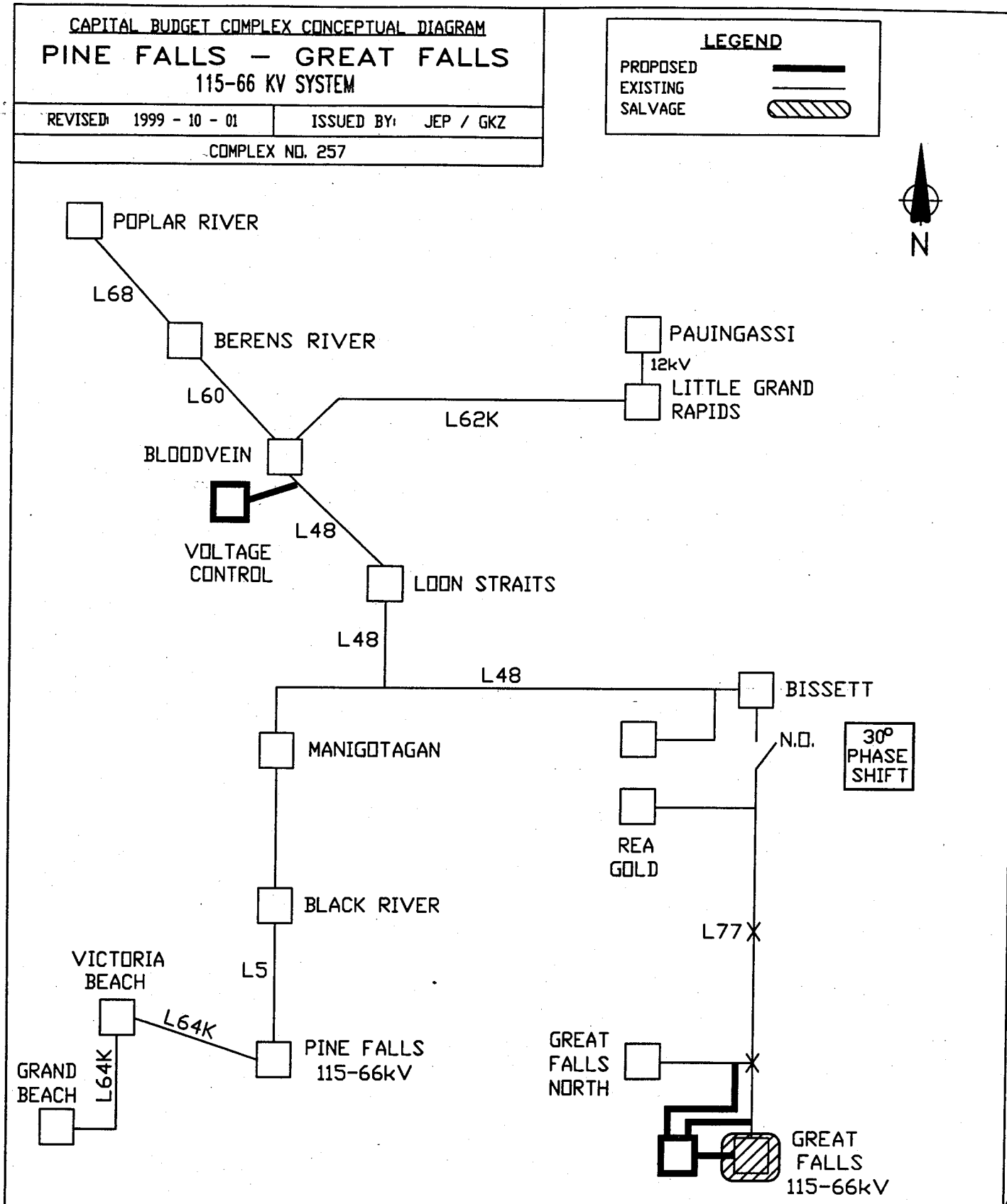
Budget reference number	Description
02-00-8004	DEDICATED LINES TO HBM&S AND PARALLELING R1F / R2F
02-00-8005	TRANSMISSION LINE HS15 SALVAGE AND UPGRADE
02-00-8006	HERBLET LAKE - CHISEL LAKE TAP 115KV LINE
03-00-8352	FLIN FLON ROSS LAKE - SALVAGE SWITCHTOWER #3 AND RECONFIGURE
03-00-8353	MILE 13 - SALVAGE 115KV STATION
03-00-8354	HERBLET LAKE - ADD SPARE 230 - 115K BANK AND 115KV T/L

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb	61	2				63	63
Mar	61	2	1			64	127
TOTAL	122	4	1			127	127
2000/01 Apr	61	2	1			64	64
May	61	3	1			65	129
Jun	20		2			22	151
Jul	32	-3	2		-96	-65	86
Aug	32	-3	2		-96	-65	21
Sep			1			1	22
Oct			1			1	23
Nov			1			1	24
Dec			1			1	25
Jan			1			1	26
Feb	1		1			2	28
Mar	2	1	2			5	33
TOTAL	209		16		- 192	33	33

CAPITAL BUDGET COMPLEX CONCEPTUAL DIAGRAM

PINE FALLS – GREAT FALLS
115-66 KV SYSTEM

REVISED: 1999 - 10 - 01	ISSUED BY: JEP / GKZ
COMPLEX NO. 257	



manitoba hydro

PLANNING AND CONTROL DIVISION

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

COMPLEX STATUS	Complex no.	REVISION STATUS
[X] Planned [ ] In progress	257	[X] New complex [ ] In service change [ ] Concept change [ ] Estimate change only

COMPLEX: PINE FALLS > GREAT FALLS 115-66KV SUPPLY

Proposal
Establish a new 115-66kV Station at Great Falls, with a 115kV circuit to the Great Falls G.S. Install a new voltage regulation device at Bloodvein. Construct a new 66kV 266.8 MCM line from Great Falls 115-66kV station to Great Falls -North 66-12kVstation and re-route line #77 to the new Great Falls 115-66kV station. Salvage the existing Great Falls 115-66kV, 5/6.67 MVA autotransformer station.

JUSTIFICATION	Explanation
[X] Load [ ] Service [ ] Safety [ ] Efficiency [X] Reliability [ ] Other	THE ADDITION OF 115-66KV CAPACITY AT GREAT FALLS WILL PROVIDE CONTINGENCY CAPACITY FOR THE PINE FALLS 66KV SYSTEM WHICH WILL RUN SHORT BY 2008/09. THE EARLIER 2003 ISD IS RECOMMENDED TO SEPARATE GREAT FALLS -N STN AND BISSETT AREA ONTO SEPARATE BREAKERS. OUTAGES HAVE BEEN A CUSTOMER CONCERN AND THIS SERVICE DOES NOT MEET BASIC RELIABILITY INTENT OF THE TRANSMISSION PLANNING CRITERIA FOR FIRM LOAD.

Estimate Level	COMPLEX START (yyyy mm)
L1	2003 04

IN SERVICE DATES AND AMOUNTS					
2002 04	$6473	2003 10	$112	2004 10	$2884

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend								
Year 99/00								
00/01	899		36		935		935	
01/02	2,447	107	180		2,734		2,734	
02/03	3,188	207	57		3,452		3,452	
03/04	1,024	86	107		1,217		1,217	
04/05	953	72	104	21	1,108		1,108	
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	8,511	472	484	21	9,446		9,446	

REVISION: New Complex

Reviewed by ORIGINATOR	yyyy mm dd	Reviewed by COORDINATOR	yyyy mm dd
99 11 08		99 11 03	
Reviewed by CONSTRUCTOR	yyyy mm dd	Approved by VICE-PRESIDENT	yyyy mm dd
99 11 03		99 11 18	

H2856/r Rev 99 03

Complex no. 257

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Advance or deferral impact

Customer satisfaction level.
Reliability level.

Factors affecting timing or viability

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
GREAT FALLS 115KV LINE				352	352	
BLOODVEIN VOLTAGE CONTROL DEVICE				5,950	5,950	
GREAT FALLS NEW 115-66KV STATION				1,982	1,982	
GREAT FALLS 115KV STATION SALVAGE				120	120	
GREAT FALLS 66KV LINES				106	106	
TOTAL				8,510	8,510	

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
1999 10	9,446	New Complex

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item

249

Title			Budget reference number
GREAT FALLS 115 KV LINE			02-00-8010
Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	70631

DESCRIPTION:
EXTEND THE 115 KV CIRCUIT FROM GREAT FALLS G.S TO THE NEW GREAT FALLS 115-66 KV STATION.

JUSTIFICATION:
THESE LINE CHANGES ARE REQUIRED IN CONJUNCTION WITH THE NEW GREAT FALLS 115-66 KV STATION.

REFERENCE:
SYSTEM PLANNING DEPARTMENT REPORT SPD 99/4 'PINE FALLS - LAKE WINNIPEG EAST AND GREAT FALLS 66 KV SYSTEMS'

REVISION:
NEW ITEM

CONTINGENCY: $50,000

IN SERVICE DATES				Base estimate
2004 10 31	390			199903 L1
				Work start date 2003 04 01

	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
PREV. AUTHORITY Authorized to date:						
TOTAL						
REV. AMOUNTS: Authorized to date: Over(under)expend:						
Auth 2003/04	19	2	1			22
Req.: 2004/05	333	29	6			368
TOTAL	352	31	7			390

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

1999-09-28 11:43 AM

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number: 02-00-8010

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS

ASSOCIATED PROJECTS

Budget reference number	Description
03-00-8403	BLOODVEIN VOLTAGE CONTROL DEVICE
03-00-8404	GREAT FALLS NEW 115-66 KV STATION
03-00-8405	GREAT FALLS 115-66 KV STATION SALVAGE
04-00-8623	GREAT FALLS 66KV LINES

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

☒ Major Item ☐ Domestic Item

250

Title			Budget reference number
BLOODVEIN VOLTAGE CONTROL DEVICE			03-00-8403
Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	70632

DESCRIPTION:
INSTALL A NEW VOLTAGE REGULATION DEVICE (STATIC VAR COMPENSATOR OR SIMILAR DEVICE) AT BLOODVEIN. A DETAILED OPTIMIZATION STUDY IN CONJUNCTION WITH AN EQUIPMENT VENDOR IS REQUIRED TO DETERMINE THE ACTUAL VOLTAGE REGULATION DEVICE.

JUSTIFICATION:
THE PINE FALLS - LAKE WINNIPEG EAST 66KV SYSTEM IS APPROACHING ITS LOAD LIMIT. BY 2002/03 VOLTAGE LEVELS BEYOND BLOODVEIN WILL BE BELOW MINIMUM ACCEPTABLE LEVELS FOR NORMAL SUPPLY AS REQUIRED BY THE TRANSMISSION PLANNING CRITERIA FOR FIRM LOAD. WHEN CENTRAL SUPPLY WAS FIRST EXTENDED TO THE LAKE WINNIPEG EAST COMMUNITIES IN 1983/84, IT WAS PLANNED TO EXTEND 115KV SUPPLY TO BLOODVEIN WHEN THE 66KV SUPPLY BECAME INADEQUATE. FOR THIS REASON LINE 48 WAS BUILT FOR FUTURE CONVERSION TO 115KV OPERATION. HOWEVER, SINCE THAT TIME, TECHNOLOGICAL ADVANCES HAVE MADE IT POSSIBLE TO EXTEND THE LIFE OF WEAK SYSTEMS WITH RAPID RESPONSE VOLTAGE REGULATION DEVICES CONFIGURATION.

REFERENCE:
SYSTEM PLANNING DEPARTMENT REPORT SPD 99/4 'PINE FALLS - LAKE WINNIPEG EAST AND GREAT FALLS 66KV SYSTEMS'

REVISION:
NEW ITEM

CONTINGENCY: $617,000

IN SERVICE DATES			Base estimate
2002 04 30	6 474		199903 L1
			Work start date 2000 04 01

	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
PREV. AUTHORITY Authorized to date:						
TOTAL						
REV. AMOUNTS:						
Authorized to date:						
Over(under)expend:						
Auth Req.: 2000/01	899		36			935
2001/02	2 447	107	180			2 734
2002/03	2 447	159	26			2 632
2003/04	157	16				173
TOTAL	5 950	282	242			6 474

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 03-00-8403

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS

ASSOCIATED PROJECTS

Budget reference number	Description
02-00-8010	GREAT FALLS 115 KV LINE
03-00-8404	GREAT FALLS NEW 115-66 KV STATION
03-00-8405	GREAT FALLS 115-66 KV STATION SALVAGE
04-00-8623	GREAT FALLS 66KV LINES

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr	75					75	75
May	75	-1	1			75	150
Jun	75		1			76	226
Jul	75		2			77	303
Aug	75		2			77	380
Sep	75		3			78	458
Oct	75		3			78	536
Nov	75		4			79	615
Dec	75		4			79	694
Jan	75		5			80	774
Feb	75		5			80	854
Mar	74	1	6			81	935
TOTAL	899		36			935	935

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item

251

Title			Budget reference number
GREAT FALLS NEW 115-66 KV STATION			03-00-8404
Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	70634

DESCRIPTION:
ESTABLISH A NEW 115-66 KV STATION AT GREAT FALLS USING ONE OF THE 15/20 MVA, 115-66 KV, 3 PHASE TRANSFORMERS SALVAGED FROM BIRTLE SOUTH. PROVIDE TWO 66 KV LINE TERMINATIONS WITH CIRCUIT BREAKER PROTECTION.

JUSTIFICATION:
THE ADDITION OF 115-66KV CAPACITY AT GREAT FALLS WILL PROVIDE CONTINGENCY CAPACITY FOR THE PINE FALLS 66KV SYSTEM WHICH WILL RUN SHORT OF FIRM 66KV CAPACITY BY 2008/09. THE EARLIER 2003 ISD IS RECOMMENDED SO THAT THE SUBSTANDARD LINE 77 CAN BE USED AS AN ALTERNATE SUPPLY TO THE BISSETT AREA, REMOVE THE 30 DEGREE PHASE SHIFT, AND SEPARATE GREAT FALLS NORTH STATION AND BISSETT AREA SUPPLIES ONTO SEPARATE BREAKERS TO IMPROVE THE RELIABILITY OF THIS SYSTEM. EXTENDED OUTAGES HAVE BEEN A CAUSE FOR CONCERN BY THE CUSTOMERS AFFECTED AND THIS SERVICE DOES NOT MEET THE BASIC RELIABILITY INTENT OF THE TRANSMISSION PLANNING CRITERIA FOR FIRM LOAD.

REFERENCE:
SYSTEM PLANNING DEPARTMENT REPORT SPD 99/4 'PINE FALLS - LAKE WINNIPEG EAST AND GREAT FALLS 66 KV SYSTEMS'

REVISION:
NEW ITEM

CONTINGENCY: $173,000

IN SERVICE DATES				Base estimate
2004 10 31	2 351			199903 L1
				Work start date 2002 04 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:						
TOTAL						
REV. AMOUNTS:						
Authorized to date:						
Over(under)expend:						
Auth. Req.: 2002/03	700	45	30			775
2003/04	700	60	99			859
2004/05	582	42	93			717
TOTAL	1 982	147	222			2 351

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 03-00-8404

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS

ASSOCIATED PROJECTS

Budget reference number	Description
02-00-8010	GREAT FALLS 115 KV LINE
03-00-8403	BLOODVEIN VOLTAGE CONTROL DEVICE
03-00-8405	GREAT FALLS 115-66 KV STATION SALVAGE
04-00-8623	GREAT FALLS 66KV LINES

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item

252

Title			Budget reference number
GREAT FALLS 115-66 KV STATION SALVAGE			03-00-8405
Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	70633

DESCRIPTION:
SALVAGE THE EXISTING GREAT FALLS 115-66 KV, 5/6.67 MVA AUTOTRANSFORMER STATION.

JUSTIFICATION:
THIS STATION SALVAGE IS REQUIRED IN CONJUNCTION WITH THE NEW GREAT FALLS 115-66 KV STATION.

REFERENCE:
SYSTEM PLANNING DEPARTMENT REPORT SPD 99/4 'PINE FALLS - LAKE WINNIPEG EAST AND GREAT FALLS 66 KV SYSTEMS'

REVISION:
NEW ITEM

CONTINGENCY: $12,000

IN SERVICE DATES				Base estimate
2004 10 31	143			199903 L1
				Work start date 2002 04 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:						
TOTAL						
REV. AMOUNTS:						
Authorized to date:						
Over(under)expend:						
Auth 2002/03	41	3	2			46
Req.: 2003/04	41	4	6			51
2004/05	38	1	5	-21		23
TOTAL	120	8	13	-21		120

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number: 03-00-8405

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS

ASSOCIATED PROJECTS

Budget reference number	Description
02-00-8010	GREAT FALLS 115 KV LINE
03-00-8403	BLOODVEIN VOLTAGE CONTROL DEVICE
03-00-8404	GREAT FALLS NEW 115-66 KV STATION
04-00-8623	GREAT FALLS 66KV LINES

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item

253

Title			Budget reference number
GREAT FALLS 66KV LINES			04-00-8623
Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	94241

DESCRIPTION:
CONSTRUCT A NEW 66KV 266.8 MCM ACSR LINE FROM GREAT FALLS 115-66KV STATION TO GREAT FALLS NORTH STATION 66-12KV. RE-ROUTE LINE #77 TO THE NEW GREAT FALLS 115-66KV STATION.

JUSTIFICATION:
THESE LINE CHANGES ARE REQUIRED IN CONJUNCTION WITH THE NEW GREAT FALLS 115-66KV STATION.

REFERENCE:
SYSTEM PLANNING DEPARTMENT REPORT SPD 99/4 'PINE FALLS - LAKE WINNIPEG EAST AND GREAT FALLS 66 KV SYSTEMS'

REVISION:
NEW ITEM

IN SERVICE DATES				Base estimate
2004 10 31	114			199903 L2
				Work start date 2003 05 01

	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
PREV. AUTHORITY Authorized to date:						
TOTAL						
REV. AMOUNTS: Authorized to date: Over(under)expend:						
Auth Req.: 2004/05	106	6	2			114
TOTAL	106	6	2			114

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 04-00-8623

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS

ASSOCIATED PROJECTS

Budget reference number	Description
02-00-8010	GREAT FALLS 115 KV LINE
03-00-8403	BLOODVEIN VOLTAGE CONTROL DEVICE
03-00-8404	GREAT FALLS NEW 115-66 KV STATION
03-00-8405	GREAT FALLS 115-66 KV STATION SALVAGE

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

COMPLEX STATUS: ☐ Planned ☒ In progress

Complex no. 55

REVISION STATUS: ☐ New complex ☒ In service change ☐ Concept change ☐ Estimate change only

COMPLEX: JENPEG-NORWAY HOUSE 66KV SUBTRANSMISSION LINE

Proposal

Perform environmental assessments and route selection, design and construct transmission and terminal facilities to provide firm supply to Norway House as follows:

Transmission: 66 KV line 85 KM Jenpeg - Norway House.

Terminations: Extend 66 KV facilities at Jenpeg station, including 3 - 66 KV breakers and 2 - 66 KV grounding transformers.

JUSTIFICATION

☒ Load ☐ Service
☐ Safety ☐ Efficiency
☒ Reliability ☐ Other

Explanation

The 66 KV line is required for reliability of supply to Norway House and voltage control.

Estimate Level	COMPLEX START (yyyy mm)
L2	1994 04

IN SERVICE DATES AND AMOUNTS

2004 10	$12675			

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	135		49		184	249	-65	-26
Year 99/00			16		16	176	-160	-91
00/01			18		18	1,696	-1,678	-99
01/02	306	6	24		336	2,311	-1,975	-85
02/03	815	28	70		913	7,247	-6,334	-87
03/04	4,413	186	303		4,902		4,902	
04/05	5,384	465	456		6,305		6,305	
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	11,053	685	936		12,674	11,679	995	9

REVISION: ISD deferred 2 years to 2004 due to financial constraints.

Reviewed by ORIGINATOR		yyyy mm dd 99 11 08	Reviewed by COORDINATOR		yyyy mm dd 99 11 03
Reviewed by CONSTRUCTOR		yyyy mm dd 99 11 03	Approved by VICE PRESIDENT		yyyy mm dd 99 11 16

H2856/r Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX
(IN THOUSANDS OF DOLLARS)

Complex no. 55

Advance or deferral impact

Deferral will continue low reliability of Norway House supply over existing 66 KV line from William River.

Factors affecting timing or viability

Environmental Licencing.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Jenpeg to Norway House 66 KV Line	5,850	8,232	8,397	8,488	91	1
Jenpeg Terminal 66 KV Changes	2,230	2,399	2,447	2,566	119	5
TOTAL	8,080	10,631	10,844	11,054	210	2

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
9510	8,479	In-service date deferred 2 years to 1999 10 31. Reflects grounding transfomer price increases.
9610	9,726	Project in-service date deferred 2 years to 2001 10 31.
1997 10	11,683	Reflects revised costing methodology with the new financial reporting system.
1998 10	11,679	Revised to reflect one year deferral of transmission line from 2001 to 2002.
1999 10	12,674	ISD deferred 2 years to 2004 due to financial constraints.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — 254 Domestic Item

Title: JENPEG TERMINAL 66 KV CHANGES

Budget reference number: 03-00-3350

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	70240

DESCRIPTION:
COMPLETE THE 66KV RING BUS. INSTALL 2-66KV 30 MVA GROUNDING TRANSFORMERS, 3-66KV CIRCUIT BREAKERS AND THE TERMINATION FOR A NEW 66KV LINE TO NORWAY HOUSE.

JUSTIFICATION:
THESE FACILITIES ARE REQUIRED FOR THE OPERATION AND PROTECTION OF A NEW 66 KV LINE TO NORWAY HOUSE.

REFERENCE:
REPORT TPD 92-6, SECOND 66KV SUPPLY TO NORWAY HOUSE. ALSO REFER TO ADDITIONAL OUTAGE STATISTICS IN MINUTES OF TRC MEETING #132 HELD ON 92-10-14.

REVISION:
ISD DEFERRED FROM 2001 10 31 TO 2004 10 31 FOR CAPITAL CONSTRAINT REASONS.
REFLECTS REVISED ACTIVITY AND OVERHEAD RATES.

CONTINGENCY: $219,000

IN SERVICE DATES

2004 10 31 — 3 031

Base estimate: 199707 L2

Work start date: 2003 04 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date	-4		4			
2000/01	659	44	23			726
2001/02	1 744	145	73			1 962
TOTAL	2 399	189	100			2 688
REV. AMOUNTS:						
Authorized to date: Over(under)expend:	-4		4			
Auth 2003/04	792	97	29			918
Req. 2004/05	1 778	248	87			2 113
TOTAL	2 566	345	120			3 031

Prepared by: yy mm dd COORDINATOR — Approved by: yy mm dd Approved by: yy mm dd

Estimated by: ORIGINATOR — COORDINATING MANAGER — ORIGINATING MANAGER

1999-08-21 05:19 PM

CAPITAL EXPENDITURE REVISION

Budget reference number 03-00-3350

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1994 10	2 198	REVISED INTEREST AND ESCALATION RATES.
1995 10	2 575	IN-SERVICE DATE DEFERRED 2 YEARS TO 1999 10 31. ESTIMATE INCREASE REFLECTS LATEST TRANSFORMER PRICES.
1996 10	2 667	ISD DEFERRED 2 YEARS FROM 1999 TO 2001 10 31. CORRECTION TO CALCULATED ESCALATION.
1997 10	2 816	SCOPE UNCHANGED, ESTIMATE REFLECTS REVISED COSTING METHODOLOGY IMPLEMENTED WITH THE NEW FINANCIAL REPORTING SYSTEM. ALSO REFLECTS REVISED INTEREST AND ESCALATION RATES.
1998 10	2 688	START DATE DELAYED, NO CHANGE TO ISD.

ASSOCIATED PROJECTS

Budget reference number	Description
04-00-3029	JENPEG TO NORWAY HOUSE 66 KV LINE

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item 255

Title: JENPEG TO NORWAY HOUSE 66 KV LINE

Budget reference number: 04-00-3029

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	93309

DESCRIPTION:
CONDUCT ENVIRONMENTAL IMPACT ASSESSMENT, SELECT A ROUTE, ACQUIRE PROPERTY AND LICENSING, AS WELL AS DESIGN AND CONSTRUCT APPROXIMATELY 85 KM OF 66kV - 266.8 MCM ACSR LINE FROM JENPEG TO NORWAY HOUSE.

INSTALL 2 - 66 kV SWITCHES NEAR THE NORWAY HOUSE STATION.

JUSTIFICATION:
STUDIES SHOW THAT THIS LINE WILL NOT BE REQUIRED UNTIL 2004 TO MAINTAIN ACCEPTABLE VOLTAGE LEVELS. HOWEVER, IT WAS TO BE ADVANCED TO 2002 TO IMPROVE SERVICE RELIABILITY TO THE NORWAY HOUSE STATION. THE SERVICE RELIABILITY RECORD OF THE EXISTING 66 kV SUPPLY TO THE NORWAY HOUSE STATION FROM THE WILLIAM RIVER TERMINAL IS MUCH WORSE THAN FOR OTHER SUPPLIES IN THE PROVINCE.

REFERENCE:
REPORT TPD 92-6, 'SECOND 66 kV SUPPLY TO NORWAY HOUSE STATION'. ALSO REFER TO ADDITIONAL OUTAGE STATISTICS IN MINUTES OF TRC MEETING #132, HELD 1992-10-14.
'ELECTRIC SUPPLY TO NORWAY HOUSE' SPD 99/1 DATED 1999-01-13

REVISION:
SYSTEM PLANNING REPORT 99/1 RECOMMENDS THAT 2 LINE SWITCHES BE INSTALLED NEAR WILLIAM RIVER IN 1999 TO IMPROVE SITUATION. ISD DEFERRED 2 YEARS FROM 2002 TO 2004 FOR CAPITAL CONSTRAINT REASONS.

IN SERVICE DATES		Base estimate
2004 10 31	9 643	199902 L1
		Work start date
		1997 04 01

	PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:		139		45			184
	1999/00	213	3	26			242
	2000/01	900	15	55			970
	2001/02	35	52	262			349
	2002/03	6 948	135	165			7 248
	TOTAL	8 235	205	553			8 993
REV. AMOUNTS.							
Authorized to date:		139		45			184
Over(under)expend:							
Auth Req.:	1999/00			16			16
	2000/01			18			18
	2001/02	306	6	24			336
	2002/03	815	28	70			913
	2003/04	3 622	89	273			3 984
	2004/05	3 606	216	370			4 192
	TOTAL	8 488	339	816			9 643

Prepared by: yy mm dd COORDINATOR — Approved by: yy mm dd — Approved by:
Estimated by: ORIGINATOR — COORDINATING MANAGER — ORIGINATING MANAGER

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 04-00-3029

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1993 10	5 778	NEW ITEM
1994 10	5 548	CASH FLOWS REVISED TO 1994 BASE; REVISED INT & ESC.
1995 10	5 904	ISD DEFERRED FROM 1997 10 31 TO 1999 10 31. BETTER PERFORMANCE OF EXISTING LINE DUE TO REPLACED INSULATORS AND LEVELLING OFTHE WORK LOAD OVER THE NEXT FEW YEARS.
1996 10	7 059	ISD DEFERRED FROM 1999 10 31 TO 2001 10 31. ESTIMATE INCREASED DUE TO: MATERIAL (308); OVERHEAD (113); PROPERTY (260); ENGINEERING (94).
1997 10	9 149	ISD moved up to 2001 01 31. Estimate increase due to overhead adjustment 1 447).
1999 10	8 992	the changes to the pricing for materials, labour(activity rates), overheads and accounts has resulted in the increase in this estimate.

ASSOCIATED PROJECTS

Budget reference number	Description
03-00-3350	JENPEG TERMINAL 66 KV CHANGES

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr			1			1	1
May			1			1	2
Jun			1			1	3
Jul			1			1	4
Aug			1			1	5
Sep			1			1	6
Oct			1			1	7
Nov			1			1	8
Dec			1			1	9
Jan			1			1	10
Feb			1			1	11
Mar			5			5	16
TOTAL			16			16	16
2000/01 Apr			1			1	1
May			1			1	2
Jun			1			1	3
Jul			1			1	4
Aug			1			1	5
Sep			1			1	
Oct			1			1	
Nov			1			1	
Dec			1			1	9
Jan			2			2	11
Feb			2			2	13
Mar			5			5	18
TOTAL			18			18	18

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

COMPLEX STATUS: ☐ Planned ☒ In progress

Complex no. 53

REVISION STATUS: ☐ New complex ☒ In service change ☐ Concept change ☐ Estimate change only

COMPLEX	RUTTAN - SOUTH INDIAN LAKE 66KV LINE

Proposal

1. Construct 75.6 km of 66kv 2/0 acsr line from Ruttan Lake to South Indian Lake. Salvage 75.6 km of 33kv line between Ruttan Lake-South Bay-South Indian Lake.
2. Salvage Southbay 33-12kv station, complete with 3 - 100kva 33 - 7.2kV transformers
3. Ruttan Lake station "a" - salvage existing 3 -1 000kva 12-33kv transformers re-locate 1 - 15/20/25mva 138-12kv transformer from Ruttan Lake station "b". Install 2 - 7.5/10mva LTC 12-66kv transformers.
4. Construct a 66-12kv station at South Indian Lake c/w 3 - 7.5/10mva LTC transformers. Salvage existing 33-12kv station.

JUSTIFICATION

☒ Load ☐ Service ☐ Safety ☐ Efficiency ☐ Reliability ☐ Other

Explanation

The existing Ruttan Lake - South Indian Lake power supply is limited to 300 kva. Based on current load forecast, the voltage regulation on the existing system will result in inadequate customer voltages. The proposed 12-66kv Ruttan Lake station, Ruttan - South Indian Lake 66kv line and South Indian Lake 66-12kv station will provide additional capacity and adequate voltage regulation.

Estimate Level	COMPLEX START (yyyy mm)
L1-3	1994 10

IN SERVICE DATES AND AMOUNTS

1997 08	$8697	1997 09	$430	1997 10	($41)	1997 11	$112
1997 12	$17	1998 04	$107	1998 06	$68	1998 12	($131)
1999 04	$95	2001 09	$251	2002 08	($7)	2003 08	$6579

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	9,361		249	502	9,108	9,312	-204	-2
Year 99/00	255	7	14		276	121	155	128
00/01	242	11	38		291	671	-380	-57
01/02	312	15	65	126	266	2,096	-1,830	-87
02/03	1,333	116	143		1,592	2,277	-685	-30
03/04	3,536	371	110	989	3,028		3,028	
04/05								
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	15,039	520	619	1,617	14,561	14,477	84	1

REVISION: Ruttan Lake Station ISD deferred one year 2003 due to financial constraints.

Reviewed by ORIGINATOR	yyyy mm dd 99 11 08	Reviewed by COORDINATOR	yyyy mm dd 99 11 03
Reviewed by CONSTRUCTOR	yyyy mm dd 99 11 03	Approved by VICE-PRESIDENT	yyyy mm dd 99 11 30

H2856/r Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Complex no. 53

Advance or deferral impact

Forecast loads at South Indian Lake will exceed capacity in 1996/97 winter.

Factors affecting timing or viability

Load growth.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
SOUTH BAY STATION	77	30	31	25	-6	-19
RUTTAN LAKE STATION	4,118	8,261	8,426	8,136	-290	-3
SOUTH INDIAN LAKE STATION	843	1,724	1,758	1,785	27	2
RUTTAN L - SOUTH INDIAN L. 66KV SUPPLY	3,905	5,002	5,102	5,094	-8	-0
TOTAL	8,943	15,017	15,317	15,040	-277	-2

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
9510	7,289	Estimates revised to more detailed level.
9610	9,234	Scope incr: move & inst 2 transf banks from Ruttan "B" stn to "A". Incr cap of new 138/12kV transf, repl cntrl bldg, serv & prot.Conductor upgrade for SIL supply.
1997 10	14,066	Customer load increase required equipment to be replaced at Ruttan Lake before winter loading. A third transformer added at South Indian Lake Station. Cost of 66kV line
1998 10	14,477	Reflects 97/98 overexpenditure 0.5M and Ruttan Lake Station ISD deferred three years from 1999 to 2002.
1999 10	14,561	Ruttan Lake Station ISD deferred one year 2003 due to financial constraints.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item

256

Title			Budget reference number
SOUTH BAY STATION SALVAGE			03-00-4857
Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	71015

DESCRIPTION:
SALVAGE 33-12 KV STATION COMPLETE WITH 3 - 100 KVA 33-7.2KV TRANSFORMERS.

JUSTIFICATION:
THIS STATION DOES NOT SERVE ANY LOAD AND RUTTAN LAKE - SOUTH INDIAN LAKE LINE IS TO BE CONSTRUCTED AND OPERATED AT 66 KV.

REVISION:
ITEM COMPLETED.

This BRN contains Deleted, Blocked, or Closed Orders.

IN SERVICE DATES				Base estimate
1998 03 31	-30			199903 L5
1998 04 30	0			Work start date
1999 04 30	53			1997 04 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:	25		-2	-53		-30
1999/00	5					5
TOTAL	30		-2	-53		-25
REV. AMOUNTS:						
Authorized to date:	25		-2	-53		-30
Over(under)expend:						
Auth Req.:						
TOTAL	25		-2	-53		-30

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

CAPITAL EXPENDITURE REVISION

Budget reference number 03-00-4857

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1994 10	74	NEW ITEM.
1995 10	75	REVISED ESCALATION AND INTEREST RATES.
1996 10	76	REVISED INTEREST RATES. CONTINGENCY AMOUNT: $8,000
1997 10	39	SCOPE REDUCED FROM SALVAGE COMPLETE STATION TO SALVAGE 33 KV EQUIPMENT ONLY.
1998 10	-24	REFLECTS COSTS TO COMPLETION.

ASSOCIATED PROJECTS

Budget reference number	Description
03-00-4858	RUTTAN LAKE STATION (A)
03-00-4859	SOUTH INDIAN LAKE STATION
04-00-5486	RUTTAN LAKE - SOUTH INDIAN LAKE 66 KV SUPPLY

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item

257

Title			Budget reference number
RUTTAN LAKE STATION (A)			03-00-4858
Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	70000:70538

DESCRIPTION:
1. SALVAGE THE EXISTING 3-1000 KVA 12-33KV TRANSFORMER BANK AND INSTALL 2X 10/13 MVA 66-12 KV TRANSFORMERS - ISD 97 08 30.

2. CONSTRUCT A NEW 138-66 KV STATION AND SALVAGE THE EXISTING RUTTAN 'A' STATION - ISD 2002 08 31.

JUSTIFICATION:
THE EXISTING RUTTAN LAKE - SOUTH INDIAN LAKE POWER SUPPLY IS LIMITED TO 3 000 KVA DUE TO LIMITED FAULT CURRENT AVAILABLE AT SOUTH INDIAN LAKE. THE PROPOSED 12 - 66 KV STATION AT RUTTAN LAKE, RUTTAN LAKE - SOUTH INDIAN LAKE 66KV LINE AND SOUTH INDIAN LAKE 66-12KV STATION WILL PROVIDE ADDITIONAL REQUIRED CAPACITY.

REVISION:
REFLECTS REVISED ACTIVITY AND OVERHEAD RATES.

CONTINGENCY: $500 000

NOTE: THE CONCEPT FOR THIS PROJECT WILL CHANGE ONCE SYSTEM PLANNING FINISHES THEIR STUDY (PRESENTLY IN PROGRESS). THE ISD WILL ALSO LIKELY BE DEFERRED. THE NEW CONCEPT WILL BE LESS EXPENSIVE.

IN SERVICE DATES						Base estimate
Prior Total	2 749	1998 09 30	0	1999 02 28	2	199803 L2
1998 06 30	1	1998 10 31	0	1999 03 31	4	
1998 07 31	2	1998 11 30	2	2002 08 31	-7	Work start date
1998 08 31	1	1998 12 31	- 176	2003 08 31	6 580	1997 04 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:	2 646		121	-57		2 710
1999/00	368	7	19			394
2000/01	500	75	96			671
2001/02	1 800	128	168			2 096
2002/03	2 992	158	117	- 989		2 278
TOTAL	8 306	368	521	-1 046		8 149
REV. AMOUNTS:						
Authorized to date:	2 646		121	-57		2 710
Over(under)expend:						
Auth 1999/00	255	8	21			284
Req.: 2000/01	242	12	46			300
2001/02	124	8	66			198
2002/03	1 333	116	143			1 592
2003/04	3 536	371	110	- 989		3 028
TOTAL	8 136	515	507	-1 046		8 112

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

CAPITAL EXPENDITURE REVISION

Budget reference number: 03-00-4858

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1994 10	1 912	NEW ITEM.
1995 10	3 041	PREVIOUS ESTIMATE WAS LEVEL II BASED ON VERY PRELIMINARY PLANNING S.L.D.'S. COST INCREASE ATTRIBUTED TO INCREASED LABOUR AND MATERIAL COSTS ASSOCIATED WITH EXTENSIVE SITE IMPROVEMENT AND STRUCTURE WORK NOT SCOPED IN ORIGINAL ESTIMATE.
1996 10	4 287	CHANGE OF SCOPE BASED ON REVISED S.L.D., RELOCATE AND INSTALL 2-TRANSFORMER BANKS FROM RUTTAN 'B' STATION TO RUTTAN 'A' STATION. INCREASE CAPACITY OF NEW 138/12 KV TRANSFORMERS TO 10/13.3 MVA (PREVIOUSLY 7.5/10 MVA), REPLACE CONTROL BUILDING AND INSTALL NEW SERVICES, PROTECTION AND CONTROL.
1997 10	7 885	CHANGE OF SCOPE BASED ON CUSTOMER LOAD INCREASE REQUIRING THE OLD EQUIPMENT TO BE REPLACED BEFORE WINTER LOADING, THUS A TEMPORARY WOODPOLE STRUCTURE WAS BUILT AND THE NEW TRANSFORMERS ARE SCHEDULED FOR IN SERVICE AUG. 31, 1997. THIS TEMPORARY SCHEME (ESTIMATED AT $1.2 MILLION) WILL BE REPLACED IN 1999 BY A YET UNDEFINED SCHEME. MONIES (ESTIMATED AT $6 MILLION) ARE ALLOTTED FOR THIS PERMANENT PLAN AND WILL BE REVISED ONCE A CONCEPT IS FINALIZED. MOST OF THE $1.2 MILLION SPENT ON THE TEMPORARY SCHEME WILL BE RECOVERABLE AS SALVAGE CREDITS.
1998 10	8 148	THE EXISTING TEMPORARY RUTTAN LAKE - SOUTH INDIAN LAKE POWER SUPPLY WAS PLACED IN SERVICE IN AUG 1997. THIS TEMPORARY SCHEME WILL BE REPLACED IN 2002 BY A NEW STATION. MONIES (ESTIMATED AT $6 MILLION) ARE ALLOTTED FOR THIS STATION. THE CER WILL BE REVISED ONCE A DETAILED CONCEPT IS FINALIZED. MOST OF THE $1.2 MILLION SPENT ON THE TEMPORARY SCHEME WILL BE RECOVERABLE AS SALVAGE CREDITS. FUNDS ARE INCLUDED FOR ENVIRONMENTAL LICENSING AND PROPERTY PURCHASE.

ASSOCIATED PROJECTS

Budget reference number	Description
03-00-4857	SOUTH BAY STATION SALVAGE
03-00-4859	SOUTH INDIAN LAKE STATION
04-00-5486	RUTTAN LAKE - SOUTH INDIAN LAKE 66 KV SUPPLY

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	26		1			27	27
May	21		1			22	49
Jun	21	1	1			23	72
Jul	21	1	1			23	95
Aug	21		2			23	118
Sep	21		2			23	141
Oct	21		2			23	164
Nov	21		2			23	187
Dec	21	1	2			24	211
Jan	21	1	2			24	235
Feb	21		3			24	259
Mar	19	4	2			25	284
TOTAL	255	8	21			284	284
2000/01 Apr	21		3			24	24
May	21	1	3			25	49
Jun	21	1	3			25	74
Jul	21	1	3			25	99
Aug	21		4			25	124
Sep	21	1	4			26	150
Oct	21	1	4			26	1
Nov	21	1	4			26	20
Dec	21	1	4			26	228
Jan	21	1	4			26	254
Feb	21	1	5			27	281
Mar	11	3	5			19	300
TOTAL	242	12	46			300	300

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item

258

Title	Budget reference number
SOUTH INDIAN LAKE STATION	03-00-4859

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	70001

DESCRIPTION:
1. CONSTRUCT NEW 66-12 KV STATION COMPLETE WITH 2-3.75/5.0 MVA LTC TRANSFORMERS IN 1997.
2. SALVAGE THE EXISTING 33 - 12 KV STATION COMPLETE WITH 6- 250 KVA AND 3 - 333 KVA TRANSFORMERS IN 1997.
3. INSTALL A THIRD 3.75/5 MVA POWER TRANSFORMER IN 1998.

JUSTIFICATION:
THE EXISTING RUTTAN LAKE - SOUTH INDIAN LAKE POWER SUPPLY IS LIMITED TO 3000 KVA DUE TO LIMITED FAULT CURRENT AVAILABLE AT SOUTH INDIAN LAKE. THE PROPOSED 12 - 66 KV STATION AT RUTTAN LAKE, RUTTAN LAKE - SOUTH INDIAN LAKE 66 KV LINE AND SOUTH INDIAN LAKE 66 - 12 KV STATION WILL PROVIDE ADDITIONAL REQUIRED CAPACITY.

REVISION:
REFLECTS COSTS TO COMPLETION.

IN SERVICE DATES						Base estimate
Prior Total	1 610	1998 07 31	14	1998 12 31	2	199902 L5
1998 04 30	92	1998 08 31	26	1999 02 28	-1	Work start date
1998 05 31	18	1998 09 30	-9	1999 03 31	0	1995 03 01
1998 06 30	49	1998 11 30	7	1999 04 30	35	

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:	1 785		58	- 237		1 606
1999/00	-44					-44
TOTAL	1 741		58	- 237		1 562
REV. AMOUNTS:						
Authorized to date:	1 785		58	- 237		1 606
Over(under)expend:						
Auth Req.:						
TOTAL	1 785		58	- 237		1 606

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 03-00-4859

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1994 10	1 900	NEW ITEM.
1995 10	819	CHANGE IN CONCEPT FROM 2-7.5/10.0 MVA TRANSFORMERS ASSUMED TO BE PURCHASED TO 2-3.75/10.0 MVA UNITS AVAILABLE FROM ANOTHER STATIONS. ESTIMATE REVISED TO A DETAILED LEVEL.
1996 10	859	ESTIMATE INCREASED DUE TO CHANGE IN CONCEPT IE. ADDITIONAL CIVIL WORK FOR FUTURE EQUIPMENT. CASH FLOW REVISED FOR EARLIER SALVAGE OF EXISTING STATION.
1997 10	1 250	CONCEPT CHANGE - A THIRD TRANSFORMER WILL BE ADDED IN 1998 THEREFORE ALL STRUCTURES, FOUNDATION ETC. WERE INSTALLED NOW. NEXT YEAR'S ITEM WILL CONTAIN ONLY THE TRANSFORMER AND COSTS TO INSTALL IT. SITE IMPROVEMENTS INCREASED FROM $90,000 TO $171,000.
1998 10	1 561	A THIRD 3.75/5 MVA BANK PLANNED TO BE INSTALLED IN 1998 UNDER A DOMESTIC ITEM WAS INCLUDED WITHIN THIS ITEM.

ASSOCIATED PROJECTS

Budget reference number	Description
03-00-4857	SOUTH BAY STATION SALVAGE
03-00-4858	RUTTAN LAKE STATION (A)
04-00-5486	RUTTAN LAKE - SOUTH INDIAN LAKE 66 KV SUPPLY

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item

259

Title	Budget reference number
RUTTAN LAKE - SOUTH INDIAN LAKE 66 KV SUPPLY	04-00-5486

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	93311

DESCRIPTION:
1. CONSTRUCT 75.6 KM 66 kV 266.8 MCM ACSR LINE FROM RUTTAN LAKE TO SOUTH INDIAN LAKE.
2. SALVAGE 51.5 KM 33 kV #1 ACSR LINE FROM RUTTAN LAKE TO SOUTH BAY.
3. SALVAGE 24.1 KM 33 kV 2/0 ACSR LINE FROM SOUTH BAY TO SOUTH INDIAN LAKE.
4. COMPLETE FEEDER EGRESS AND DISTRIBUTION CHANGES AT SOUTH INDIAN LAKE.
5. COMPLETE STATION EGRESS AND DISTRIBUTION CHANGES AT RUTTAN LAKE.

JUSTIFICATION:
THE EXISTING 33 kV RUTTAN LAKE TO SOUTH INDIAN LAKE LINE IS LIMITED TO 3,000 kVA DUE TO LIMITED FAULT CURRENT AND THE CAPACITY OF SUBMARINE CABLES AT SOUTH INDIAN LAKE. BASED ON LOAD FORECASTS, THE LOADS AT SOUTH INDIAN LAKE WILL EXCEED THE CAPACITY OF THE SYSTEM IN 1996/97 WINTER. THE PROPOSED 66 kV SYSTEM WILL PROVIDE ADDITIONAL REQUIRED CAPACITY.

REFERENCE:
E.R REPORT #95-22: RUTTAN LAKE - SOUTH INDIAN LAKE 66 kV SUPPLY.

REVISION:
SALVAGE FROM SOUTH BAY TO SOUTH INDIAN LAKE DELAYED UNITL HIGHWAY IS COMPLETED IN THE FALL OF YEAR 2000. ITEM DEFERRED 1 YEAR.

IN SERVICE DATES						Base estimate
Prior Total	4 905	1998 06 30	-1	1998 11 30	1	199909 L4
1998 03 31	0	1998 08 31	0	1998 12 31	-0	
1998 04 30	-2	1998 09 30	-2	1999 03 31	-0	Work start date
1998 05 31	0	1998 10 31	2	2001 09 30	253	1997 04 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:	4 906		72	- 155		4 823
1999/00	149			- 178		-29
TOTAL	5 055		72	- 333		4 794
REV. AMOUNTS:						
Authorized to date:	4 906		72	- 155		4 823
Over(under)expend:						
Auth 1999/00			-7			-7
Req.: 2000/01			-8			-8
2001/02	188	7	-2	- 126		67
TOTAL	5 094	7	55	- 281		4 875

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

CAPITAL EXPENDITURE REVISION

Budget reference number 04-00-5486

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1994 10	3 199	TRSF FROM DOMESTIC ITEM BRN 9504-00-4411. GROSS DOLLARS ADJTO 1994 BASE WITH REVISED INT & ESC.
1995 10	3 354	EST IMPROVED FROM A PER MILE COST PRICE TO A TRUE LEVEL 1 ESTIMATE C/W SUB ACCOUNT BACK-UP.
1996 10	4 012	IN-SERVICE DATE REVISED FROM 97-08-31 TO 97-09-30. IN ORDERTO INCREASE THE SYSTEM CAPACITY CONDUCTOR WAS CHANGED FROM 2/0 ACSR TO 266.8 MCM ACSR, IN ADDITION MATERIAL COSTS AND CAPITALIZED OVERHEAD INCREASED FROM 95/96 TO 96/97 BY 20%.
1997 10	4 746	Items #4 & #5 in the above description have been added. Increases in Material (+114), L&E (+312), and O/H (+317).
1999 10	4 863	Positive variance is due to increased credits realized on salvaged materials.
1999 10	4 879	SALVAGE FROM SOUTH BAY TO SOUTH INDIAN LAKE DELAYED UNITL HIGHWAY IS COMPLETED IN THE FALL OF YEAR 2000.

ASSOCIATED PROJECTS

Budget reference number	Description
03-00-4857	SOUTH BAY STATION SALVAGE
03-00-4858	RUTTAN LAKE STATION (A)
03-00-4859	SOUTH INDIAN LAKE STATION

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr			-1			-1	-1
May			-1			-1	-2
Jun			-1			-1	-3
Jul			-1			-1	-4
Aug			-1			-1	-5
Sep			-1			-1	-6
Oct			-1			-1	-7
Nov			-1			-1	-8
Dec			-1			-1	-9
Jan			-1			-1	-10
Feb			-1			-1	-11
Mar			4			4	-7
TOTAL			-7			-7	-7
2000/01 Apr			-1			-1	-1
May			-1			-1	-2
Jun			-1			-1	-3
Jul			-1			-1	-4
Aug			-1			-1	-5
Sep			-1			-1	-6
Oct			-1			-1	-7
Nov			-1			-1	-8
Dec			-1			-1	-9
Jan			-1			-1	-10
Feb			-1			-1	-11
Mar			3			3	-8
TOTAL			-8			-8	-8

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

COMPLEX STATUS: ☐ Planned ☒ In progress

Complex no. 17

REVISION STATUS: ☐ New complex ☒ In service change ☐ Concept change ☒ Estimate change only

COMPLEX	CENTRAL SUPPLY TO PIKWITONEI AND THICKET PORTAGE

Proposal

1. Construct 5km-66kV line (operating 12kV) from Mystery L. Stn. Fdr.TM9 to jctn of PTH#6 and Jonas Rd.
2. Construct a 12-25kV interchange bank c/w 4-1000kVA single phase 7.2-14.4kV units (one spare).
3. Construct 44.3km-66kV line (operating 25kV) from jctn PTH#6 & Jonas Rd. to Sipiwesk.
4. Construct 21.5km-25kV line from Sipiwesk to Pikwitonei. Rebuild and convert Pikwitonei distribution to 25kV.
5. Construct 24.7km-25kV line from Sipiwesk to Thicket Portage. Rebuild and convert distribution to 25kV.
6. Salvage diesel units at Pikwitonei and Thicket Portage and remediate sites.

JUSTIFICATION: ☒ Load ☒ Service ☐ Safety ☐ Efficiency ☐ Reliability ☐ Other

Explanation: The communities of Pikwitonei and Thicket Portage were scheduled for conversion to enhanced diesel supply in 1997. Due to the proximity of central station supply at Thompson and the associated benefits to our customers and Manitoba Hydro, central supply is the preferred option, provided that a contribution can be negotiated.

Estimate Level	COMPLEX START (yyyy mm)
L3	1992 01

IN SERVICE DATES AND AMOUNTS

1997 03	$577	1997 04	$1582	1997 05	$99	1998 06	$2
1999 04	$3610	1999 12	$135	2000 09	$330	2000 12	$331

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	5,818		152	3,498	2,472	2,011	461	23
Year 99/00	31	0	9		40		40	
00/01	608	32	16		656	641	15	2
01/02								
02/03								
03/04								
04/05								
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	6,457	32	177	3,498	3,168	2,652	516	19

REVISION	Revised to remove estimated salvage which has not materialized .

Reviewed by ORIGINATOR	yyyy mm dd 99 11 09	Reviewed by COORDINATOR	yyyy mm dd 99 11 03		
Reviewed by CONSTRUCTOR	yyyy mm dd 99 11 03	Approved by VICE-PRESIDENT	yyyy mm dd 99 11 16		

H2856/r Rev 99 03

Complex no. 17

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Advance or deferral impact

Factors affecting timing or viability

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE	
					Amount	%
Central Supply to Pikwitonei & Thicket Portage	5,368	5,456	5,565	5,453	-112	-2
Thicket Portage D.G.S. - Site Clean-up	446	508	518	520	2	0
Pikwitonei D.G.S. - Site Clean-up	446	468	477	484	7	1
TOTAL	6,260	6,432	6,560	6,457	-103	-2

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
9510	1,519	Enhanced diesel operation costs inadvertently applied to the line land cost in the 1994 estimate.
9610	1,516	Work deferred two years at Thicket & Pikwitone. Net amount adjusted to 577,000 per agreement, and interest and escalation revised.
1997 10	2,169	Cost of central supply increase due to increases inconstruction costs and reduced capital contibutions. ISD of D.D.S. site clean up advanced two years.
1998 10	2,652	Reflects 97/98 overexpenditure 0.8M, final costs for central supply item, increases to site investigation estimates and one year deferral to Thicket Portage and Pikwitonei items.
1999 10	3,168	Revised to remove estimated salvage which has not materialized .

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item 260

Title	Budget reference number
CENTRAL SUPPLY TO PIKWITONEI AND THICKET PORTAGE	04-00-5498

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	93312

DESCRIPTION:
Extend central station supply to the communities of Thicket Portage and Pikwitonei (presently supplied by diesel - electric generation) as follows:

1. Construct 5 km 66 kV - 266.8 MCM ACSR (operating 12 kV) from Mystery Lake Station Feeder TM9 to junction of PTH #6 & Jonas Road.
2. Construct a 12-25 kV interchange bank c/w 4x1000 kva single phase 7.2 - 14.4 kV units (one spare).
3. Construct 44.3 km 66 kV - 266.8 MCM ACSR (operating 25 kV) from junction PTH #6 & Jonas Road to Sipiwesk.
4. Construct 21.5 km 25 kV - 2/0 ACSR line from Sipiwesk to Pikwitonei.
5. Construct 24.7 km 25 kV - 2/0 ACSR line from Sipiwesk to Thicket Portage.
6. Pikwitonei rebuild.
7. Convert pikwitonei distibution to 25 kV.
8. Thicket Portage rebuild.
9. Convert Thicket Portage distribution to 25 kV.

*** REPORT PENDING ***

JUSTIFICATION:
The communities of Pikwitonei and Thicket Portage have been scheduled for conversion to enhanced diesel supply in 1997. Due to the proximity of central station supply at Thompson and the associated benefits to our customers and Manitoba Hydro, central station supply is the preferred option.

Provided that a capital contribution can be negotiated to reduce the central supply capital expenditure to equal the cost of enhanced diesel supply, Manitoba Hydro will extend central supply.

REVISION:
Item Complete

IN SERVICE DATES				Base estimate
1997 03 31	577	1998 02 28	0	199903 L5
1997 04 30	1 582	1998 06 30	2	
1997 05 31	99	1998 12 31	0	Work start date
1998 01 31	0	1999 04 30	3 329	1997 04 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:	5 453		137	-48	-3 438	2 104
1999/00	3					3
TOTAL	5 456		137	-48	-3 438	2 107
REV. AMOUNTS:						
Authorized to date:	5 453		137	-48	-3 438	2 104
Over(under)expend:						
Auth 1999/00 Req.:			-1			-1
TOTAL	5 453		136	-48	-3 438	2 103

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

CAPITAL EXPENDITURE REVISION

Budget reference number: 04-00-5498

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1994 10	5 935	NEW ITEM.
1995 10	629	ENHANCED DIESEL OPERATION COSTS INADVERTENTLY APPLIED TO THELAND LINE COST IN 1994 ESTIMATE. ANICIPATED PROVINCIAL CONTRIBUTION QUIVALENT TO 87% OF CAPITAL COST IS OW INCLUDED.
1996 10	577	THE NET AMOUNT IS TO BE 577,000 AS PER AGREEMENT. INTEREST AND ESCALATION REVISED.
1996 10	1 744	An increase (+1 168) in the estimate mainly due to a decrease in expected contribution (+272), a material requirement increase (+267), a construction cost increase (+370), additional brush clearing costs (+156), and increased engineering costs (+59).
1998 10	2 107	ITEM COMPLETE. Final costs continued to accumulate following the revision in 1997. Ultimately, a process review team was assembled to determine methods to improve the process for response to this type of project, to enable better management of resources.

ASSOCIATED PROJECTS

Budget reference number	Description
04-00-5499	THICKET PORTAGE D.G.S. - SITE CLEAN-UP
04-00-5500	PIKWITONEI D.G.S. - SITE CLEAN-UP

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr			-1			-1	-1
May							-1
Jun							-1
Jul							-1
Aug							-1
Sep							-1
Oct							-1
Nov							-1
Dec							-1
Jan							-1
Feb							-1
Mar							-1
TOTAL			-1			-1	-1
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98.11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item

261

Title	Budget reference number
THICKET PORTAGE D.G.S. - SITE CLEAN-UP	04-00-5499

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Operating & Maintenance	Construction	Construction	70134:70441

DESCRIPTION:
1. SALVAGE OF DIESEL EQUIPMENT FROM THE SITE. COMPLETION 1998 09 30 (POG 70135)

2. CONDUCT GEOTECHNICAL INVESTIGATION OF THE DECOMMISSIONED DIESEL GENERATING STATION TO DELINEATE THE EXTENT OF ANY HYDROCARBON CONTAMINATION ON AND/OR AROUND THE SITE; PREPARE SITE INVESTIGATION REPORT INCLUDING RECOMMENDATIONS FOR CLEAN UP. COMPLETION 1998 12 31.

3. REMEDIATE ANY CONTAMINATED AREAS IDENTIFIED IN THE SITE INVESTIGATION REPORT TO ENVIRONMENTALLY ACCEPTABLE LIMITS AND DEVELOP ANY LANDFARM AREAS NECESSARY FOR THE REMEDIATION PROCESS. COMPLETION 2000 09 30. LAND FARM ANY CONTAMINATED SOILS REMOVED FROM THE DIESEL SITE AREA AT THE LANDFARM SITE UNTIL CONTAMINATION IS REDUCED TO ENVIRONMENTALLY ACCEPTABLE LEVELS. COMPLETION 2000 09 30 (POG 70441).

4. ISSUE A FINAL REPORT ON THE PROJECT CONFIRMING THE DIESEL SITE AND SURROUNDING AREA WERE REMEDIATED AND ALL AREAS OF THE WORKS WERE LEFT IN ACCORDANCE WITH APPLICABLE ENVIRONMENTAL REGULATIONS. COMPLETION 1999 11 30 (POG 70441).

JUSTIFICATION:
DUE TO ENVIRONMENTAL CONCERNS AND/OR REGULATIONS THE SITE MUST BE INVESTIGATED, REMEDIATED AS REQUIRED, AND RESTORED TO A LEVEL WHICH PERMITS UNRESTRICTED USE OF THE SITE AND THE SURROUNDING AREA.

REVISION:
THE ESTIMATE FOR SALVAGE WAS TOO HIGH AND HAVE NOT BEEN MATERIALIZED. REFLECTS REVISED ACTIVITY AND OVERHEAD RATES.

CONTINGENCY: $27,000

IN SERVICE DATES				Base estimate
1999 04 30	220			199903 L2
2000 09 30	329			Work start date
				1997 04 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:	193		7	-9		191
1999/00	- 233					- 233
2000/01	300	18	4			322
TOTAL	260	18	11	-9		280
REV. AMOUNTS:						
Authorized to date:	193		7	-9		191
Over(under)expend:						
Auth 1999/00	23		2			25
Req.: 2000/01	304	16	4			324
TOTAL	520	16	13	-9		540

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

CAPITAL EXPENDITURE REVISION

Budget reference number: 04-00-5499

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1994 10	445	NEW ITEM.
1995 10	445	ESCALATION AND INTEREST REVISED.
1996 10	468	WORK DEFERRED BY TWO YEARS.
1997 10	204	BASE ESTIMATE UNCHANGED. SALVAGE ESTIMATE NOW BASED ON DETAILED REVIEW. ISD'S ADVANCED.
1998 10	279	ITEM DEFERRED TO 2000 12 31.

ASSOCIATED PROJECTS

Budget reference number	Description
04-00-5498	CENTRAL SUPPLY TO PIKWITONEI AND THICKET PORTAGE
04-00-5500	PIKWITONEI D.G.S. - SITE CLEAN-UP

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	23	1	1			25	25
May							25
Jun							25
Jul							25
Aug							25
Sep							25
Oct							25
Nov							25
Dec							25
Jan							25
Feb							25
Mar		-1	1				25
TOTAL	23		2			25	25
2000/01 Apr							
May	12	1				13	13
Jun	85	5				90	103
Jul	85	4	1			90	193
Aug	84	6	1			91	284
Sep	38		2			40	324
Oct							32
Nov							32
Dec							324
Jan							324
Feb							324
Mar							324
TOTAL	304	16	4			324	324

1999-09-28 11:45 AM

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item

262

Title	Budget reference number
PIKWITONEI D.G.S. - SITE CLEAN-UP	04-00-5500

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Operating & Maintenance	Construction	Construction	70136:70442

DESCRIPTION:
1. SALVAGE OF DIESEL EQUIPMENT FROM THE SITE. COMPLETION 1998 02 28 (POG 70137)

2. CONDUCT GEOTECHNICAL INVESTIGATION OF THE DECOMMISSIONED DIESEL GENERATING STATION TO DELINEATE THE EXTENT OF ANY HYDROCARBON CONTAMINATION ON AND/OR AROUND THE SITE; PREPARE SITE INVESTIGATION REPORT INCLUDING RECOMMENDATIONS FOR CLEAN UP. COMPLETION 1999 12 31 (POG 70136)

3. REMEDIATE ANY CONTAMINATED AREAS IDENTIFIED IN THE SITE INVESTIGATION REPORT TO ENVIRONMENTALLY ACCEPTABLE LIMITS AND DEVELOP ANY LAND FARM AREAS NECESSARY FOR THE REMEDIATION PROCESS. LAND FARM ANY CONTAMINATED SOILS REMOVED FROM THE DIESEL SITE AREA AT THE LAND FARM SITE UNTIL CONTAMINATION IS REDUCED TO ENVIRONMENTALLY ACCEPTABLE LEVELS. COMPLETION 2000.12.30. (POG 70442)

4. ISSUE A FINAL REPORT ON THE PROJECT CONFIRMING THE DIESEL SITE AND SURROUNDING AREA WERE REMEDIATED AND ALL AREAS OF THE WORKS WERE LEFT IN ACCORDANCE WITH APPLICABLE ENVIRONMENTAL REGULATIONS. COMPLETION 2000.12.31. (POG 70442)

JUSTIFICATION:
DUE TO ENVIRONMENTAL CONCERNS AND/OR REGULATIONS THE SITE MUST BE INVESTIGATED, REMEDIATED AS REQUIRED, AND RESTORED TO A LEVEL WHICH PERMITS UNRESTRICTED USE OF THE SITE AND THE SURROUNDING AREA.

REVISION:
THE ESTIMATE FOR SALVAGE WAS TOO HIGH AND HAVE NOT BEEN MATERIALIZED. REFLECTS REVISED ACTIVITY AND OVERHEAD RATES.

CONTINGENCY: $27,000

IN SERVICE DATES				Base estimate
1999 04 30	62			199903 L2
1999 12 31	135			Work start date
2000 12 31	331			1997 04 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:	172		8	-2		178
1999/00	- 232					- 232
2000/01	300	18				318
TOTAL	240	18	8	-2		264
REV. AMOUNTS:						
Authorized to date:	172		8	-2		178
Over(under)expend:						
Auth 1999/00	8		9			17
Req.: 2000/01	304	16	11			331
TOTAL	484	16	28	-2		526

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

CAPITAL EXPENDITURE REVISION

Budget reference number: 04-00-5500

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1994 10	445	NEW ITEM.
1995 10	445	ESCALATION AND INTEREST REVISED.
1996 10	471	WORK DEFERRED BY TWO YEARS.
1997 10	231	BASE ESTIMATE UNCHANGED. SALVAGE ESTIMATE NOW BASED ON DETAILED REVIEW. SCHEDULE AND ISD'S ADVANCED BY TWO YEARS.
1998 10	264	ISD DEFERRED TO 2000 12 31.

ASSOCIATED PROJECTS

Budget reference number	Description
04-00-5498	CENTRAL SUPPLY TO PIKWITONEI AND THICKET PORTAGE
04-00-5499	THICKET PORTAGE D.G.S. - SITE CLEAN-UP

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	8		1			9	9
May			1			1	10
Jun			1			1	11
Jul			1			1	12
Aug			1			1	13
Sep			1			1	14
Oct			1			1	15
Nov			1			1	16
Dec			1			1	17
Jan							17
Feb							17
Mar							17
TOTAL	8		9			17	17
2000/01 Apr							
May	12	1				13	13
Jun	85	5				90	103
Jul	85	4	1			90	193
Aug	84	6	1			91	284
Sep	37	1	2			40	324
Oct			2			2	32
Nov			2			2	32
Dec	1	-1	3			3	331
Jan							331
Feb							331
Mar							331
TOTAL	304	16	11			331	331

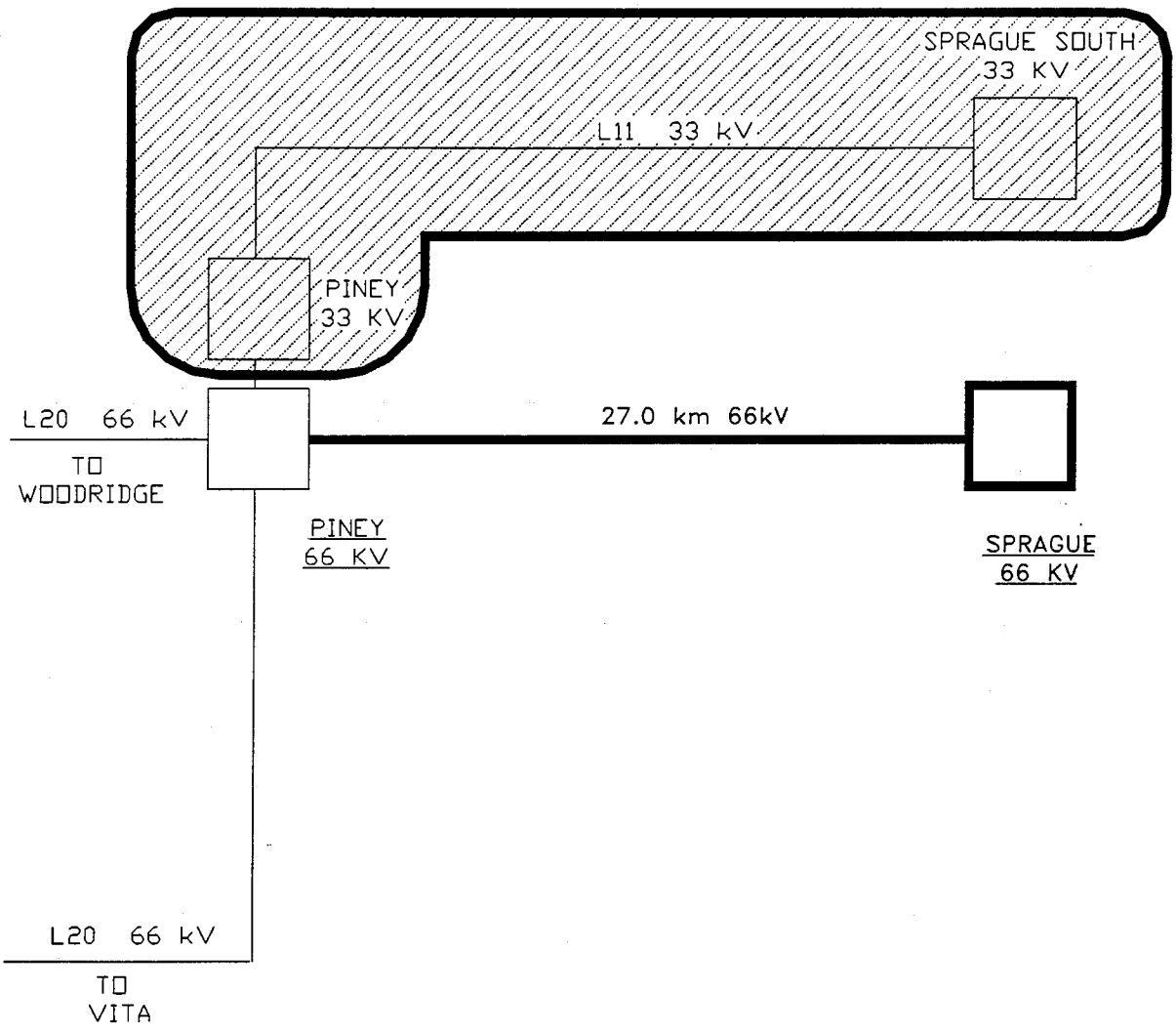
1999-09-28 11:45 AM

CAPITAL BUDGET COMPLEX CONCEPTUAL DIAGRAM

PINEY – SPRAGUE 66KV LINE

REVISED: 1999 - 10 - 01	ISSUED BY: WNZ

COMPLEX NO. 206



LEGEND

PROPOSED

EXISTING

SALVAGE

manitoba hydro

PLANNING AND CONTROL DIVISION

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

COMPLEX STATUS: ☐ Planned ☒ In progress

Complex no. 206

REVISION STATUS: ☐ New complex ☐ In service change ☐ Concept change ☒ Estimate change only

COMPLEX	PINEY - SPRAGUE 66 KV LINE

Proposal

Perform route selection, design and construct transmission and terminal facilities for the supply of Sprague as follows:

Transmission: 66 KV line 27 km Piney - Sprague. Salvage 33 KV line L11 Piney - Sprague.

Terminations: Construct 66-12 KV station at Sprague, including 66-12 KV 10 MVA transfomer and 2 - 66 KV bays. Salvage Sprague 33-12 KV station and Piney 66-33 KV station.

JUSTIFICATION

☒ Load ☐ Service
☐ Safety ☐ Efficiency
☒ Reliability ☐ Other

Explanation

This complex provides support for load increases and eliminates requirement for extensive 33 KV system rebuilding in Sprague area.

Estimate Level	COMPLEX START (yyyy mm)
L2	1996 08

IN SERVICE DATES AND AMOUNTS					
1999 07	$3753	2000 07	$288		

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	1,944		145	1	2,088	2,459	-371	-15
Year 99/00	1,737	19	77	117	1,716	1,237	479	39
00/01	108	4	5	83	34	31	3	10
01/02								
02/03								
03/04								
04/05								
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	3,789	23	227	201	3,838	3,727	111	3

REVISION	Scope Unchanged

Reviewed by ORIGINATOR	yyyy mm dd 99 11 08	Reviewed by COORDINATOR	yyyy mm dd 99 11 03
Reviewed by CONSTRUCTOR	yyyy mm dd 99 11 03	Approved by VICE PRESIDENT	yyyy mm dd 99 11 16

H2856/r Rev 99 03

Complex no. 206

CAPITAL EXPENDITURE FORECAST COMPLEX
(IN THOUSANDS OF DOLLARS)

Advance or deferral impact

Deferral will limit load supply at Sprague or cause overloading of existing 33 KV transformers.

Factors affecting timing or viability

Sprague area load.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Sprague 66-12 KV Station	1,453	1,430	1,459	1,453	-6	-0
Piney Station 33 KV Equipment Salvage		117	119	121	2	2
Sprague Station 33-12 KV Salvage		142	145	146	1	1
Piney-Sprague 66 KV T/L	2,069	1,955	1,994	2,069	75	4
TOTAL	3,522	3,644	3,717	3,789	72	2

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy mm	TOTAL AMOUNT	AMENDMENT
96 10	3,039	New complex.
1997 10	4,247	ISD of line deferred 1 year to 1999 and DC project cancelled .
1998 10	3,727	Reflects 97/98 underexpenditure 1.2M, and current transmission line costs.
1999 10	3,838	Scope Unchanged

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item

263

Title			Budget reference number
SPRAGUE 66-12KV STATION			03-00-6161
Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	71021

DESCRIPTION:
BUILD NEW 66-12KV STATION AT SPRAGUE COMPLETE WITH 1 - 7.5/10 MVA BANK, 3 - 12KV FEEDER EXITS, 2 - 66KV BAYS, MOBILE CONNECTION, ETC.

JUSTIFICATION:
REQUIRED TO MEET FORECASTED LOAD LEVELS AT SPRAGUE AND TO REMOVE REQUIREMENT FOR AN EXTENSIVE 33KV SYSTEM REBUILD.

REFERENCE:
MEMO, B.M. ZNIDAREC TO G.K. ZIELKE, 1996 01 08, PINEY - SPRAGUE 33KV SYSTEM. SPED TM-9 96 05, SPRAGUE-PINEY 66KV LINE AND NEW SPRAGUE 66-12KV STATION.

REVISION:
REFLECTS REVISED ACTIVITY AND OVERHEAD RATES.

CONTINGENCY: $91,000

IN SERVICE DATES			Base estimate
1999 07 31	1 507		199902 L3
			Work start date
			1996 08 01

	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
PREV. AUTHORITY						
Authorized to date:	299		26	-1		324
1999/00	1 139	24	21			1 184
TOTAL	1 438	24	47	-1		1 508
REV. AMOUNTS:						
Authorized to date:	299		26	-1		324
Over(under)expend:						
Auth Req.: 1999/00	1 154	11	17			1 182
TOTAL	1 453	11	43	-1		1 506

Prepared by	yy mm dd COORDINATOR	Approved by	yy mm dd Approved by	yy mm dd
Estimated by	ORIGINATOR	COORDINATING MANAGER	ORIGINATING MANAGER	

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number: 03-00-6161

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1997 10	1 112	INCREASE REFLECTS CURRENT TYPICAL COSTS FOR SITE IMPROVEMENTS ($35,000) . LABOUR AND MATERIAL ESCALATED 2% OVER 1996 ESTIMATE CONVERSION TO SAP.
1998 10	1 508	THE INCREASE IS DUE IN PART TO THE INSTALLATION OF AN INTERCHANGE BANK 12KV TO 25KV STEP-UP) TO SUPPLY CUSTOMERS IN THE NORTHWEST ANGLE WHICH ADDED $200,000 TO THE ESTIMATE SINCE ALL STRUCTURES HAVE TO BE INSTALLED WHEN THE STATION IS CONSTRUCTED. THE SITE IMPROVEMENTS COST AN ADDITIONAL 91,000 MAINLY DUE TO FILL MATERIAL HAVING TO TO BE TRUCKED IN AS OPPOSED TO LOCAL MATERIALS. THE REMAINDER OF THE INCREASE IS SPREAD OVER THE OTHER ACCOUNTS. ESTIMATE REVISED TO A DETAILED LEVEL.

ASSOCIATED PROJECTS

Budget reference number	Description
03-00-6162	PINEY STATION 33KV EQUIPMENT SALVAGE
03-00-6163	SPRAGUE STATION 33-12KV SALVAGE
04-00-6537	PINEY - SPRAGUE 66KV LINE

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	120	2	2			124	124
May	138	2	3			143	267
Jun	494	4	4			502	769
Jul	400	4	8			412	1 181
Aug	2	-1				1	1 182
Sep							1 182
Oct							1 182
Nov							1 182
Dec							1 182
Jan							1 182
Feb							1 182
Mar							1 182
TOTAL	1 154	11	17			1 182	1 182
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item

264

Title
PINEY STATION 33KV EQUIPMENT SALVAGE

Budget reference number
03-00-6162

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	70363

DESCRIPTION:
SALVAGE EXISTING 33KV EQUIPMENT AT PINEY WHICH INCLUDES THE BREAKER, 66-33KV BANK, REGULATOR, PTS, CTS, AND CONTROLS.

JUSTIFICATION:
REMOVE EQUIPMENT THAT IS NO LONGER REQUIRED.

REFERENCE:
MEMO, B.M. ZNIDAREC TO G.K. ZIELKE, 1996 01 08, 'PINEY - SPRAGUE 33KV SYSTEM'.
SPED TM-9 96 05, 'SPRAGUE-PINEY 66KV LINE AND NEW SPRAGUE 66-12KV STATION'.

REVISION:
REFLECTS REVISED ACTIVITY AND OVERHEAD RATES.

CONTINGENCY: $10,000

IN SERVICE DATES

2000 07 31 129

Base estimate
199707 L2

Work start date
1999 10 01

PREV AUTHORITY Authorized to date	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
1999/00	60	3	1			64
2000/01	57	3	2	-53		9
TOTAL	117	6	3	-53		73
REV AMOUNTS: Authorized to date:						
Over(under)expend:						
Auth 1999/00	62	3	1			66
Req.: 2000/01	59	2	2	-53		10
TOTAL	121	5	3	-53		76

Prepared by: yy mm dd COORDINATOR
Approved by: yy mm dd Approved by: yy mm dd
Estimated by: ORIGINATOR
COORDINATING MANAGER
ORIGINATING MANAGER

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 03-00-6162

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1996 10	56	NEW ITEM.
1997 10	70	SCOPE UNCHANGED, ESTIMATE REFLECTS REVISED COSTING METHODOLOGY IMPLEMENTED WITH THE NEW FINANCIAL REPORTING SYSTEM. ALSO REFLECTS REVISED INTEREST AND ESCALATION RATES.
1998 10	73	NO CHANGE.

ASSOCIATED PROJECTS

Budget reference number	Description
03-00-6161	SPRAGUE 66-12KV STATION
03-00-6163	SPRAGUE STATION 33-12KV SALVAGE
04-00-6537	PINEY - SPRAGUE 66KV LINE

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct	10	1				11	11
Nov	10	1				11	22
Dec	10	1				11	33
Jan	10	1				11	44
Feb	10	1				11	55
Mar	12	-2	1			11	66
TOTAL	62	3	1			66	66
2000/01 Apr	12	1			-13		
May	12	1			-13		
Jun	12	1			-13		
Jul	23	-1	2		-14	10	10
Aug							10
Sep							10
Oct							
Nov							
Dec							10
Jan							10
Feb							10
Mar							10
TOTAL	59	2	2		-53	10	10

1999-08-21 05:21 PM

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item

265

Title			Budget reference number
SPRAGUE STATION 33-12KV SALVAGE			03-00-6163
Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	70364

DESCRIPTION:
SALVAGE THE ENTIRE 33-12KV STATION AT SPRAGUE, INCLUDING THE SIX SINGLE PHASE 500KVA TRANSFORMERS AND TWO SETS OF 12KV OCRS.

JUSTIFICATION:
REQUIRED TO REMOVE EQUIPMENT THAT IS NO LONGER NEEDED.

REFERENCE:
MEMO, B.M. ZNIDAREC TO G.K. ZIELKE, 1996 10 08, 'PINEY - SPRAGUE 33KV SYSTEM'.
SPED TM-9 96 05, 'SPRAGUE-PINEY 66KV LINE AND NEW SPRAGUE 66-12KV STATION'.

REVISION:
REFLECTS REVISED ACTIVITY AND OVERHEAD RATES.

CONTINGENCY: $13,000

IN SERVICE DATES		Base estimate
2000 07 31	160	199707 L2
		Work start date
		1999 04 01

PREV. AUTHORITY Authorized to date:	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
1999/00	94	4	4			102
2000/01	48	1	3	-30		22
TOTAL	142	5	7	-30		124
REV. AMOUNTS: Authorized to date: Over(under)expend:						
Auth 1999/00	97	4	4			105
Req. 2000/01	49	1	3	-30		23
TOTAL	146	5	7	-30		128

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR		COORDINATING MANAGER		ORIGINATING MANAGER

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 03-00-6163

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1997 10	127	SCOPE UNCHANGED. ESTIMATE REFLECTS REVISED COSTING METHODOLOGY IMPLEMENTED WITH THE NEW FINANCIAL REPORTING SYSTEM. ALSO REFLECTS REVISED INTEREST AND ESCALATION RATES.
1998 10	124	NO CHANGE.

ASSOCIATED PROJECTS

Budget reference number	Description
03-00-6161	SPRAGUE 66-12KV STATION
03-00-6162	PINEY STATION 33KV EQUIPMENT SALVAGE
04-00-6537	PINEY - SPRAGUE 66KV LINE

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	8					8	8
May	8					8	16
Jun	8					8	24
Jul	8	1				9	33
Aug	8	1				9	42
Sep	8	1				9	51
Oct	8	1				9	60
Nov	8	1				9	69
Dec	8	1				9	78
Jan	8		1			9	87
Feb	8		1			9	96
Mar	9	-2	2			9	105
TOTAL	97	4	4			105	105
2000/01 Apr	9		1		-8	2	2
May	9	1	1		-8	3	5
Jun	9	1	1		-8	3	8
Jul	22	-1			-6	15	23
Aug							23
Sep							23
Oct							23
Nov							23
Dec							23
Jan							23
Feb							23
Mar							23
TOTAL	49	1	3		-30	23	23

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item

266

Title
PINEY - SPRAGUE 66KV LINE

Budget reference number
04-00-6537

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	93310

DESCRIPTION:
CONSTRUCT A 66KV LINE FROM PINEY TO SPRAGUE, 29.7 KM, 2/0 ACSR CONDUCTOR. SALVAGE 33KV LINE FROM PINEY TO SPRAGUE.

JUSTIFICATION:
REQUIRED TO MEET FORECASTED LOAD LEVELS AT SPRAGUE AND TO REMOVE REQUIREMENT FOR AN EXTENSIVE 33KV SYSTEM REBUILD.

REFERENCE:
MEMO, B.M. ZNIDAREC TO G.K. ZIELKE, 1996 01 08, PINEY - SPRAGUE 33KV SYSTEM.
SPD REPORT 97/2 'NEW SPRAGUE-PINEY 66KV LINE AND NEW SPRAGUE 66-12KV STATION'

REVISION:
CASH FLOW ADJUSTED. PROJECT IS EXPECTED TO BE COMPLETED WITHIN THIS BUDGET.

IN SERVICE DATES

1999 07 31 | 2 245

Base estimate
199902 L1

Work start date
1997 04 01

	PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date		1 645		119			1 764
1999/00		302	-1	58	- 100		259
TOTAL		1 947	-1	177	- 100		2 023
REV. AMOUNTS:							
Authorized to date		1 645		119			1 764
Over(under)expend:							
Auth Req.: 1999/00		424	1	55	- 117		363
TOTAL		2 069	1	174	- 117		2 127

Prepared by: yy mm dd COORDINATOR — Approved by: yy mm dd — Approved by:

Estimated by: ORIGINATOR — COORDINATING MANAGER — ORIGINATING MANAGER

1999-08-21 05:27 PM

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 04-00-6537

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1996 04	0	NEW ITEM
1997 07	2 941	ISD DEFERED 1 YEAR FROM 1998 07 31 TO 1999 07 31. DC PROJECT CANCELLED AND SALVAGE OF THE EXISTING 33KV LINE ADDDED TO ITEM.
1999 10	2 016	Design has been completed and clearing and construction have commenced. This has resulted in a much improved estimate.
1999 10	2 023	Design has been completed and clearing and construction have commenced. This has resulted in a much improved estimate.

ASSOCIATED PROJECTS

Budget reference number	Description
03-00-6161	SPRAGUE 66-12KV STATION
03-00-6162	PINEY STATION 33KV EQUIPMENT SALVAGE
03-00-6163	SPRAGUE STATION 33-12KV SALVAGE

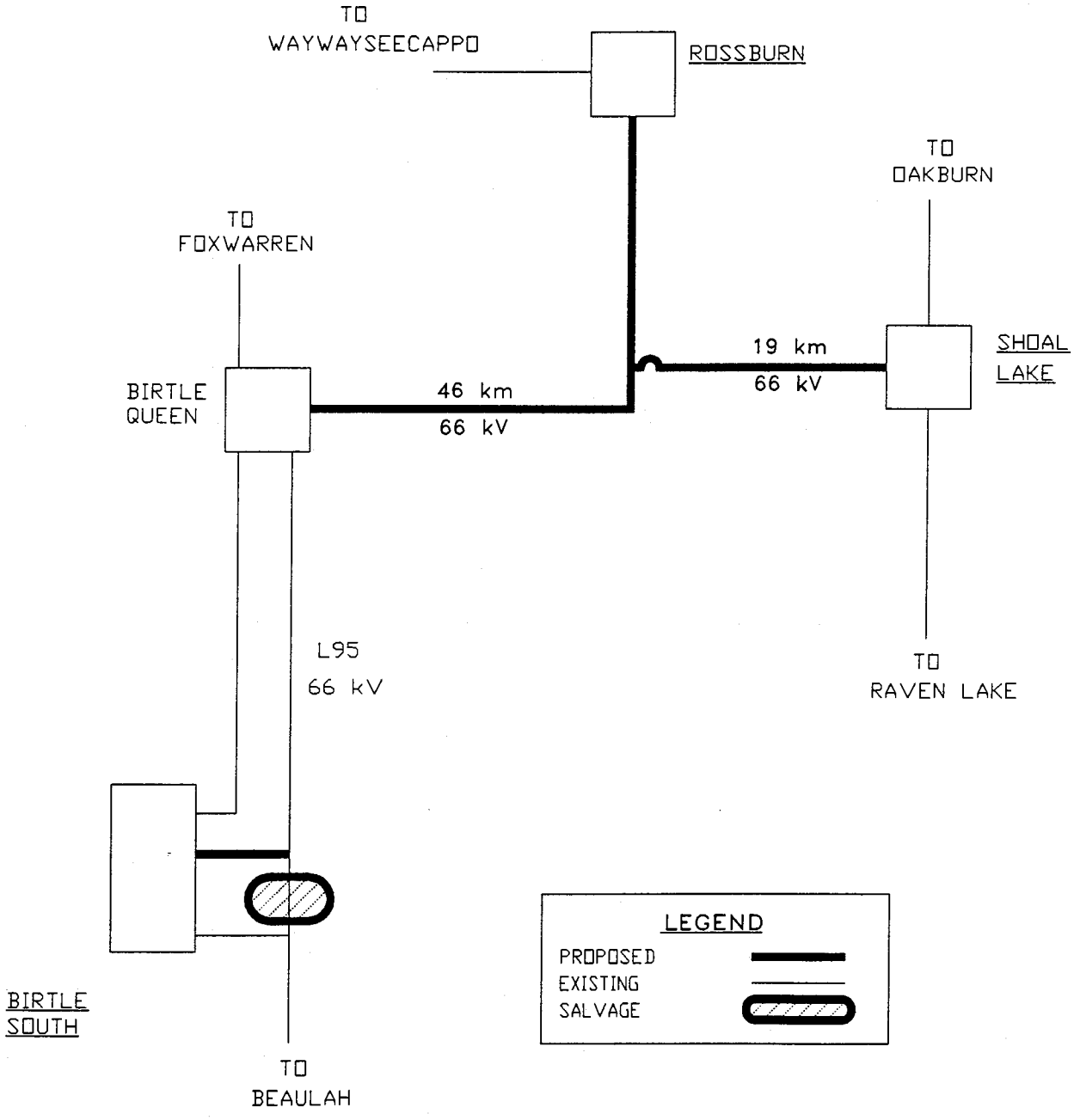
Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	158	1	12			171	171
May	159	1	13		-8	165	336
Jun	99		15		-54	60	396
Jul	8	-1	15		-55	-33	363
Aug							363
Sep							363
Oct							363
Nov							363
Dec							363
Jan							363
Feb							363
Mar							363
TOTAL	424	1	55		- 117	363	363
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

CAPITAL BUDGET COMPLEX CONCEPTUAL DIAGRAM

BIRTLE – ROSSBURN 66KV LINE

REVISED: 1999 - 10 - 01	ISSUED BY: WNZ

COMPLEX NO. 209



manitoba hydro

PLANNING AND CONTROL DIVISION

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

COMPLEX STATUS: [X] Planned [ ] In progress

Complex no. 209

REVISION STATUS: [ ] New complex [ ] In service change [ ] Concept change [X] Estimate change only

COMPLEX: BIRTLE - ROSSBURN 66 KV LINE

Proposal

Perform route selection, design and construct transmission and terminal facilities for supply to Rossburn and Shoal Lake as follows:

Transmission: 66 KV line 46 km Birtle Queen - Rossburn, 66 KV line 19 km Shoal Lake - Tap on Birtle Queen to Rossburn line. Open 66 KV line L95 at Birtle South north of Beaulah tap and extend open end into Birtle South.

Terminations: Extend 66 KV facilities at Birtle South.

JUSTIFICATION

[X] Load [ ] Service
[ ] Safety [ ] Efficiency
[X] Reliability [ ] Other

Explanation

This complex provides voltage support for distribution loads in the Rossburn area, maintains firm supply to increased load at Shoal Lake, and extends the service life of the Raven Lake 33 KV system.

Estimate Level	COMPLEX START (yyyy mm)
L2	2002 04

IN SERVICE DATES AND AMOUNTS					
2004 10	$3997	2005 10	$1559		

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend								
Year 99/00								
00/01								
01/02								
02/03	73	7	3		83	73	10	14
03/04	196	24	13		233	233	0	0
04/05	3,221	328	136	48	3,637	3,783	-146	-4
05/06	1,329	158	56	48	1,495	1,568	-73	-5
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	4,819	517	208	96	5,448	5,657	-209	-4

REVISION: Scope unchanged.

Reviewed by ORIGINATOR	yyyy mm dd 99 11 08	Reviewed by COORDINATOR	yyyy mm dd 99 11 09
Reviewed by CONSTRUCTOR	yyyy mm dd 99 11 03	Approved by VICE PRESIDENT	yyyy mm dd 99 11 16

H2856/r Rev 99 03

Complex no.
209

CAPITAL EXPENDITURE FORECAST COMPLEX
(IN THOUSANDS OF DOLLARS)

Advance or deferral impact

Deferral will result in inadequate Rossburn area voltage support under peak conditions and reduce firm load support capability to Shoal Lake.

Factors affecting timing or viability

Rossburn and Shoal Lake area load growth.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Birtle South Stn- Rossburn 66 KV Line Termination		481	491	508	17	3
Birtle South - Rossburn 66 KV Line		2,997	3,057	2,974	-83	-3
Shoal Lake Station 66 KV Supply		1,352	1,379	1,337	-42	-3
TOTAL		4,830	4,927	4,819	-108	-2

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
96 10	5,104	New complex.
1997 10	5,577	Estimate reflects revised costing methodology implemented with the new financial reporting system.
1998 10	5,657	Revised to include interest.
1999 10	5,448	Scope unchanged.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item

267

Title: BIRTLE SOUTH - ROSSBURN 66KV LINE TERMINATION

Budget reference number: 03-00-6165

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	70367

DESCRIPTION:
TERMINATE THE BIRTLE SOUTH - ROSSBURN 66KV LINE AT BIRTLE SOUTH. INSTALL A 3500 MVA, 72.5KV BREAKER IN POSITION R26.

JUSTIFICATION:
ELSEWHERE IN THE BUDGET JUSTIFICATION IS GIVEN FOR A NEW 66KV LINE FROM BIRTLE SOUTH TO ROSSBURN.

REFERENCE:
BIRTLE SOUTH AND RAVEN LAKE SYSTEMS SPED REPORT 96-04.

REVISION:
REFLECTS REVISED ACTIVITY AND OVERHEAD RATES.

CONTINGENCY $ 43, 000

IN SERVICE DATES: 2004 10 31 — 603

Base estimate: 199707 L2

Work start date: 2002 04 01

PREV. AUTHORITY Authorized to date:	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
2002/03	63	7	3			73
2003/04	166	22	12			200
2004/05	252	31	19			302
TOTAL	481	60	34			575
REV. AMOUNTS. Authorized to date: Over(under)expend:						
Auth 2002/03	73	7	3			83
Req 2003/04	176	22	13			211
2004/05	259	30	20			309
TOTAL	508	59	36			603

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number: 03-00-6165

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1996 10	571	NEW ITEM.
1997 10	550	SCOPE UNCHANGED, ESTIMATE REFLECTS REVISED COSTING METHODOLOGY IMPLEMENTED WITH THE NEW FINANCIAL REPORTING SYSTEM. ESTIMATE ALSO REFLECTS REVISED INTEREST AND ESCALATION RATES.
1998 10	575	NO CHANGE.

ASSOCIATED PROJECTS

Budget reference number	Description
04-00-6538	BIRTLE SOUTH - ROSSBURN 66KV T/L
04-00-6539	SHOAL LAKE - 66KV SUPPLY

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item — 268

Title
BIRTLE SOUTH - ROSSBURN 66KV T/L

Budget reference number
04-00-6538

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	70365:94208

DESCRIPTION:
CONSTRUCT 46 KM OF 66KV, 266.8 KCMIL LINE FROM BIRTLE QUEEN STATION TO ROSSBURN STATION. PROVIDE A NEW LINE SECTION AT BIRTLE SOUTH STATION TO TURN THE NORTH TAP (TOWARDS BIRTLE QUEEN STATION) OF LINE 95 INTO A NEW TERMINATION AT BIRTLE SOUTH STATION.

JUSTIFICATION:
THE 66KV STATIONS AT ANGUSVILLE, WAYWAYSEECAPO, AND ROSSBURN DEPEND ON DISTRIBUTION VOLTAGE REGULATION TO MAINTAIN ADEQUATE DISTRIBUTION VOLTAGE LEVELS. BY 2004/05 IT IS EXPECTED THAT 66KV VOLTAGE LEVELS WILL NOT PROVIDE ADEQUATE INPUT LEVELS TO MAINTAIN MINIMUM DISTRIBUTION VOLTAGE LEVELS.

REFERENCE:
BIRTLE SOUTH AND RAVEN LAKE SYSTEMS SPED REPORT 96-04

REVISION:
REVISED TO REFLECT OVERHEAD AND ACTIVITY RATE CHANGES

CONTINGENCY AMOUNT: $0

IN SERVICE DATES

2004 10 31 3 394

Base estimate
199902 L2

Work start date
2003 10 01

PREV. AUTHORITY Authorized to date.	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
2003/04	27	4	1			32
2004/05	2 970	424	122	-48		3 468
TOTAL	2 997	428	123	-48		3 500
REV. AMOUNTS. Authorized to date: Over(under)expend:						
Auth 2003/04	20	3				23
Req.: 2004/05	2 954	296	116	-48		3 318
TOTAL	2 974	299	116	-48		3 341

Prepared by yy mm dd COORDINATOR — Approved by yy mm dd COORDINATING MANAGER — Approved by yy mm dd ORIGINATING MANAGER

Estimated by ORIGINATOR

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number: 04-00-6538

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1996 07	3 213	NEW ITEM
1997 04	3 390	REVISED TO REFECT THE INCREASE CAUSED BY NEW O/H'S.
1998 10	3 465	REVISED TO REFECT THE INCREASE DUE TO SAP.
1999 10	3 407	REVISED TO REFLECT OVERHEAD AND ACTIVITY RATE CHANGES.

ASSOCIATED PROJECTS

Budget reference number	Description
03-00-6165	BIRTLE SOUTH - ROSSBURN 66KV LINE TERMINATION
04-00-6539	SHOAL LAKE - 66KV SUPPLY

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item

269

Title: SHOAL LAKE - 66KV SUPPLY

Budget reference number: 04-00-6539

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	70366:94209

DESCRIPTION:
CONSTRUCT 19 KM OF 66KV 266.8 KCMIL LINE FROM NW35-16-25W (BIRTLE - ROSSBURN LINE) TO SHOAL LAKE STATION.

JUSTIFICATION:
SHOAL LAKE IS PRESENTLY SUPPLIED AT 33KV FROM RAVEN LAKE STATION. BY 2005/06 IT IS ANTICIPATED THAT THE RAVEN L 33KV FIRM CAPACITY OF 25 MVA WILL BE EXCEEDED. THE TRANSFER OF SHOAL LAKE STATION TO BIRTLE SOUTH 66KV SUPPLY WILL EXTEND THE LIFE OF THE RAVEN LAKE 33KV SYSTEM. IN 2000/01 IT IS PLANNED TO INCREASE CAPACITY AT SHOAL LAKE. DUAL VOLTAGE (66/33KV) TRANSFORMERS WILL BE INSTALLED TO SET UP THE TRANSFER TO BIRTLE SOUTH 66KV SUPPLY.

CONTINGENCY AMOUNT: $0

REFERENCE:
BIRTLE SOUTH AND RAVEN LAKE SYSTEMS SPED REPORT 96-04

REVISION:
REVISED TO REFLECT OVERHEAD AND ACTIVITY RATE CHANGES.

CONTINGENCY AMOUNT: $0

IN SERVICE DATES			Base estimate
2005 10 31	1 558		199902 L2
			Work start date
			2004 11 01

	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
PREV. AUTHORITY						
Authorized to date:						
2004/05	11	2				13
2005/06	1 341	216	59	-48		1 568
TOTAL	1 352	218	59	-48		1 581
REV. AMOUNTS:						
Authorized to date:						
Over(under)expend:						
Auth 2004/05	8	1				9
Req. 2005/06	1 329	158	56	-48		1 495
TOTAL	1 337	159	56	-48		1 504

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR		COORDINATING MANAGER		ORIGINATING MANAGER

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number: 04-00-6539

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1996 07	1 320	NEW ITEM
1998 06	1 620	REVISED TO INCLUDE INTEREST.
1999 10	1 541	REVISED TO REFLECT OVERHEAD AND ACTIVITY RATE CHANGES.

ASSOCIATED PROJECTS

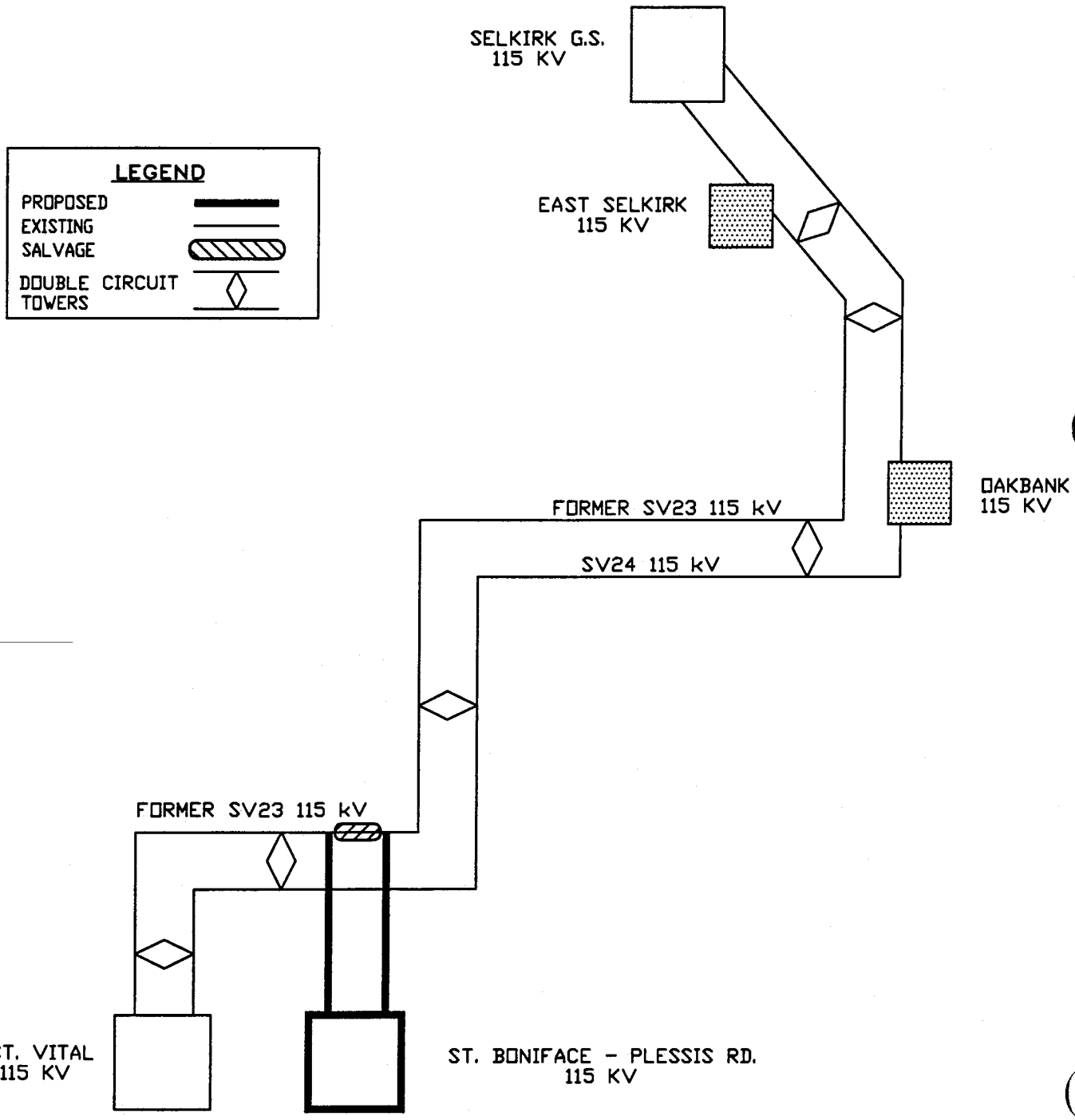
Budget reference number	Description
03-00-6165	BIRTLE SOUTH - ROSSBURN 66KV LINE TERMINATION
04-00-6538	BIRTLE SOUTH - ROSSBURN 66KV T/L

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

CAPITAL BUDGET COMPLEX CONCEPTUAL DIAGRAM

ST BONIFACE – PLESSIS ROAD
115-24 KV STATION

REVISED: 1999 - 10 - 01	ISSUED BY: CS
COMPLEX NO. 237	



manitoba hydro

PLANNING AND CONTROL DIVISION

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

COMPLEX STATUS: ☐ Planned ☒ In progress

Complex no.: 237

REVISION STATUS: ☐ New complex ☐ In service change ☐ Concept change ☒ Estimate change only

COMPLEX	ST BONIFACE - PLESSIS RD 115-24KV STATION

Proposal

DESIGN AND CONSTRUCT A NEW STEEL 115/24 KV STN ALONG PLESSIS ROAD TO ACCOMMODATE 2- 60/80/100/112 MVA, 114.3-24/13.8 KV LTC TRANSF'S WITH NEUTRAL REACTORS, A 115KV BRKR AND 12 - 24KV FDR LINES. INTIALLY, INSTALL 1- 60/80/100/112 MVA, 114.3-24/13.8 KV +/- 10% LTC TRANSF AND NEUTRAL REACTOR, 8-24KV CIRCUIT BREAKERS, 6-24 KV CIRCUIT LINE REACTORS, 2-24 KV CIRCUIT SWITCHERS, AND 2-14.4 MVAR 24 KV CAPACITOR BANKS. PROTECTION FOR THE TRANSF AND THE SECTIONALIZED 115 KV SV23 LINE TERMINATIONS INTO THE STATION IS PROVIDED BY OPENING BRKRS ON LINES AT ST BONIFACE RD AND SELKIRK GENERATING STATION, (TRANSCONA-FUTURE) OR ST. VITAL TERMINAL VIA TELECOMMUNICATIONS. TRANSIENT VOLTAGE STUDIES MAY BE REQUIRED TO DEFINE THE TRANSIENT RECOVERY VOLTAGE MITIGATING EQUIPMENT.

JUSTIFICATION

☒ Load ☐ Service
☐ Safety ☐ Efficiency
☒ Reliability ☐ Other

Explanation

THIS NEW STATION IS REQUIRED TO SUPPORT THE LOAD GROWTH IN THE AREA AND TO PROVIDE BACKUP TO OTHER 24 KV STATIONS NEARBY.

Estimate Level	COMPLEX START (yyyy mm)
L2	1997 08

IN SERVICE DATES AND AMOUNTS					
2000 09	$17315	2001 04	$487		

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	1,329		78		1,407	1,603	-196	-12
Year 99/00	7,237	198	352		7,787	5,032	2,755	55
00/01	7,457	279	549	2	8,283	3,242	5,041	155
01/02	309	13	1		323	7,053	-6,730	-95
02/03								
03/04								
04/05								
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	16,332	490	980	2	17,800	16,930	870	5

REVISION	Reflects revised activity and overhead rates.

Reviewed by ORIGINATOR	yyyy mm dd 99 11 03	Reviewed by COORDINATOR	yyyy mm dd 99 11 03
Reviewed by CONSTRUCTOR	yyyy mm dd 99 11 03	Approved by VICE PRESIDENT	yyyy mm dd 99 11 16

H2856/r Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Complex no. 237

Advance or deferral impact

Delay in components of this complex will reduce service reliability and quality in the St. Boniface, and St.Vital areas.

Factors affecting timing or viability

Load Growth

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
St Boniface-Plessis Road Stn 115kv T/L Improvements		946	965	969	4	0
St Boniface Plessis Road New Station	11,204	11,867	12,104	11,681	-423	-3
St Vital Terminal 115kv Line SV23 Protection Repl		221	225	236	11	5
Selkirk GS 115kV Line SV23 Protection Replacement		221	225	236	11	5
St Boniface - Plessis Road Stn 4 -24kV Feeder Lines		1,957	1,996	2,820	824	41
St Boniface-Plessis Road Stn Communication Req		381	389	389	0	0
TOTAL	11,204	15,593	15,904	16,331	427	3

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
1997 10	15,140	New Complex
1998 10	16,930	ISD of complex advanced nine months to September 2000. Scope changed from SV23 tap to sectionallization and reconductoring of 2.7 Km of 115 kV lines GT1/ST2.
1999 10	17,800	Reflects revised activity and overhead rates.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item __ Domestic Item 270

Title: ST. BONIFACE PLESSIS ROAD STATION 115kV T/L IMPROVEMENTS

Budget reference number: 02-00-7998

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	70410

DESCRIPTION:
SECTIONALIZE 115 KV TRANSMISSION LINE SV23 FROM THE SELKIRK - ST. VITAL 115 KV RIGHT-OF-WAY AND TERMINATE BOTH LINES AT THE NEW ST BONIFACE PLESSIS ROAD STATION - ISD 2000 09 30.
RECONDUCTOR/REBUILD APPROXIMATELY 2.7 KM OF GT1/ST2 FROM SV23 TO TRANSCONA WITH 795 MCM ACSR @ 100C - ISD 2001 04 30.

JUSTIFICATION:
ELSEWHERE IN THE BUDGET, JUSTIFICATION IS GIVEN FOR ESTABLISHMENT OF THE NEW ST. BONIFACE PLESSIS ROAD STATION. THIS ITEM PROVIDES PRIMARY SUPPLY FOR BANK 1.

REFERENCE:
L.A. MILLER TO W. PYL, 'GOULET 4 KV FEEDER CHANGES', 96-05-29.
G.K. ZIELKE TO V. KOSCHIK, 'DAWSON ROAD - ST. VITAL 24 KV SYSTEM', 96-06-20.
W.N. ZURBA TO C.V. THIO 'ST BONIFACE RD STATION 115KV SUPPLY AND STATION DEVELOPMENT', 1998 01 22.

REVISION:
REFLECTS REVISED ACTIVITY AND OVERHEAD RATES.

CONTINGENCY: $85,000

IN SERVICE DATES

2000 09 30	536
2001 04 30	487

Base estimate: 199804 L3

Work start date: 1998 04 01

PREV AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:						
1999/00	130	3	6			139
2000/01	513	26	8			547
2001/02	305	14	1			320
TOTAL	948	43	15			1 006
REV. AMOUNTS:						
Authorized to date:						
Over(under)expend:						
Auth 1999/00	130	3	4			137
Req. 2000/01	530	25	8			563
2001/02	309	13	1			323
TOTAL	969	41	13			1 023

Prepared by: yy mm dd COORDINATOR — Approved by: yy mm dd — Approved by: yy mm dd

Estimated by: ORIGINATOR — COORDINATING MANAGER — ORIGINATING MANAGER

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 02-00-7998

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1997 10	68	NEW ITEM
1998 10	1 006	ST. BONIFACE STATION SITE RELOCATED AND NAME CHANGED FROM 'SPRINGFIELD - ST. BONIFACE ROAD'. SCOPE CHANGED FROM SV23 TAP TO SECTIONALIZATION AND NOW INCLUDES RECONDUCTORING OF 2.7 KM OF 115 KV LINES GT1/ST2.

ASSOCIATED PROJECTS

Budget reference number	Description
03-00-7260	ST. BONIFACE PLESSIS RD NEW STATION
03-00-7261	ST. VITAL TERMINAL 115KV LINE SV23 PROTECTION REPLACEMENT
03-00-7262	SELKIRK G.S. 115 KV LINE SV23 PROTECTION RELACEMENT
04-00-7564	ST BONIFACE PLESSIS RD STATION - 4-24KV FEEDER LINES
05-00-7584	ST BONIFACE - PLESSIS ROAD STATION COMMUNICATION REQUIREMENT

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	4					4	4
May	4					4	8
Jun	11					11	19
Jul	6					6	25
Aug	6					6	31
Sep	12					12	43
Oct	12					12	55
Nov	15	1				16	71
Dec	15		1			16	87
Jan	15		1			16	103
Feb	15		1			16	119
Mar	15	2	1			18	137
TOTAL	130	3	4			137	137
2000/01 Apr	14	1	1			16	16
May	12		1			13	29
Jun	31	2	1			34	63
Jul	140	7	1			148	211
Aug	44	3	2			49	260
Sep	29	2	3			34	294
Oct	24	1	-1			24	31
Nov	3		-1			2	32
Dec	3		-1			2	322
Jan	77	4	-1			80	402
Feb	75	4				79	481
Mar	78	1	3			82	563
TOTAL	530	25	8			563	563

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item 271

Title			Budget reference number
ST. BONIFACE PLESSIS RD NEW STATION			03-00-7260
Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	70470

DESCRIPTION:
DESIGN AND CONSTRUCT A NEW STEEL 115/24 KV STATION ALONG PLESSIS ROAD TO ACCOMMODATE TWO 60/80/100/112 MVA, 114.3-24/13.8 KV LTC TRANSFORMERS WITH NEUTRAL REACTORS, A 115KV BREAKER AND TWELVE 24KV FEEDER LINES. INTIALLY, INSTALL ONE 60/80/100/112 MVA, 114.3-24/13.8 KV +/- 10% LTC TRANSFORMER AND NEUTRAL REACTOR, 8-24KV CIRCUIT BREAKERS, 6-24 KV CIRCUIT LINE REACTORS, 2-24 KV CIRCUIT SWITCHERS, AND 2-14.4 MVAR 24 KV CAPACITOR BANKS. PROTECTION FOR THE TRANSFORMER AND THE SECTIONALIZED 115 KV SV23 LINE TERMINATIONS INTO THE STATION IS PROVIDED BY OPENING BREAKERS ON LINES AT ST BONIFACE RD AND SELKIRK GENERATING STATION, (TRANSCONA-FUTURE) OR ST. VITAL TERMINAL VIA TELECOMMUNICATIONS. TRANSIENT VOLTAGE STUDIES MAY BE REQUIRED TO DEFINE THE TRANSIENT RECOVERY VOLTAGE MITIGATING EQUIPMENT.

JUSTIFICATION:
THIS NEW STATION IS REQUIRED TO SUPPORT THE LOAD GROWTH IN THE AREA AND TO PROVIDE BACKUP TO OTHER 24 KV STATIONS NEARBY.

REFERENCE:
L.A. MILLER TO W. PYL, 'GOULET 4 KV FEEDER CHANGES', 96-05-29, FILE 74P
G.K. ZIELKE TO V. KOSCHIK, 'DAWSON ROAD - ST. VITAL 24 KV SYSTEM', 96-06-20
W.N. ZURBA TO C.V. THIO 'ST BONIFACE RD STATION 115KV SUPPLY AND STATION DEVELOPMENT', 1998 01 22.

REVISION:
REFLECTS REVISED ACTIVITY AND OVERHEAD RATES.

CONTINGENCY: $1,200,000

IN SERVICE DATES				Base estimate
2000 09 30	12 759			199802 L3
				Work start date
				1997 08 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:	1 327		78			1 405
1999/00	3 192	167	283			3 642
2000/01	615	151	294			1 060
2001/02	6 733					6 733
TOTAL	11 867	318	655			12 840
REV. AMOUNTS:						
Authorized to date:	1 327		78			1 405
Over(under)expend:						
Auth 1999/00	5 911	147	305			6 363
Req.: 2000/01	4 443	130	418			4 991
TOTAL	11 681	277	801			12 759

Prepared by yy mm dd COORDINATOR — Approved by yy mm dd COORDINATING MANAGER — Approved by yy mm dd ORIGINATING MANAGER

Estimated by ORIGINATOR

1999-08-21 05:23 PM

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 03-00-7260

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1997 10	11 620	NEW ITEM.
1998 10	12 839	ISD ADVANCED FROM 2001 06 30 TO 2000 09 30. ESTIMATE REVISED TO A DETAILED ESTIMATE. NAME CHANGED FROM ST. BONIFACE ROAD.

ASSOCIATED PROJECTS

Budget reference number	Description
02-00-7998	ST. BONIFACE PLESSIS ROAD STATION 115kV T/L IMPROVEMENTS
03-00-7261	ST. VITAL TERMINAL 115KV LINE SV23 PROTECTION REPLACEMENT
03-00-7262	SELKIRK G.S. 115 KV LINE SV23 PROTECTION RELACEMENT
04-00-7564	ST BONIFACE PLESSIS RD STATION - 4-24KV FEEDER LINES
05-00-7584	ST BONIFACE - PLESSIS ROAD STATION COMMUNICATION REQUIREMENT

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	169	4	10			183	183
May	138	3	11			152	335
Jun	494	12	12			518	853
Jul	451	12	16			479	1 332
Aug	476	14	19			509	1 841
Sep	584	17	23			624	2 465
Oct	271	8	27			306	2 771
Nov	324	9	29			362	3 133
Dec	295	7	32			334	3 467
Jan	1 600	24	34			1 658	5 125
Feb	327	9	45			381	5 506
Mar	782	28	47			857	6 363
TOTAL	5 911	147	305			6 363	6 363
2000/01 Apr	304	8	55			367	367
May	1 547	59	57			1 663	2 030
Jun	359	12	69			440	2 470
Jul	1 080	30	72			1 182	3 652
Aug	368	13	81			462	4 114
Sep	265	8	84			357	4 471
Oct	87					87	4 55
Nov	105	1				106	4 664
Dec	79					79	4 743
Jan	80					80	4 823
Feb	84	1				85	4 908
Mar	85	-2				83	4 991
TOTAL	4 443	130	418			4 991	4 991

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item ___ Domestic Item 272

Title
ST. VITAL TERMINAL 115KV LINE SV23 PROTECTION REPLACEMENT

Budget reference number
03-00-7261

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	70453

DESCRIPTION:
115 KV LINE SV23 PROTECTION AT ST. VITAL STATION MUST BE REPLACED WITH A PROTECTION SYSTEM CAPABLE OF ACCOMMODATING THE ST. BONIFACE ROAD 115-24KV STATION.

JUSTIFICATION:
ELSEWHERE IN THE BUDGET, JUSTIFICATION IS PROVIDED FOR THE ESTABLISHMENT OF THE NEW SPRINGFIELD-ST. BONIFACE STATION TO BE SUPPLIED FROM SECTIONALIZED 115KV LINE SV23. THIS ITEM PROVIDES FOR PROTECTION CHANGES REQUIRED AT ST. VITAL TO ACCOMMODATE THIS NEW STATION.

REFERENCE:
L.A. MILLER TO W PYL, 'GOULET 4 KV FEEDER CHANGES,' 96-05-29, FILE 74P
G.K. ZIELKE TO V. KOSCHIK, 'DAWSON ROAD-ST. VITAL 24 KV SYSTEM,' 96-06-20
W.N. ZURBA TO C.V. THIO 'ST BONIFACE RD STATION 115KV SUPPLY AND STATION DEVELOPMENT', 1998 01 22.

REVISION:
REFLECTS REVISED ACTIVITY AND OVERHEAD RATES.

CONTINGENCY: $20,000

IN SERVICE DATES		Base estimate
2000 09 30	253	199707 L2
		Work start date
		1999 07 01

	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
PREV AUTHORITY						
Authorized to date:						
1999/00	61	2	2			65
2000/01	160	9	4	-1		172
TOTAL	221	11	6	-1		237
REV AMOUNTS:						
Authorized to date:						
Over(under)expend:						
Auth 1999/00	67	3	2			72
Req 2000/01	169	7	5	-1		180
TOTAL	236	10	7	-1		252

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR		COORDINATING MANAGER		ORIGINATING MANAGER

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 03-00-7261

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1997 10	242	NEW ITEM.
1998 10	237	ISD ADVANCED FROM 2001 06 30 TO 2000 09 30.

ASSOCIATED PROJECTS

Budget reference number	Description
02-00-7998	ST. BONIFACE PLESSIS ROAD STATION 115kV T/L IMPROVEMENTS
03-00-7260	ST. BONIFACE PLESSIS RD NEW STATION
03-00-7262	SELKIRK G.S. 115 KV LINE SV23 PROTECTION RELACEMENT
04-00-7564	ST BONIFACE PLESSIS RD STATION - 4-24KV FEEDER LINES
05-00-7584	ST BONIFACE - PLESSIS ROAD STATION COMMUNICATION REQUIREMENT

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul	6	1				7	7
Aug	6	1				7	14
Sep	6	1				7	21
Oct	6	1				7	28
Nov	6	1				7	35
Dec	9					9	44
Jan	9	1				10	54
Feb	9	1				10	64
Mar	10	-4	2			8	72
TOTAL	67	3	2			72	72
2000/01 Apr	9		1			10	10
May	9		1			10	20
Jun	9		1			10	30
Jul	41	2	1			44	74
Aug	41	2	1			44	118
Sep	60	3			-1	62	180
Oct							180
Nov							180
Dec							180
Jan							180
Feb							180
Mar							180
TOTAL	169	7	5		-1	180	180

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item 273

Title
SELKIRK G.S. 115 KV LINE SV23 PROTECTION RELACEMENT

Budget reference number
03-00-7262

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	70452

DESCRIPTION:
115 KV LINE SV23 PROTECTION AT SELKIRK GENERATING STATION MUST BE REPLACED WITH A PROTECTION SYSTEM CAPABLE OF ACCOMMODATING THE ST. BONIFACE ROAD 115-24KV STATION.

JUSTIFICATION:
ELSEWHERE IN THE BUDGET, JUSTIFICATION IS PROVIDED FOR THE ESTABLISHMENT OF THE NEW SPRINGFIELD-ST. BONIFACE STATION TO BE SUPPLIED FROM SECTIONALIZED 115KV LINE SV23. THIS ITEM PROVIDES FOR PROTECTION CHANGES REQUIRED AT SELKIRK GENERATING STATION TO ACCOMMODATE THIS NEW STATION.

REFERENCE:
L.A. MILLER TO W. PYL, 'GOULET 4 KV FEEDER CHANGES,' 96-05-29, FILE 74P
G.K. ZIELKE TO V. KOSCHIK, 'DAWSON ROAD-ST. VITAL 24 KV SYSTEM,' 96-06-20
W.N. ZURBA TO C.V. THIO 'ST BONIFACE RD STATION 115KV SUPPLY AND STATION DEVELOPMENT', 1998 01 22.

REVISION:
REFLECTS REVISED ACTIVITY AND OVERHEAD RATES.

CONTINGENCY: $20,000.

IN SERVICE DATES

2000 09 30 254

Base estimate
199707 L2

Work start date
1999 07 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:						
1999/00	61	2	2			65
2000/01	160	9	4	-1		172
TOTAL	221	11	6	-1		237
REV. AMOUNTS:						
Authorized to date:						
Over(under)expend:						
Auth 1999/00	67	3	2			72
Req.: 2000/01	169	8	5	-1		181
TOTAL	236	11	7	-1		253

Prepared by yy mm dd COORDINATOR Approved by yy mm dd Approved by yy mm dd
Estimated by ORIGINATOR COORDINATING MANAGER ORIGINATING MANAGER

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number: 03-00-7262

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1997 10	242	NEW ITEM. INCLUDES COMMUNICATIONS FACILITIES FROM CANCELLED BRN 03-00-5909.
1998 10	237	ISD ADVANCED FROM 2001 06 30 TO 2000 09 30.

ASSOCIATED PROJECTS

Budget reference number	Description
02-00-7998	ST. BONIFACE PLESSIS ROAD STATION 115kV T/L IMPROVEMENTS
03-00-7260	ST. BONIFACE PLESSIS RD NEW STATION
03-00-7261	ST. VITAL TERMINAL 115KV LINE SV23 PROTECTION REPLACEMENT
04-00-7564	ST BONIFACE PLESSIS RD STATION - 4-24KV FEEDER LINES
05-00-7584	ST BONIFACE - PLESSIS ROAD STATION COMMUNICATION REQUIREMENT

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul	6	1				7	7
Aug	6	1				7	14
Sep	6	1				7	21
Oct	6	1				7	28
Nov	6	1				7	35
Dec	9					9	44
Jan	9	1				10	54
Feb	9	1				10	64
Mar	10	-4	2			8	72
TOTAL	67	3	2			72	72
2000/01 Apr	9		1			10	10
May	9		1			10	20
Jun	9		1			10	30
Jul	41	2	1			44	74
Aug	41	2	1			44	118
Sep	60	4			-1	63	1[illegible]
Oct							1[illegible]
Nov							181
Dec							181
Jan							181
Feb							181
Mar							181
TOTAL	169	8	5		-1	181	181

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item

274

Title
ST BONIFACE PLESSIS RD STATION - 4-24KV FEEDER LINES

Budget reference number
04-00-7564

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	93387

DESCRIPTION:
BUILD FOUR 24KV CIRCUITS FROM THE PROPOSED ST BONIFACE STATION SITE TO TIE INTO THE EXISTING 24KV LINES D41, D43, V41 AND V45. TIE TWO CIRCUITS INTO D41 AND D43 IN THE VICINITY OF LAGIMODIERE BOULEVARD AND MARION STREET. TIE TWO CIRCUITS INTO V41 AND V45 IN THE VICINITY OF LAGIMODIERE BOULEVARD AND FERMOR AVENUE.

JUSTIFICATION:
UTILIZE THE NEW FEEDER LINES TO SUPPLY LOAD GROWTH IN THE ST VITAL AND DAWSON ROAD STATION AREAS AND TO INCREASE THE FEEDER TIE CAPACITY IN THE AREA.

REFERENCE:
L.A. MILLER TO W.PYL 'GOULET 4KV FEEDER CHANGES', 96-05-29, FILE 74P
G.K. ZIELKE TO V. KOSCHIK 'DAWSON ROAD - ST VITAL 24KV SYSTEM', 96-06-20

REVISION:
CHANGE IN PROPOSED STATION LOCATION REQUIRES LONGER FEEDER LINES AND AN UNDERGROUND DUCT BANK.

IN SERVICE DATES		Base estimate	
2000 09 30	3 085	199805 L2	
		Work start date	
		1999 01 01	

PREV AUTHORITY Authorized to date	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
1999/00	891	34	45			970
2000/01	1 070	61	70			1 201
TOTAL	1 961	95	115			2 171
REV. AMOUNTS:						
Authorized to date:						
Over(under)expend:						
Auth 1999/00	750	30	34			814
Req. 2000/01	2 070	103	98			2 271
TOTAL	2 820	133	132			3 085

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR		COORDINATING MANAGER		ORIGINATING MANAGER

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 04-00-7564

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1997 10	2 536	NEW ITEM.
1998 10	2 545	IN SERVICE DATE ADVANCED FROM 2001 06 30 TO 2000 09 30.
1999 10	3 338	CHANGE IN PROPOSED STATION LOCATION REQUIRES LONGER FEEDER LINES AND AN UNDERGROUND DUCT BANK.

ASSOCIATED PROJECTS

Budget reference number	Description
02-00-7998	ST. BONIFACE PLESSIS ROAD STATION 115kV T/L IMPROVEMENTS
03-00-7260	ST. BONIFACE PLESSIS RD NEW STATION
03-00-7261	ST. VITAL TERMINAL 115KV LINE SV23 PROTECTION REPLACEMENT
03-00-7262	SELKIRK G.S. 115 KV LINE SV23 PROTECTION RELACEMENT
05-00-7584	ST BONIFACE - PLESSIS ROAD STATION COMMUNICATION REQUIREMENT

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	156	5				161	161
May	51	2	1			54	215
Jun	51	2	1			54	269
Jul	51	2	2			55	324
Aug	51	2	2			55	379
Sep	51	1	3			55	434
Oct	51	2	3			56	490
Nov	51	2	3			56	546
Dec	50	2	4			56	602
Jan	88	4	4			96	698
Feb	50	2	5			57	755
Mar	49	4	6			59	814
TOTAL	750	30	34			814	814
2000/01 Apr	1 413	68	6			1 487	1 487
May	130	6	16			152	1 639
Jun	131	7	17			155	1 794
Jul	131	8	18			157	1 951
Aug	131	7	20			158	2 10[illegible]
Sep	92	4	21			117	2 [illegible]
Oct	7					7	2 [illegible]
Nov	7					7	2 240
Dec	7					7	2 247
Jan	7					7	2 254
Feb	7					7	2 261
Mar	7	3				10	2 271
TOTAL	2 070	103	98			2 271	2 271

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item

275

Title: ST BONIFACE - PLESSIS ROAD STATION COMMUNICATION REQUIREMENT

Budget reference number: 05-00-7584

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Planning & Control	Construction	70445

DESCRIPTION:
DESIGN, PURCHASE AND INSTALL COMMUNICATIONS FACILITIES FOR THE ESTABLISHMENT OF THE 115-24 KV ST. BONIFACE STATION.

JUSTIFICATION:
ELSEWHERE IN THE BUDGET, JUSTIFICATION IS PROVIDED FOR THE ESTABLISHMENT OF THE NEW SPRINGFIELD-ST. BONIFACE STATION. THIS ITEM PROVIDES COMMUNICATION FACILITIES FOR THIS NEW STATION.

REFERENCE:
L.A. MILLER TO W. PYL, 'GOULET 4 KV FEEDER CHANGES', 96-05-29, FILE 74P G.K. ZIELKE TO V. KOSCHIK, 'DAWSON ROAD - ST. VITAL 24 KV SYSTEM', 96-06-20.

REVISION:
REFLECTS REVISED ACTIVITY AND OVERHEAD RATES.

CONTINGENCY: $30,000

IN SERVICE DATES: 2000 09 30 — 434

Base estimate: 199704 L2

Work start date: 1998 04 01

	PREV AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:		1					1
	1999/00	321	9	17			347
	2000/01	67	5	17			89
	TOTAL	389	14	34			437
REV. AMOUNTS:							
Authorized to date:		1					1
Over(under)expend:							
Auth	1999/00	311	12	12			335
Req.	2000/01	77	5	16			98
	TOTAL	389	17	28			434

Prepared by: yy mm dd — COORDINATOR

Approved by: yy mm dd — COORDINATING MANAGER

Approved by: yy mm dd — ORIGINATING MANAGER

Estimated by: — ORIGINATOR

1999-08-21 05:30 PM

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 05-00-7584

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1998 10	437	REVISED CASH FLOW TO REFLECT CHANGE IN START DATE AND IN-SERVICE DATE. ISD 2000 09 30.

ASSOCIATED PROJECTS

Budget reference number	Description
02-00-7998	ST. BONIFACE PLESSIS ROAD STATION 115kV T/L IMPROVEMENTS
03-00-7260	ST. BONIFACE PLESSIS RD NEW STATION
03-00-7261	ST. VITAL TERMINAL 115KV LINE SV23 PROTECTION REPLACEMENT
03-00-7262	SELKIRK G.S. 115 KV LINE SV23 PROTECTION RELACEMENT
04-00-7564	ST BONIFACE PLESSIS RD STATION - 4-24KV FEEDER LINES

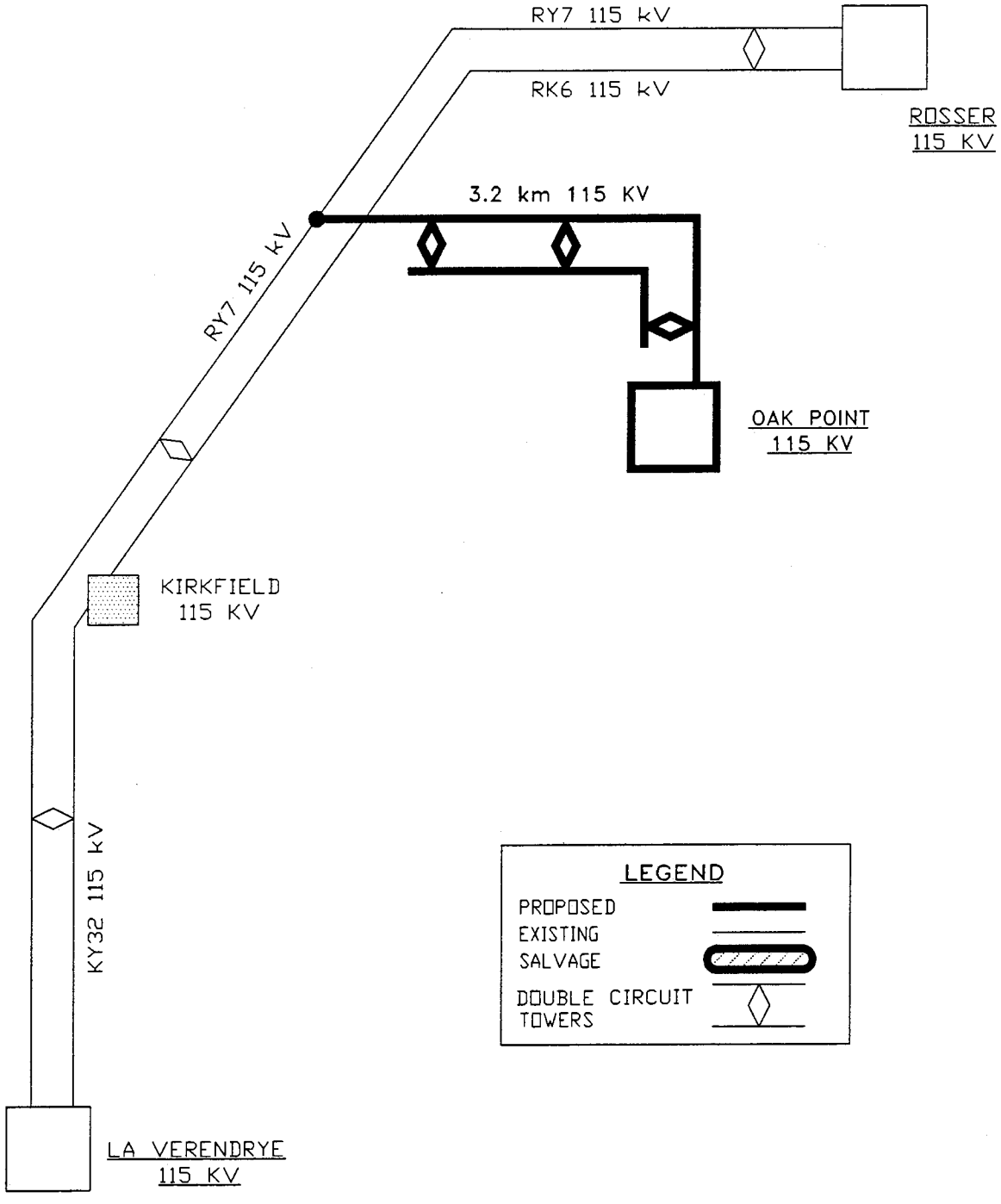
Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	23	1				24	24
May	23	1				24	48
Jun	23	2				25	73
Jul	23	1	1			25	98
Aug	23	1	1			25	123
Sep	23	1	1			25	148
Oct	23	1	1			25	173
Nov	23	1	1			25	198
Dec	23	2	1			26	224
Jan	34	1	2			37	261
Feb	19	1	2			22	283
Mar	51	-1	2			52	335
TOTAL	311	12	12			335	335
2000/01 Apr	20	1	2			23	23
May	20	1	3			24	47
Jun	21	1	3			25	72
Jul	6		3			9	81
Aug	6		3			9	90
Sep	1		3			4	94
Oct	1					1	95
Nov	1					1	96
Dec	1					1	97
Jan	1					1	98
Feb	1					1	99
Mar	-2	2	-1			-1	98
TOTAL	77	5	16			98	98

CAPITAL BUDGET COMPLEX CONCEPTUAL DIAGRAM

OAK POINT
115–24 KV STATION

REVISED: 1999 - 10 - 01	ISSUED BY: WNZ

COMPLEX NO. 238



manitoba hydro

PLANNING AND CONTROL DIVISION

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

COMPLEX STATUS	Complex no.	REVISION STATUS
☒ Planned ☐ In progress	238	☐ New complex ☒ In service change ☐ Concept change ☐ Estimate change only

COMPLEX	ROSSER-OAK POINT 115-24KV STATION

Proposal

Design and construct a new low profile 115/24 kV steel station in the Rosser area to accommodate 2-60/80/100//112 MVA transformers and 12-24 kV feeder lines. Use 115 kV lines RK6 and RY7 as the primary supply. Complete site selection and environmental requirements. Design and construct the subtransmission, protection, communication, and terminal facilities for the first transformer. In addition, design and construct 4-24 kV feeder lines to supply customer load

JUSTIFICATION		Explanation
☒ Load	☐ Service	Existing 24 kV stations in the area are at firm capacity. Additional transformer capacity is required to accommodate future voltage conversions, load growth and to provide surplus firm capacity for the area.
☐ Safety	☐ Efficiency	
☒ Reliability	☐ Other	

Estimate Level	COMPLEX START (yyyy mm)
12	2000 04

IN SERVICE DATES AND AMOUNTS					
2004 06	$2984	2005 06	$15514		

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend								
Year 99/00								
00/01						27	-27	-100
01/02	25	2	1		28	578	-550	-95
02/03	582	57	27		666	847	-181	-21
03/04	1,696	206	123		2,025	10,538	-8,513	-81
04/05	8,393	1208	470		10,071	5,920	4,151	70
05/06	4,733	733	241	4	5,703		5,703	
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	15,429	2,206	862	4	18,493	17,910	583	3

REVISION	ISD deferred one year 2003 due to financial constraints.

Reviewed by ORIGINATOR	yyyy mm dd 99 11 03	Reviewed by COORDINATOR	yyyy mm dd 99 11 03
Reviewed by CONSTRUCTOR	yyyy mm dd 99 11 03	Approved by VICE PRESIDENT	yyyy mm dd 99 11 16

H2856/r Rev 99 03

Complex no. 238

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Advance or deferral impact

Delay in components of this complex will reduce service reliability and quality in the St. James area.

Factors affecting timing or viability

The I.S.D. of this complex is in part, contingent upon the development of the Winport Industrial Park, west of the Winnipeg International Airport

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Rosser-Oak Point Station - RY7 115kV T/L Tap		651	664	706	42	6
Rosser-Oak Point New Station		10,192	10,396	10,466	70	1
LaVerendrye Station 115kV Line Protection		415	423	446	23	5
Rosser Station 115kV Line Protection Repl		415	423	446	23	5
Rosser-Oak Point Station 4-24kV Feeder Lines		2,618	2,670	2,570	-100	-4
Rosser-Oak Point Station Communication Req't		758	773	795	22	3
TOTAL		15,049	15,349	15,429	80	1

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
1997 10	18,435	New Complex
1998 10	17,910	Scope unchanged..Start date advanced one year.
1999 10	18,493	ISD deferred one year 2003 due to financial constraints.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item

276

Title	Budget reference number
ROSSER - OAK POINT STATION RY7 115 KV T/L TAP	02-00-7000

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	70409

DESCRIPTION:
BUILD 2.1 KM 115 KV DOUBLE CIRCUIT LINE WITH BOTH CIRCUITS STRUNG UTILIZING 795 MCM ACSR FROM LA VERENDRYE - ROSSER 115 KV RIGHT-OF-WAY AND TO BANK 1 AT ROSSER - OAK POINT STATION.

JUSTIFICATION:
ELSEWHERE IN THE BUDGET, JUSTIFICATION IS GIVEN FOR ESTABLISHMENT OF THE NEW ROSSER - OAK POINT STATION. THIS ITEM PROVIDES PRIMARY SUPPLY FOR BANK 1.

REFERENCE:
R.E HERON TO H.E. WICHERT, 'REDESIGNATION OF LANDS LOCATED WEST OF WINNIPEG INTERNATIONAL AIRPORT AND NORTH OF SASKATCHEWAN AVE', 95-04-27, File 317REH.

REVISION:
INSERVICE DATE DEFERRED FROM 2004 06 30 TO 2005 06 30.

CONTINGENCY: $68,000.

IN SERVICE DATES				Base estimate
2005 06 30	852			199802 L2
				Work start date
				2001 04 01

PREV. AUTHORITY Authorized to date:	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
2000/01	25	1	1			27
2001/02	57	4	4			65
2002/03	106	10	10			126
2003/04	319	42	26			387
2004/05	144	21	14			179
TOTAL	651	78	55			784
REV. AMOUNTS: Authorized to date: Over(under)expend:						
Auth 2001/02	25	2	1			28
Req.: 2002/03	62	5	4			71
2003/04	112	13	11			136
2004/05	342	51	28			421
2005/06	165	16	15			196
TOTAL	706	87	59			852

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number: 02-00-7000

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1997 06	829	NEW ITEM.
1998 10	784	ENVIRONMENTAL ASSESSMENT AND PROPERTY ACQUISITION ADDED. ISD DEFERRED FROM 2003 11 30 TO 2004 06 30. CONSTRUCTION COMPONENT ESTIMATE REDUCED.

ASSOCIATED PROJECTS

Budget reference number	Description
03-00-7268	ROSSER - OAK POINT NEW STATION
03-00-7269	LAVERENDRYE STATION 115 KV LINE PROTECTION REPLACEMENT
03-00-7270	ROSSER STATION 115 KV LINE PROTECTION REPLACEMENT
04-00-7566	ROSSER - OAK POINT STATION - 4-24KV FEEDER LINES
05-00-7585	ROSSER-OAK POINT STATION COMMUNICATION REQUIREMENTS

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item

277

Title			Budget reference number
ROSSER - OAK POINT NEW STATION			03-00-7268
Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	70469

DESCRIPTION:
CONDUCT ENVIRONMENTAL ASSESSMENT, ACQUIRE PROPERTY AND OBTAIN NECESSARY APPROVALS AND LICENSES TO DESIGN AND CONSTRUCT A NEW LOW PROFILE 115/24 KV STEEL STATION IN ALONG OAK POINT HIGHWAY TO ACCOMMODATE TWO 60/80/100/112 MVA, 114.3-24/13.8 KV LTC TRANSFORMERS WITH NEUTRAL REACTORS AND TWELVE 24 KV FEEDER LINES. INITIALLY, INSTALL ONE 60/80/100/112 MVA, 114.3-24/13.8KV +/- 10% LTC TRANSFORMER AND NEUTRAL REACTOR, 8-24 KV CIRCUIT BREAKERS, 6-24 KV CIRCUIT LINE REACTORS, 2-24 KV CIRCUIT SWITCHERS, AND 2-14.4 MVAR 24 KV CAPACITOR BANKS. PROTECTION FOR THE TRANSFORMER AND THE 115 KV RY7 LINE TAP INTO THE STATION IS PROVIDED BY OPENING BREAKERS ON LINE RY7 AT KIRKFIELD PARK STATION AND ROSSER STATION VIA TELECOMMUNICATIONS. TRANSIENT VOLTAGE STUDIES MAY BE REQUIRED TO DEFINE THE TRANSIENT RECOVERY VOLTAGE MITIGATING EQUIPMENT.

JUSTIFICATION:
THIS NEW STATION IS REQUIRED TO SUPPORT THE LOAD GROWTH IN THE WINPORT INDUSTRIAL PARK AREA AND TO PROVIDE BACKUP TO OTHER 24 KV STATIONS NEARBY.

REFERENCE:
R.E. HERON TO H.E. WICHERT, 'REDESIGNATION OF LANDS LOCATED WEST OF WINNIPEG INTERNATIONAL AIRPORT AND NORTH OF SASKATCHEWAN AVE.', 95-04-27, FILE 317REH

REVISION:
INSERVICE DATE DEFERRED FROM 2004 06 30 TO 2005 06 30.

CONTINGENCY: $1,837,000

IN SERVICE DATES				Base estimate
2005 06 30	12 675			199707 L2
				Work start date
				2002 04 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:						
2001/02	453	39	20			512
2002/03	453	49	64			566
2003/04	5 957	779	358			7 094
2004/05	3 329	486	186			4 001
TOTAL	10 192	1 353	628			12 173
REV. AMOUNTS:						
Authorized to date:						
Over(under)expend:						
Auth 2002/03	521	51	23			595
Req.: 2003/04	521	63	76			660
2004/05	6 067	872	391			7 330
2005/06	3 357	534	199			4 090
TOTAL	10 466	1 520	689			12 675

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number: 03-00-7268

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1997 07	12 240	NEW ITEM.
1998 10	12 173	NO CHANGE.

ASSOCIATED PROJECTS

Budget reference number	Description
02-00-7000	ROSSER - OAK POINT STATION RY7 115 KV T/L TAP
03-00-7269	LAVERENDRYE STATION 115 KV LINE PROTECTION REPLACEMENT
03-00-7270	ROSSER STATION 115 KV LINE PROTECTION REPLACEMENT
04-00-7566	ROSSER - OAK POINT STATION - 4-24KV FEEDER LINES
05-00-7585	ROSSER-OAK POINT STATION COMMUNICATION REQUIREMENTS

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item

278

Title			Budget reference number
LAVERENDRYE STATION 115 KV LINE PROTECTION REPLACEMENT			03-00-7269
Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	70271

DESCRIPTION:
MODIFY RY7 AND KY32 115 KV LINE PROTECTION AT LAVERENDRYE STATION TO ACCOMMODATE THE ROSSER-OAK POINT 115-24 KV STATION AND NEW SECTIONALIZING BREAKERS AT KIRKFIELD PARK STATION. CHANGE PROTECTION ON 115 KV LINE RY7 AND KY32 TO IMPROVE FAULT CLEARING TIMES.

JUSTIFICATION:
ELSEWHERE IN THE BUDGET, JUSTIFICATION IS PROVIDED FOR THE ESTABLISHMENT OF THE NEW ROSSER-OAK POINT STATION AND THE KIRKFIELD PARK BREAKER. THIS ITEM PROVIDES FOR PROTECTION CHANGES REQUIRED AT LAVERENDRYE STATION TO ACCOMMODATE THIS NEW STATION AND SECTIONALIZING BREAKERS.

REFERENCE:
R.E. HERON TO H.E. WICHERT, 'REDESIGNATION OF LANDS LOCATED WEST OF WINNIPEG INTERNATIONAL AIRPORT AND NORTH OF SASKATCHEWAN AVENUE', 95 04 27, FILE 317REH.

C.J. FORTIER TO I.H. MCKAY, '115KV YX48 SLOW FAULT CLEARING', 91 10 18, FILE MEMO 65100.

REVISION:
INSERVICE DATE DEFERRED FROM 2004 06 30 TO 2005 06 30.

CONTINGENCY: $36,959

IN SERVICE DATES				Base estimate
2005 06 30	527			199704 L2
				Work start date 2004 04 01

PREV. AUTHORITY Authorized to date:	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
2003/04	161	22	6			189
2004/05	254	37	6	-2		295
TOTAL	415	59	12	-2		484
REV. AMOUNTS: Authorized to date: Over(under)expend:						
Auth 2004/05	179	26	7			212
Req.: 2005/06	267	41	7	-2		313
TOTAL	446	67	14	-2		525

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number: 03-00-7269

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1997 04	483	NEW ITEM.
1998 10	484	NO CHANGE

ASSOCIATED PROJECTS

Budget reference number	Description
02-00-7000	ROSSER - OAK POINT STATION RY7 115 KV T/L TAP
03-00-7268	ROSSER - OAK POINT NEW STATION
03-00-7270	ROSSER STATION 115 KV LINE PROTECTION REPLACEMENT
04-00-7566	ROSSER - OAK POINT STATION - 4-24KV FEEDER LINES
05-00-7585	ROSSER-OAK POINT STATION COMMUNICATION REQUIREMENTS

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item

279

Title			Budget reference number
ROSSER STATION 115 KV LINE PROTECTION REPLACEMENT			03-00-7270
Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	70269

DESCRIPTION:
MODIFY RY7 AND RY6 115KV LINE PROTECTION AT ROSSER STATION TO ACCOMMODATE THE ROSSER - OAK POINT 115-24KV STATION AND NEW SECTIONALIZING BREAKERS AT KIRKFIELD PARK STATION. CHANGE PROTECTION ON 115KV LINE RY7 AND RY6 TO IMPROVE FAULT CLEARING TIMES.

JUSTIFICATION:
ELSEWHERE IN THE BUDGET, JUSTIFICATION IS PROVIDED FOR THE ESTABLISHMENT OF THE NEW ROSSER - OAK POINT STATION AND THE SECTIONALIZING BREAKERS AT KIRKFIELD PARK STATION. THIS ITEM PROVIDES FOR PROTECTION CHANGES REQUIRED AT ROSSER STATION TO ACCOMMODATE THIS NEW STATION AND THE SECTIONALIZING BREAKERS.

REFERENCE:
R.E. HERON TO H.E. WICHERT, 'REDESIGNATION OF LANDS LOCATED WEST OF WINNIPEG INTERNATIONAL AIRPORT AND NORTH OF SASKATCHEWAN AVE.',95-04-27, FILE 317REH
C.J. FORTIER TO I.H. MCKAY, '115KV YX48 SLOW FAULT CLEARING', 91-10-18, FILE MEMO 65100

REVISION:
INSERVICE DEFERRED FROM 2004 06 30 TO 2005 06 30.

CONTINGENCY: $36,959

IN SERVICE DATES				Base estimate
2005 06 30	528			199707 L2
				Work start date
				2004 04 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:						
2003/04	161	22	6			189
2004/05	254	37	6	-2		295
TOTAL	415	59	12	-2		484
REV. AMOUNTS:						
Authorized to date:						
Over(under)expend:						
Auth 2004/05	179	26	7			212
Req.: 2005/06	267	42	7	-2		314
TOTAL	446	68	14	-2		526

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

CAPITAL EXPENDITURE REVISION

Budget reference number: 03-00-7270

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1997 07	483	NEW ITEM.
1998 10	484	NO CHANGE.

ASSOCIATED PROJECTS

Budget reference number	Description
02-00-7000	ROSSER - OAK POINT STATION RY7 115 KV T/L TAP
03-00-7268	ROSSER - OAK POINT NEW STATION
03-00-7269	LAVERENDRYE STATION 115 KV LINE PROTECTION REPLACEMENT
04-00-7566	ROSSER - OAK POINT STATION - 4-24KV FEEDER LINES
05-00-7585	ROSSER-OAK POINT STATION COMMUNICATION REQUIREMENTS

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item

250

Title			Budget reference number
ROSSER - OAK POINT STATION - 4-24KV FEEDER LINES			04-00-7566
Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	93389

DESCRIPTION:
BUILD FOUR 24KV CIRCUITS FROM THE PROPOSED ROSSER-OAK POINT STATION SITE TO TIE INTO THE EXISTING 24KV LINES K21, K25, L12 AND L13. TIE TWO CIRCUITS INTO K21 AND K25 IN THE VICINITY OF CRESTVIEW STATION. TIE TWO CIRCUITS INTO L12 AND L13 NORTH EAST OF KING EDWARD STREET AND SELKIRK AVENUE.

JUSTIFICATION:
UTILIZE THE NEW FEEDER LINES TO SUPPLY THE WINPORT LOAD GROWTH IN THE KIRKFIELD AND SELKIRK STATION AREA AND TO INCREASE THE FEEDER TIE CAPACITY IN THE AREA.

REFERENCE:
R.E. HERON TO H.E. WICHERT, 'REDESIGNATION OF LANDS LOCATED WEST OF WINNIPEG INTERNATIONAL AIRPORT AND NORTH OF SASKATCHEWAN AVENUE', 95-04-27, FILE 317REH

REVISION:
ESTIMATE REFLECTS CURRENT INTEREST AND ESCALATION RATES. PROJECT SCOPE REMAINS UNCHANGED.
ITEM DEFERRED 1 YEAR

IN SERVICE DATES				Base estimate
2004 06 30	2 952			199909 L2
				Work start date 2002 10 01

PREV. AUTHORITY Authorized to date:	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
2002/03	112	13	2			127
2003/04	1 933	253	81			2 267
2004/05	573	81	56			710
TOTAL	2 618	347	139			3 104
REV. AMOUNTS:						
Authorized to date:						
Over(under)expend:						
Auth 2003/04	119	16	2			137
Req.: 2004/05	1 892	273	3			2 168
2005/06	559	88				647
TOTAL	2 570	377	5			2 952

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

CAPITAL EXPENDITURE REVISION

Budget reference number: 04-00-7566

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1997 10	3 555	NEW ITEM.
1998 10	3 555	ESTIMATE REFLECTS CURRENT INTEREST AND ESCALATION RATES. PROJECT SCOPE REMAINS UNNCHANGED.
1999 10	3 027	ESTIMATE REFLECTS CURRENT INTEREST AND ESCALATION RATES. PROJECT SCOPE REMAINS UNCHANGED.

ASSOCIATED PROJECTS

Budget reference number	Description
02-00-7000	ROSSER - OAK POINT STATION RY7 115 KV T/L TAP
03-00-7268	ROSSER - OAK POINT NEW STATION
03-00-7269	LAVERENDRYE STATION 115 KV LINE PROTECTION REPLACEMENT
03-00-7270	ROSSER STATION 115 KV LINE PROTECTION REPLACEMENT
05-00-7585	ROSSER-OAK POINT STATION COMMUNICATION REQUIREMENTS

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item

281

Title			Budget reference number
ROSSER-OAK POINT STATION COMMUNICATION REQUIREMENTS			05-00-7585
Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Planning & Control	Construction	70444

DESCRIPTION:
Design, purchase and install communications facilities for the establishment of the 115-24KV Rosser-Oak Point station.

JUSTIFICATION:
Elsewhere in the budget, justification is provided for the establishment of the new Rosser-Oak Point Station. This item provides communication facilities for this new sation.

REFERENCE:
R.E. Heron to H.E. Wichert, 'Redesignation of lands located west of Winnipeg International Airport and north of Saskatchewan Ave,' 95-04-27, File 317REH

REVISION:
Inservice Date deferred from 2004 06 30 to 2005 06 30.

Contingency: $75,000

IN SERVICE DATES				Base estimate
2005 06 30	930			199704 L2
				Work start date
				2003 10 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:						
2002/03	24	4				28
2003/04	356	48	7			411
2004/05	378	49	13			440
TOTAL	758	101	20			879
REV. AMOUNTS:						
Authorized to date:						
Over(under)expend:						
Auth 2003/04	27	4				31
Req.: 2004/05	373	55	8			436
2005/06	395	54	14			463
TOTAL	795	113	22			930

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number: 05-00-7585

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1997 04	874	NEW ITEM.
1998 10	879	No Change.

ASSOCIATED PROJECTS

Budget reference number	Description
02-00-7000	ROSSER - OAK POINT STATION RY7 115 KV T/L TAP
03-00-7268	ROSSER - OAK POINT NEW STATION
03-00-7269	LAVERENDRYE STATION 115 KV LINE PROTECTION REPLACEMENT
03-00-7270	ROSSER STATION 115 KV LINE PROTECTION REPLACEMENT
04-00-7566	ROSSER - OAK POINT STATION - 4-24KV FEEDER LINES

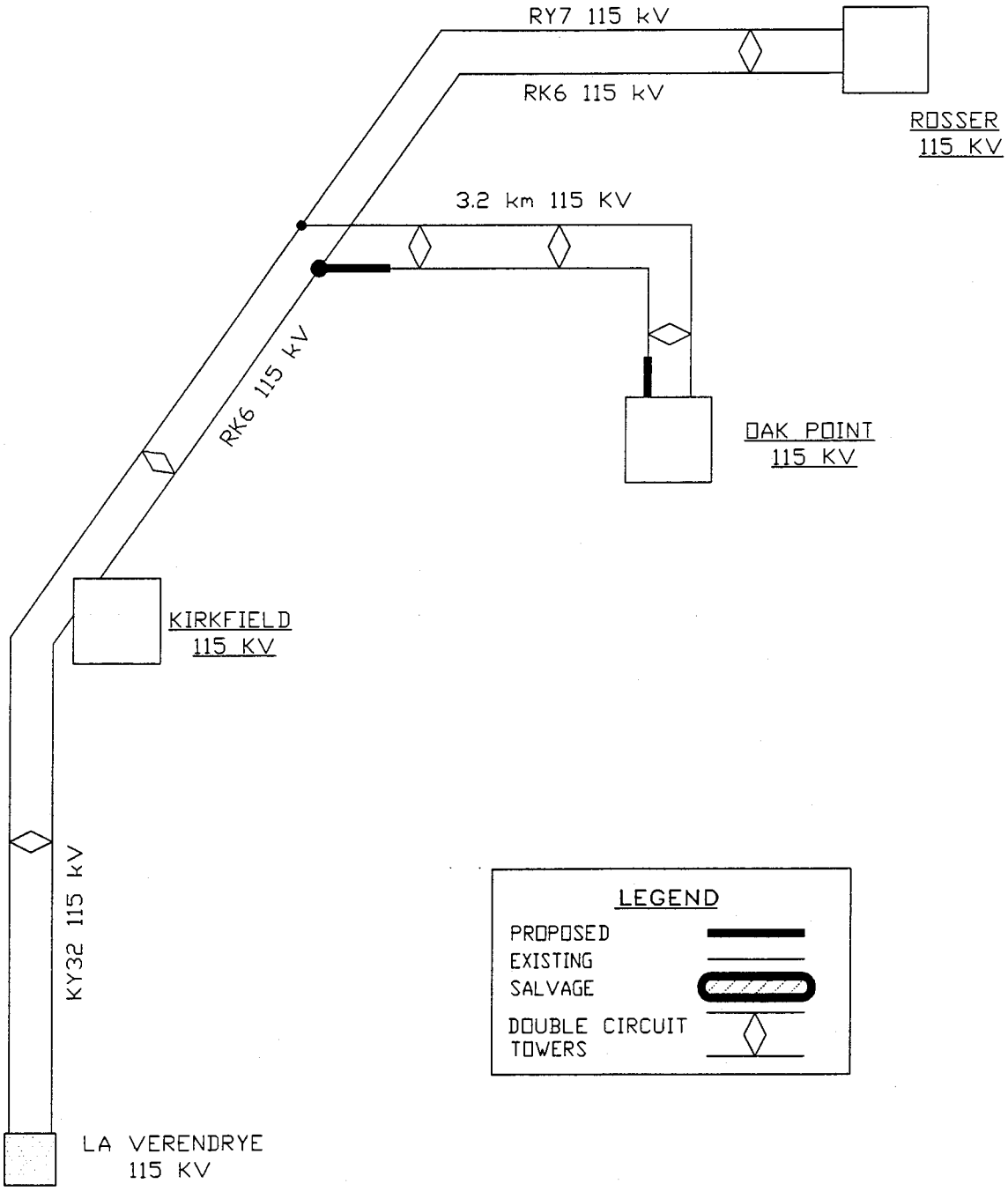
Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

CAPITAL BUDGET COMPLEX CONCEPTUAL DIAGRAM

OAK POINT
115–24 KV BANK 2 ADDITION

REVISED: 1999 - 10 - 01	ISSUED BY: WNZ

COMPLEX NO. 239



manitoba hydro

PLANNING AND CONTROL DIVISION

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

COMPLEX STATUS: [X] Planned [ ] In progress

Complex no. 239

REVISION STATUS: [ ] New complex [ ] In service change [ ] Concept change [X] Estimate change only

COMPLEX: ROSSER-OAK POINT BANK 2 ADDITION

Proposal

Install a second 60/80/100//112 MVA transformer, 2-24 kV 1500 MVA circuit breakers with associated equipment and 2-24 kV feeder lines. Use 115 kV line RK6 and RY7 as the primary supply. Complete environmental requirements for the second bank and the 115 kV RK6 tap. Design and construct the subtransmission, protection, communication, and terminal facilities for the second transformer.

JUSTIFICATION

[X] Load [ ] Service
[ ] Safety [ ] Efficiency
[X] Reliability [ ] Other

Explanation

Additional transformer capacity is required to accomodate future voltage conversions, load growth and to provide surplus firm capacity for the area.

Estimate Level	COMPLEX START (yyyy mm)
L2	2008 04

IN SERVICE DATES AND AMOUNTS

2010 06	$9753			

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend								
Year 99/00								
00/01								
01/02								
02/03								
03/04								
04/05								
05/06								
06/07								
07/08								
08/09	630	151	27		808	722	86	12
09/10	4,685	1236	294		6,215	6,254	-39	-1
10/11	1,998	546	185	2	2,727	2,744	-17	-1
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	7,313	1,933	506	2	9,750	9,720	30	0

REVISION: Scope unchanged.

Reviewed by ORIGINATOR	yyyy mm dd 99 11 03	Reviewed by COORDINATOR	yyyy mm dd 99 11 03
Reviewed by CONSTRUCTOR	yyyy mm dd 99 11 03	Approved by VICE PRESIDENT	yyyy mm dd 99 11 16

H2856/r Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Complex no. 239

Advance or deferral impact

Delay in components of this complex will reduce service reliability and quality in the St. James area.

Factors affecting timing or viability

The I.S.D. of this complex is in part, contingent upon the development of the Winport Industrial Park, west of the Winnipeg International Airport.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Rosser-Oak Point Station - RK6 115kV T/L Tap		60	61	63	2	3
Rosser-Oak Point 115-24kV Transformer Addition		4,857	4,954	4,985	31	1
Kirkfield Station 115kV Line RK6 Protection Repl		151	154	162	8	5
Rosser Station 115kV Line RK6 Protection Repl		151	154	162	8	5
Rosser-Oak Point 2-24kV feeder Lines		2,038	2,079	1,944	-135	-6
TOTAL		7,257	7,402	7,316	-86	-1

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
1997 10	10,283	New Complex
1998 10	9,720	Scope unchanged
1999 10	9,750	Scope unchanged.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item 282

Title
ROSSER - OAK POINT STATION - RK6 115KV TRANSMISSION LINE TAP

Budget reference number
02-00-7001

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	70408

DESCRIPTION:
TERMINATE THE SECOND UNUSED CIRCUIT ON THE RY7 DOUBLE CIRCUIT TRANSMISSION LINE TAP, TO LINE RK6 AT THE LA VERENDRYE - ROSSER 115KV RIGHT-OF-WAY AND BANK2 AT ROSSER - OAK POINT STATION.

JUSTIFICATION:
ELSEWHERE IN THE BUDGET, JUSTIFICATION IS GIVEN FOR THE INSTALLATION OF BANK 2 AT ROSSER - OAK POINT STATION. THIS ITEM PROVIDES PRIMARY SUPPLY FOR BANK 2.

REFERENCE:
R.E. HERON TO H.E. WICHERT, 'REDESIGNATION OF LANDS LOCATED WEST OF WINNIPEG INTERNATIONAL AIRPORT AND NORTH OF SASKATCHEWAN AVE.', 95-04-27.

REVISION:
REFLECTS REVISED ACTIVITY AND OVERHEAD RATES.

IN SERVICE DATES

2010 06 30 | 85

Base estimate
199706 L2

Work start date
2009 01 01

PREV. AUTHORITY Authorized to date	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
2008/09	10	3				13
2009/10	40	11	3			54
2010/11	10	2	2			14
TOTAL	60	16	5			81
REV. AMOUNTS:						
Authorized to date:						
Over(under)expend:						
Auth 2008/09	10	3				13
Req 2009/10	42	11	4			57
2010/11	11	2	2			15
TOTAL	63	16	6			85

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

1999-08-21 05:17 PM

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number: 02-00-7001

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1997 10	82	NEW ITEM
1998 10	81	NO CHANGE.

ASSOCIATED PROJECTS

Budget reference number	Description
03-00-7272	ROSSER - OAK POINT STATION 115-24KV TRANSFORMER ADDITION
03-00-7273	KIRKFIELD STATION 115KV LINE RK6 PROTECTION REPLACEMENT
03-00-7274	ROSSER STATION 115KV LINE RK6 PROTECTION REPLACEMENT
04-00-7567	ROSSER - OAK POINT STATION - ADDN OF 2-24KV CIRCUIT LINES

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item

283

Title	Budget reference number
ROSSER - OAK POINT STATION 115-24KV TRANSFORMER ADDITION	03-00-7272

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	70468

DESCRIPTION:
INSTALL ONE 80/90/100/112 MVA, 114.3-24/13.8 KV +/- 10% LTC TRANSFORMER AND NEUTRAL REACTOR IN BANK 2 POSITION AT ROSSER - OAK POINT STATION TO MATCH THE EXISTING BANK 1 UNIT. INSTALL 1-24 KV BREAKER TO CONNECT THE TRANSFORMER TO FACILITATE SWITCHING AND PROTECTION. TERMINATE 115KV LINE RK6 TO BANK 2 AT ROSSER - OAK POINT STATION. INSTALL 2-24 KV 1500 MVA CIRCUIT BREAKERS AND ASSOCIATED EQUIPMENT TO PROVIDE TWO ADDITIONAL 24 KV CIRCUITS.

JUSTIFICATION:
THE SECOND BANK AND ADDITIONAL CIRCUITS AT ROSSER - OAK POINT STATION ARE REQUIRED TO SUPPORT THE LOAD GROWTH IN THE AREA AND TO PROVIDE BACKUP TO OTHER 24 KV STATIONS NEARBY.

REFERENCE:
R.E. HERON TO H.E. WICHERT, 'REDESIGNATION OF LANDS LOCATED WEST OF WINNIPEG INTERNATIONAL AIRPORT AND NORTH OF SASKATCHEWAN AVE.', 95-04-27, FILE 317REH

REVISION:
REFLECTS REVISED ACTIVITY AND OVERHEAD RATES.

CONTINGENCY: $441 000

IN SERVICE DATES		Base estimate
2010 06 30	6 668	199707 L2
		Work start date
		2008 04 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:						
2008/09	474	118	22			614
2009/10	3 008	830	186			4 024
2010/11	1 375	399	116			1 890
TOTAL	4 857	1 347	324			6 528
REV. AMOUNTS:						
Authorized to date:						
Over(under)expend:						
Auth 2008/09	540	129	25			694
Req. 2009/10	3 058	810	207			4 075
2010/11	1 387	387	125			1 899
TOTAL	4 985	1 326	357			6 668

Prepared by: yy mm dd COORDINATOR	Approved by: yy mm dd Approved by:	yy mm dd
Estimated by: ORIGINATOR	COORDINATING MANAGER	ORIGINATING MANAGER

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number: 03-00-7272

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1997 10	6 543	NEW ITEM
1998 10	6 528	NO CHANGE.

ASSOCIATED PROJECTS

Budget reference number	Description
02-00-7001	ROSSER - OAK POINT STATION - RK6 115KV TRANSMISSION LINE TAP
03-00-7273	KIRKFIELD STATION 115KV LINE RK6 PROTECTION REPLACEMENT
03-00-7274	ROSSER STATION 115KV LINE RK6 PROTECTION REPLACEMENT
04-00-7567	ROSSER - OAK POINT STATION - ADDN OF 2-24KV CIRCUIT LINES

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item

284

Title
KIRKFIELD STATION 115KV LINE RK6 PROTECTION REPLACEMENT

Budget reference number
03-00-7273

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	70449

DESCRIPTION:
115 KV LINE RK6 PROTECTION AT KIRKFIELD STATION MUST BE REPLACED WITH A PROTECTION SYSTEM CAPABLE OF ACCOMMODATING THE ROSSER-OAK POINT 115-24KV STATION BANK 2 ADDITION.

JUSTIFICATION:
ELSEWHERE IN THE BUDGET, JUSTIFICATION IS PROVIDED FOR THE ESTABLISHMENT OF THE ROSSER-OAK POINT STATION BANK 2 ADDITION.

REFERENCE:
R.E. HERON TO H.E. WICHERT, 'REDESIGNATION OF LANDS LOCATED WEST OF WINNIPEG INTERNATIONAL AIRPORT AND NORTH OF SAKATCHEWAN AVE.' 95-04-27, FILE 317REH.

REVISION:
REFLECTS REVISED ACTIVITY AND OVERHEAD RATES.

CONTINGENCY: $14 000

IN SERVICE DATES			Base estimate
2010 06 30	206		199807 L2
			Work start date 2009 04 01

PREV. AUTHORITY Authorized to date:	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
2009/10	66	16	3			85
2010/11	85	19	3	-1		106
TOTAL	151	35	6	-1		191
REV. AMOUNTS: Authorized to date: Over(under)expend:						
Auth 2009/10	73	17	4			94
Req. 2010/11	89	20	3	-1		111
TOTAL	162	37	7	-1		205

Prepared by	yy mm dd	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by	COORDINATOR				
	ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 03-00-7273

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1997 10	3 087	NEW ITEM.
1998 10	191	ESTIMATE REDUCED TO REFLECT ACTUAL COSTS AT SIMILAR PROJECTS IN RECENT YEARS.

ASSOCIATED PROJECTS

Budget reference number	Description
02-00-7001	ROSSER - OAK POINT STATION - RK6 115KV TRANSMISSION LINE TAP
03-00-7272	ROSSER - OAK POINT STATION 115-24KV TRANSFORMER ADDITION
03-00-7274	ROSSER STATION 115KV LINE RK6 PROTECTION REPLACEMENT
04-00-7567	ROSSER - OAK POINT STATION - ADDN OF 2-24KV CIRCUIT LINES

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item

285

Title
ROSSER STATION 115KV LINE RK6 PROTECTION REPLACEMENT

Budget reference number
03-00-7274

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	70448

DESCRIPTION:
115 KV LINE RK6 PROTECTION AT ROSSER STATION MUST BE REPLACED WITH A PROTECTION SYSTEM CAPABLE OF ACCOMMODATING THE ROSSER-OAK POINT 115-24 KV STATION BANK 2 ADDITION.

JUSTIFICATION:
ELSEWHERE IN THE BUDGET, JUSTIFICATION IS PROVIDED FOR THE ESTABLISHMENT OF THE ROSSER-OAK POINT STATION BANK 2 ADDITION. THIS ITEM PROVIDES FOR PROTECTION CHANGES REQUIRED AT ROSSER STATION TO ACCOMMODATE THE ROSSER-OAK POINT STATION BANK 2 ADDITION.

REFERENCE:
R.E. HERON TO H.E. WICHERT, 'REDESIGNATION OF LANDS LOCATED WEST OF WINNIPEG INTERNATIONAL AIRPORT AND NORTH OF SASKATCHEWAN AVE. '95-04-27, FILE 317REH

REVISION:
REFLECTS REVISED ACTIVITY AND OVERHEAD RATES.

CONTINGENCY: $13 000

2010 06 30	205	IN SERVICE DATES		Base estimate 199807 L2
				Work start date 2009 04 01

PREV. AUTHORITY Authorized to date	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
2009/10	66	16	3			85
2010/11	85	18	3	-1		105
TOTAL	151	34	6	-1		190
REV. AMOUNTS:						
Authorized to date:						
Over(under)expend:						
Auth 2009/10	73	17	4			94
Req: 2010/11	89	19	3	-1		110
TOTAL	162	36	7	-1		204

Prepared by: yy mm dd COORDINATOR — Approved by: yy mm dd Approved by: yy mm dd

Estimated by: ORIGINATOR — COORDINATING MANAGER — ORIGINATING MANAGER

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number: 03-00-7274

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1997 10	286	NEW ITEM.
1999 10	190	ESTIMATE REDUCED TO REFLECT ACTUAL COSTS AT SIMILAR PROJECTS IN RECENT YEARS.

ASSOCIATED PROJECTS

Budget reference number	Description
02-00-7001	ROSSER - OAK POINT STATION - RK6 115KV TRANSMISSION LINE TAP
03-00-7272	ROSSER - OAK POINT STATION 115-24KV TRANSFORMER ADDITION
03-00-7273	KIRKFIELD STATION 115KV LINE RK6 PROTECTION REPLACEMENT
04-00-7567	ROSSER - OAK POINT STATION - ADDN OF 2-24KV CIRCUIT LINES

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item

286

Title: ROSSER - OAK POINT STATION - ADDN OF 2-24KV CIRCUIT LINES

Budget reference number: 04-00-7567

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	93390

DESCRIPTION:
BUILD TWO 24KV CIRCUITS FROM THE PROPOSED ROSSER-OAK POINT STATION SITE TO SUPPORT ADDITIONAL LOAD GROWTH IN THE LOCAL AREA.

JUSTIFICATION:
TWO NEW FEEDER LINES ARE REQUIRED TO SUPPLY LOAD GROWTH IN THE ST JAMES AND KIRKFIELD STATION AREAS AND TO INCREASE THE FEEDER TIE CAPACITY IN THE AREA.

REFERENCE:
R.E. HERON TO H.E. WICHERT, 'REDESIGNATION OF LANDS LOCATED WEST OF WINNIPEG INTERNATIONAL AIRPORT AND NORTH OF SASKATCHEWAN AVENUE', 95-04-27, FILE 317REH.

REVISION:
REFLECTS CURRENT ESCALATION AND INTEREST RATES. PROJECT SCOPE REMAINS UNCHANGED.

IN SERVICE DATES: 2010 06 30 — 2 590

Base estimate: 199707 L2

Work start date: 2008 10 01

	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
PREV. AUTHORITY Authorized to date:						
2008/09	75	18	2			95
2009/10	1 516	414	75			2 005
2010/11	447	128	53			628
TOTAL	2 038	560	130			2 728
REV. AMOUNTS: Authorized to date: Over(under)expend.						
Auth 2008/09	80	19	2			101
Req. 2009/10	1 440	379	76			1 895
2010/11	424	117	53			594
TOTAL	1 944	515	131			2 590

Prepared by: yy mm dd COORDINATOR — Approved by: yy mm dd

Estimated by: ORIGINATOR — COORDINATING MANAGER — Approved by: ORIGINATING MANAGER — yy mm dd

1999-08-21 05:28 PM

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 04-00-7567

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1997 10	3 073	NEW ITEM.
1998 10	3 087	ESTIMATE REFLECTS CURRENT INTEREST AND ESCALATION RATES. PROJECT SCOPE REMAINS UNCHANGED.

ASSOCIATED PROJECTS

Budget reference number	Description
02-00-7001	ROSSER - OAK POINT STATION - RK6 115KV TRANSMISSION LINE TAP
03-00-7272	ROSSER - OAK POINT STATION 115-24KV TRANSFORMER ADDITION
03-00-7273	KIRKFIELD STATION 115KV LINE RK6 PROTECTION REPLACEMENT
03-00-7274	ROSSER STATION 115KV LINE RK6 PROTECTION REPLACEMENT

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

COMPLEX STATUS: [X] Planned [ ] In progress

Complex no. 240

REVISION STATUS: [ ] New complex [ ] In service change [ ] Concept change [X] Estimate change only

COMPLEX: ST BONIFACE - PLESSIS RD BANK 2 ADDITION

Proposal

Install a second 60/80/100//112 MVA transformer, 2-24 kV 1500 MVA circuit breakers with associated equipment and 2-24 kV feeder lines. Use sectionalized 115 kV line SV23 as the primary supply. Complete environmental requirements for the second bank Design and construct the subtransmission, protection, communication, and terminal facilities for the second transformer.

JUSTIFICATION

[X] Load [ ] Service
[ ] Safety [ ] Efficiency
[X] Reliability [ ] Other

Explanation

Additional transformer capacity is required to accomodate future voltage conversions, load growth and to provide surplus firm capacity for the area.

Estimate Level	COMPLEX START (yyyy mm)
L2	1999 06

IN SERVICE DATES AND AMOUNTS					
2001 07	$4768	2001 12	$158		

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend								
Year 99/00	99	4	2		105	84	21	25
00/01	1,447	76	77		1,600	1,638	-38	-2
01/02	2,955	186	79		3,220	2,710	510	19
02/03								
03/04								
04/05								
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	4,501	266	158		4,925	4,432	493	11

REVISION: Reflects revised activity and overhead rates.

Reviewed by ORIGINATOR	yyyy mm dd 99 11 03	Reviewed by COORDINATOR	yyyy mm dd 99 11 03
Reviewed by CONSTRUCTOR	yyyy mm dd 99 11 03	Approved by VICE-PRESIDENT	yyyy mm dd 99 11 16

H2856/r Rev 99 03

Complex no. 240

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Advance or deferral impact

Delay in components of this complex will reduce service reliability and quality in the St. Boniface, and St.Vital areas

Factors affecting timing or viability

Load Growth

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
St Boniface-Plessis Rd SV24 115kV T/L Tap		0	0	0	0	
St Boniface-Plessis Rd Stn 115-24kV Transformer Add		2,045	2,086	2,058	-28	-1
St Vital Terminal 115kV Line SV24 Protection Repl		0	0	0	0	
Selkirk GS 115kV Line SV24 Protection Repl		0	0	0	0	
Transcona Stn SV23 T/L Retermination & Prot chg		193	197	204	7	4
St Boniface - Plessis Rd Stn add'n 2-24kV Circuits		1,671	1,704	2,103	399	23
St Boniface-Plessis Rd Bk 2 Addition Communication		115	117	137	20	17
TOTAL		4,024	4,104	4,502	398	10

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
1997 10	9,003	New Complex
1998 10	4,432	ISD of complex advanced four years to July 2001 to add firm tranformer capacity in the area. Scope changed from SV24 tap to sectionallization of SV23.
1999 10	4,925	Reflects revised activity and overhead rates.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item _ Domestic Item

287

Title
ST. BONIFACE PLESSIS RD. STATION SV24 115KV T/L TAP

Budget reference number
02-00-7999

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	70411

DESCRIPTION:
TAP 115KV TRANSMISSION LINE SV24 FROM THE SELKIRK - ST. VITAL 115 KV RIGHT-OF-WAY AND TERMINATE AT BANK 2 AT SPRINGFIELD - ST. BONIFACE ROAD STATION.

JUSTIFICATION:
ELSEWHERE IN THE BUDGET, JUSTIFICATION IS GIVEN FOR THE INSTALLATION OF BANK 2 AT SPRINGFIELD - ST. BONIFACE STATION. THIS ITEM PROVIDES PRIMARY SUPPLY FOR BANK 2.

REFERENCE:
L.A. MILLER TO W. PYL, 'GOULET 4 KV FEEDER CHANGES', 96-05-29, FILE 74P
G.K. ZIELKE TO V. KOSCHIK, 'DAWSON ROAD - ST. VITAL 24 KV SYSTEM', 96-06-20.

REVISION:
ITEM CANCELLED. SUPPLY CONCEPT TO STATION CHANGED, SV24 TAP NO LONGER REQUIRED. STATION NAME CHANGED TO ST. BONIFACE PLESSIS ROAD.

IN SERVICE DATES

Base estimate
199706 L2

Work start date
2004 01 01

	PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date.							
TOTAL							
REV. AMOUNTS:							
Authorized to date:							
Over(under)expend:							
Auth Req.:							
TOTAL							

Prepared by: yy mm dd COORDINATOR
Approved by: yy mm dd Approved by: yy mm dd
Estimated by: ORIGINATOR | COORDINATING MANAGER | ORIGINATING MANAGER

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number: 02-00-7999

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1997 10	73	NEW ITEM.
1998 10	0	ITEM CANCELLED. SUPPLY CONCEPT TO STATION CHANGED, SV24 TAP NO LONGER REQUIRED. STATION NAME CHANGED TO ST. BONIFACE PLESSIS ROAD.

ASSOCIATED PROJECTS

Budget reference number	Description
03-00-7264	ST. BONIFACE-PLESSISS ROAD STATION 115-24KV TRANSFORMER ADD
03-00-7265	ST. VITAL TERMINAL 115KV LINE SV24 PROTECTION REPLACEMENT
03-00-7266	SELKIRK G.S. 115KV LINE SV24 PROTECTION REPLACEMENT
03-00-8347	TRANSCONA STN. - SV23 T/L RETERMINATION AND PROTECTION CHANG
04-00-7565	ST BONIFACE PLESSIS RD STATION - ADDN OF 2-24KV CIRCUITS
05-00-8587	ST BONIFACE- PLESSIS ROAD BANK 2 ADDITION COMMUNICATION REQU

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item ___ Domestic Item 288

Title
ST. BONIFACE-PLESSISS ROAD STATION 115-24KV TRANSFORMER ADD

Budget reference number
03-00-7264

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	70467

DESCRIPTION:
INSTALL ONE 60/80/100/112 MVA, 114.3-24/13.8KV +/- 10% LTC TRANSFORMER AND NEUTRAL REACTOR IN BANK 2 POSITION AT SPRINGFIELD - ST. BONIFACE STATION TO MATCH THE EXISTING BANK 1 UNIT. INSTALL 1-24KV BREAKER TO CONNECT THE TRANSFORMER TO FACILITATE SWITCHING AND PROTECTION. INSTALL 2-24KV 1500 MVA CIRCUIT BREAKERS AND ASSOCIATED EQUIPMENT TO PROVIDE TWO ADDITIONAL 24 KV CIRCUITS.

JUSTIFICATION:
THE SECOND BANK AND ADDITIONAL CIRCUITS AT SPRINGFIELD - ST. BONIFACE STATION ARE REQUIRED TO SUPPORT THE LOAD GROWTH IN THE AREA AND TO PROVIDE BACKUP TO OTHER 24 KV STATIONS NEARBY.

REFERENCE:
L.A. MILLER TO W. PYL, 'GOULET 4 KV FEEDER CHANGES', FILE 74P
G.K. ZIELKE TO V. KOSCHIK, 'DAWSON ROAD - ST. VITAL 24KV SYSTEM', 96-06-20

REVISION:
REFLECTS REVISED ACTIVITY AND OVERHEAD RATES.

CONTINGENCY: $185,000

IN SERVICE DATES		Base estimate
2001 07 31	2 193	199804 L2
		Work start date
		2000 10 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:						
2000/01	95	5	2			102
2001/02	1 950	128	10			2 088
TOTAL	2 045	133	12			2 190
REV. AMOUNTS:						
Authorized to date:						
Over(under)expend:						
Auth 2000/01	103	5	2			110
Req.: 2001/02	1 955	118	10			2 083
TOTAL	2 058	123	12			2 193

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 03-00-7264

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1997 10	5 917	NEW ITEM
1998 10	2 190	ISD ADVANCED FROM 2005 06 30 TO 2001 07 30 TO ADD FIRM TRANSFORMER CAPACITY IN THE AREA. TRANSFORMER PRICE DECREASED. SCOPE REDUCED DUE TO TRANSFER OF WORK TO NEW STATION BI 03-00-7260. NAME CHANGED.

ASSOCIATED PROJECTS

Budget reference number	Description
02-00-7999	ST. BONIFACE PLESSIS RD. STATION SV24 115KV T/L TAP
03-00-7265	ST. VITAL TERMINAL 115KV LINE SV24 PROTECTION REPLACEMENT
03-00-7266	SELKIRK G.S. 115KV LINE SV24 PROTECTION REPLACEMENT
03-00-8347	TRANSCONA STN. - SV23 T/L RETERMINATION AND PROTECTION CHANG
04-00-7565	ST BONIFACE PLESSIS RD STATION - ADDN OF 2-24KV CIRCUITS
05-00-8587	ST BONIFACE- PLESSIS ROAD BANK 2 ADDITION COMMUNICATION REQU

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct	17	1				18	18
Nov	17	1				18	36
Dec	17	1				18	54
Jan	17	1				18	72
Feb	17		1			18	90
Mar	18	1	1			20	110
TOTAL	103	5	2			110	110

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item ___ Domestic Item 289

Title
ST. VITAL TERMINAL 115KV LINE SV24 PROTECTION REPLACEMENT

Budget reference number
03-00-7265

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	70451

DESCRIPTION:
115 KV LINE SV24 PROTECTION AT ST. VITAL STATION MUST BE REPLACED WITH A PROTECTION SYSTEM CAPABLE OF ACCOMMODATING THE SPRINGFIELD-ST. BONIFACE ROAD BANK 2 ADDITION.

JUSTIFICATION:
ELSEWHERE IN THE BUDGET, JUSTIFICATION IS PROVIDED FOR THE ESTABLISHMENT OF BANK 2 AT SPRINGFIELD-ST. BONIFACE STATION TO BE TAPPED OFF 115KV LINE SV24. THIS ITEM PROVIDES FOR PROTECTION CHANGES REQUIRED AT ST. VITAL TO ACCOMMODATE THE BANK 2 ADDITION.

REFERENCE:
L.A. MILLER TO W. PYL, 'GOULET 4KV FEEDER CHANGES,' 96-05-29, FILE 74P
G.K. ZIELKE TO V. KOSCHIK, 'DAWSON ROAD-ST. VITAL 24KV SYSTEM,' 96-06-20

REVISION:
ITEM CANCELLED. SUPPLY CONCEPT TO STATION CHANGED, SV24 TAP NO LONGER REQUIRED.

IN SERVICE DATES		Base estimate
2005 06 30	0	199707 L2
		Work start date 2004 04 01

	PREV. AUTHORITY Authorized to date.	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
TOTAL							
REV. AMOUNTS:							
Authorized to date:							
Over(under)expend:							
Auth Req.:							
TOTAL							

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR		COORDINATING MANAGER		ORIGINATING MANAGER	

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 03-00-7265

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1997 10	262	NEW ITEM
1998 10	0	ITEM CANCELLED. SUPPLY CONCEPT TO STATION CHANGED, SV24 TAP NO LONGER REQUIRED.

ASSOCIATED PROJECTS

Budget reference number	Description
02-00-7999	ST. BONIFACE PLESSIS RD. STATION SV24 115KV T/L TAP
03-00-7264	ST. BONIFACE-PLESSISS ROAD STATION 115-24KV TRANSFORMER ADD
03-00-7266	SELKIRK G.S. 115KV LINE SV24 PROTECTION REPLACEMENT
03-00-8347	TRANSCONA STN. - SV23 T/L RETERMINATION AND PROTECTION CHANG
04-00-7565	ST BONIFACE PLESSIS RD STATION - ADDN OF 2-24KV CIRCUITS
05-00-8587	ST BONIFACE- PLESSIS ROAD BANK 2 ADDITION COMMUNICATION REQU

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item 290

Title: SELKIRK G.S. 115KV LINE SV24 PROTECTION REPLACEMENT

Budget reference number: 03-00-7266

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	70450

DESCRIPTION:
115 kV line SV24 protection at Selkirk GS must be replaced with a protection system capable of accommodating the Springfield-St. Boniface Road Bank 2 addition.

JUSTIFICATION:
Elsewhere in the budget, justification is provided for the establishment of Bank 2 at Springfield-St. Boniface Station to be tapped off 115kV line SV24. This item provides for protection changes required at Selkirk GS to accommodate the Bank 2 addition.

REFERENCE:
L.A. Miller to W. Pyl, 'Goulet 4 kV Feeder Changes,' 96-05-29, file 74P
G.K. Zielke to V. Koschik, 'Dawson Road-St. Vital 24 kV System,' 96-06-20

REVISION:
Item cancelled. Supply concept to station changed,
SV24 tap no longer required.

IN SERVICE DATES			Base estimate
2005 06 30	0		199707 L2
			Work start date: 2004 04 01

	PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:							
TOTAL							
REV. AMOUNTS:							
Authorized to date:							
Over(under)expend:							
Auth Req.:							
TOTAL							

Prepared by	yy mm dd	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by					
COORDINATOR / ORIGINATOR		COORDINATING MANAGER		ORIGINATING MANAGER	

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number: 03-00-7266

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1997 10	261	NEW ITEM
1998 10	0	Item cancelled. Supply concept to station changed, required.

ASSOCIATED PROJECTS

Budget reference number	Description
02-00-7999	ST. BONIFACE PLESSIS RD. STATION SV24 115KV T/L TAP
03-00-7264	ST. BONIFACE-PLESSISS ROAD STATION 115-24KV TRANSFORMER ADD
03-00-7265	ST. VITAL TERMINAL 115KV LINE SV24 PROTECTION REPLACEMENT
03-00-8347	TRANSCONA STN. - SV23 T/L RETERMINATION AND PROTECTION CHANG
04-00-7565	ST BONIFACE PLESSIS RD STATION - ADDN OF 2-24KV CIRCUITS
05-00-8587	ST BONIFACE- PLESSIS ROAD BANK 2 ADDITION COMMUNICATION REQU

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — 291 Domestic Item

Title: TRANSCONA STN. - SV23 T/L RETERMINATION AND PROTECTION CHANG

Budget reference number: 03-00-8347

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	70563

DESCRIPTION:
RETERMINATE SV23 INTO TRANSCONA STATION USING A PORTION OF LINES GT1 AND ST2. ALSO, 115KV LINE SV23 PROTECTION AT TRANSCONA STATION MUST BE REPLACED WITH A PROTECTION SYSTEM CAPABLE OF ACCOMMODATING THE ST. BONIFACE RD. STATION.

JUSTIFICATION:
ELSEWHERE IN THE BUDGET, JUSTIFICATION IS PROVIDED FOR THE ESTABLISHMENT OF THE NEW ST. BONIFACE STATION TO BE SUPPLIED FROM SECTIONALIZED 115KV LINE SV23. THIS ITEM PROVIDES FOR PROTECTION CHANGES REQUIRED AT TRANSCONA STATION TO ACCOMMODATE THIS NEW STATION.

REFERENCE:
L.A. MILLER TO W. PYL, 'GOULET 4 KV FEEDER CHANGERS', 96-05-29, FILE 74P

G.K. ZIELKE TO V. KOSCHIK, 'DAWSON ROAD-ST.VITAL 24 KV SYSTEM', 96-06-20

W.N. ZURBA TO C.V. THIO, 'ST. BONIFACE RD. STATION - 115KV SUPPLY & STATION DEVELOPMENT', 1998 01 22

REVISION:
REFLECTS REVISED ACTIVITY AND OVERHEAD RATES.

CONTINGENCY: $18 000

IN SERVICE DATES: 2001 07 31 — 225

Base estimate: 199805 L2

Work start date: 2000 04 01

	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
PREV. AUTHORITY Authorized to date:						
2000/01	165	8	5			178
2001/02	28	2	6			36
TOTAL	193	10	11			214
REV. AMOUNTS:						
Authorized to date:						
Over(under)expend:						
Auth 2000/01	175	9	5			189
Req 2001/02	29	1	6			36
TOTAL	204	10	11			225

Prepared by — yy mm dd — COORDINATOR

Estimated by — ORIGINATOR

Approved by — yy mm dd — COORDINATING MANAGER

Approved by — ORIGINATING MANAGER — yy mm dd

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 03-00-8347

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1998 10	214	NEW ITEM.

ASSOCIATED PROJECTS

Budget reference number	Description
02-00-7999	ST. BONIFACE PLESSIS RD. STATION SV24 115KV T/L TAP
03-00-7264	ST. BONIFACE-PLESSISS ROAD STATION 115-24KV TRANSFORMER ADD
03-00-7265	ST. VITAL TERMINAL 115KV LINE SV24 PROTECTION REPLACEMENT
03-00-7266	SELKIRK G.S. 115KV LINE SV24 PROTECTION REPLACEMENT
04-00-7565	ST BONIFACE PLESSIS RD STATION - ADDN OF 2-24KV CIRCUITS
05-00-8587	ST BONIFACE- PLESSIS ROAD BANK 2 ADDITION COMMUNICATION REQU

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr	3					3	3
May	3					3	6
Jun	3					3	9
Jul	17					17	26
Aug	17					17	43
Sep	17	1				18	61
Oct	19	2				21	82
Nov	19	1	1			21	103
Dec	19	1	1			21	124
Jan	20		1			21	145
Feb	20	1	1			22	167
Mar	18	3	1			22	189
TOTAL	175	9	5			189	189

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item ___ Domestic Item 292

Title
ST BONIFACE PLESSIS RD STATION - ADDN OF 2-24KV CIRCUITS

Budget reference number
04-00-7565

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	93388

DESCRIPTION:
BUILD TWO 24KV CIRCUITS FROM THE PROPOSED SPRINGFIELD-ST BONIFACE STATION SITE TO SUPPORT ADDITIONAL LOAD GROWTH IN THE LOCAL AREA.

JUSTIFICATION:
TWO NEW FEEDER LINES ARE REQUIRED TO SUPPLY LOAD GROWTH IN THE ST VITAL AND DAWSON ROAD STATION AREAS AND TO INCREASE THE FEEDER TIE CAPACITY IN THE AREA.

REFERENCE:
L.A. MILLER TO W. PYL, 'GOULET 4KV FEEDER CHANGES', 96-05-29, FILE 74P
G.K. ZIELKE TO V. KOSCHIK, 'DAWSON ROAD - ST VITAL 24KV SYSTEM" 96-06-20

REVISION:
CHANGE IN PROPOSED STATION LOCATION REQUIRES LONGER FEEDER LINES.

IN SERVICE DATES

2001 07 31 — 2 349

Base estimate
199805 L2

Work start date
1999 10 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:						
1999/00	73	3	2			78
2000/01	1 163	70	73			1 306
2001/02	435	34	45			514
TOTAL	1 671	107	120			1 898
REV. AMOUNTS:						
Authorized to date:						
Over(under)expend:						
Auth 1999/00	78	3	2			83
Req 2000/01	1 091	60	64			1 215
2001/02	934	63	54			1 051
TOTAL	2 103	126	120			2 349

Prepared by: yy mm dd COORDINATOR — Approved by: yy mm dd Approved by: yy mm dd

Estimated by: ORIGINATOR — COORDINATING MANAGER — ORIGINATING MANAGER

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 04-00-7565

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1997 10	2 345	NEW ITEM.
1998 10	2 228	ISD ADVANCED FROM 2005 06 30 TO 2001 07 30 TO ADD FIRM TRANSFORMER CAPACITY IN THE AREA.
1999 10	2 475	CHANGE IN PROPOSED STATION LOCATION REQUIRES LONGER FEEDER LINES.

ASSOCIATED PROJECTS

Budget reference number	Description
02-00-7999	ST. BONIFACE PLESSIS RD. STATION SV24 115KV T/L TAP
03-00-7264	ST. BONIFACE-PLESSISS ROAD STATION 115-24KV TRANSFORMER ADD
03-00-7265	ST. VITAL TERMINAL 115KV LINE SV24 PROTECTION REPLACEMENT
03-00-7266	SELKIRK G.S. 115KV LINE SV24 PROTECTION REPLACEMENT
03-00-8347	TRANSCONA STN. - SV23 T/L RETERMINATION AND PROTECTION CHANG
05-00-8587	ST BONIFACE- PLESSIS ROAD BANK 2 ADDITION COMMUNICATION REQU

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	3					3	3
May	3					3	6
Jun	3					3	9
Jul	3					3	12
Aug	3					3	15
Sep	3					3	18
Oct	3					3	21
Nov	3					3	24
Dec	3					3	27
Jan	17	1				18	45
Feb	17	2				19	64
Mar	17		2			19	83
TOTAL	78	3	2			83	83
2000/01 Apr	329	15	1			345	345
May	70	3	3			76	421
Jun	70	3	4			77	498
Jul	70	3	4			77	575
Aug	70	3	5			78	653
Sep	69	4	5			78	731
Oct	69	4	6			79	810
Nov	69	5	6			80	890
Dec	69	4	7			80	970
Jan	69	5	7			81	1 051
Feb	69	4	8			81	1 132
Mar	68	7	8			83	1 215
TOTAL	1 091	60	64			1 215	1 215

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item 293

Title: ST BONIFACE- PLESSIS ROAD BANK 2 ADDITION COMMUNICATION REQU

Budget reference number: 05-00-8587

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Planning & Control	Construction	70270

DESCRIPTION:
DESIGN, PURCHASE, AND INSTALL COMMUNICATION FACILITIES FOR THE ESTABLISHMENT OF THE SECOND 115-24KV TRANSFORMER AT SPRINGFIELD - ST. BONIFACE STATION.

JUSTIFICATION:
ELSEWHERE IN THE BUDGET, JUSTIFICATION IS PROVIDED FOR THE ESTABLISHMENT OF THE NEW SPRINGFIELD - ST. BONIFACE STATION. THIS ITEM PROVIDES COMMUNICATION FACILITIES FOR THE SECOND TRANSFORMER.

REFERENCE:
L.A. MILLER TO W. PYL, 'GOULET 4KV FEEDER CHANGES', 96-05-29, FILE 74P.
G.K. ZIELKE TO V. KOSCHIK, 'DAWSON ROAD - ST. VITAL 24KV SYSTEM', 96-06-20.

REVISION:
CHANGES REFLECT SECTIONALIZATION OF ST.BONIFACE-SELKIRK TRANSMISSION LINE AT TRANSCONA. WORK START DATE CHANGED TO 199906 FROM 200001. INSERVICE DATE DEFERRED FROM 200107 TO 200112.

CONTINGENCY: $10,000

IN SERVICE DATES: 2001 12 31 — 159

Base estimate: 199804 L3

Work start date: 1999 06 01

PREV. AUTHORITY Authorized to date	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
1999/00	5					5
2000/01	46	4	1			51
2001/02	64	6	2			72
TOTAL	115	10	3			128
REV. AMOUNTS:						
Authorized to date:						
Over(under)expend:						
Auth 1999/00	21	1				22
Req.: 2000/01	78	4	6			88
2001/02	38	3	8			49
TOTAL	137	8	14			159

Prepared by: yy mm dd COORDINATOR — Approved by: yy mm dd — Approved by: yy mm dd

Estimated by: ORIGINATOR — COORDINATING MANAGER — ORIGINATING MANAGER

MajCER(2) Rev. 97 0

CAPITAL EXPENDITURE REVISION

Budget reference number 05-00-8587

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1997 10	136	NEW ITEM
1998 10	128	ISD ADVANCED FROM 2005 06 30 TO 2001 07 30 TO ADD FIRM TRANSFORMER CAPACITY IN THE AREA. NAME CHANGED.

ASSOCIATED PROJECTS

Budget reference number	Description
02-00-7999	ST. BONIFACE PLESSIS RD. STATION SV24 115KV T/L TAP
03-00-7264	ST. BONIFACE-PLESSISS ROAD STATION 115-24KV TRANSFORMER ADD
03-00-7265	ST. VITAL TERMINAL 115KV LINE SV24 PROTECTION REPLACEMENT
03-00-7266	SELKIRK G.S. 115KV LINE SV24 PROTECTION REPLACEMENT
03-00-8347	TRANSCONA STN. - SV23 T/L RETERMINATION AND PROTECTION CHANG
04-00-7565	ST BONIFACE PLESSIS RD STATION - ADDN OF 2-24KV CIRCUITS

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun	1					1	1
Jul	1					1	2
Aug	1					1	3
Sep	1					1	4
Oct	1					1	5
Nov	1					1	6
Dec	1					1	7
Jan	2	1				3	10
Feb	2	1				3	13
Mar	10	-1				9	22
TOTAL	21	1				22	22
2000/01 Apr	9					9	9
May	9					9	18
Jun	9					9	27
Jul	9	1				10	37
Aug	9	1				10	47
Sep	9	1				10	57
Oct	9		1			10	67
Nov	3		1			4	71
Dec	3		1			4	75
Jan	3		1			4	79
Feb	3		1			4	83
Mar	3	1	1			5	88
TOTAL	78	4	6			88	88

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

COMPLEX STATUS	Complex no.	REVISION STATUS
[X] Planned [ ] In progress	241	[ ] New complex [ ] In service change [ ] Concept change [X] Estimate change only

COMPLEX	NEEPAWA 66 KV SYSTEM

Proposal

Perform route selection, design and construct transmission and terminal facilities to off load 66kV Line 85.

Transmission: 23.3 km, 66kV from Neepawa to Plumas tap.

Terminations: A 66kV breaker and termination at Neepawa.

JUSTIFICATION	Explanation
[X] Load [ ] Service [ ] Safety [ ] Efficiency [X] Reliability [ ] Other	This complex provides support to the Gladstone, Langruth, Plumas, Amaranth area which is required due to the load limit on Line 85 which supplies this area.

Estimate Level	COMPLEX START (yyyy mm)
L2	2000 03

IN SERVICE DATES AND AMOUNTS			
2002 10	$3443		

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend								
Year 99/00								
00/01								
01/02	139	10	5		154	188	-34	-18
02/03	2,979	189	120		3,288	3,364	-76	-2
03/04								
04/05								
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	3,118	199	125		3,442	3,552	-110	-3

REVISION	Scope unchanged.

Reviewed by ORIGINATOR	yyyy mm dd	Reviewed by COORDINATOR	yyyy mm dd
	99 11 05		99 11 03
Reviewed by CONSTRUCTOR	yyyy mm dd	Approved by VICE PRESIDENT	yyyy mm dd
	99 11 03		99 11 16

H2856/r Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Complex no. 241

Advance or deferral impact

Deferral will cause Line 85 to become overloaded.

Factors affecting timing or viability

Load Growth.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Neepawa 66kV Breaker Addition		493	503	517	14	3
Neepawa - Plumas Tap 66kV Line		2,620	2,672	2,601	-71	-3
TOTAL		3,113	3,175	3,118	-57	-2

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
1997 10	3,460	New Complex
1998 10	3,552	Revised to include interest.
1999 10	3,442	Scope unchanged.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item 294

Title
NEEPAWA 66 KV BREAKER ADDITION

Budget reference number
03-00-7277

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	70457

DESCRIPTION:
INSTALL A 66 KV BREAKER AND 66 KV LINE TERMINATION AT NEEPAWA 115-66 KV STATION.

JUSTIFICATION:
ELSEWHERE IN THE BUDGET, JUSTIFICATION IS PROVIDED FOR A NEW 26KM, 66 KV LINE FROM NEEPAWA STATION TO PLUMAS TAP TO OFF LOAD LINE 85 WHICH WILL REACH ITS LOAD LIMIT BY 2002.

REFERENCE:
MEMO FROM J.E. POLKOWSKI TO G.K. ZIELKE, 97 02 21
MEMO FROM S.D. HOLM TO D.H. WOOD, 95 05 10.
MEMO FROM D.G. CHAPMAN TO E.T. FLOYDE, 96 09 04.

REVISION:
REFLECTS REVISED ACTIVITY AND OVERHEAD RATES.

CONTINGENCY: $44 000

IN SERVICE DATES		Base estimate
2002 10 31	585	199707 L2
		Work start date
		2001 04 01

	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
PREV. AUTHORITY Authorized to date:						
2001/02	104	9	4			117
2002/03	389	41	14			444
TOTAL	493	50	18			561
REV. AMOUNTS. Authorized to date:						
Over(under)expend:						
Auth 2001/02	119	10	5			134
Req. 2002/03	398	38	15			451
TOTAL	517	48	20			585

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

CAPITAL EXPENDITURE REVISION

Budget reference number: 03-00-7277

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1997 07	561	NEW ITEM.
1998 10	561	NO CHANGE.

ASSOCIATED PROJECTS

Budget reference number	Description
04-00-7568	NEEPAWA - PLUMAS TAP 66kV LINE

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item

295

Title
NEEPAWA - PLUMAS TAP 66kV LINE

Budget reference number
04-00-7568

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	94205

DESCRIPTION:
CONSTRUCT 26.23 KM OF 66KV, 266.8 ACSR LINE FROM NEEPAWA 115-66KV STATION TO PLUMAS TAP.

JUSTIFICATION:
LINE 85 WHICH SUPPLIES GLADSTONE, LANGRUTH, PLUMAS, AND AMARANTH STATIONS IS NEARING ITS LOAD LIMIT OF 32 MVA. THE CONSTRUCTION OF THIS NEW LINE WILL OFF LOAD LINE 85.

REFERENCE:
MEMO FROM J.E. POLKOWSKI TO G.K. ZIELKE, 97 02 21
MEMO FROM S.D. HOLM TO D.H. WOOD, 95 05 10
MEMO FROM D.G. CHAPMAN TO E.T. FLOYDE, 96 09 04

REVISION:
REVISED TO REFLECT O/H AND ACTIVITY RATE CHANGES ONLY.

CONTINGENCY AMOUNT: $0

IN SERVICE DATES

2002 10 31 — 2 858

Base estimate
199902 L2

Work start date
2001 01 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:						
2001/02	65	6				71
2002/03	2 555	255	110			2 920
TOTAL	2 620	261	110			2 991
REV. AMOUNTS:						
Authorized to date:						
Over(under)expend:						
Auth 2001/02	20	1				21
Req 2002/03	2 581	151	105			2 837
TOTAL	2 601	152	105			2 858

Prepared by — yy mm dd — COORDINATOR
Approved by — yy mm dd — COORDINATING MANAGER
Approved by — yy mm dd — ORIGINATING MANAGER
Estimated by — ORIGINATOR

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 04-00-7568

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1997 07	2 836	NEW ITEM.
1998 10	2 955	NEW ITEM.
1999 10	2 918	REVISED TO REFLECT O/H AND ACTIVITY RATE CHANGES ONLY.

ASSOCIATED PROJECTS

Budget reference number	Description
03-00-7277	NEEPAWA 66 KV BREAKER ADDITION

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

COMPLEX STATUS: [X] Planned [ ] In progress

Complex no. 242

REVISION STATUS: [ ] New complex [ ] In service change [ ] Concept change [X] Estimate change only

COMPLEX: RESTON - GLENBORO CAPACITY INCREASE

Proposal

Design and construct facilities at Reston and Glenboro as Follows:

Replace the 56.3 MVA 230-66kV Bank 1 at Reston with a 93.7 MVA unit and install the 56.3 unit at Glenboro in a new Bank 3 position.

JUSTIFICATION: [X] Load [ ] Service [ ] Safety [ ] Efficiency [X] Reliability [ ] Other

Explanation

Capacity increases at Reston and Glenboro are required to provide firm supply to distribution stations in their respective areas and for load increases at Cromer and Glenboro IPL stations.

Estimate Level	COMPLEX START (yyyy mm)
L2	1999 04

IN SERVICE DATES AND AMOUNTS					
2001 07	$2611	2001 10	$2480		

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend								
Year 99/00	454	19	18		491	430	61	14
00/01	2,526	146	149		2,821	2,774	47	2
01/02	1,526	110	143	195	1,584	1,570	14	1
02/03								
03/04								
04/05								
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	4,506	275	310	195	4,896	4,774	122	3

REVISION: Scope unchanged.

Reviewed by ORIGINATOR	yyyy mm dd 99 11 00	Reviewed by COORDINATOR	yyyy mm dd 99 11 03
Reviewed by CONSTRUCTOR	yyyy mm dd 99 11 03	Approved by VICE PRESIDENT	yyyy mm dd 99 11 3663

H2856/r Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Complex no. 242

Advance or deferral impact

Deferral will reduce reliability of support for IPL and Reston - Glenboro South areas.

Factors affecting timing or viability

Load Growth.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Reston Station - Bank 1 Replacement		2,265	2,310	2,335	25	1
Glenboro South Station - Bank 3 Addition		2,102	2,144	2,171	27	1
TOTAL		4,367	4,454	4,506	52	1

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
1997 10	4,788	New Complex
1998 10	4,774	Scope unchanged.
1999 10	4,896	Scope unchanged.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item

296

Title			Budget reference number
RESTON STATION - BANK 1 REPLACEMENT			03-00-7275
Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	70273

DESCRIPTION:
REPLACE RESTON STATION BANK 1 (230-66KV, 30/40//53.6 MVA, +/- 10% LTC) WITH A NEW 50/66.6/83.3//93.7 MVA +/- 15% LTC TRANSFORMER. (THE REPLACED UNIT WILL BE INSTALLED AT GLENBORO SOUTH STATION IN A NEW BANK 3 POSITION.)

JUSTIFICATION:
THIS TRANSFORMER REPLACEMENT IS REQUIRED TO PROVIDE FIRM 66KV TRANSFORMER CAPACITY FOR THE DISTRIBUTION STATIONS SUPPLIED BY THE RESTON 66KV SYSTEM DUE TO NORMAL LOAD GROWTH AND INCREASED LOAD AT CROMER IPL.

REFERENCE:
MEMO FROM J.E. POLKOWSKI TO G.K. ZIELKE 97 02 04
REPORT SPD 97/1 'INTERPROVINCIAL PIPELINES SYSTEM EXPANSION PROGRAM (SEPI & II)
TASK FORCE REPORT ON INTERPROVINCIAL PIPELINES SEPI & II EXPANSION PROGRAMS 1997 01 17.

REVISION:
REFLECTS REVISED ACTIVITY AND OVERHEAD RATES.

CONTINGENCY: $203 000

IN SERVICE DATES		Base estimate
2001 07 31	2 611	199707 L2
		Work start date
		1999 04 01

PREV. AUTHORITY Authorized to date	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
1999/00	126	6	5			137
2000/01	1 432	94	73			1 599
2001/02	707	55	53	- 195		620
TOTAL	2 265	155	131	- 195		2 356
REV. AMOUNTS:						
Authorized to date:						
Over(under)expend:						
Auth 1999/00	144	6	6			156
Req. 2000/01	1 471	86	75			1 632
2001/02	720	49	54	- 195		628
TOTAL	2 335	141	135	- 195		2 416

Prepared by: yy mm dd COORDINATOR — Approved by: yy mm dd Approved by: yy mm dd

Estimated by: ORIGINATOR — COORDINATING MANAGER — ORIGINATING MANAGER

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number: 03-00-7275

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1997 10	2 359	NEW ITEM.
1998 10	2 356	NO CHANGE.

ASSOCIATED PROJECTS

Budget reference number	Description
03-00-7276	GLENBORO SOUTH STATION - BANK 3 ADDITION

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	12	1				13	13
May	12	1				13	26
Jun	12	1				13	39
Jul	12	1				13	52
Aug	12	1				13	65
Sep	12	1				13	78
Oct	12		1			13	91
Nov	12		1			13	104
Dec	12		1			13	117
Jan	12		1			13	130
Feb	12		1			13	143
Mar	12		1			13	156
TOTAL	144	6	6			156	156
2000/01 Apr	123	6	1			130	130
May	123	6	2			131	261
Jun	123	6	3			132	393
Jul	123	6	4			133	526
Aug	123	6	5			134	660
Sep	123	6	6			135	795
Oct	123	6	7			136	931
Nov	123	7	8			138	1 069
Dec	122	8	9			139	1 208
Jan	122	8	10			140	1 348
Feb	122	8	11			141	1 489
Mar	121	13	9			143	1 632
TOTAL	1 471	86	75			1 632	1 632

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — 297 Domestic Item

Title: GLENBORO SOUTH STATION - BANK 3 ADDITION

Budget reference number: 03-00-7276

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	70459

DESCRIPTION:
INSTALL A 230-66 KV, 30/40/50/56.3 MVA +/-10% LTC TRANSFORMER AT GLENBORO SOUTH STATION. THIS TRANSFORMER WAS FORMERLY AT RESTON STATION DESIGNATED AS BANK 1. ALSO INSTALL A 40 MVA GROUNDING BANK, A 230 KV BREAKER, AND A 66 KV BREAKER.

JUSTIFICATION:
THIS TRANSFORMER ADDITION IS REQUIRED TO PROVIDE FIRM 66 KV SUPPLY TO THE DISTRIBUTION STATIONS IN THE GLENBORO SOUTH 66 KV SYSTEM DUE TO NORMAL LOAD GROWTH AND INCREASED LOAD AT CROMER IPL.

REFERENCE:
MEMO FROM J.E. POLKOWSKI TO G.K. ZIELKE 97 02 04.
REPORT SPD 97/1 'INTERPROVINCIAL PIPELINES SYSTEM EXPANSION PROGRAMS (SEPI & SEPII).
TASK FORCE REPORT ON INTERPROVINCIAL PIPELINES SEPI & II EXPANSION PROGRAMS 1997 01 17.

REVISION:
REFLECTS REVISED ACTIVITY AND OVERHEAD RATES.

CONTINGENCY: $191 000

IN SERVICE DATES		Base estimate
2001 10 31	2 480	199707 L2
		Work start date: 1999 04 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:						
1999/00	270	12	11			293
2000/01	1 036	69	70			1 175
2001/02	796	66	88			950
TOTAL	2 102	147	169			2 418
REV. AMOUNTS:						
Authorized to date:						
Over(under)expend:						
Auth 1999/00	309	13	13			335
Req. 2000/01	1 055	60	74			1 189
2001/02	807	60	89			956
TOTAL	2 171	133	176			2 480

Prepared by: yy mm dd COORDINATOR — Approved by: yy mm dd Approved by:
Estimated by: ORIGINATOR — COORDINATING MANAGER — ORIGINATING MANAGER

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number: 03-00-7276

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1997 10	2 429	NEW ITEM.
1998 10	2 418	NO CHANGE.

ASSOCIATED PROJECTS

Budget reference number	Description
03-00-7275	RESTON STATION - BANK 1 REPLACEMENT

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	26	1				27	27
May	26	1				27	54
Jun	26	1				27	81
Jul	26		1			27	108
Aug	26	1	1			28	136
Sep	26	1	1			28	164
Oct	26	1	1			28	192
Nov	26	1	1			28	220
Dec	26		2			28	248
Jan	26	1	2			29	277
Feb	26	1	2			29	306
Mar	23	4	2			29	335
TOTAL	309	13	13			335	335
2000/01 Apr	88	5	2			95	95
May	88	5	3			96	191
Jun	88	4	4			96	287
Jul	88	5	4			97	384
Aug	88	5	5			98	482
Sep	88	5	6			99	581
Oct	88	5	6			99	680
Nov	88	5	7			100	780
Dec	88	5	8			101	881
Jan	88	5	9			102	983
Feb	88	6	9			103	1 086
Mar	87	5	11			103	1 189
TOTAL	1 055	60	74			1 189	1 189

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

COMPLEX STATUS: ☐ Planned ☒ In progress

Complex no. 80

REVISION STATUS: ☐ New complex ☐ In service change ☐ Concept change ☒ Estimate change only

COMPLEX	ST LEON 230-66KV TRANSFORMER ADD'N & IPL EXPANSION

Proposal

Design and construct facilities at St Leon , Virden West, Cromer North, Letellier, Gretna IPL, Souris IPL East, Souris IPL West and Manitou IPL Stations to provide supplies to meet IPL operational requirements.

JUSTIFICATION		Explanation
☒ Load	☐ Service	IPL is implementing a major system expansion and require full voltage motor starting capability for motors sized up to 3500 HP and the ability to continue operation with failure of customer owned motor drives and PF correction.
☐ Safety	☐ Efficiency	
☒ Reliability	☐ Other	

Estimate Level	COMPLEX START (yyyy mm)
L2	1995 09

IN SERVICE DATES AND AMOUNTS							
1999 04	$2357	1999 08	$1363	1999 09	$433	2001 09	$6494
2001 10	$1024	2004 09	$2696	2004 10	$617		

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	357		-5	350	2	-18	20	-111
Year 99/00	1,435	7	11	1,279	174	-39	213	-546
00/01	688	201	29		918	700	218	31
01/02	1,319	183	99		1,601	1,300	301	23
02/03	5,004	0	1		5,005	5,004	1	0
03/04	1,028	110	20	450	708	655	53	8
04/05	1,862	236	40	1,635	503	1,063	-560	-53
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	11,693	737	195	3,714	8,911	8,665	246	3

REVISION	Scope unchanged.

Reviewed by ORIGINATOR		yyyy mm dd 99 11 08		Reviewed by COORDINATOR		yyyy mm dd 99 11 03	
Reviewed by CONSTRUCTOR		yyyy mm dd 99 11 03		Approved by VICE PRESIDENT		yyyy mm dd 99 11 16	

H2856/r Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Complex no. 80

Advance or deferral impact

Deferral will decrease supply reliability in the St. Leon area in case of an outage of the existing St. Leon 230-66 KV transformer.

Factors affecting timing or viability

Manitoba Load.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
St. Leon Station 230-66 KV Transformer Addition		5,785	5,901	6,084	183	3
Virden West Station 66kV Breaker Addition		534	545	533	-12	-2
Cromer North Station 66kV Breaker Addition	821	828	845	821	-24	-3
Letellier Station 66kV Breaker Addition		0	0	0	0	
Souris IPL East Station 66kV Breaker Additions		777	793	812	19	2
St Leon Station 66kV Breaker Addition		502	512	529	17	3
Souris IPL West Station Bank Addition		0	0	0	0	
Souris IPL East - Souris IPL West 66kV Line		539	550	550	0	0
St Leon - Manitou IPL 66kV Line		924	942	1,011	69	7
Letellier - Gretna IPL 66kV Line e		0	0	0	0	
Virden West - Cromer IPL 66kV Line	426	304	310	426	116	37
IPL Capital Contributions		0	0	0	0	
Richer South Add 230-66kV Spare Power Transformer		712	726	924	198	27
TOTAL	1,247	10,905	11,124	11,690	566	5

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
9510	6,357	Reflects transformer price increase.
9610	6,634	In-service date deferred 2 years to 2001 10 31.
1997 10	6,588	The St Leon 230-66kV transformer addition requires advancement to 1998 10 31 and additional new facilities are required to provide IPL supplies.
1998 10	8,665	Based on IPL's reduced electric requirement, St Leon 230-66kV transformer deferred 3 years to September 2001, dedicated supply to Manitou and Souris West IPL deferred to 2004 .
1999 10	8,911	Scope unchanged.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item ___ Domestic Item

298

Title: ST. LEON STATION 230-66KV TRANSFORMER ADDITION

Budget reference number: 03-00-5899

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	72029

DESCRIPTION:
INSTALL A SECOND 230-66KV, 50/66.7/83.3//93.7 MVA 230-66KV TRANSFORMER COMPLETE WITH OFF-CIRCUIT TAPS AND LTC GEAR HAVING A TOTAL RANGE OF 181KV TO 241KV ON THE 230KV SIDE. ALSO INSTALL A 40MVA 66KV GROUNDING TRANSFORMER, ONE 66KV CIRCUIT BREAKER AND ONE 230KV CIRCUIT BREAKER.

JUSTIFICATION:
THE SECOND TRANSFORMER IS REQUIRED TO PROVIDE FIRM 66KV SUPPLY TO DISTRIBUTION STATIONS IN THE AREA.

REFERENCE:
REPORT SPD 82-13 SOUTH CENTRAL SUBTRANSMISSION SYSTEM 1984-1993.
REPORT G&TP 87-7 SOUTH CENTRAL SUBTRANSMISSION SYSTEM IMPROVEMENTS 1987-1996.
IPL/MANITOBA HYDRO JOINT TASK FORCE REPORT 1997 05 15 - LOCKLEY ENGINEERING LTD.
MEMO C.V. THIO TO T.E. TYMOFICHUK, 1997 05 15. IPL. MANITOBA JOINT TASK FORCE.

REVISION:
REFLECTS REVISED ACTIVITY AND OVERHEAD RATES.

CONTINGENCY: $456,000

IN SERVICE DATES				Base estimate
2001 09 30	6 494			199707 L2
				Work start date: 1998 05 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:	1					1
1999/00	-1					-1
2000/01	177	198	15			390
2001/02	608	155	57			820
2002/03	5 000					5 000
TOTAL	5 785	353	72			6 210
REV. AMOUNTS:						
Authorized to date:	1					1
Over(under)expend:						
Auth 1999/00						
Req.: 2000/01	254	180	15			449
2001/02	829	153	62			1 044
2002/03	5 000					5 000
TOTAL	6 084	333	77			6 494

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR		COORDINATING MANAGER		ORIGINATING MANAGER

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 03-00-5899

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1994 10	5 093	NEW ITEM. TRANSFERRED FROM DOMESTIC 9703-00-9149.
1995 10	6 357	INCREASED TO REFLECT CURRENT TRANSFORMER PRICES.
1996 10	6 634	ISD DEFERRED 3 YEARS FROM 1999 10 31 TO 2001 10 31.
1997 10	5 379	REDUCED PRICES FOR POWER TRANSFORMER AND GROUND BANK. ISD ADVANCED FROM 2001 10 31 TO 1998 10 31 TO INCREASE FAULT LEVELS AT MANITOU IPL 66-4KV STATION IN ORDER TO MEET IPL'S OPERATING REQUIREMENTS.
1998 10	6 210	ISD DEFERRED TO 2001 09 30 TO COINCIDE WITH IPL EXPANSION.

ASSOCIATED PROJECTS

Budget reference number	Description
03-00-8286	VIRDEN WEST STATION 66KV BREAKER ADDITION
03-00-8287	CROMER NORTH STATION 66 KV BREAKER ADDITION
03-00-8290	SOURIS EAST IPL 66KV BREAKER ADDITIONS
03-00-8292	ST. LEON 66 KV BREAKER ADDITION
03-00-8345	RICHER SOUTH ADD 230-66kV EMERGENCY SPARE POWER TRANSFORMER
04-00-8577	SOURIS IPL EAST - SOURIS IPL WEST 66kV LINE
04-00-8578	ST. LEON - MANITOU IPL 66KV LINE
04-00-8580	VIRDEN WEST - CROMER IPL 66kV LINE
04-00-8606	WINNIPEG PIPE LINE TRANSFER TO LINE 50

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb	1 991	129				2 120	2 120
Mar	-1 737	51	15			-1 671	449
TOTAL	254	180	15			449	449

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item

299

Title: VIRDEN WEST STATION 66KV BREAKER ADDITION

Budget reference number: 03-00-8286

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	70465

DESCRIPTION:
INSTALL ONE 66KV BREAKER R28, COMPLETE WITH ASSOCIATED EQUIPMENT, AT VIRDEN WEST 230-66KV STATION. RETERMINATE LINE 95 TO THE NEW BREAKER POSITION AND TERMINATE A NEW DEDICATED SUPPLY TO CROMER IPL IN THE VACATED LINE 95 POSITION. DESIGN PROTECTION FOR NETWORKED OPERATION WITH THE EXISTING RESTON-CROMER IPL 66KV SUPPLY.

JUSTIFICATION:
THIS BREAKER IS REQUIRED TO TERMINATE A NEW DEDICATED 66KV LINE TO CROMER IPL 66-4KV STATION. THIS LINE WILL OPERATE NETWORKED WITH THE EXISTING RESTON-CROMER IPL 66KV SUPPLY. A NEW 66KV BREAKER AT CROMER WILL SECTIONALIZE THE TWO SUPPLIES TO CROMER IPL. THIS PROJECT IS CONTINGENT UPON CUSTOMER EXPANSION AT CROMER IPL.

REFERENCE:
TASK FORCE REPORT ON INTERPROVINCIAL PIPELINES SEP I & II EXPANSION PROGRAMS 1997 01 17. SYSTEM PLANNING DEPARTMENT REPORT ON INTERPROVINCIAL PIPE LINES SYSTEM EXPANSION PROGRAM (SEPI & SEPII) - SPD 97/1
I.P.L./MANITOBA HYDRO JOINT TASK FORCE REPORT DATED 15 MAY 1997 - LOCKLEY ENGINEERING LTD.
MEMO FROM C.V.THIO TO T.E. TYMOFICHUK, IPL/MANITOBA HYDRO JOINT TASK FORCE, 1997 05 15

REVISION:
REDUCTION DUE TO ESTIMATES PROVIDED AT MORE DETAILED LEVEL.

CONTINGENCY: $49,000

IN SERVICE DATES

		Base estimate
1999 08 31	536	199901 L3
		Work start date
		1998 01 01

	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
PREV. AUTHORITY						
Authorized to date:	86		-2		- 112	-28
1999/00	329	10			- 321	18
TOTAL	415	10	-2		- 433	-10
REV. AMOUNTS:						
Authorized to date:	86		-2		- 112	-28
Over(under)expend:						
Auth Req. 1999/00	447	1	1		- 415	34
TOTAL	533	1	-1		- 527	6

Prepared by: yy mm dd COORDINATOR — Approved by: yy mm dd — Approved by: yy mm dd

Estimated by: ORIGINATOR — COORDINATING MANAGER — ORIGINATING MANAGER

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 03-00-8286

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1997 10	570	NEW ITEM.
1998 10	-10	ISD DEFERRED FROM 1998 10 31 TO 1999 08 30 TO COINCIDE WITH IPL EXPANSION. CONTRIBUTION PREVIOUSLY IN CER 03-8308 HAS BEEN DISTRIBUTED TO APPLICABLE PROJECTS.

ASSOCIATED PROJECTS

Budget reference number	Description
03-00-5899	ST. LEON STATION 230-66KV TRANSFORMER ADDITION
03-00-8287	CROMER NORTH STATION 66 KV BREAKER ADDITION
03-00-8290	SOURIS EAST IPL 66KV BREAKER ADDITIONS
03-00-8292	ST. LEON 66 KV BREAKER ADDITION
03-00-8345	RICHER SOUTH ADD 230-66kV EMERGENCY SPARE POWER TRANSFORMER
04-00-8577	SOURIS IPL EAST - SOURIS IPL WEST 66kV LINE
04-00-8578	ST. LEON - MANITOU IPL 66KV LINE
04-00-8580	VIRDEN WEST - CROMER IPL 66kV LINE
04-00-8606	WINNIPEG PIPE LINE TRANSFER TO LINE 50

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	36			-35		1	1
May	83			-35		48	49
Jun	25	1		-35		-9	40
Jul	221	2		-35		188	228
Aug	81	3	1	-35		50	278
Sep				-35		-35	243
Oct				-35		-35	208
Nov				-35		-35	173
Dec				-35		-35	138
Jan				-35		-35	103
Feb				-35		-35	68
Mar	1	-5		-30		-34	34
TOTAL	447	1	1	-415		34	34
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — 300 Domestic Item

Title: CROMER NORTH STATION 66 KV BREAKER ADDITION

Budget reference number: 03-00-8287

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	70458

DESCRIPTION:
INSTALL ONE 66 KV BREAKER AND ASSOCIATED EQUIPMENT AT CROMER NORTH STATION. THIS WILL REQUIRE THE ADDITION OF ONE 66 KV STEEL BAY, RELOCATION OF 25 KV FEEDER CN25-8, AND INSTALLATION OF A CONTROL BUILDING.

JUSTIFICATION:
THIS BREAKER IS REQUIRED TO SECTIONALIZE THE TWO 66 KV SUPPLIES TO CROMER IPL 66-4KV STATION. THE VIRDEN WEST-CROMER IPL STANDARD 66 KV LINE IS LESS RELIABLE THAN THE RESTON-CROMER IPL, 230 KV CONSTRUCTED LINE, OPERATING AT 66 KV. THIS BREAKER WILL ISOLATE LINE FAULTS ON THE VIRDEN SUPPLY. THIS PROJECT IS CONTINGENT UPON CUSTOMER EXPANSION AT CROMER IPL.

REFERENCE:
TASK FORCE REPORT ON INTERPROVINCIAL PIPELINES SEPI & II EXPANSION PROGRAMS 1997 01 17.
SYSTEM PLANNING DEPARTMENT REPORT ON 'INTERPROVINCIAL PIPELINES SYSTEM EXPANSION PROGRAM (SEPI & SEPII) - SPD 97/1
IPL/MANITOBA HYDRO JOINT TASK FORCE REPORT DATED 15 MAY 1997 - LOCKLEY ENGINEERING LTD.
MEMO FROM C.V. THIO TO T.E. TYMOFICHUK, IPL/MANITOBA HYDRO JOINT TASK FORCE, 1997 05 15.

REVISION:
REDUCTION DUE TO ESTIMATES PROVIDED AT A MORE DETAILED LEVEL.

CONTINGENCY: $72 000

IN SERVICE DATES		Base estimate
1999 08 31	824	199901 L3
		Work start date
		1998 05 01

	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
PREV. AUTHORITY						
Authorized to date:	117		-3		- 175	-61
1999/00	485	9	-1		- 467	26
TOTAL	602	9	-4		- 642	-35
REV. AMOUNTS:						
Authorized to date:	117		-3		- 175	-61
Over(under)expend:						
Auth 1999/00 Req.:	704	4	2		- 630	80
TOTAL	821	4	-1		- 805	19

Prepared by: yy mm dd COORDINATOR — Approved by: yy mm dd Approved by: yy mm dd

Estimated by: ORIGINATOR — COORDINATING MANAGER — ORIGINATING MANAGER

1999-08-21 05:24 PM

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 03-00-8287

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1997 10	901	NEW ITEM.
1998 10	-34	ISD DEFERRED FROM 1998 10 31 TO 1999 08 31. IPL CONTRIBUTION PREVIOUSLY IN CER 03-8308 HAS BEEN DISTRIBUTED TO APPLICABLE PROJECTS.

ASSOCIATED PROJECTS

Budget reference number	Description
03-00-5899	ST. LEON STATION 230-66KV TRANSFORMER ADDITION
03-00-8286	VIRDEN WEST STATION 66KV BREAKER ADDITION
03-00-8290	SOURIS EAST IPL 66KV BREAKER ADDITIONS
03-00-8292	ST. LEON 66 KV BREAKER ADDITION
03-00-8345	RICHER SOUTH ADD 230-66kV EMERGENCY SPARE POWER TRANSFORMER
04-00-8577	SOURIS IPL EAST - SOURIS IPL WEST 66kV LINE
04-00-8578	ST. LEON - MANITOU IPL 66KV LINE
04-00-8580	VIRDEN WEST - CROMER IPL 66kV LINE
04-00-8606	WINNIPEG PIPE LINE TRANSFER TO LINE 50

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	78			-53		25	25
May	132	1		-53		80	105
Jun	93	2		-53		42	147
Jul	255	2	1	-53		205	352
Aug	145	2	2	-53		96	448
Sep				-53		-53	395
Oct				-53		-53	342
Nov				-53		-53	289
Dec				-53		-53	236
Jan				-53		-53	183
Feb				-53		-53	130
Mar	1	-3	-1	-47		-50	80
TOTAL	704	4	2	- 630		80	80
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item 301

Title			Budget reference number
LETELLIER STATION - 66KV BREAKER ADDITION			03-00-8288
Originating division: Planning & Control	Coordinating division: Design	Constructing division: Construction	Project Order Group (Range): 70462

DESCRIPTION:
INSTALL ONE 66KV BREAKER R28, COMPLETE WITH ASSOCIATED EQUIPMENT, AT LETELLIER 230-66KV STATION. TERMINATE A NEW 66KV LINE TO GRETNA IPL.

JUSTIFICATION:
THIS BREAKER IS REQUIRED TO TERMINATE A NEW DEDICATED 66KV LINE TO GRETNA IPL 66-4KV STATION. THIS PROJECT IS CONTINGENT UPON CUSTOMER EXPANSION AT GRETNA IPL.

REFERENCE:
TASK FORCE REPORT ON INTERPROVINCIAL PIPELINES SEP I & II EXPANSION PROGRAMS 1997 01 17.
SYSTEM PLANNING DEPARTMENT REPORT ON 'INTERPROVINCIAL PIPELINES SYSTEM EXPANSION PROGRAM (SEP I & SEP II) - SPD 97/1
IPL/MANITOBA HYDRO JOINT TASK FORCE REPORT DATED 97-05-15 - LOCKLEY ENGINEERING LTD.
MEMO FROM C.V. THIO TO T.E. TYMOFICHUK, IPL/MANITOBA HYDRO JOINT TASK FORCE, 1997 05 15.

REVISION:
ITEM CANCELLED, NOT REQUIRED FOR IPL EXPANSION.

IN SERVICE DATES			Base estimate 199707 L2
			Work start date 1997 08 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date						
TOTAL						
REV. AMOUNTS.						
Authorized to date:						
Over(under)expend:						
Auth Req.:						
TOTAL						

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

1999-08-21 05:24 PM

3877

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 03-00-8288

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1997 10	528	NEW ITEM
1998 10	0	ITEM CANCELLED, NOT REQUIRED FOR IPL EXPANSION.

ASSOCIATED PROJECTS

Budget reference number	Description
01-08-8116	CEDAR LAKE DEBRIS REMEDIATION
01-26-8124	CONAWAPA GENERATING STATION
01-42-8125	240 MW CCCT GENERATION
01-42-8126	84 MW CCCT GENERATION
02-00-8012	CONAWAPA TRANSMISSION
02-00-8013	240MW CCCT TRANSMISSION LINE
02-00-8014	84MW SCCT STATION
03-00-8291	SOURIS IPL WEST STATION BANK ADDITION
03-00-8308	IPL CAPITAL CONTRIBUTIONS
03-00-8408	CONAWAPA GENERATING STATION
03-00-8409	240 MW CCCT STATION
03-00-8410	84MW SCCT STATION
04-00-8579	LETELLIER - GRETNA IPL 66KV LINE
04-00-8624	BRERETON LAKE DISTRIBUTION SYSTEM

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item

302

Title
SOURIS EAST IPL 66KV BREAKER ADDITIONS

Budget reference number
03-00-8290

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	70461

DESCRIPTION:
INSTALL TWO 66KV BREAKERS, R21 AND R22, COMPLETE WITH ASSOCIATED EQUIPMENT AND ONE 66KV STEEL BAY AT SOURIS IPL EAST 230-66KV STATION.

JUSTIFICATION:
THESE BREAKERS ARE REQUIRED TO CREATE A RING BUS AT SOURIS IPL EAST 230-66KV STATION IN ORDER TO TERMINATE A NEW 66KV LINE TO SOURIS IPL WEST 66-4KV STATION. THIS PROJECT IS CONTINGENT UPON CUSTOMER EXPANSION AT SOURIS WEST IPL.

REFERENCE:
1) TASK FORCE REPORT ON INTERPROVINCIAL PIPELINES SEP I & II EXPANSION PROGRAMS 1997 01 17.
2) SYSTEM PLANNING DEPARTMENT REPORT ON 'INTERPROVINCIAL PIPE LINES SYSTEM EXPANSION PROGRAM (SEPI & SEPII) - SPD 97/1.
3) I.P.L./MANITOBA HYDRO JOINT TASK FORCE REPORT DATED 15 MAY 1997 - LOCKLEY ENGINEERING LTD.
4) MEMO FROM C.V. THIO TO T.E. TYMOFICHUK, IPL/MANITOBA HYDRO JOINT TASK FORCE, 1997 05 15.

REVISION:
REFLECTS REVISED ACTIVITY AND OVERHEAD RATES.

CONTINGENCY: $ 70,000

This BRN contains Deleted, Blocked, or Closed Orders.

2004 09 30	924	IN SERVICE DATES		Base estimate 199707 L2 Work start date 2003 09 01	
PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:						
1999/00						
2003/04	231	32			- 259	4
2004/05	546	81			- 635	-8
TOTAL	777	113			- 894	-4
REV. AMOUNTS.						
Authorized to date:						
Over(under)expend.						
Auth 2003/04	249	32			- 259	22
Req. 2004/05	563	79	1		- 635	8
TOTAL	812	111	1		- 894	30

Prepared by — yy mm dd — COORDINATOR
Approved by — yy mm dd — COORDINATING MANAGER
Approved by — yy mm dd — ORIGINATING MANAGER
Estimated by — ORIGINATOR

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number: 03-00-8290

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1997 10	815	NEW ITEM.
1998 10	-4	ISD DEFERRED FROM 1998 10 31 TO 2004 09 30 TO COINCIDE WITH IPL EXPANSION. CONTRIBUTION PREVIOUSLY IN CER 03-8308 HAS BEEN DISTRIBUTED TO APPLICABLE PROJECTS.

ASSOCIATED PROJECTS

Budget reference number	Description
03-00-5899	ST. LEON STATION 230-66KV TRANSFORMER ADDITION
03-00-8286	VIRDEN WEST STATION 66KV BREAKER ADDITION
03-00-8287	CROMER NORTH STATION 66 KV BREAKER ADDITION
03-00-8292	ST. LEON 66 KV BREAKER ADDITION
03-00-8345	RICHER SOUTH ADD 230-66kV EMERGENCY SPARE POWER TRANSFORMER
04-00-8577	SOURIS IPL EAST - SOURIS IPL WEST 66kV LINE
04-00-8578	ST. LEON - MANITOU IPL 66KV LINE
04-00-8580	VIRDEN WEST - CROMER IPL 66kV LINE
04-00-8606	WINNIPEG PIPE LINE TRANSFER TO LINE 50

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item

303

Title: SOURIS IPL WEST STATION BANK ADDITION

Budget reference number: 03-00-8291

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	70466

DESCRIPTION:
INSTALL A SECOND 7.5/10 MVA, 66-4KV TRANSFORMER AT SOURIS IPL WEST 66-4KV STATION. ALSO INSTALL 66KV SWITCHES TO TERMINATE A NEW 66KV SUPPLY FROM SOURIS EAST 230-66KV STATION.

JUSTIFICATION:
THE LOAD AT SOURIS WEST IPL IS EXPECTED TO EXCEED THE 10 MVA CAPACITY OF THIS STATION. IPL'S FORECAST IS 10.3 MVA NORMAL LOADING AND 11.2 MVA CONTINGENCY LOADING. ADDITIONAL TRANSFORMATION IS ALSO REQUIRED TO REDUCE VOLTAGE DIP DUE TO MOTOR STARTING. THIS PROJECT IS CONTINGENT UPON CUSTOMER EXPANSION AT SOURIS WEST IPL.

REFERENCE:
1) TASK FORCE REPORT ON INTERPROVINCIAL PIPELINES SEP I & II EXPANSION PROGRAMS 1997 01 17.
2) SYSTEM PLANNING DEPARTMENT REPORT ON 'INTERPROVINCIAL PIPE LINES SYSTEM EXPANSION PROGRAM (SEPI & SEPII) - SPD 97/1.
3) I.P.L./MANITOBA HYDRO JOINT TASK FORCE REPORT DATED 15 MAY 1997 - LOCKLEY ENGINEERING LTD.
4) MEMO FROM C.V. THIO TO T.E. TYMOFICHUK, IPL/MANITOBA HYDRO JOINT TASK FORCE, 1997 05 15.

REVISION:
ITEM CANCELLED, NOT REQUIRED FOR IPL EXPANSION.

IN SERVICE DATES

Base estimate: 199707 L2

Work start date: 1997 10 01

	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
PREV. AUTHORITY Authorized to date:						
TOTAL						
REV. AMOUNTS: Authorized to date:						
Over(under)expend:						
Auth Req.:						
TOTAL						

Prepared by: yy mm dd COORDINATOR — Approved by: yy mm dd Approved by: yy mm dd

Estimated by: ORIGINATOR — COORDINATING MANAGER — ORIGINATING MANAGER

1999-08-21 05:24 PM

CAPITAL EXPENDITURE REVISION

Budget reference number 03-00-8291

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1997 10	669	NEW ITEM
1998 10	0	ITEM CANCELLED, NOT REQUIRED FOR IPL EXPANSION.

ASSOCIATED PROJECTS

Budget reference number	Description
01-08-8116	CEDAR LAKE DEBRIS REMEDIATION
01-26-8124	CONAWAPA GENERATING STATION
01-42-8125	240 MW CCCT GENERATION
01-42-8126	84 MW CCCT GENERATION
02-00-8012	CONAWAPA TRANSMISSION
02-00-8013	240MW CCCT TRANSMISSION LINE
02-00-8014	84MW SCCT STATION
03-00-8288	LETELLIER STATION - 66KV BREAKER ADDITION
03-00-8308	IPL CAPITAL CONTRIBUTIONS
03-00-8408	CONAWAPA GENERATING STATION
03-00-8409	240 MW CCCT STATION
03-00-8410	84MW SCCT STATION
04-00-8579	LETELLIER - GRETNA IPL 66KV LINE
04-00-8624	BRERETON LAKE DISTRIBUTION SYSTEM

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item

304

Title: ST. LEON 66 KV BREAKER ADDITION

Budget reference number: 03-00-8292

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	70460

DESCRIPTION:
INSTALL ONE 66 KV BREAKER, COMPLETE WITH ASSOCIATED EQUIPMENT, AT ST. LEON 230-66 KV STATION.

JUSTIFICATION:
THIS BREAKER IS REQUIRED TO TERMINATE A NEW DEDICATED 66 KV LINE TO MANITOU IPL 66-4 KV STATION. THIS PROJECT IS CONTINGENT UPON CUSTOMER EXPANSION AT MANITOU IPL.

REFERENCE:
TASK FORCE REPORT ON INTERPROVINCIAL PIPELINES SEP I & II EXPANSION PROGRAMS 1997 01 17.

SYSTEM PLANNING DEPARTMENT REPORT ON 'INTERPROVINCIAL PIPELINES SYSTEM EXPANSION PROGRAM (SEPI & SEPII) - SPD 97/1'.

I.P.L./MANITOBA HYDRO JOINT TASK FORCE REPORT DATED 97 05 15 - LOCKLEY ENGINEERING LTD.

MEMO FROM C.V. THIO TO T.E. TYMOFICHUK, IPL/MANITOBA HYDRO JOINT TASK FORCE, 1997 05 15

REVISION:
REFLECTS REVISED ACTIVITY AND OVERHEAD RATES.

CONTINGENCY: $45,000

IN SERVICE DATES: 2004 09 30 — 602

Base estimate: 199707 L2

Work start date: 2003 08 01

	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
PREV. AUTHORITY Authorized to date:						
2003/04	160	22			- 180	2
2004/05	342	50			- 398	-6
TOTAL	502	72			- 578	-4
REV. AMOUNTS: Authorized to date: Over(under)expend:						
Auth 2003/04	174	23			- 180	17
Req.: 2004/05	355	49	1		- 398	7
TOTAL	529	72	1		- 578	24

Prepared by: yy mm dd COORDINATOR

Estimated by: ORIGINATOR

Approved by: yy mm dd COORDINATING MANAGER

Approved by: yy mm dd ORIGINATING MANAGER

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 03-00-8292

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1997 10	529	NEW ITEM.
1998 10	20	ISD DEFERRED FROM 1998 10 31 TO 2004 09 30 TO COINCIDE WITH IPL EXPANSION. IPL CONTRIBUTION PREVIOUSLY IN CER 03-8308 HAS BEEN DISTRIBUTED TO APPLICABLE PROJECTS.

ASSOCIATED PROJECTS

Budget reference number	Description
03-00-5899	ST. LEON STATION 230-66KV TRANSFORMER ADDITION
03-00-8286	VIRDEN WEST STATION 66KV BREAKER ADDITION
03-00-8287	CROMER NORTH STATION 66 KV BREAKER ADDITION
03-00-8290	SOURIS EAST IPL 66KV BREAKER ADDITIONS
03-00-8345	RICHER SOUTH ADD 230-66kV EMERGENCY SPARE POWER TRANSFORMER
04-00-8577	SOURIS IPL EAST - SOURIS IPL WEST 66kV LINE
04-00-8578	ST. LEON - MANITOU IPL 66KV LINE
04-00-8580	VIRDEN WEST - CROMER IPL 66kV LINE
04-00-8606	WINNIPEG PIPE LINE TRANSFER TO LINE 50

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item

305

Title
IPL CAPITAL CONTRIBUTIONS

Budget reference number
03-00-8308

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	70474

DESCRIPTION:
RECORD CONTRIBUTIONS FROM INTERPROVINCIAL PIPE LINE TOWARD THE COST TO UPGRADE MANITOBA HYDRO'S ELECTRICAL FACILITIES AND PLANT DEDICATED TO VARIOUS IPL PUMPING STATIONS WITHIN MANITOBA TO ACCOMMODATE IPL'S EXPECTED ADDITIONAL MOTOR LOADS.

JUSTIFICATION:
AN AGREEMENT IS BEING NEGOTIATED BETWEEN IPL AND MH TO UPGRADE MANITOBA HYDRO'S ELECTRICAL FACILITIES AND PLANT DEDICATED TO VARIOUS IPL PUMPING STATIONS WITHIN MANITOBA TO ACCOMMDATE IPL'S EXPECTED ADDITIONAL MOTOR LOADS. IPL WILL PAY MH $8,247,000.00 FOR THE TOTAL COST OF THE WORK AS FOLLOWS:
A) $825,000.00 AT TIME OF SIGNING CONTRACT
B) $2,000,000.00 BY 1998 07 31
C) $3,000,000.00 BY 1998 10 31
D) $1,600,000.00 BY 1999 03 31
F) THE OUTSTANDING BALANCE FOR COMPLETION OF THE WORK ($822,000.00) BY 1999 09 30

REFERENCE:
TASK FORCE REPORT ON INTERPROVINCIAL PIPELINES SEP I & II EXPANSION PROGRAMS 1997 01 17.
SYSTEM PLANNING DEPARTMENT REPORT ON 'INTERPROVINCIAL PIPE LINES SYSTEM EXPANSION PROGRAM' (SEP I & SEP II) - SPD 97/1
I.P.L./MANITOBA HYDRO JOINT TASK FORCE REPORT DATED 15 MAY 1997 - LOCKLEY ENGINEERING LTD.
MEMO FROM C.V. THIO TO T.E. TYMOFICHUK, IPL/MANITOBA HYDRO JOINT TASK FORCE, 1997 05 15.

REVISION:
ITEM CANCELLED. CONTRIBUTION IS REFLECTED IN APPLICABLE ITEMS.

IN SERVICE DATES

Base estimate
199803 L2

Work start date
1998 06 01

	PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:							
TOTAL							
REV. AMOUNTS:							
Authorized to date:							
Over(under)expend:							
Auth Req :							
TOTAL							

Prepared by — yy mm dd — COORDINATOR
Estimated by — ORIGINATOR
Approved by — yy mm dd — COORDINATING MANAGER
Approved by — ORIGINATING MANAGER
yy mm dd

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 03-00-8308

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1998 10	0	ITEM CANCELLED. CONTRIBUTION IS REFLECTED IN APPLICABLE ITEMS.

ASSOCIATED PROJECTS

Budget reference number	Description
01-08-8116	CEDAR LAKE DEBRIS REMEDIATION
01-26-8124	CONAWAPA GENERATING STATION
01-42-8125	240 MW CCCT GENERATION
01-42-8126	84 MW CCCT GENERATION
02-00-8012	CONAWAPA TRANSMISSION
02-00-8013	240MW CCCT TRANSMISSION LINE
02-00-8014	84MW SCCT STATION
03-00-8288	LETELLIER STATION - 66KV BREAKER ADDITION
03-00-8291	SOURIS IPL WEST STATION BANK ADDITION
03-00-8408	CONAWAPA GENERATING STATION
03-00-8409	240 MW CCCT STATION
03-00-8410	84MW SCCT STATION
04-00-8579	LETELLIER - GRETNA IPL 66KV LINE
04-00-8624	BRERETON LAKE DISTRIBUTION SYSTEM

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — 306 — Domestic Item

Title
RICHER SOUTH ADD 230-66kV EMERGENCY SPARE POWER TRANSFORMER

Budget reference number
03-00-8345

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	70562

DESCRIPTION:
PURCHASE AND INSTALL 1 - 50/66.6/83.3/93.3 MVA, 3 PHASE, +/-15% LTC EQUIPPED TRANSFORMER COMPLETE WITH A 230 KV SWITCH (CAPABLE OF BREAKING MAGNETIZING CURRENT) AND ASSOCIATED EQUIPMENT.

JUSTIFICATION:
THE EXISTING SYSTEM SPARE UNIT IS SCHEDULED TO BE INSTALLED AT ST. LEON IN 2001. A REPLACEMENT EMERGENCY SPARE UNIT IS REQUIRED TO PROVIDE A 2ND CONTINGENCY BACKUP TO ALL 230-66KV TRANSFORMERS ON THE MANITOBA HYDRO SYSTEM.

NOTE:

TRANSFORMER COST TO BE CHARGED TO CENTRAL STORES.
INSTALLATION COST TO BE CHARGED TO THIS ITEM.

REFERENCE:
IPL TERRACE EXPANSION PROGRAM ADDENDUM TO REPORT SPD 97/1.

REVISION:
REFLECTS REVISED ACTIVITY AND OVERHEAD RATES.

CONTINGENCY: $78,000

IN SERVICE DATES

2001 10 31	1 023

Base estimate
199804 L2

Work start date
2000 04 01

PREV AUTHORITY Authorized to date	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
2000/01	286	15	9			310
2001/02	426	27	27			480
TOTAL	712	42	36			790
REV. AMOUNTS:						
Authorized to date:						
Over(under)expend:						
Auth 2000/01	434	21	13			468
Req. 2001/02	490	29	36			555
TOTAL	924	50	49			1 023

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR		COORDINATING MANAGER		ORIGINATING MANAGER

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 03-00-8345

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1998 10	790	NEW ITEM.

ASSOCIATED PROJECTS

Budget reference number	Description
03-00-5899	ST. LEON STATION 230-66KV TRANSFORMER ADDITION
03-00-8286	VIRDEN WEST STATION 66KV BREAKER ADDITION
03-00-8287	CROMER NORTH STATION 66 KV BREAKER ADDITION
03-00-8290	SOURIS EAST IPL 66KV BREAKER ADDITIONS
03-00-8292	ST. LEON 66 KV BREAKER ADDITION
04-00-8577	SOURIS IPL EAST - SOURIS IPL WEST 66kV LINE
04-00-8578	ST. LEON - MANITOU IPL 66KV LINE
04-00-8580	VIRDEN WEST - CROMER IPL 66kV LINE
04-00-8606	WINNIPEG PIPE LINE TRANSFER TO LINE 50

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr	10					10	10
May	18	1				19	29
Jun	18	1				19	48
Jul	18	1				19	67
Aug	34	2				36	103
Sep	36	1	1			38	141
Oct	30	1	1			32	173
Nov	49	2	1			52	225
Dec	49	2	2			53	278
Jan	56	3	2			61	339
Feb	56	3	2			61	400
Mar	60	4	4			68	468
TOTAL	434	21	13			468	468

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item

307

Title
SOURIS IPL EAST - SOURIS IPL WEST 66kV LINE

Budget reference number
04-00-8577

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	94203

DESCRIPTION:
CONSTRUCT APPROXIMATELY 10 KM OF 66KV, 266.8 KCMIL LINE FROM SOURIS IPL EAST 230-66KV STATION TO SOURIS IPL WEST 66-4KV STATION. THIS LINE IS TO BE EQUIPPED WITH SKY WIRE PROTECTION.

JUSTIFICATION:
THIS NEW DEDICATED 66KV LINE IS REQUIRED TO PROVIDE AN ELECTRICAL SUPPLY TO MEET IPL'S OPERATING CONDITIONS;
I) ABILITY FOR FULL VOLTAGE STARTING, 1 START/HOUR OF 3500 HP OR LESS MOTORS. II) MAINTAIN MH SUPPLY VOLTAGE AT NOMINAL +/- 5% DURING IPL EQUIPMENT CONTINGENCIES. III) MAINTAIN MAXIMUM 15% VDIP AT IPL MOTOR TERMINALS DURING FULL VOLTAGE STARTING. THIS PROJECT IS CONTINGENT UPON CUSTOMER EXPANSION AT SOURIS WEST IPL.

REFERENCE:
TASK FORCE REPORT ON INTERPROVINCIAL PIPELINES SEP I & II EXPANSION PROGRAMS 1997 01 17.
SYSTEM PLANNING DEPARTMENT REPORT ON INTERPROVINCIAL PIPELINES SYSTEM EXPANSION PROGRAM (SEPI & SEPII) - SPD 97/1.
I.P.L./MANITOBA HYDRO JOINT TASK FORCE REPORT DATED 1997 05 15, LOCKLEY ENGINEERING LTD.
MEMO FROM C.V. THIO TO T.E. TYMOFICHUK, IPL/MANITOBA HYDRO JOINT TASK FORCE, 1997 05 15.

REVISION:
REVISED TO REFLECT IPL CONTRIBUTION. WOULD BE FULLY BILLABLE UNLESS IPL INCREASE THEIR LOAD.

CONTINGENCY AMOUNT: $0

IN SERVICE DATES			Base estimate
2004 10 31	618		199902 L2
			Work start date
			2004 02 01

PREV. AUTHORITY Authorized to date:	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
2003/04	8	1				9
2004/05	531	67	18			616
TOTAL	539	68	18			625
REV. AMOUNTS:						
Authorized to date:						
Over(under)expend:						
Auth 2003/04	9	1			-10	
Req. 2004/05	541	67			- 602	6
TOTAL	550	68			- 612	6

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR		COORDINATING MANAGER		ORIGINATING MANAGER

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 04-00-8577

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1997 07	739	NEW ITEM.
1999 10	0	REVISED TO REFLECT IPL CONTRIBUTION. WOULD BE FULLY BILLABLE UNLESS IPL INCREASE THEIR LOAD.

ASSOCIATED PROJECTS

Budget reference number	Description
03-00-5899	ST. LEON STATION 230-66KV TRANSFORMER ADDITION
03-00-8286	VIRDEN WEST STATION 66KV BREAKER ADDITION
03-00-8287	CROMER NORTH STATION 66 KV BREAKER ADDITION
03-00-8290	SOURIS EAST IPL 66KV BREAKER ADDITIONS
03-00-8292	ST. LEON 66 KV BREAKER ADDITION
03-00-8345	RICHER SOUTH ADD 230-66kV EMERGENCY SPARE POWER TRANSFORMER
04-00-8578	ST. LEON - MANITOU IPL 66KV LINE
04-00-8580	VIRDEN WEST - CROMER IPL 66kV LINE
04-00-8606	WINNIPEG PIPE LINE TRANSFER TO LINE 50

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — 308 — Domestic Item

Title
ST. LEON - MANITOU IPL 66KV LINE

Budget reference number
04-00-8578

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	94228

DESCRIPTION:
CONSTRUCT 13.3 KM OF DEDICATED 66 kV, 266.8 KCMIL LINE FROM ST. LEON 230-66kV STATION TO MANITOU IPL STATION. THIS LINE IS TO BE EQUIPPED WITH LIGHTENING PROTECTION. PROVIDE SWITCHING TO NORMAL SUPPLY MANITOU IPL FROM THE NEW LINE AND ALTERNATE SUPPLY FROM EXISTING LINE #51.

JUSTIFICATION:
THE PRESENT SUPPLY TO MANITOU IPL REQUIRES STARTING RESTRICTIONS. THIS NEW DEDICATED 66kV KINE IS REQUIRED TO PROVIDE AN ELECTRICAL SUPPLY TO MEET IPL'S OPERATING CONDITIONS:
1. ABILITY FOR FULL VOLTAGE STARTING, 1 START/HOUR OF 3 500 HP, OR LESS, MOTORS;
2. MAINTAIN MH SUPPLY VOLTAGE AT NOMINAL +/-5% DURING IPL EQUIPMENT CONTINGENCIES;
3. MAINTAIN MAXIMUM 15% VDIP AT IPL MOTOR TERMINALS DURING FULL VOLTAGE STARTING.
THIS PROJECT IS CONTINGENT UPON CUSTOMER EXPANSION AT MANITOU IPL.

REFERENCE:
TASK FORCE REPORT ON INTERPROVINCIAL PIPELINES SEP I & II EXPANSION PROGRAMS 1997 01 17.
- SYSTEM PLANNING DEPARTMENT REPORT ON 'INTERPROVINCIAL PIPE LINES SYSTEM EXPANSION PROGRAM' (SEP I & SEP II) - SPD 97/1.
- IPL/MANITOBA HYDRO JOINT TASK FORCE REPORT DATED 1997 05 15 - LOCKLEY ENGINEERING LTD.
- MEMO FROM CV THIO TO TE TYMOFICHUK, IPL/MANITOBA HYDRO JOINT TASK FORCE, 1997 05 15.

REVISION:
PRELIMINARY DESIGN COSTS INCURRED DURING 1998/99. ESTIMATE REVIEWED AND NO CHANGE NECESSARY AT THIS TIME.

NOTE:
THIS ITEM IS SUBJECT TO FULL FUNDING BY ENBRIDGE. IF FUNDING CAN NOT BE NEGOTIATED THIS PROJECT WILL BE CANCELLED AND MOTOR STARTING RESTRICTIONS WILL BE APPLIED.

IN SERVICE DATES

2004 09 30 — 1 169

Base estimate
199902 L1

Work start date
1997 07 01

PREV AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date	8					8
1999/00	-8					-8
2000/01						
2001/02						
2002/03	4					4
2003/04	549	73	18			640
2004/05	370	55	35			460
TOTAL	923	128	53			1 104
REV. AMOUNTS:						
Authorized to date:	8					8
Over(under)expend:						
Auth 1999/00			1			1
Req: 2000/01			1			1
2001/02			1			1
2002/03	4		1			5
2003/04	596	54	20			670
2004/05	403	42	38			483
TOTAL	1 011	96	62			1 169

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 04-00-8578

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1997 07	915	New Item.
1999 10	1 105	ISD deferred from 1998 10 31 to 2004 09 30 due to IPL expansion.

ASSOCIATED PROJECTS

Budget reference number	Description
03-00-5899	ST. LEON STATION 230-66KV TRANSFORMER ADDITION
03-00-8286	VIRDEN WEST STATION 66KV BREAKER ADDITION
03-00-8287	CROMER NORTH STATION 66 KV BREAKER ADDITION
03-00-8290	SOURIS EAST IPL 66KV BREAKER ADDITIONS
03-00-8292	ST. LEON 66 KV BREAKER ADDITION
03-00-8345	RICHER SOUTH ADD 230-66kV EMERGENCY SPARE POWER TRANSFORMER
04-00-8577	SOURIS IPL EAST - SOURIS IPL WEST 66kV LINE
04-00-8580	VIRDEN WEST - CROMER IPL 66kV LINE
04-00-8606	WINNIPEG PIPE LINE TRANSFER TO LINE 50

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar			1			1	1
TOTAL			1			1	1
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar			1			1	1
TOTAL			1			1	1

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item

309

Title
LETELLIER - GRETNA IPL 66KV LINE

Budget reference number
04-00-8579

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Master Deleted	Master Deleted	Master Deleted	94229

DESCRIPTION:
CONSTRUCT 30.6 KM OF 66 KV, 266.8 KCMIL LINE FROM LETELLIER 230-66 KV STATION TO GRETNA IPL 66-4 KV STATION. THIS LINE IS TO BE EQUIPPED WITH SKY WIRE PROTECTION.

JUSTIFICATION:
THIS NEW DEDICATED 66 KV LINE, WHICH WILL OPERATE IN PARALLEL WITH LINE 21, IS REQUIRED TO PROVIDE AN ELECTRICAL SUPPLY TO MEET IPL'S OPERATING CONDITIONS;
1. ABILITY FOR FULL VOLTAAGE STARTING, 1 START/HOUR OF 3 500 HP, OR LESS, MOTORS;
2. MAINTAIN MH SUPPLY VOLTAGE AT NOMINAL +/- 5% DURING IPL EQUIPMENT CONTINGENCIES;
3. MAINTAIN MAXIMUM 15% VDIP AT IPL MOTOR TERMINALS DURING FULL VOLTAGE STARTING.
THIS PROJECT IS CONTINGENT UPON CUSTOMER EXPANSION AT MANITOU IPL.

REFERENCE:
TASK FORCE ON INTERPROVINCIAL PIPELINES SEP I & II EXPANSION PROGRAMS 1997 01 17.
- SYSTEM PLANNING DEPARTMENT REPORT ON 'INTERPROVINCIAL PIPE LINES SYSTEM EXPANSION PROGRAM' (SEP I & SEP II) - SPD 97/1
- IPL/MANITOBA HYDRO JOINT TASK FORCE REPORT DATED 1997 05 15 - LOCKLEY ENGINEERING LTD.
- MEMO FROM CV THIO TO T.E. TYMOFICHUK, IPL/MANITOBA HYDRO JOINT TASK FORCE, 1997 05 15.

REVISION:
ITEM CANCELLED, NOT REQUIRED FOR IPL EXPANSION.

IN SERVICE DATES

Base estimate
199707 L1

Work start date
1997 06 01

	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
PREV. AUTHORITY Authorized to date:						
TOTAL						
REV. AMOUNTS:						
Authorized to date.						
Over(under)expend:						
Auth						
Req :						
TOTAL						

Prepared by yy mm dd COORDINATOR	Approved by yy mm dd	Approved by	yy mm dd
Estimated by ORIGINATOR	COORDINATING MANAGER	ORIGINATING MANAGER	

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 04-00-8579

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1997 07	2 641	New Item.

ASSOCIATED PROJECTS

Budget reference number	Description
03-00-5899	ST. LEON STATION 230-66KV TRANSFORMER ADDITION
03-00-8286	VIRDEN WEST STATION 66KV BREAKER ADDITION
03-00-8287	CROMER NORTH STATION 66 KV BREAKER ADDITION
03-00-8290	SOURIS EAST IPL 66KV BREAKER ADDITIONS
03-00-8292	ST. LEON 66 KV BREAKER ADDITION
03-00-8345	RICHER SOUTH ADD 230-66kV EMERGENCY SPARE POWER TRANSFORMER
04-00-8577	SOURIS IPL EAST - SOURIS IPL WEST 66kV LINE
04-00-8578	ST. LEON - MANITOU IPL 66KV LINE
04-00-8580	VIRDEN WEST - CROMER IPL 66kV LINE
04-00-8606	WINNIPEG PIPE LINE TRANSFER TO LINE 50

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — 310 Domestic Item

Title
VIRDEN WEST - CROMER IPL 66kV LINE

Budget reference number
04-00-8580

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	94204

DESCRIPTION:
BUILD 3.2 MILES OF 66 KV 266.8 MCM FROM VIRDEN WEST TERMINAL SOUTHWARD TO TIE TO LINE 94. (THE SWITCH REQUESTED IN THE STUDY ALREADY EXISTS).

JUSTIFICATION:
THE LINE IS REQUIRED TO BYPASS THE EXISTING VIRDEN STATIONS IN ORDER FOR THE NETWORKED OPERATION OF THE 66 KV TO CROMER IPL. THIS ITEM WILL BE FULLY BILLABLE AND SHOULD NET OUT AT $0.

REFERENCE:
INTERPROVINCIAL PIPE LINES TERRACE EXPANSION PROGRAM ADDENDUM TO REPORT SPD 97/1 DATED 98 04 14.

REVISION:
REVISED TO REFLECT ACTUALS TO DATE.

CONTINGENCY AMOUNT: $0

IN SERVICE DATES						Base estimate 199902 L4
1999 09 30	433					Work start date 1999 01 01
PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:	142		-1		-63	78
1999/00	221	7			- 323	-95
TOTAL	363	7	-1		- 386	-17
REV. AMOUNTS:						
Authorized to date:	142		-1		-63	78
Over(under)expend						
Auth Req.: 1999/00	284	2	6	-2	- 232	58
TOTAL	426	2	5	-2	- 295	136

Prepared by: yy mm dd COORDINATOR — Approved by: yy mm dd COORDINATING MANAGER — Approved by: yy mm dd ORIGINATING MANAGER

Estimated by: ORIGINATOR

MajCER(2) Rev. 97/09

CAPITAL EXPENDITURE REVISION

Budget reference number 04-00-8580

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1997 07	0	NEW ITEM.
1999 10	0	REVISED TO REFLECT ACTUALS TO DATE.

ASSOCIATED PROJECTS

Budget reference number	Description
03-00-5899	ST. LEON STATION 230-66KV TRANSFORMER ADDITION
03-00-8286	VIRDEN WEST STATION 66KV BREAKER ADDITION
03-00-8287	CROMER NORTH STATION 66 KV BREAKER ADDITION
03-00-8290	SOURIS EAST IPL 66KV BREAKER ADDITIONS
03-00-8292	ST. LEON 66 KV BREAKER ADDITION
03-00-8345	RICHER SOUTH ADD 230-66kV EMERGENCY SPARE POWER TRANSFORMER
04-00-8577	SOURIS IPL EAST - SOURIS IPL WEST 66kV LINE
04-00-8578	ST. LEON - MANITOU IPL 66KV LINE
04-00-8606	WINNIPEG PIPE LINE TRANSFER TO LINE 50

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	177	-1	1			177	177
May	2		2			4	181
Jun	32		2	- 232		- 198	-17
Jul	50	2				52	35
Aug	23		1			24	59
Sep		1			-2	-1	58
Oct							58
Nov							58
Dec							58
Jan							58
Feb							58
Mar							58
TOTAL	284	2	6	- 232	-2	58	58
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

COMPLEX STATUS: ☐ Planned ☒ In progress

Complex no. 253

REVISION STATUS: ☒ New complex ☐ In service change ☐ Concept change ☐ Estimate change only

COMPLEX: BRANDON EAST 115KV IMPROVEMENTS

Proposal

Conduct environmental assessment,acquire prorerty,and obtain licencing for construction of 2.63km of 795 MCM ACSR double circuit tubular steel transmission line between Brandon GS and structure 9A. Terminate the new 115kV, 795 MCM ACSR transmission lines replacing BD52 and BK41 at tower 9A and connect to existing transmission lines BD52 to crocus plains and BK41 to CXY Chemicals and Maple Leaf. Construct a new 115-25kV steel stn with 1x10/13.3/16.6MVA,3PH LTC transformers and two feeders at the proposed Maple Leaf hog processing plant site in Brandon and a supply line tap at 115kV line BK41.

JUSTIFICATION: ☒ Load ☒ Service ☐ Safety ☒ Efficiency ☐ Reliability ☐ Other

Explanation

New steel station and system changes required to transmit power from Brandon GS to the proposed Maple Leaf hog processing plant, to upgrade existing 115kV facilities for supplying additional load at CXY Chemicals and to accommodate Brandon area load growth.

Estimate Level	COMPLEX START (yyyy mm)
L2-3	1998 03

IN SERVICE DATES AND AMOUNTS

1999 04	$1527	1999 05	$2225		

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	2,679		62		2,741	2,541	200	8
Year 99/00	965	15	31	3	1,008	900	108	12
00/01								
01/02								
02/03								
03/04								
04/05								
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	3,644	15	93	3	3,749	3,441	308	9

REVISION: Increased to reflect a design concept change in foundation type, and costs to completion.

Reviewed by ORIGINATOR	yyyy mm dd 99 11 08	Reviewed by COORDINATOR	yyyy mm dd 99 11 03
Reviewed by CONSTRUCTOR	yyyy mm dd 99 11 03	Approved by VICE PRESIDENT	yyyy mm dd 99 11 16

H2856/r Rev 99 03

Complex no. 253

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Advance or deferral impact

Ability to supply power requirements at the planned Maple Leaf hog processing plant, and load growth in the Brandon area, and at CXY Chemicals.

Factors affecting timing or viability

Rate of current load growth, and progress on develpoment of the Maple Leaf hog processing plant.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Brandon East 115kV Improvements	1,314	1,316	1,342	1,499	157	12
Brandon 65th St East New 115-25kV Stn	1,776	1,773	1,808	1,926	118	7
Brandon GS Term of Tower 9A 115kV T/L	220	196	200	220	20	10
TOTAL	3,310	3,285	3,350	3,645	295	9

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
1998 06	3,441	NEW ITEM
1999 10	3,749	Increased to reflect a design concept change in foundation type, and costs to completion.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item

311

Title: BRANDON EAST 115 KV IMPROVEMENTS

Budget reference number: 02-00-8002

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	70514

DESCRIPTION:
CONDUCT ENVIRONMENTAL IMPACT ASSESSMENT, ACQUIRE ADDITIONAL PROPERTY AND OBTAIN NECESSARY APPROVALS AND LICENCES FOR CONSTRUCTION OF 2.63 KM OF 795 MCM ACSR DOUBLE CIRCUIT TUBULAR STEEL TRANSMISSION LINE BETWEEN BRANDON GENERATING STATION AND STRUCTURE 9A. TERMINATE THE NEW 115 KV, 795 MCM ACSR TRANSMISSION LINES REPLACING BD52 AND BK41 AT TOWER 9A AND CONNECT TO EXISTING TRANSMISSION LINES BD52 TO CROCUS PLAINS AND BK41 TO CXY CHEMICALS AND MAPLE LEAF. THIS WILL REPLACE 2.63 KM OF EXISTING DOUBLE CIRCUIT 336.4 MCM ACSR, 115 KV TRANSMISSION LINES BD52 AND BK41.

CONSTRUCT A 115 KV LINE TAP TO SUPPLY A NEW 115-25 KV STEEL STATION FOR THE PROPOSED MAPLE LEAF HOG PROCESSING PLANT SITE ON 65TH ST. EAST.

JUSTIFICATION:
THIS ITEM PROVIDES FOR PART OF SYSTEM CHANGES REQUIRED TO TRANSMIT POWER FROM BRANDON G.S. TO THE PROPOSED MAPLE LEAF HOG PROCESSING PLANT, TO UPGRADE EXISTING 115KV FACILITIES FOR SUPPLYING ADDITIONAL LOAD AT CXY CHEMICALS AND TO ACCOMMODATE BRANDON AREA LOAD GROWTH.

REFERENCE:
KEY ACCOUNTS - BRANDON REQUEST FOR SERVICE

REVISION:
INCREASE IS DUE TO A DESIGN CONCEPT CHANGE (FOUNDATION TYPE). REFLECTS REVISED ACTIVITY AND OVERHEAD RATES.

CONTINGENCY: $120,000

IN SERVICE DATES		Base estimate
1999 04 30	1 527	199903 L3
		Work start date
		1998 04 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date	1 263		18			1 281
1999/00	75		9			84
TOTAL	1 338		27			1 365
REV. AMOUNTS:						
Authorized to date:	1 263		18			1 281
Over(under)expend.						
Auth 1999/00 Req.:	236	1	9			246
TOTAL	1 499	1	27			1 527

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 02-00-8002

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1998 10	1 365	NEW ITEM.

ASSOCIATED PROJECTS

Budget reference number	Description
03-00-8332	BRANDON - 65TH ST. EAST NEW 115-25 KV STATION
03-00-8343	BRANDON GS TERMINATION OF TOWER 9A 115KV T/L

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	101		9			110	110
May	7	1				8	118
Jun	2					2	120
Jul	2					2	122
Aug	1					1	123
Sep	1					1	124
Oct	122					122	246
Nov							246
Dec							246
Jan							246
Feb							246
Mar							246
TOTAL	236	1	9			246	246
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item

3/2

Title
BRANDON - 65TH ST. EAST NEW 115-25 KV STATION

Budget reference number
03-00-8332

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	70513

DESCRIPTION:
CONSTRUCT A NEW 115-25 KV STEEL STATION WITH 1 X 10/13.3/16.6 MVA, 3 PH LTC TRANSFORMERS AND TWO FEEDERS AT THE PROPOSED MAPLE LEAF HOG PROCESSING PLANT SITE IN BRANDON (SOUTH 1/2 OF SEC. 16-10-18W). THE STATION WILL BE TAPPED OFF 115 KV LINE BK41 WHICH TRANSVERSES THE PROPOSED STATION LOCATION.

JUSTIFICATION:
THIS STATION IS REQUIRED TO SUPPLY THE PROPOSED MAPLE LEAF HOG PROCESSING PLANT AND IS CONTINGENT ON ITS DEVELOPMENT.

REFERENCE:
KEY ACCOUNTS - BRANDON REQUEST FOR SERVICE.

REVISION:
REFLECTS REVISED ACTIVITY AND OVERHEAD RATES AND ALSO COSTS TO COMPLETION.

CONTINGENCY: $50,000

IN SERVICE DATES		Base estimate
1999 05 31	2 003	199903 L4
		Work start date
		1998 03 01

	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
PREV. AUTHORITY						
Authorized to date	1 376		43			1 419
1999/00	424	17	17			458
TOTAL	1 800	17	60			1 877
REV. AMOUNTS:						
Authorized to date:	1 376		43			1 419
Over(under)expend:						
Auth Req: 1999/00	550	13	21			584
TOTAL	1 926	13	64			2 003

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 03-00-8332

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1998 10	1 878	TRANSFERRED FROM DOMESTIC TO MAJOR. TRANSFORMER CASHFLOW MOVED TO 99/00. STATION NAME CHANGED.

ASSOCIATED PROJECTS

Budget reference number	Description
02-00-8002	BRANDON EAST 115 KV IMPROVEMENTS
03-00-8343	BRANDON GS TERMINATION OF TOWER 9A 115KV T/L

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	215	4	10			229	229
May	104	3	11			118	347
Jun	77	2				79	426
Jul	77	2				79	505
Aug	77	2				79	584
Sep							584
Oct							584
Nov							584
Dec							584
Jan							584
Feb							584
Mar							584
TOTAL	550	13	21			584	584
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item 313

Title
BRANDON GS TERMINATION OF TOWER 9A 115KV T/L

Budget reference number
03-00-8343

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	70593

DESCRIPTION:
TERMINATE THE NEW 115KV, 795 MCM ACSR TRANSMISSION LINES REPLACING DB52 AND BK41 IN FORMER BD52 AND BK41 CIRCUIT BREAKER POSITIONS 22, 23, AND 24 AT BRANDON GS.

JUSTIFICATION:
ELSEWHERE IN THE BUDGET, JUSTIFICATION IS GIVEN FOR CONSTRUCTION OF 2.63 KM OF NEW 115KV DOUBLE CIRCUIT 795 MCM ACSR TO REPLACE 2.63 KM OF UNDER RATED SECTION OF BD52 AND BK41 FROM BRANDON GS TO TURNING STRUCTURE 9A. THIS ITEM PROVIDES FOR THE TERMINATION OF THESE LINES AT BRANDON GS.

REFERENCE:
KEY ACCOUNTS - BRANDON REQUEST FOR SERVICE

REVISION:
REFLECTS REVISED ACTIVITY AND OVERHEAD RATES.

CONTINGENCY: $18,000

IN SERVICE DATES		Base estimate
1999 05 31	222	199808 L2
		Work start date
		1998 09 01

	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
PREV AUTHORITY Authorized to date.	41					41
1999/00	158	1	2	-3		158
TOTAL	199	1	2	-3		199
REV. AMOUNTS. Authorized to date:	41					41
Over(under)expend.						
Auth Req.: 1999/00	179	1	1	-3		178
TOTAL	220	1	1	-3		219

Prepared by: yy mm dd COORDINATOR Approved by: yy mm dd Approved by: yy mm dd
Estimated by: ORIGINATOR COORDINATING MANAGER ORIGINATING MANAGER

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number: 03-00-8343

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1998 10	199	NEW ITEM.

ASSOCIATED PROJECTS

Budget reference number	Description
02-00-8002	BRANDON EAST 115 KV IMPROVEMENTS
03-00-8332	BRANDON - 65TH ST. EAST NEW 115-25 KV STATION

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	81	1			-2	80	80
May	98		1		-1	98	178
Jun							178
Jul							178
Aug							178
Sep							178
Oct							178
Nov							178
Dec							178
Jan							178
Feb							178
Mar							178
TOTAL	179	1	1		-3	178	178
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

COMPLEX STATUS: [X] Planned [ ] In progress

Complex no. 250

REVISION STATUS: [ ] New complex [ ] In service change [ ] Concept change [X] Estimate change only

COMPLEX: BRANDON CROCUS PLAINS 115-25KV STN ADDITION

Proposal
Install two 15/20/25 MVA 115-25KV transformers with OLTC. Install one 115KV breaker to connect the transformers to line BF52. Install 7x25KV breakers and associated equipment to connect the transformers and to provide four additional 25KV feeders into the industrial park. Salvage a bypass jumper.

JUSTIFICATION
[X] Load [X] Service
[ ] Safety [X] Efficiency
[X] Reliability [ ] Other

Explanation
To supply the load growth and the industrial loads in the south Brandon area.

Estimate Level	COMPLEX START (yyyy mm)
L2	2001 01

IN SERVICE DATES AND AMOUNTS

2003 10	$7159			

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend								
Year 99/00								
00/01	82	4	1		87	85	2	2
01/02	546	37	23		606	588	18	3
02/03	3,377	293	183		3,853	3,585	268	7
03/04	1,791	181	289		2,261	2,206	55	2
04/05	314	38			352	354	-2	-1
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	6,110	553	496		7,159	6,818	341	5

REVISION: Scope unchanged.

Reviewed by ORIGINATOR	yyyy mm dd 99 11 03	Reviewed by COORDINATOR	yyyy mm dd 99 11 03
Reviewed by CONSTRUCTOR	yyyy mm dd 99 11 03	Approved by VICE-PRESIDENT	yyyy mm dd 99 11 16

H2856/r Rev 99 03

Complex no. 250

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Advance or deferral impact

Ability to supply load growth and the industrial loads in the south Brandon area.

Factors affecting timing or viability

Rate of current load growth.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE	
					Amount	%
Brandon Crocus Plains 115-25KV Stn addition		5,803	5,919	6,110	191	3
TOTAL		5,803	5,919	6,110	191	3

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
1998 10	6,818	NEW ITEM
1999 10	7,159	Scope unchanged.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item _ Domestic Item

314

Title
BRANDON CROCUS PLAINS 115-25KV STATION ADDITION

Budget reference number
03-00-8350

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	70564

DESCRIPTION:
INSTALL TWO 15/20/25 MVA 115-24.9 KV TRANSFORMERS WITH OLTC. INSTALL ONE 115KV BREAKER TO CONNECT THE TRANSFORMERS TO LINE BF52. INSTALL 7 X 25 KV BREAKERS AND THE ASSOCIATED EQUIPMENT TO CONNECT THE TRANSFORMERS AND TO PROVIDE FOUR ADDITIONAL 25 KV FEEDERS INTO THE INDUSTRIAL PARK. SALVAGE THE BYPASS JUMPER. INSTALL ALL OF THE ASSOCIATED EQUIPMENT AS SHOWN IN THE SLD.

JUSTIFICATION:
TO SUPPLY THE LOAD GROWTH AND THE INDUSTRIAL LOADS IN THE SOUTH BRANDON AREA.

REFERENCE:
MEMO, S. SEAFOOT TO D.K. SOLKOSKI, 1998 01 27, 'BRANDON CROCUS PLAINS 115-24.9 KV BANK ADDITION'.

REVISION:
REFLECTS REVISED ACTIVITY AND OVERHEAD RATES.

CONTINGENCY: $529,000

IN SERVICE DATES		Base estimate
2003 10 31	7 159	199805 L2
		Work start date
		2001 01 01

PREV. AUTHORITY Authorized to date:	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
2000/01	80	4	1			85
2001/02	527	38	23			588
2002/03	3 131	290	164			3 585
2003/04	1 751	187	269			2 207
2004/05	314	40				354
TOTAL	5 803	559	457			6 819
REV. AMOUNTS:						
Authorized to date:						
Over(under)expend:						
Auth 2000/01	82	4	1			87
Req 2001/02	546	37	23			606
2002/03	3 377	293	183			3 853
2003/04	1 791	181	289			2 261
2004/05	314	38				352
TOTAL	6 110	553	496			7 159

Prepared by: yy mm dd COORDINATOR — Approved by: yy mm dd Approved by: yy mm dd

Estimated by: ORIGINATOR — COORDINATING MANAGER — ORIGINATING MANAGER

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 03-00-8350

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1998 10	6 819	NEW ITEM.

ASSOCIATED PROJECTS

Budget reference number ..... Description .....

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan	27	2				29	29
Feb	27	2				29	58
Mar	28		1			29	87
TOTAL	82	4	1			87	87

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

COMPLEX STATUS	Complex no.	REVISION STATUS
☐ Planned ☒ In progress	86	☐ New complex ☒ In service change ☒ Concept change ☐ Estimate change only

COMPLEX	DIESEL UPGRADING ENHANCEMENT

Proposal

Increase capacity to provide 60 amp service at 4 diesel sites:
1) Brochet - Larger units, additional units, tanks and plant expansion.
2) Lac Brochet - Larger units, additional units, tanks and plant expansion.
3) Tadoule - Site improvements, additional units and plant expansion.
4) Shamattawa - Additional tanks, two mobiles and new plant.
5) Distribution - Pik/Thicket- 25kv tie line; other sites- rebuild distribution system to deliver enhanced.

JUSTIFICATION		Explanation
☒ Load	☒ Service	The provision of service to isolated diesel served customers has not been equivalent to that enjoyed by southern rural customers. Expansion of service to accommodate 60 amp residential supply is a priority.
☐ Safety	☐ Efficiency	
☐ Reliability	☐ Other	

Estimate Level	COMPLEX START (yyyy mm)
L3	1990 04

IN SERVICE DATES AND AMOUNTS							
1997 03	$9886	1998 01	$2181	1998 07	$875	1998 08	$112
1999 02	$186	1999 08	$1952	1999 10	$7830	2000 03	$241
2002 10	$8297	2003 03	$220				

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	19,870		1,342	1,078	20,134	18,651	1,483	8
Year 99/00	1,860	29	408	183	2,114	3,000	-886	-30
00/01	1,598	101	47	8	1,738	1,129	609	54
01/02	3,828	306	317	27	4,424	253	4,171	NA
02/03	1,558	145	356	76	1,983	5,500	-3,517	-64
03/04								
04/05								
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	28,714	581	2,470	1,372	30,393	28,533	1,860	7

REVISION	Reflects additional costs for:CT & PT metering (Brochet), Eng & Consult'g (Brochet & Lac Brochet), welding & commissioning (Lac Brochet), & 1 YR deferral of Shamattawa Mods

		yyyy mm dd			yyyy mm dd
Reviewed by	ORIGINATOR	99 11 09	Reviewed by	COORDINATOR	99 11 09
Reviewed by	CONSTRUCTOR	99 11 03	Approved by	VICE-PRESIDENT	99 11 [illegible]09

H2856/r Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Complex no. 86

Advance or deferral impact

The provision of electrical service equivalent to that enjoyed by southern rural customers is a priority.

Factors affecting timing or viability

Decision/ agreement to connect community(s) to the central system supply.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE	
					Amount	%
Diesel Generation - Enhanced Requirements	10,377	3,740	3,815	3,740	-75	-2
Brochet Powerhouse - Tank Farm	1,752	7,212	7,356	8,307	951	13
Lac Brochet Modifications	1,722	3,804	3,880	3,904	24	1
St. Theresa Modifications	344	341	348	343	-5	-1
Shamatawa Modifications	1,717	7,092	7,013	7,362	349	5
Tadoule Lake New Powerhouse	2,314	4,891	4,989	4,891	-98	-2
Lac Brochet Distribution upgrade to 25kV	241	151	154	166	12	8
TOTAL	18,467	27,231	27,555	28,713	1,158	4

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
9510	23,929	Reflects 1995 base and adds requirements to complete Tadoule Lake powerhouse.
9610	24,913	Lac Brochet advanced & Shamatawa deferred 1 year, Brochet powerhoust tank farm deferred 2 years, shamatawa mods estimate updated & ISD deferred to 2000 11 30.
9710	27,252	The est. reflects the relocation extension and expansion of the existing Brochet powerhouse and final design estimates associated with the distribution and upgrades at Lac Brochet
1998 10	28,533	Reflects additional fire protection, scope increase for consultant, and higher distribution and interest costs for Brochet tank farm. Shamattawa Mods have been deferred one year.
1999 10	30,393	Reflects additional costs for:CT & PT metering (Brochet), Eng & Consult'g (Brochet & Lac Brochet), welding & commissioning (Lac Brochet), & 1 YR deferral of Shamattawa Mods

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item __ Domestic Item 315

Title
TADOULE LAKE NEW POWERHOUSE

Budget reference number
04-00-9304

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Operating & Maintenance	Construction	Construction	70372

DESCRIPTION:
INSTALL A NEW POWERHOUSE, C/W NEW GENERATING SETS AND PLANT AUTOMATION, ON A NEW SITE C/W A NEW TANK FARM.

ENHANCED PORTION TO BE CHARGED TO ENHANCED REQUIREMENTS - ITEM 9104-00-1413; W/O #46052.

JUSTIFICATION:
THE NEW SITE IS REQUIRED TO ACCOMMODATE THE 6 0 AMP ENHANCED SERVICE SCHEDULED FOR TADOULE LAKE.

REVISION:
ITEM COMPLETED.

IN SERVICE DATES

1997 03 31 | 5 221

Base estimate
199805 L3

Work start date
1997 10 01

	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
PREV. AUTHORITY Authorized to date.	4 891		330	-1 026		4 195
TOTAL	4 891		330	-1 026		4 195
REV. AMOUNTS:						
Authorized to date:	4 891		330	-1 026		4 195
Over(under)expend.						
Auth Req.:						
TOTAL	4 891		330	-1 026		4 195

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 04-00-9304

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1990 10	3 296	NEW ITEM
1991 10	3 040	REVISED ESCALATION AND INTEREST RATES.
1992 10	3 000	REVISED ESCALATION AND INTEREST RATES. 'GROSS' REVISED TO 1992 BASE. SOME WORK ADVANCED, CHANGING THE CASH FLOW.
1993 10	3 535	REVISED ESCALATION AND INTEREST RATES. 'GROSS' REVISED TO 1993 BASE. EXTRA COSTS INVOLVED IN FUEL MONITORING AND BUILDING MODIFICATIONS. I.S.D. ADJUSTED TO REFLECT REVENUE RECOGNITION.
1994 10	3 636	DOLLARS ADJUSTED TO 1994BASE WITH REVISED INT & ESC. FLOWS ADUSTED FOR REVISED I.S.D.
1995 10	4 682	REVISED TO REFLECT ACTUAL EXPENDITURES.
1996 10	4 827	TO REFLECT ACTUAL COSTS TO JULY /96. COST OVERRUNS DUE TO SET-UP DIFFICULTIES RELATED TO THE AUTOMATION COMMUNICATIONS SOFTWARE. THESE EXPENDITURES WILL BENEFIT THE ASSOCIATED PROJECTS AS WELL. ADDITIONAL FUNDS REQUIRED TO COMPLETE SET-UP OF THE AUTOMATION COMMUNICATIONS SOFTWARE.
1997 10	4 195	ITEM COMPLETED.
1998 10	4 195	ITEM COMPLETED.

ASSOCIATED PROJECTS

Budget reference number	Description
04-00-1385	BROCHET POWERHOUSE - TANK FARM
04-00-1395	LAC BROCHET MODIFICATIONS
04-00-1405	ST. THERESA - MODIFICATIONS
04-00-1413	DIESEL GENERATION - ENHANCED REQUIREMENTS
04-00-8594	LAC BROCHET DISTRIBUTION UPGRADE TO 25 KV
04-00-9303	SHAMATTAWA MODIFICATIONS

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

1999-08-21 05:28 PM

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item

316

Title: DIESEL GENERATION - ENHANCED REQUIREMENTS

Budget reference number: 04-00-1413

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Operating & Maintenance	Construction	Construction	70044

DESCRIPTION:
INCREASE CAPACITY TO PROVIDE 60 AMP SERVICE AT 4 DIESEL SITES:
1) BROCHET
2) LAC BROCHET
3) TADOULE LAKE
4) SHAMATTAWA
REBUILD DISTRIBUTION TO ENABLE SUPPLY OF ENHANCED DIESEL CAPACITY TO CUSTOMERS.

JUSTIFICATION:
REPLACE EXISTING GENERATION WITH LARGER UNITS, ADDITIONAL GENERATION UNITS AND FUEL TANKS; CONSTRUCT PLANT EXTENSIONS TO PROVIDE 60 AMP SERVICE TO CUSTOMERS AT THE SITES.

REVISION:
ITEM COMPLETED.

IN SERVICE DATES						Base estimate
1997 03 31	3 776	1997 07 31	0	1997 11 30	-0	199805 L5
1997 04 30	3	1997 08 31	-4	1998 03 31	0	
1997 05 31	1	1997 09 30	0	1999 01 31	1	Work start date
1997 06 30	0	1997 10 31	0	1999 04 30	0	1997 04 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date	3 740		37			3 777
1999/00	-1					-1
TOTAL	3 739		37			3 776
REV. AMOUNTS:						
Authorized to date:	3 740		37			3 777
Over(under)expend:						
Auth Req.:						
TOTAL	3 740		37			3 777

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR		COORDINATING MANAGER		ORIGINATING MANAGER

1999-08-21 05:26 PM

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 04-00-1413

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1990 10	9 012	NEW ITEM.
1991 10	13 298	DISTRIBUTION COSTS PREVIOUSLY NOT FORECAST ADDED TO ALL SITES THICKET/PIKWITONEI DISTRIBUTION COSTS ARE $3,362)
1992 10	13 335	REVISED INTEREST AND ESCALATION RATES. 'GROSS' REVISED TO 1992 BASE DOLLARS. DISTRIBUTION COSTS INCREASED DUE TO REVISED REGION CONCEPT IN ESTIMATING - TO ACCOMMODATE MORE STRINGENT CONSTRUCTION PRACTICES AND DUE TO INCREASED MATERIAL COSTS. CHANGED SHAMATTAWA PLAN TO ADVANCE ENHANCED SERVICE BY ADDING TWO MOBILES, BUILDING A NEW DIESEL GENERATING FACILITY AND SALVAGING THE EXISTING FACILITY WHICH IS UNSUITABLE FOR LONG TERM ENHANCED SERVICE.
1993 10	13 079	REVISED ESCALATION AND INTEREST RATES. 'GROSS' REVISED TO 1993 BASE DOLLARS. ISD'S ADJUSTED TO COINCIDE WITH THE VARIOUS W/O'S.
1994 10	9 253	ELIMINATION OF THICKET/PIKWITONEI CENTRAL PLANT AS WORK WILLBE COMPLETED UNDER CENTRAL SUPPLY ITEM, BRN 9204-00-5498.
1995 10	9 253	REVISED GROSS DOLLARS TO 1995 BASE.
1996 10	8 779	REDUCED COST ESTIMATE. ADVANCED LAC BROCHET BY 1 YEAR AND DEFERRED SHAMATTWA BY 1 YEAR.
1997 10	3 796	BRN 04001413 - DIESEL GENERATION - ENHANCED REQUIREMENTS CLOSED. REMAINING $4,983,000 TRANSFERRED TO DIESEL SITE BRN'S AS REQUIRED.
1998 10	3 777	ITEM COMPLETED. $19k CHANGE IN PREVIOUS AUTHORITY IS DUE TO TRANSFER OF A COMPLETED PROJECT TO RELATED BRN 04-00-9303.

ASSOCIATED PROJECTS

Budget reference number	Description
04-00-1385	BROCHET POWERHOUSE - TANK FARM
04-00-1395	LAC BROCHET MODIFICATIONS
04-00-1405	ST. THERESA - MODIFICATIONS
04-00-8594	LAC BROCHET DISTRIBUTION UPGRADE TO 25 KV
04-00-9303	SHAMATTAWA MODIFICATIONS
04-00-9304	TADOULE LAKE NEW POWERHOUSE

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item

317

Title
BROCHET POWERHOUSE - TANK FARM

Budget reference number
04-00-1385

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Operating & Maintenance	Construction	Construction	71855:93354

DESCRIPTION:
ACQUIRE A NEW SITE FOR THE NEW PLANT.
BUILD NEW POWERHOUSE C/W 1 - 450KW AND 2 - 855KW DIESEL GENERATORS.
CONSTRUCT A NEW FUEL TANK FARM.
SALVAGE OF EXISTING PLANT & SITE.

JUSTIFICATION:
ADDITIONAL FUEL STORAGE, ADDITIONAL UNITS, NEW POWERHOUSE, AND LARGER UNITS REQUIRED TO ACCOMMODATE THE 60 AMP ENHANCED SERVICE AND LOAD GROWTH.

REFERENCE:
SYSTEM PLANNING AND ENVIRONMENT DIVISION REPORT ON POWER RESOURCE OPTIONS FOR BROCHET AND LAC BROCHET SPED 95-3 REVISION 1 DATED 95-10-17.

REVISION:
ADDITIONAL COSTS INCURRED FOR THE FOLLOWING: CT & PT METERING, ENGINEERING AND CONSULTING. REFLECTS REVISED ACTIVITY AND OVERHEAD RATES.

IN SERVICE DATES

1997 03 31	5	1998 10 31	-3	1999 02 28	-31
1998 07 31	875	1998 11 30	1	1999 03 31	0
1998 08 31	112	1998 12 31	1	1999 10 31	7 830
1998 09 30	22	1999 01 31	-0	2000 03 31	228

Base estimate
199805 L3

Work start date
1991 08 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:	6 702		379	-15	-31	7 035
1999/00	- 404	21	270	- 120		- 233
2000/01	984	31		-8		1 007
TOTAL	7 282	52	649	- 143	-31	7 809
REV. AMOUNTS:						
Authorized to date:	6 702		379	-15	-31	7 035
Over(under)expend:						
Auth 1999/00	1 590	23	327	- 123		1 817
Req.: 2000/01	15			-8		7
TOTAL	8 307	23	706	- 146	-31	8 859

Prepared by: yy mm dd COORDINATOR	Approved by: yy mm dd	Approved by:	yy mm dd
Estimated by: ORIGINATOR	COORDINATING MANAGER	ORIGINATING MANAGER	

1999-08-21 05:26 PM

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 04-00-1385

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1990 10	2 480	NEW ITEM
1991 10	2 328	REVISED INTEREST AND ESCALATION RATES.
1992 10	2 126	REVISED INTEREST AND ESCALATION RATES. GROSS REVISED TO 1992 BASE.
1993 10	2 798	REVISED INTEREST AND ESCALATION RATES. GROSS REVISED TO 1993 BASE. STAGE II IS NOW A 3-YR PROJECT RATHER THAN 2-YR. I.S.D. ADJUSTED TO REFLECT REVENUE RECOGNITION.
1994 10	2 570	REVISED GROSS DOLLARS TO1994 BASE. STUDY TO BE CONDUCTED IN 94/95, BAL OF MOVED AHEAD TO 9 5/96.
1995 10	2 570	REVISED DOLLARS TO 1995 BASE.
1996 10	2 800	PROJECT DEFERRED 2 YEARS. THE PLANT CANNOT BE EXPANDED AT THE EXISTING LOCATION.
1997 10	7 010	RELATED COSTS ($2,240K) PREVIOUSLY ALLOCATED UNDER THE DIESEL ENHANCED BRN 04-00-1413 IN 1998/99 AND 1999/00 ARE NOW PLANNED HERE TO REFLECT CLOSURE OF THAT ITEM. ACTUAL TOTAL NET INCREASE IS $1,946K. THE ORIGINAL PLAN AND ESTIMATE WAS BASED ON A PLANT EXTENSION WITHIN THE OLD SITE. DUE TO INCREASED LOAD GROWTH AND THE COLD LOAD PICKUP REQUIREMENTS, A MUCH LARGER EXTENSION AND EXPANSION WAS REQUIRED. THE COMMUNITY ALSO REQUESTED THAT THE PLANT BE RELOCATED OUTSIDE THE MAIN COMMUNITY. THIS ENTAILED A NEW SITE, PLANT, TANK FARM AND BUILDING AND ASSOCIATED EQUIPMENT. THE ESTIMATE ALSO INCLUDES NEW ITEMS NOT COVERED IN PREVIOUS ESTIMATES SUCH AS: NEW ESTIMATING SYSTEM, CATWALKS REQUIRED FOR FUEL TANKS, DIESEL FUEL TANK MONITORING SYSTEM, NEW PLC AND AUTOMATION SYSTEM, AND FOUNDATION FOR RELOCATION OF ACCOMMODATION TRAILER, GARAGE, WATER AND SEWAGE.
1998 10	7 810	INCREASE A RESULT OF (i) HIGHER DISTRIBUTION COSTS; (ii) ADDITIONAL FIRE PROTECTION REQUIREMENTS; (iii) INCREASED SCOPE FOR CONSULTANT (UNDER REVIEW).

ASSOCIATED PROJECTS

Budget reference number	Description
04-00-1395	LAC BROCHET MODIFICATIONS
04-00-1405	ST. THERESA - MODIFICATIONS
04-00-1413	DIESEL GENERATION - ENHANCED REQUIREMENTS
04-00-8594	LAC BROCHET DISTRIBUTION UPGRADE TO 25 KV
04-00-9303	SHAMATTAWA MODIFICATIONS
04-00-9304	TADOULE LAKE NEW POWERHOUSE

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	195	3	42			240	240
May	195	3	44			242	482
Jun	98	3	45		-10	136	618
Jul	146	3	46		-10	185	803
Aug	263	4	48			315	1 118
Sep	274	5	50			329	1 447
Oct	208	4	52			264	1 711
Nov	5	-1				4	1 715
Dec	55	1				56	1 771
Jan	56	1				57	1 828
Feb	55	-1			- 104	-50	1 778
Mar	40	-2			1	39	1 817
TOTAL	1 590	23	327		- 123	1 817	1 817
2000/01 Apr	15				-8	7	7
May							7
Jun							7
Jul							7
Aug							7
Sep							7
Oct							7
Nov							7
Dec							7
Jan							7
Feb							7
Mar							7
TOTAL	15				-8	7	7

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item ___ Domestic Item 318

Title
LAC BROCHET MODIFICATIONS

Budget reference number
04-00-1395

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Operating & Maintenance	Construction	Construction	70110

DESCRIPTION:
INSTALL 18 - 50 000 LITRE ULC FUEL TANKS.
INSTALL 1 - 855 KW DIESEL GENERATOR.
INSTALL A PLANT EXTENSION TO ACCOMMODATE GENERATORS AND EXPAND THE TANK FARM TO ACCOMMODATE ADDITIONAL FUEL TANKS.

JUSTIFICATION:
ADDITIONAL FUEL STORAGE, PLANT EXTENSION, LARGER UNITS, AND ADDITIONAL UNITS ARE REQUIRED TO ACCOMMODATE THE 60 AMP ENHANCED SERVICE SCHEDULED FOR LAC BROCHET.

REFERENCE:
NORTHERN REGION, REMOTE COMMUNITIES, DIESEL PLANNING STUDY REPORT DATED JANUARY1996.

REVISION:
REFLECTS REVISED ACTIVITY AND OVERHEAD RATES. ADDITIONAL ENGINEERING SERVICES REQUIRED FROM CONSULTANT TO FINISH AS-BUILT DRAWINGS. INCREASE IN COST FOR COMMISSIONING, AND FOR THE WELDING OF FUEL PIPES FOR THE ADDITIONAL TANKS.

IN SERVICE DATES

1997 03 31	250
1998 01 31	2 181
1999 08 31	1 957

Base estimate
199710 L3

Work start date
1990 08 01

	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
PREV. AUTHORITY Authorized to date:	3 645		419			4 064
1999/00	96	3	18			117
TOTAL	3 741	3	437			4 181
REV. AMOUNTS:						
Authorized to date:	3 645		419			4 064
Over(under)expend:						
Auth Req.: 1999/00	259	6	59			324
TOTAL	3 904	6	478			4 388

Prepared by: yy mm dd COORDINATOR
Estimated by: ORIGINATOR
Approved by: yy mm dd COORDINATING MANAGER
Approved by: ORIGINATING MANAGER
yy mm dd

1999-08-21 05:26 PM

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 04-00-1395

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1991 10	2 244	REVISED INTEREST AND ESCALATION RATES.
1992 10	2 236	REVISED INTEREST AND ESCALATION RATES. GROSS REVISED TO 1992 BASE DOLLARS.
1993 10	2 829	REVISED INT & ESC RATES. GROSS REVISED TO 1993 BASE DOLLARS. PROJECT REDUCED 3 YRS; CASH FLOWS MOVED AHEAD 1 YR.
1994 10	2 707	REVISED GROSS DOLLARS TO1994 BASE. STUDY CONDUCTED IN 94/95, BAL OF $ MOVED AHEAD TO 95/96
1995 10	2 707	REVISED GROSS DOLLARS TO 1995 BASE.
1996 10	2 759	REVISED SCOPE AND ISD'S.
1997 10	4 069	1,019k TRANSFERRED FROM RELATED BRN 04-00-1413; $250k TRANSFERRED TO RELATED BRN 04-00-8594; NET INCREASE OF $514k DUE TO INCREASE IN SCOPE OF PROJECT TO INCLUDE DIESEL FUEL TANK CATWALKS, DIESEL FUEL TANK LEVEL MONITORING SYSTEM, UPGRADE OF PLC AND AUTOMATION SYSTEMS AND UPGRADE OF FIRE PROTECTION SYSTEM.
1998 10	4 181	THE ISD FOR THE DIESEL FUEL TANK FARM COMPONENT OF THE PROJECT HAS BEEN DEFERRED TO 1998-08-31, SINCE MATERIALS COULD NOT BE DELIVERED TO THE SITE AS SCHEDULED. WEATHER CONDITIONS DID NOT ALLOW FOR A WINTER ROAD TO BE BUILT TO THE COMMUNITY OF LAC BROCHET DURING THE WINTER OF 1997/98.

ASSOCIATED PROJECTS

Budget reference number	Description
04-00-1385	BROCHET POWERHOUSE - TANK FARM
04-00-1405	ST. THERESA - MODIFICATIONS
04-00-1413	DIESEL GENERATION - ENHANCED REQUIREMENTS
04-00-8594	LAC BROCHET DISTRIBUTION UPGRADE TO 25 KV
04-00-9303	SHAMATTAWA MODIFICATIONS
04-00-9304	TADOULE LAKE NEW POWERHOUSE

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	30	1	11			42	42
May			12			12	54
Jun	19		12			31	85
Jul	98	2	12			112	197
Aug	105	2	13			120	317
Sep	7	1	-1			7	324
Oct							324
Nov							324
Dec							324
Jan							324
Feb							324
Mar							324
TOTAL	259	6	59			324	324
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item

319

Title			Budget reference number
LAC BROCHET DISTRIBUTION UPGRADE TO 25 KV			04-00-8594
riginating division	Coordinating division	Constructing division	Project Order Group (Range):
anning & Control	Design	Construction	93351

DESCRIPTION:
CONVERT COMMUNITY DISTRIBUTION SYSTEM FROM 8KV TO 25KV.

JUSTIFICATION:
DISTRIBUTION UPGRADE IS REQUIRED TO ACCOMMODATE THE 60 AMP ENHANCED SERVICE SCHEDULED FOR LAC BROCHET.

REFERENCE:
NORTHERN REGION, REMOTE COMMUNITIES, DIESEL PLANNING STUDY REPORT DATED JANUARY1996.

REVISION:
REFLECTS ACTUAL COMPLETED PROJECT COSTS.

IN SERVICE DATES				Base estimate
1999 02 28	196			199902 L3
1999 03 31	-6			
1999 04 30	1			Work start date
				1997 01 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:	166		25	-6		185
1999/00	-15					-15
TOTAL	151		25	-6		170
REV. AMOUNTS:						
Authorized to date:	166		25	-6		185
Over(under)expend:						
Auth Req.: 1999/00						
TOTAL	166		25	-6		185

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number: 04-00-8594

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1997 10	247	NEW ITEM.
1999 10	170	REVISION REFLECTS NEW IN SERVICE DATE AND COSTS REMAINING TO COMPLETE SALVAGE PORTION.

ASSOCIATED PROJECTS

Budget reference number	Description
04-00-1385	BROCHET POWERHOUSE - TANK FARM
04-00-1395	LAC BROCHET MODIFICATIONS
04-00-1405	ST. THERESA - MODIFICATIONS
04-00-1413	DIESEL GENERATION - ENHANCED REQUIREMENTS
04-00-9303	SHAMATTAWA MODIFICATIONS
04-00-9304	TADOULE LAKE NEW POWERHOUSE

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — 320 Domestic Item

Title
ST. THERESA - MODIFICATIONS

Budget reference number
04-00-1405

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Operating & Maintenance	Operating & Maintenance	Operating & Maintenance	70373:93355

DESCRIPTION:
PURCHASE AND INSTALL 1 - 855 KW MOBILE AND 1 - 855 KW POWERHOUSE UNIT (ENHANCED PORTION ONLY). CREDIT WILL OCCUR WHEN UNIT SALVAGED FROM SITE.

JUSTIFICATION:
WE ARE INSTALLING LARGER FUEL EFFICIENT UNITS AT ST. THERESA, RATHER THAN REFURBISH THE OLD AND INEFFICIENT UNITS, TO MEET THE LOAD AT THIS SITE. THESE UNITS WILL BE REQUIRED AT THE ENHANCED COMMUNITIES ONCE THE NORTH CENTRAL MANITOBA PROJECT IS COMPLETED. THIS REPRESENTS THE INCREMENTAL COSTS ASSOCIATED WITH PROVIDING FUTURE ENHANCED SERVICE TO ONE OF THE SIX COMMUNITIES.

ST. THERESA WILL BE DECOMMISSIONED AND THE VALUE OF THE UNITS TO THE ENHANCED SITES WILL BE TRANSFERRED OUT.

REVISION:
NO CHANGE

IN SERVICE DATES

1997 03 31	335
2000 03 31	12

Base estimate
199805 L3

Work start date
1997 06 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:	332		3			335
1999/00	9			-60		-51
TOTAL	341		3	-60		284
REV. AMOUNTS:						
Authorized to date:	332		3			335
Over(under)expend:						
Auth Req.: 1999/00	11	1		-60		-48
TOTAL	343	1	3	-60		287

Prepared by — yy mm dd — COORDINATOR
Approved by — yy mm dd — COORDINATING MANAGER
Approved by — yy mm dd — ORIGINATING MANAGER
Estimated by — ORIGINATOR

CAPITAL EXPENDITURE REVISION

Budget reference number 04-00-1405

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1990 10	0	NEW ITEM. COSTS TO BE TRANSFERRED FROM DOMESTIC ITEMS 9104-00-1382 AND 1383, IN MARCH 1991.
1991 10	-3	NONE
1991 10	0	ST. THERESA WILL BE DECOMMISSIONED AND THE VALUE OF THE UNITS TO THE ENHANCED SITES WILL BE TRANSFERRED OUT.
1992 10	0	NONE
1993 10	0	NONE
1994 10	0	NONE
1995 10	0	NONE
1996 10	0	SALVAGE DEFERRED TO 1998/99 TO COINCIDE WITH NORTH CENTRAL IN-SERVICE DATE.
1997 10	50	ESTIMATE INCREASED TO PROVIDE FOR COSTS ASSOCIATED WITH REMOVAL OF THE UNIT FROM THE SITE.
1998 10	284	SALVAGE CREDIT REDUCED TO FAIR MARKET VALUE TO REFLECT CHANGE IN ACCOUNTING POLICY. SALVAGE DEFERRED TO 1999/2000.

ASSOCIATED PROJECTS

Budget reference number	Description
04-00-1385	BROCHET POWERHOUSE - TANK FARM
04-00-1395	LAC BROCHET MODIFICATIONS
04-00-1413	DIESEL GENERATION - ENHANCED REQUIREMENTS
04-00-8594	LAC BROCHET DISTRIBUTION UPGRADE TO 25 KV
04-00-9303	SHAMATTAWA MODIFICATIONS
04-00-9304	TADOULE LAKE NEW POWERHOUSE

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul	1					1	1
Aug							1
Sep							1
Oct							1
Nov							1
Dec							1
Jan							1
Feb	10					10	11
Mar			1		-60	-59	-48
TOTAL	11		1		-60	-48	-48
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item

321

Title: SHAMATTAWA MODIFICATIONS

Budget reference number: 04-00-9303

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Operating & Maintenance	Construction	Construction	70039:93353

DESCRIPTION:
INSTALL 1 X 450 KW GENERATING SETS.
INSTALL 2 X 850 KW GENERATING SETS C/W PLANT AUTOMATION.
CONSTRUCT A NEW POWERHOUSE.
INSTALL 2 X 1,070,000 LITRE FUEL TANKS OR EQUIVALENT ULC FUEL TANKS.

**** ON HOLD PENDING AGREEMENT WITH BAND ****

JUSTIFICATION:
ADDITIONAL FUEL STORAGE AND ADDITIONAL GENERATING CAPACITY IS REQUIRED TO ACCOMMODATE THE PROJECTED LOAD GROWTH AT SHAMATTAWA IN CONNECTION WITH THE ENHANCED PROGRAM.

THE TWO MOBILES WILL ALLOW EARLY IMPLEMENTATION OF THE ENHANCED SERVICE BY PROVIDING THE ADDITIONAL CAPACITY REQUIRED, WHILE DEFERRING THE MAJOR EXPENDITURES OF THE NEW PLANT UNTIL ALL LINE OPTIONS ARE EXHAUSED.

A NEW PLANT IS REQUIRED TO MEET THE LONG TERM ENHANCED REQUIREMENTS. THE EXISTING PLANT, LOCATED ON RESERVE LAND, IS ENVIRONMENTALLY SENSITIVE WITH LIMITED POTENTIAL FOR THE EXPANSION NECESSARY TO MEET THE ENHANCED NEEDS.

REFERENCE:
NORTHERN REGION, REMOTE COMMUNITIES, DIESEL PLANNING STUDY REPORT DATED JANUARY 1996.

REVISION:
PROJECT DEFERRED ONE YEAR. REFLECTS REVISED ACTIVITY AND OVERHEAD RATES.

IN SERVICE DATES

1997 03 31	298
2002 10 31	8 297
2003 03 31	220

Base estimate: 199805 L3

Work start date: 1991 08 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:	393		150			543
1999/00	1 571	83	45			1 699
2000/01	- 188	27	310	-27		122
2001/02	318	28	-16	-76		254
2002/03	4 998	502				5 500
TOTAL	7 092	640	489	- 103		8 118
REV. AMOUNTS:						
Authorized to date:	393		150			543
Over(under)expend:						
Auth 1999/00			21			21
Req: 2000/01	1 583	101	47			1 731
2001/02	3 828	306	317	-27		4 424
2002/03	1 558	146	356	-76		1 984
TOTAL	7 362	553	891	- 103		8 703

Prepared by: yy mm dd COORDINATOR — Approved by: yy mm dd Approved by

Estimated by: ORIGINATOR — COORDINATING MANAGER — ORIGINATING MANAGER

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 04-00-9303

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1990 10	2 362	NEW ITEM
1991 10	2 155	REVISED INTEREST AND ESCALATION RATES.
1992 10	4 173	REVISED PROJECT TO INCLUDE THE INSTALLATION OF TWO TEMPORARYMOBILES, CONSTRUCTION OF A NEW SITE, RESTORATION OF THE EXISTING SITE AND ADVANCEMENT OF THE ENHANCED PROGRAM IN-SERVICE DATE BY ONE YEAR TO 1994 01.
1993 10	4 854	PROJECT IS ON HOLD PENDING AGREEMENT WITH BAND. CASH FLOWS MOVED AHEAD ONE YEAR. I.S.D. ADJUSTED TO REFLECT REVENUE RECOGNITION.
1994 10	4 718	PROJECT REMAINS ON HOLD; DOLLARS ADJUSTED TO 1994 BASE WITH REVISED INTEREST AND ESCALATION.
1995 10	4 717	REVISED GROSS DOLLARS TO 1995 BASE.
1996 10	5 748	UPDATED ESTIMATE BASED ON A COMPLETE REVIEW OF THE PROJECT REQUIREMENTS. PROJECT IDS NOW SCHEDULED FOR 2000-11-30.
1997 10	7 858	RELATED COSTS ($1,724k) PREVIOUSLY ALLOCATED UNDER THE DIESEL ENHANCED BRN 04-00-1413 IN 1998/99 AND 1999/00 ARE NOW PLANNED HERE TO REFLECT CLOSURE OF THAT ITEM. ACTUAL TOTAL NET INCREASE IS $386k, WHICH IS ATTRIBUTED TO THE CURRENT ESTIMATE REFLECTING THE FINAL SCOPE OF WORK BASED ON DETAILED DESIGN AND CUSTOMER REQUIREMENTS INCLUDING NEW ITEMS NOT COVERED IN PREVIOUS ESTIMATES SUCH AS: NEW ESTIMATING SYSTEM, CATWALKS REQUIRED FOR FUEL TANKS, DIESEL FUEL TANK MONITORING SYSTEM AND SALVAGE OF OLD PLANT AND SITE. CASH FLOW AND ISD ALSO REVISED TO REFLECT FINAL PLANNING.
1998 10	8 118	PROJECT DEFERRED ONE YEAR. CASH FLOWS CHANGED TO REFLECT NEW IN SERVICE DATES.

ASSOCIATED PROJECTS

Budget reference number	Description
04-00-1385	BROCHET POWERHOUSE - TANK FARM
04-00-1395	LAC BROCHET MODIFICATIONS
04-00-1405	ST. THERESA - MODIFICATIONS
04-00-1413	DIESEL GENERATION - ENHANCED REQUIREMENTS
04-00-8594	LAC BROCHET DISTRIBUTION UPGRADE TO 25 KV
04-00-9304	TADOULE LAKE NEW POWERHOUSE

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr			2			2	2
May			2			2	4
Jun			2			2	6
Jul			2			2	8
Aug			2			2	10
Sep			2			2	12
Oct			2			2	14
Nov			2			2	16
Dec			2			2	18
Jan			2			2	20
Feb			2			2	22
Mar			-1			-1	21
TOTAL			21			21	21
2000/01 Apr	10		2			12	12
May	10		2			12	24
Jun	29	2	2			33	57
Jul	30	2	2			34	91
Aug	74	4	3			81	172
Sep	110	6	3			119	291
Oct	25	1	4			30	321
Nov	31	2	4			37	358
Dec	31	3	4			38	396
Jan	36	2	5			43	439
Feb	766	51	5			822	1 261
Mar	431	28	11			470	1 731
TOTAL	1 583	101	47			1 731	1 731

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

COMPLEX STATUS: ☐ Planned ☒ In progress

Complex no. 221

REVISION STATUS: ☐ New complex ☒ In service change ☐ Concept change ☒ Estimate change only

COMPLEX: VIRDEN AREA DISTRIBUTION CHANGES

Proposal

Rebuild 136 KM (85%) of primary distribution served by Virden-Seventh, Virden-North, Hargrave & Kenton Stns, and convert 438 transformers from 4.8/8.32kV to 14.4/24.9kV. Salvage & rebuild 33kV L66 Virden to Kenton.

Rebuild 95 KM of 66kV lines #95 & 97 and 24 KM of primary distribution Elkhorn to Manson.

Build a new 66-25kV station 1 mile west of the town of Virden.

JUSTIFICATION

☒ Load ☐ Service
☒ Safety ☒ Efficiency
☒ Reliability ☐ Other

Explanation

136 km line is old (rural electrification-30 ft poles) & does not meet CSA clearance criteria. Transformer upgrades will correct high voltage fluctuations, & losses, and reduce monitoring requirements. Line 95/97 is over 40 years old, deteriorated and does not comply with CSA standards, posing a safety hazard. The new Virden-Wallace Stn is required to meet 1998 projected load requirements..

Estimate Level	COMPLEX START (yyyy mm)
L2-3	1995 10

IN SERVICE DATES AND AMOUNTS

1997 09	$1966	1998 07	$868	1999 03	$41	1999 04	$1382
1999 10	$4299	2000 10	$1795	2001 10	$1907	2002 10	$925
2003 10	$1055	2004 10	$1073				

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	4,434		200	264	4,370	4,200	170	4
Year 99/00	4,234	66	119	190	4,229	3,351	878	26
00/01	1,351	59	40	182	1,268	1,292	-24	-2
01/02	1,477	80	49		1,606	1,514	92	6
02/03	920	69	9	138	860	775	85	11
03/04	990	96	10	72	1,024	947	77	8
04/05	980	116	20	73	1,043	966	77	8
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	14,386	486	447	919	14,400	13,045	1,355	10

REVISION: Increased to reflect the addition of larger conductor (Birtle > Foxwarren), installation of ground rods (Virden-Wallace Stn), and revised activity and overhead rates.

Reviewed by ORIGINATOR	yyyy mm dd 99 11 05	Reviewed by COORDINATOR	yyyy mm dd 99 11 05
Reviewed by CONSTRUCTOR	yyyy mm dd 99 11 03	Approved by VICE PRESIDENT	yyyy mm dd 99 11 16

H2856/r Rev 99 03

Complex no. 221

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Advance or deferral impact

Factors affecting timing or viability

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Virden - Wallace new 66-25kV Stn	2,097	2,113	2,155	2,376	221	10
Kenton Distribution Rebuild	5,419	5,912	6,030	6,824	794	13
Line 95 & Line 97 Rebuild	5,851	4,766	4,861	5,188	327	7
TOTAL	13,367	12,791	13,046	14,388	1,342	10

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
96 10	13,394	NEW COMPLEX
9710	13,786	REFLECTS FULL COSTING METHODOLOGY IMPLEMENTED WITH THE NEW FINANCIAL REPORTING SYSTEM.
1998 10	13,045	Reflects 97/98 underexpenditure 0.5M, a new estimate for Kenton distribution rbld and in-service dates revised to align with the Dept of Highways schedule for Lines 95 & 97 rbld.
1999 10	14,400	Increased to reflect the addition of larger conductor (Birtle > Foxwarren), installation of ground rods (Virden-Wallace Stn), and revised activity and overhead rates.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item 322

Title: VIRDEN WALLACE NEW 66-25KV STATION

Budget reference number: 03-D0-7227

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
anning & Control	Design	Construction	70019

DESCRIPTION:
BUILD A NEW STATION 1 MILE WEST OF THE TOWN OF VIRDEN. THE STATION WILL BE EQUIPPED WITH 2 X 7.5/10 MVA 66-25KV TRANSFORMERS, AND 4 FEEDER POSITIONS.

JUSTIFICATION:
STUDY 90-W-24 OUTLINES A FUTURE REQUIREMENT FOR A VIRDEN STATION IN 1998 WHEN THE 8 KV LOAD REACHES 22 MVA. LOAD IS EXPECTED TO APPROACH THESE VALUES BY 1998.
STUDY TPD92-1 RECOMMENDS THE SALVAGE OF THE VIRDEN NORTH TERMINAL AS IT IS ANTICIPATED THAT THE REGION WILL HAVE PHASED OUT ALL THE 33KV DISTRIBUTION STATIONS IN THE AREA BY THE FALL OF 1998.

REFERENCE:
WESTERN REGION STUDY 90-W-24
TRANSMISSION PLANNING TPD92-1
WESTERN REGION STUDY 95-W-10 'VIRDEN NORTH TERMINAL SALVAGE AND NEW 66-25KV STATION'

REVISION:
MINOR COST INCREASE CAUSED BY THE INSTALLATION OF GROUND RODS. REFLECTS REVISED ACTIVITY AND OVERHEAD RATES.

CONTINGENCY: $100,000

IN SERVICE DATES: 1999 10 31 — 2 464

Base estimate: 199902 L3

Work start date: 1996 10 01

	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
PREV. AUTHORITY						
Authorized to date:	439		27			466
1999/00	1 684	61	59			1 804
TOTAL	2 123	61	86			2 270
REV. AMOUNTS:						
Authorized to date:	439		27			466
Over(under)expend. Auth 1999/00 Req.:	1 937	6	55			1 998
TOTAL	2 376	6	82			2 464

Prepared by: yy mm dd COORDINATOR

Approved by: yy mm dd Approved by: yy mm dd

Estimated by: ORIGINATOR — COORDINATING MANAGER — ORIGINATING MANAGER

1999-08-21 05:23 PM

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 03-00-7227

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1996 10	2 084	NEW ITEM - THIS IS AN APPROVED ITEM (9603-00-6977) BEING TRANSFERRED FROM THE DOMESTIC FORECAST.
1997 10	2 254	SCOPE UNCHANGED. ESTIMATE REFLECTS REVISED COSTING METHODOLOGY IMPLEMENTED WITH THE NEW FINANCIAL REPORTING SYSTEM. ESTIMATE ALSO REFLECTS REVISED INTEREST AND ESCALATION RATES.
1998 10	2 270	NO CHANGE.

ASSOCIATED PROJECTS

Budget reference number	Description
04-00-7551	KENTON DISTRIBUTION REBUILD
04-00-7552	LINE 95 & LINE 97 REBUILD

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	46		3			49	49
May	126	1	4			131	180
Jun	116	1	4			121	301
Jul	274	2	5			281	582
Aug	1 056	1	7			1 064	1 646
Sep	150	2	15			167	1 813
Oct	151	1	16			168	1 981
Nov	15					15	1 996
Dec	3	-2	1			2	1 998
Jan							1 998
Feb							1 998
Mar							1 998
TOTAL	1 937	6	55			1 998	1 998
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

1999-08-21 05:23 PM

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item ___ Domestic Item

323

Title: KENTON DISTRIBUTION REBUILD

Budget reference number: 04-00-7551

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	93286

DESCRIPTION:
REBUILD 136KM (85%) OF PRIMARY DISTRIBUTION PRESENTLY SERVED BY THE VIRDEN SEVENTH, VIRDEN NORTH, HARGRAVE AND KENTON STATION AREAS. CONVERT 438 TRANSFORMERS IN THESE AREAS FROM 4.8/8.32KV TO 14.4/24.9KV. TRANSFER THE KENTON STATION AREA TO SIOUX VALLEY. TRANSFER THE VIRDEN NORTH STATION AREA TO VIRDEN SOUTH STATION. TRANSFER THE HARGRAVE AND VIRDEN SEVENTH STATION AREAS TO A NEW STATION CALLED VIRDEN WALLACE. SALVAGE AND REBUILD 33KV L66 FROM VIRDEN TO KENTON. CONVERT 33KV L66 FROM KENTON TO HAMIOTA TO PRIMARY DISTRIBUTION.

JUSTIFICATION:
1. THE VIRDEN NORTH, VIRDEN SEVENTH AND KENTON STATIONS ARE APPROACHING THEIR LOADING LIMITS. A NEW 66 - 24KV STATION WILL RESOLVE THE CAPACITY ISSUE AT VIRDEN.

2. HARGRAVE STATION WAS RECOMMENDED FOR REPLACEMENT IN 1985 BECAUSE OF ITS POOR POLE AND TIMBER CONDITION. THIS STATION AREA CAN BE SERVED FROM THE NEW VIRDEN WALLACE STATION ONCE THE DISTRIBUTION IS REBUILT AND CONVERTED. THIS WILL RESOLVE THE MAINTENANCE ISSUE.

3. VIRDEN NORTH TERMINAL CONTAINS OBSOLETE 33KV EQUIPMENT. SALVAGING THIS TERMINAL RESOLVES THE MAINTENANCE ISSUE.

4. 136 KM OF DISTRIBUTION DOES NOT MEET CSA CLEARANCE CRITERIA. THIS DISTRIBUTION IS OLD, ORIGINAL RURAL ELECTRIFICATION LINE. MANY OF THE POLES ARE ONLY 30' WITH VERY LONG SPANS AND POOR SAFETY FACTORS. MANY OF THE LINES ARE BUILT ON A NON-PREFERRED ALIGNMENT.

5. 8KV IS NOT A PREFERRED DISTRIBUTION VOLTAGE BECAUSE OF THE HIGH VOLTAGE FLUCTUATIONS. THE KENTON STATION HAS 2 SETS OF REGS WITHIN THE FIRST 4 MILES. LOSSES ARE HIGH. VOLTAGE MUST BE CONTINUALLY MONITORED AT KENTON AND HARGRAVE. THIS PROJECT IS RECOMMENDED TO BE SPREAD OVER 6 YEARS, AS IN MEMO 1996 07 30, TO LEVELIZE SPENDING AND LABOUR.

REFERENCE:
WESTERN REGION STUDY 95-W-10. MEMO FROM C. B. ELLIOTT TO T. E. TYMOFICHUK DATED 96 07 30. MEMO FROM D.K. SOLKOSKI TO T.E. TYMOFICHUK DATED 98 02 04.

REVISION:
REVISED TO REFLECT CARRYOVER FROM 98/99 TO 99/00. IINCREASE IN T&D O/H RATES. INCREASE IN DISTRIBUTION CONSTRUCTION ACTIVITY RATES. L4 ESTIMATE EXCEEDED THE L2 ESTIMATE FOR 99/00 ITEMS.
CONTINGENCY AMOUNT: $0.

IN SERVICE DATES						Base estimate
Prior Total	1 979	1998 10 31	-3	1999 03 31	55	199902 L2
1998 06 30	0	1998 11 30	-12	1999 04 30	1 388	
1998 07 31	853	1999 01 31	-0	1999 10 31	1 106	Work start date
1998 09 30	0	1999 02 28	1	2000 10 31	1 799	1997 04 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date	3 986		172	- 257	-7	3 894
1999/00	712	21	28	-43		718
2000/01	1 233	59	33	-58		1 267
TOTAL	5 931	80	233	- 358	-7	5 879
REV. AMOUNTS:						
Authorized to date:	3 986		172	- 257	-7	3 894
Over(under)expend:						
Auth 1999/00	1 517	43	34	- 135		1 459
Req. 2000/01	1 321	58	35	- 182		1 232
TOTAL	6 824	101	241	- 574	-7	6 585

Prepared by: yy mm dd COORDINATOR — Approved by: yy mm dd Approved by: yy mm dd

Estimated by: ORIGINATOR — COORDINATING MANAGER — ORIGINATING MANAGER

1999-08-21 05:27 PM

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 04-00-7551

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1996 07	5 651	STAGE #1 OF THIS ITEM HAS BEEN APPROVED IN DOMESTIC ITEM (9604-00-5505)
1996 10	6 655	REVISED TO REFLECT INCREASE DUE TO CHANGE TO SAP.
1998 05	6 006	REVISED TO REFLECT ACTUALS TO DATE AND A NEW ESTIMATE.
1999 10	5 956	REVISED TO REFLECT CARRYOVER FROM 1998/99 TO 1999/2000.

ASSOCIATED PROJECTS

Budget reference number	Description
03-00-7227	VIRDEN WALLACE NEW 66-25KV STATION
04-00-7552	LINE 95 & LINE 97 REBUILD

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr			7			7	7
May	642	19	-3			658	665
Jun			2			2	667
Jul	857	25	2			884	1 551
Aug			8			8	1 559
Sep			8			8	1 567
Oct			8			8	1 575
Nov			1			1	1 576
Dec	18	-1	1		- 135	- 117	1 459
Jan							1 459
Feb							1 459
Mar							1 459
TOTAL	1 517	43	34		- 135	1 459	1 459
2000/01 Apr							
May	476	20				496	496
Jun			3			3	499
Jul	822	37	3			862	1 361
Aug			9			9	1 370
Sep			10			10	1 380
Oct			10			10	1 390
Nov							1 390
Dec	23	1			- 182	- 158	1 232
Jan							1 232
Feb							1 232
Mar							1 232
TOTAL	1 321	58	35		- 182	1 232	1 232

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item

324

Title
LINE 95 & LINE 97 REBUILD

Budget reference number
04-00-7552

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	93287

DESCRIPTION:
BUILD 95.1 KM OF 66 KV LINES #95 AND #97, AND 24.1 KM. OF PRIMARY DISTRIBUTION BROKEN DOWN INTO THE FOLLOWING SECTIONS:
1999/00 - 12.9 KM FROM BIRTLE QUEEN TO FOXWARREN.
2001/02 - 30.5 KM FROM MANSON TO ELKHORN.
2002/03 - 5.6 KM FROM BIRTLE QUEEN TO FOXWARREN.
- 24.1 KM DISTRIBUTION FROM HIGHWAY #1 TO MINIOTA.
2003/04 - 4.8 KM FROM BIRTLE SOUTH TO BIRTLE QUEEN.
- 11.2 KM FROM BEULAH TO BIRTLE SOUTH.
2004/05 - 12.9 KM FROM MINIOTA TO BEULAH.
- 6.4 KM FROM INGLIS TO RUSSELL.

JUSTIFICATION:
A 1995 STUDY OUTLINED 97.3 KM OF 66KV THAT REQUIRED REBUILDING. THE STUDY INDICATED THESE LINES WERE 40 AND 41 YEARS OLD RESPECTIVELY. THE POLES ARE BUILT TO A STANDARD THAT IS UNACCEPTABLE. THE POLES ARE GENERALLY 40' THEREFORE CLEARANCE IS A PROBLEM. MOST SPAN LENGTHS ARE 10 METERS TOO LONG TO MEET SAFETY FACTOR AND CLEARANCE STANDARDS. THE ALIGNMENT OF THE LINE IS GENERALLY ON THE ROAD SIDE OF THE DITCH, AN UNSAFE LOCATION FOR TRAFFIC. SPOT REPLACEMENT IS NOT RECOMMENDED BECAUSE OF ALL OF THESE REASONS. THE REPLACEMENT WAS RECOMMENDED OVER A SPAN OF SEVEN YEARS, IN ORDER TO LEVELIZE THE COST AND WORKLOAD OVER A PERIOD OF TIME. THE LINES WILL BE 49 YEARS OLD AT THAT TIME AND IN SERIOUS CONDITION BY THE END OF THE PROGRAM.

A NEW LINE IS BEING BUILT FROM ELKHORN TO MANSON IN ORDER TO IMPROVE RELIABILITY TO THOSE STATIONS WHICH ARE RADIAL NOW. THIS LINE WAS RECOMMENDED FOR BUILDING RATHER THAN REBUILDING THE MINIOTA TO HARGRAVE TO VIRDEN LINE THAT IS IN POOR CONDITION.

REFERENCE:
WESTERN REGION STUDY 95-W-15. MEMO FROM C.B. ELLIOTT TO T. E. TYMOFICHUK DATED 96 07 30. MEMO FROM D.K. SOLKOSKI TO T.E. TYMOFICHUK DATED 98 02 04.

REVISION:
THE COST OF THE BIRTLE TO FOXWARREN SEGMENT WAS INCREASED TO COVER A TRANSMISSION PLANNING REQUEST FOR LARGER CONDUCTOR.

IN SERVICE DATES

1999 10 31	729	2004 10 31	1 074
2001 10 31	1 907		
2002 10 31	925		
2003 10 31	1 055		

Base estimate
199902 L2

Work start date
1997 05 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date.	10		1			11
1999/00	678	12	25	-55		660
2000/01	24	2				26
2001/02	1 387	83	44			1 514
2002/03	839	67	7	- 138		775
2003/04	919	94	7	-72		948
2004/05	910	113	17	-73		967
TOTAL	4 767	371	101	- 338		4 901
REV. AMOUNTS:						
Authorized to date:	10		1			11
Over(under)expend.						
Auth Req.: 1999/00	781	15	30	-55		771
2000/01	30	2	5			37
2001/02	1 477	80	49			1 606
2002/03	920	69	9	- 138		860
2003/04	990	96	10	-72		1 024
2004/05	980	116	20	-73		1 043
TOTAL	5 188	378	124	- 338		5 352

Prepared by (yy mm dd)	Approved by (yy mm dd)	Approved by (yy mm dd)
COORDINATOR		
Estimated by		
ORIGINATOR	COORDINATING MANAGER	ORIGINATING MANAGER

1999-08-21 05:27 PM

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 04-00-7552

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1996 07	5 660	NEW ITEM.
1999 10	5 186	THE COST OF THE BIRTLE TO FOXWARREN SEGMENT WAS INCREASED TO COVER A TRANSMISSION PLANNING REQUEST FOR LARGER CONDUCTOR.

ASSOCIATED PROJECTS

Budget reference number	Description
03-00-7227	VIRDEN WALLACE NEW 66-25KV STATION
04-00-7551	KENTON DISTRIBUTION REBUILD

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	449	9				458	458
May			3			3	461
Jun	178	4	3			185	646
Jul	3		5			8	654
Aug	137	3	5			145	799
Sep	4	-1	6			9	808
Oct	2	-1	6			7	815
Nov			1			1	816
Dec	7		1		-55	-47	769
Jan							769
Feb							769
Mar	1	1				2	771
TOTAL	781	15	30		-55	771	771
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan	30	2				32	32
Feb			1			1	33
Mar			4			4	37
TOTAL	30	2	5			37	37

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

COMPLEX STATUS: ☐ Planned ☒ In progress

Complex no. 217

REVISION STATUS: ☐ New complex ☒ In service change ☐ Concept change ☒ Estimate change only

COMPLEX: DEFECTIVE RINJ CABLE REPLACEMENT

Proposal

Replace approximately 62,500 metres of rinj (red Jacket) cable within the city of Winnipeg.

JUSTIFICATION

☐ Load ☒ Service ☐ Safety ☐ Efficiency ☒ Reliability ☐ Other

Explanation

The failure rate of rinj underground cable installed in the City of Winnipeg during the 1960's is three times the rate at which CSA recommends cable replacement.

Estimate Level	COMPLEX START (yyyy mm)
L2	1996 11

IN SERVICE DATES AND AMOUNTS

1999 06	$399	1999 09	$399	1999 12	$399	2000 03	$399
2000 06	$399	2000 09	$399	2000 12	$399	2001 03	$399
2001 06	$399	2001 09	$399	2001 12	$399	2002 on	$3587

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	152		8		160	147	13	9
Year 99/00	779	27	2		808	896	-88	-10
00/01	1,146	45	-37		1,154	1,248	-94	-8
01/02	1,780	107	-43		1,844	2,041	-197	-10
02/03	1,756	138	-24		1,870	2,045	-175	-9
03/04	1,922	200	13		2,135	2,401	-266	-11
04/05								
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	7,535	517	-81		7,971	8,778	-807	-9

REVISION: Reduced to reflect the effect of placing sections in service as completed, rather than annually.

Reviewed by ORIGINATOR	yyyy mm dd 99 11 03	Reviewed by COORDINATOR	yyyy mm dd 99 11 03
Reviewed by CONSTRUCTOR	yyyy mm dd 99 11 03	Approved by VICE-PRESIDENT	yyyy mm dd 99 11 3033

H2856/r Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Complex no. 217

Advance or deferral impact

Factors affecting timing or viability

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Defective Rinj Cable Replacement	7,534	7,661	7,814	7,534	-280	-4
TOTAL	7,534	7,661	7,814	7,534	-280	-4

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
96 10	8,613	NEW COMPLEX
9710	9,506	Reflects revised costing methodology implemented with the new financial reporting system, revised interest and escalation, and staged in-service dates.
1998 10	8,778	Deferred one year due to budget constraints.
1999 10	7,971	Reduced to reflect the effect of placing sections in service as completed, rather than annually.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item

325

Title
DEFECTIVE RINJ CABLE REPLACEMENT

Budget reference number
04-00-7550

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Operating & Maintenance	Design	Construction	94277

DESCRIPTION:
REPLACE APPROXIMATELY 62,500 METERS OF RINJ (RED jACKET) CABLE WITHIN THE CITY OF WINNIPEG.

JUSTIFICATION:
THE RINJ UNDERGROUND CABLE INSTALLED DURING THE 1960'S WITHIN THE CITY OF WINNIPEG HAS BEEN FAILING AT A RATE OF 9.6 FAILURES PER 100KM. THIS EXCEEDS THE CEA RECOMMENDED RATE AT WHICH CABLE REPLACEMENT IS RECOMMENDED BY A FACTOR OF THREE. THESE FAILURES RESULT IN UNSATISFACTORY RELIABILITY FOR CUSTOMERS SERVED BY THIS CABLE.

REFERENCE:
REPORT CR96-05 'PROPOSAL FOR THE REPLACEMENT OF THE RED JACKET CABLE IN CENTRAL REGION'

REVISION:
NO CHANGE IN PROJECT SCOPE OR IN-SERVICE DATES.

IN SERVICE DATES

1999 06 30	399	2000 06 30	399	2001 06 30	399
1999 09 30	399	2000 09 30	399	2001 09 30	399
1999 12 31	399	2000 12 31	399	2001 12 31	399
2000 03 31	399	2001 03 31	399	And On	3 582

Base estimate
199707 L2

Work start date
1997 08 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date	152		8			160
1999/00	804	35	44			883
2000/01	1 116	68	64			1 248
2001/02	1 796	151	95			2 042
2002/03	1 768	188	90			2 046
2003/04	2 029	259	113			2 401
TOTAL	7 665	701	414			8 780
REV. AMOUNTS						
Authorized to date	152		8			160
Over(under)expend						
Auth 1999/00	779	27	2			808
Req. 2000/01	1 145	46	-37			1 154
2001/02	1 780	108	-43			1 845
2002/03	1 756	138	-24			1 870
2003/04	1 922	199	13			2 134
TOTAL	7 534	518	-81			7 971

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number: 04-00-7550

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1996 10	8 613	NEW ITEM
1997 10	9 477	DUE TO STAFFING AND HIGHER PRIORITY WORK DESIGN COULD NOT BE DONE ON THIS PROJECT TO ALLOW CONSTRUCTION IN 1997/98. ESTIMATE REFLECTS REVISED COSTING METHODOLOGY IMPLEMENTED WITH THE NEW FINANCIAL REPORTING SYSTEM. IT ALSO REFLECTS REVISED INTEREST AND ESCALATION. IN-SERVICE DATES REVISED TO CAPITALIZE MORE FREQUENT STAGES OF WORK DONE.
1998 10	8 781	PROJECT DEFERRED ONE YEAR DUE TO BUDGET CONSTRAINTS.
1999 10	8 780	NO CHANGE IN PROJECT SCOPE OR IN-SERVICE DATES.

ASSOCIATED PROJECTS

Budget reference number	Description

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	73	2	1			76	76
May	72	3	2			77	153
Jun	180	3	2			185	338
Jul	72	3	1			76	414
Aug	72	3	1			76	490
Sep	72	3	2			77	567
Oct	69	2				71	638
Nov	66	3				69	707
Dec	12	1				13	720
Jan	12	1	-2			11	731
Feb	12	1	-2			11	742
Mar	67	2	-3			66	808
TOTAL	779	27	2			808	808
2000/01 Apr	74	3	-4			73	73
May	569	13	-4			578	651
Jun	86	4				90	741
Jul	73	4	-2			75	816
Aug	73	4	-1			76	892
Sep	73	5	-1			77	969
Oct	73	4	-3			74	1 043
Nov	13	1	-3			11	1 054
Dec	13	1	-3			11	1 065
Jan	13		-5			8	1 073
Feb	13		-5			8	1 081
Mar	72	7	-6			73	1 154
TOTAL	1 145	46	-37			1 154	1 154

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

COMPLEX STATUS: [X] Planned [ ] In progress

Complex no. 261

REVISION STATUS: [X] New complex [ ] In service change [ ] Concept change [ ] Estimate change only

COMPLEX: BRERETON LAKE STATION AREA

Proposal

Construct a new 124-12/25kV steel station c/w 2-7.5/10MVA 124-12/25kV LTC transformers and 2-560A WVE 12kV OCRs.

JUSTIFICATION

[ ] Load [X] Service
[ ] Safety [X] Efficiency
[X] Reliability [ ] Other

Explanation

The existing 33kV line from SW 293 to White Lake Stn, Rennie Stn and SW 1810 is at the end of its life expectancy. There are deficiencies associated with White Lake and Rennie stations, as well. A new station complete with a rebuilt distribution system will provide more acceptable customer service reliability.

Estimate Level	COMPLEX START (yyyy mm)
L2	2000 04

IN SERVICE DATES AND AMOUNTS

2002 03	$3534	2002 04	$1037	2003 04	$985	2004 03	$322
2004 04	$156	2005 04	$529				

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend								
Year 99/00								
00/01	2,485	44	102		2,631		2,631	
01/02	1,792	72	299		2,163		2,163	
02/03	550	49	71		670		670	
03/04	470	37	23		530		530	
04/05	400	40	15		455		455	
05/06	100	11	3		114		114	
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	5,797	253	513		6,563		6,563	

REVISION: New Complex

Reviewed by ORIGINATOR	yyyy mm dd 99 11 05	Reviewed by COORDINATOR	yyyy mm dd 99 11 03
Reviewed by CONSTRUCTOR	yyyy mm dd 99 11 03	Approved by VICE-PRESIDENT	yyyy mm dd 99 11 30

H2856/r Rev 99 03

Complex no. 261

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Advance or deferral impact

Will have an affect on maintenance costs, and customer service.

Factors affecting timing or viability

Construction season.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE	
					Amount	%
Brereton Lake Station				5,797	5,797	
TOTAL				5,797	5,797	

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
1999 10	6,563	New Complex

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item

326

Title			Budget reference number
BRERETON LAKE STATION			03-00-8397
riginating division	Coordinating division	Constructing division	Project Order Group (Range):
anning & Control	Design	Construction	74489

DESCRIPTION:
CONSTRUCT A NEW 124-12/25kV STEEL STATION C/W 2-7.5/10MVA 124-12/25kV LTC TRANSFORMERS AND 2-560A WVE 12kV OCRs.

JUSTIFICATION:
THE EXISTING 33kV LINE FROM SW 293 TO WHITE LAKE STATION, RENNIE STATION AND SW 1810 IS AT THE END OF ITS LIFE EXPECTANCY. THERE ARE DEFICIENCIES ASSOCIATED WITH WHITE LAKE AND RENNIE STATIONS, AS WELL. A NEW STATION C/W A REBUILT DISTRIBUTION SYSTEM WILL PROVIDE MORE ACCEPTABLE CUSTOMER SERVICE RELIABILITY.

REFERENCE:
REPORT DPS98-19, NEW BRERETON LAKE STATION AREA STUDY

REVISION:
NEW ITEM.

CONTINGENCY: $350,000

IN SERVICE DATES				Base estimate
2002 03 31	3 534	2004 04 30	156	199909 L2
2002 04 30	1 037	2005 04 30	529	Work start date
2003 04 30	985			2000 04 01
2004 03 31	322			

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:						
TOTAL						
REV. AMOUNTS:						
Authorized to date:						
Over(under)expend:						
Auth 2000/01	2 485	44	102			2 631
Req.: 2001/02	1 792	72	299			2 163
2002/03	550	49	71			670
2003/04	470	37	23			530
2004/05	400	40	15			455
2005/06	100	11	3			114
TOTAL	5 797	253	513			6 563

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 03-00-8397

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS

ASSOCIATED PROJECTS

Budget reference number	Description
04-00-8624	BRERETON LAKE DISTRIBUTION SYSTEM

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr	216	2				218	218
May	216	2	2			220	438
Jun	218	3	3			224	662
Jul	208	3	5			216	878
Aug	208	4	6			218	1 096
Sep	208	4	8			220	1 316
Oct	210	4	9			223	1 539
Nov	197	4	11			212	1 751
Dec	199	5	12			216	1 967
Jan	199	5	14			218	2 185
Feb	202	6	15			223	2 408
Mar	204	2	17			223	2 631
TOTAL	2 485	44	102			2 631	2 631

1999-09-28 11:47 AM

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

COMPLEX STATUS: [X] Planned [ ] In progress

Complex no. 267

REVISION STATUS: [X] New complex [ ] In service change [ ] Concept change [ ] Estimate change only

COMPLEX: PAINT LAKE NEW FEEDER

Proposal

Construct 24 KM Z-2/0 AASC 25kV feeder from Jonas Road, Thompson to Paint Lake.Rebuild and convert Paint Lake 12 kV distribution system to 25 kV, and salvage Pipe Lake 1500KVA 4-12kV interchange transformer bank and associated 4kV and 12kV feeder sections.

JUSTIFICATION

[ ] Load [X] Service
[ ] Safety [X] Efficiency
[X] Reliability [ ] Other

Explanation

Power supply to Paint Lake is provided from Pipe Lake 230-4kV station owned by Inco. Contract with Inco will expire in March 2001. Based on a cost analysis it is recommended to construct a new Jonas Road-Paint Lake 25kV feeder. Purchasing and upgrading Pipe Lake station would be more costly.

Estimate Level	COMPLEX START (yyyy mm)
L1	1999 04

IN SERVICE DATES AND AMOUNTS				
2002 03	$1774			

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend								
Year 99/00								
00/01								
01/02	1,662	51	37		1,750		1,750	
02/03	23			180	-157		-157	
03/04								
04/05								
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	1,685	51	37	180	1,593		1,593	

REVISION: New Complex

Reviewed by ORIGINATOR	yyyy mm dd 99 11 05	Reviewed by COORDINATOR	yyyy mm dd 99 11 03
Reviewed by CONSTRUCTOR	yyyy mm dd 99 11 03	Approved by VICE PRESIDENT	yyyy mm dd 99 11 15

H2856/r Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Complex no. 267

Advance or deferral impact

Customers will continue to be served by a 12kV system.

Factors affecting timing or viability

Present contract expires in 2001may have to be renewed.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Paint Lake New Feeder				1,685	1,685	
TOTAL				1,685	1,685	

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
1999 10	1,593	New Complex

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item

327

Title			Budget reference number
PAINT LAKE - NEW FEEDER			04-00-7546
Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Design	Construction	74488:94242

DESCRIPTION:
1. CONSTRUCT 24 KM Z-2/0 AASC 25KV FEEDER FROM JONAS ROAD, THOMPSON TO PAINT LAKE
2. REBUILD AND CONVERT PAINT LAKE 12KV DISTRIBUTION SYSTEM TO 25KV
3. SALVAGE PIPE LAKE 1500KVA 4-12KV INTERCHANGE TRANSFORMER BANK AND ASSOCIATED 4KV AND 12KV FEEDER SECTIONS.

JUSTIFICATION:
POWER SUPPLY TO PAINT LAKE IS PROVIDED FROM PIPE LAKE 230-4KV STATION OWNED BY INCO. CONTRACT WITH INCO WILL EXPIRE IN MARCH 2001. BASED ON A COST ANALYSIS IT IS RECOMMENDED TO CONSTRUCT NEW JONAS ROAD-PAINT LAKE 25KV FEEDER. OTHER ALTERNATIVE I.E. PURCHASING AND UPGRADING PIPE LAKE STATION WOULD BE MORE COSTLY.

REFERENCE:
REPORT #DPS98-10, SUPPLY TO PAINT LAKE

REVISION:
NEW ITEM.

IN SERVICE DATES				Base estimate
2002 03 31	1 773			199909 L3
				Work start date 1999 04 01

	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
PREV. AUTHORITY Authorized to date:						
TOTAL						
REV. AMOUNTS: Authorized to date: Over(under)expend:						
Auth 2001/02	1 662	51	37			1 750
Req.: 2002/03	23			- 180		- 157
TOTAL	1 685	51	37	- 180		1 593

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

1999-09-30 09:14 AM

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 04-00-7546

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1999 10	0	New Item

ASSOCIATED PROJECTS

Budget reference number	Description

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

COMPLEX STATUS: ☐ Planned ☒ In progress

Complex no. 10

REVISION STATUS: ☐ New complex ☒ In service change ☐ Concept change ☒ Estimate change only

COMPLEX: E M S SCADA

Proposal
Establish site, define, procure and install an EMS SCADA to replace the existing AGC SCADA. Provide any additional renovations or plant additions required to house the new EMS SCADA and salvage the old.

JUSTIFICATION: ☐ Load ☒ Service ☐ Safety ☒ Efficiency ☒ Reliability ☐ Other

Explanation
The existing AGC SCADA has reached its maximum capability and can not be expanded without high risk to the Corporation. The applications of the existing AGC SCADA are limited and are not able to run the new generation of applications that are required. The reliability of the existing AGC SCADA may also become a concern as supply of new and used parts diminish.

Estimate Level	COMPLEX START (yyyy mm)
L2	1996 02

IN SERVICE DATES AND AMOUNTS

1998 02	$3244	1998 03	$2576	1998 04	$698	1998 06	$456
1998 09	($314)	1998 10	$51969	1998 11	$1224	1998 12	$763
1999 02	$893	1999 03	$2046	1999 06	$1582	1999 09	$743

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	59,815		3,984	73	63,726	63,957	-231	-0
Year 99/00	2,075	6			2,081	461	1,620	351
00/01								
01/02								
02/03								
03/04								
04/05								
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	61,890	6	3,984	73	65,807	64,418	1,389	2

REVISION: Reflects additional costs to salvage and renovate existing system control ctr (cc), and clean up Brandon and Dorsey emergency cc's.

Reviewed by ORIGINATOR	yyyy mm dd 99 11 08	Reviewed by COORDINATOR	yyyy mm dd
Reviewed by CONSTRUCTOR	yyyy mm dd 99 11 03	Approved by VICE PRESIDENT	yyyy mm dd 99 11 24

H2856/r Rev 99 03

Complex no.
10

CAPITAL EXPENDITURE FORECAST COMPLEX
(IN THOUSANDS OF DOLLARS)

Advance or deferral impact

Increasingly unstable operating control system.

Factors affecting timing or viability

Degree of dependence on the new generation of applications.
Availability of new and used parts for the AGC SCADA system.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
EMS SCADA	54,048	60,391	61,599	61,890	291	0
TOTAL	54,048	60,391	61,599	61,890	291	0

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
95 10	30,194	NEW COMPLEX
96 10	60,847	Revised to include a new building facility and communications.
1997 10	60,717	In Service date advanced from 1999 01 01 to 1998 10 31. Previous estimate was based on an even cashflow whereas this revision reflects a detailed schedule.
1998 10	64,418	Reflects 97/98 undexp 4.1M,purch of video proj, + more work than orig est on 48V battery sys, MTS serv, SCC bkup facil, Multiplex, WLFOS, WAFOS, Alarms, and SCC/BUCC facil.
1999 10	65,807	Reflects additional costs to salvage and renovate existing system control ctr (cc), and clean up Brandon and Dorsey emergency cc's.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item

328

Title: EMS/SCADA PROJECT

Budget reference number: 05-00-5542

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Planning & Control	Planning & Control	70057:70151

DESCRIPTION:
THERE ARE 3 MAIN COMPONENTS TO THIS PROJECT:
1) PLAN, PROCURE AND INSTALL A NEW EMS/SCADA SYSTEM TO REPLACE EXISTING AGC/SCADA.
2) PLAN, DESIGN AND CONSTRUCT A NEW FACILTIY IN WINNIPEG TO HOUSE AND FULLY SUPPORT THE NEW EMS/SCADA SYSTEM.
3) PLAN, DESIGN AND INSTALL COMMUNICATIONS NECESSARY TO SUPPORT THE NEW SYSTEM AND FACILITY.

JUSTIFICATION:
THE EXISTING AGC/SCADA SYSTEM HAS REACHED ITS END OF LIFE. THE LIFE EXPECTANCY AT TIME OF PURCHASE WAS 15 YEARS MAXIMUM. WHEN REPLACED MANITOBA HYDRO'S SYSTEM WILL HAVE BEEN INSTALLED 20 YEARS. THE SYSTEM IS NO LONGER EXPANDABLE AND IS A CAUSE OF CONCERN TO THE CORPORATION FROM AN OPERATIONAL, MAINTENANCE AND RISK PERSPECTIVE. NEW SPARE PARTS ARE NO LONGER AVAILABLE.

THE EXISTING SCC AND WCC FACILITY IS INADEQUATE AND OUTDATED TO MEET THE SPACE AND FUNCTIONALITY REQUIREMENTS OF MODERN CONTROL CENTRES.

REFERENCE:
THE EMS/SCADA PROJECT TEAM HAS PREPARED THE FOLLOWING REPORTS AS PART OF THE PLANNING PHASE. THESE REPORTS SUPPORT THE RECOMMENDATIONS AND BUDGET, AND INCLUDE: 95-EMS /SCADA3 PROJECT IMPLEMENATION; 95-EMS/SCADA2 COMMUNICATIONS; 95-EMS/SCADA6 CONTROL CENTRE STUDY; 95-EMS/SCADA1 EMS/SCADA FUNCTIONAL REQUIREMENTS; 95-EMS/SCDA7 EMERGENCY CONTROL CENTRE; 95-EMS/SCADA8 OPERATIONS TRAINING SIMULATORS; 95-EMS/SCADA4 VENDOR SELECTION DOCUMENT; 95-EMS/SCADA5 MAINTENANCE AND SUPPORT STRATEGY.

REVISION:
THE INCREASE HAS OCCURRED DUE TO ADDITIONAL COSTS RELATED TO THE SALVAGE AND RENOVATION OF THE EXISTING SYSTEM CONTROL CENTRE (SCC) INTO A BACK UP CONTROL CENTRE (BUCC) AS WELL AS COSTS RELATED TO THE CLEAN-UP OF THE BRANDON CONTROL CENTRE (BCC) AND EMERGENCY CONTROL CENTRE (ECC) AT DORSEY WHICH HAD NOT BEEN PREVIOUSLY IDENTIFIED.

This BRN contains Deleted, Blocked, or Closed Orders.

IN SERVICE DATES						Base estimate
Prior Total	6 974	1998 10 31	51 969	1999 02 28	622	199803 L4
1998 07 31	14	1998 11 30	1 224	1999 03 31	2 046	
1998 08 31	11	1998 12 31	763	1999 06 30	1 582	Work start date
1998 09 30	- 339	1999 01 31	271	1999 09 30	743	1995 07 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:	59 815		3 984	-3	-70	63 726
1999/00	685	8				693
TOTAL	60 500	8	3 984	-3	-70	64 419
REV. AMOUNTS:						
Authorized to date:	59 815		3 984	-3	-70	63 726
Over(under)expend:						
Auth 1999/00 Req.:	2 075	6				2 081
TOTAL	61 890	6	3 984	-3	-70	65 807

Prepared by: yy mm dd COORDINATOR — Approved by: yy mm dd Approved by: yy mm dd

Estimated by: ORIGINATOR — COORDINATING MANAGER — ORIGINATING MANAGER

1999-08-21 05:29 PM

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 05-00-5542

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1995 10	30 194	NEW ITEM
1996 10	60 847	LEVEL II ESTIMATE. CASH FLOW AND DOLLARS REVISED FROM PREVIOUS CER TO REFLECT THE PLANNING WORK DESCRIBED IN THE 'EMS/SCADA PLANNING PHASE - SUMMARY REPORT' DATED 96 05 22 AND APPROVED BY THE MANITOBA HYDRO ELECTRIC BOARD (ITEM 684-96-02), MAY 30, 1996.
1997 10	60 716	SCOPE UNCHANGED. IN SERVICE DATE ADVANCED FROM 1999 01 01 TO 1998 10 31. ALTHOUGH CONTRACT AMOUNTS HAVE BEEN BELOW ESTIMATES FOR THE FACILITY, SONET COMMUNICATIONS NETWORK AND EMS/SCADA, THESE REDUCTIONS HAVE BEEN OFFSET BY RE-ESTIMATE OF OTHER ACTIVITIES. PREVIOUS ESTIMATE WAS BASED ON AN EVEN CASHFLOW WHEREAS THIS REVISION REFLECTS A DETAILED SCHEDULE.
1998 10	64 419	SCOPE UNCHANGED. COST OF WORK NOT PREVIOUSLY IDENTIFIED HAS ABSORBED ALL OF THE PROJECT CONTINGENCY AND INCREASED THE PROJECT BUDGET.

ASSOCIATED PROJECTS

Budget reference number	Description

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	918	2				920	920
May	510	2				512	1 432
Jun	530	2				532	1 964
Jul	67	1				68	2 032
Aug	50	-1				49	2 081
Sep							2 081
Oct							2 081
Nov							2 081
Dec							2 081
Jan							2 081
Feb							2 081
Mar							2 081
TOTAL	2 075	6				2 081	2 081
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

COMPLEX STATUS: ☐ Planned ☒ In progress

Complex no.: 12

REVISION STATUS: ☐ New complex ☒ In service change ☒ Concept change ☐ Estimate change only

COMPLEX: MICROWAVE RADIO REPLACEMENTS

Proposal

Upgrade and refurbish the Lake Winnipeg Microwave System.
Replace the Winnipeg River Microwave System.
Replace Thompson/Kelsey/Radisson Communications.
Provide a Fiber Optic cable system from Winnipeg Area to Brandon Area.
Provide replacement microwave equipment required to access Industry Canada re-allocated frequencies.
Replace the Interlake Digital Microwave System.

JUSTIFICATION

☐ Load ☒ Service
☐ Safety ☐ Efficiency
☒ Reliability ☐ Other

Explanation

The joint MH/MTS Dorsey-Radisson link is nearing end of life. Details will be determined in future studies. The Wpg R MW System is less reliable due to age, and unavailability of parts. Thompson, Kelsey, Radisson comm channels will replace those which MTS is removing. Wpg/Bdn fibre optics will provide more channels and digital capacity to meet forecast requirements. Various microwave equipment must be replaced as it is dedicated to frequencies which have been re-allocated from our licence. Interlake syst repl required for all of the above reasons.

Estimate Level	COMPLEX START (yyyy mm)
L2	1997 04

IN SERVICE DATES AND AMOUNTS

1999 03	($150)	1999 04	$6911	1999 08	$109	1999 12	$448
2000 03	$9618	2001 12	$1483	2002 01	$1987	2002 03	$6897
2002 12	$12437	2005 10	$18124				

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	8,576		677	142	9,111	9,486	-375	-4
Year 99/00	8,690	81	701	505	8,967	5,760	3,207	56
00/01	2,927	108	249		3,284	2,524	760	30
01/02	8,524	388	718		9,630	12,947	-3,317	-26
02/03	7,109	484	509		8,102	3,427	4,675	136
03/04								
04/05	1,384	184	63		1,631	1,495	136	9
05/06	14,252	1974	266		16,492	15,910	582	4
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	51,462	3,219	3,183	647	57,217	51,549	5,668	11

REVISION: Add'n of: 1)site,upgrades,reloc of comm rm on Wpg R syst.2)Grd Rpds > Tyrell Mw Repl.3) Thompson cable repl.4)Wpg > Bdn upgr & equip,&5) scope chg in Minn & Thomp areas.

Reviewed by ORIGINATOR	yyyy mm dd 99 11 08	Reviewed by COORDINATOR	yyyy mm dd
Reviewed by CONSTRUCTOR	yyyy mm dd 99 11 03	Approved by VICE PRESIDENT	yyyy mm dd 99 11 16

H2856/r Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Complex no. 12

Advance or deferral impact

Factors affecting timing or viability

n/a

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Lake Winnipeg Microwave Upgrade		10,719	10,933	11,032	99	1
Wpg River Microwave System Replacement	7,152	6,641	6,774	8,544	1,770	26
Microwave Frequency Displacement (2GH)	5,561	5,771	5,886	5,852	-34	-1
Thompson/Kelsey/Radisson Communications Repl		250	255	108	-147	-58
Wpg/Bdn Fibre Optic Communications	8,403	5,962	6,081	6,750	669	11
Minnedosa area 71E3 microwave replacement		1,657	1,690	1,742	52	3
Jenpeg-Whiskey Jack-Wabowden M/W replacement	425	392	400	425	25	6
Interlake Digital Microwave Replacement		14,970	15,269	15,636	367	2
Thompson Communications Cables Repl				650	650	
Grand rapids > Tyrell RCA 9202 Microwave Repl				723	723	
.						
TOTAL	21,541	46,362	47,288	51,462	4,174	9

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
9510	36,047	Complex increased to include Wpg R MW repl, Thompson/Kelsey/Radisson comm repl, frequency change equip, and Wpg/Bdn fibre optic cable system.
9610	39,349	Increase due to 1) deferrals, Lake Wpg, MW frequency displacement, Thompson-Kelsey-Rad, and Wpg/Bdn fibre optic. 2)addition of Minnedosa, & Jenpeg-Whiskeyjack-Wabowden.
1997 10	40,798	Winnipeg River Microwave system replacement deferred 15 mo to 1999 03 31. Estimate reflects revised costing methodology implemented with the new financial reporting system.
1998 10	51,549	Reflects 97/98 underexpenditure 9.5M, and addition of the Interlake Digital Microwave Replacement item.
1999 10	57,217	Add'n of: 1)site,upgrades,reloc of comm rm on Wpg R syst.2)Grd Rpds > Tyrell Mw Repl.3) Thompson cable repl.4)Wpg > Bdn upgr & equip,&5) scope chg in Minn & Thomp areas.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION
94 - T2	Telecontrol Communications Option Winnipeg Area to Brandon Area

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item

329

Title			Budget reference number
LAKE WINNIPEG MICROWAVE UPGRADE			05-00-4500
Originating division Planning & Control	Coordinating division Planning & Control	Constructing division Construction	Project Order Group (Range): 70369

DESCRIPTION:
UPGRADE AND REFURBISH THE LAKE WINNIPEG MICROWAVE SYSTEM.

JUSTIFICATION:
THE JOINT MANITOBA HYDRO - MANITOBA TELECOM SERVICES MICROWAVE SYSTEM FROM DORSEY TO RADISSON EAST OF LAKE WINNIPEG HAS MAJOR COMPONENTS NEARING END OF LIFE. THE MANITOBA TELECOM SERVICES, WHO MAINTAINS AND ALSO USES THIS SYSTEM, EXPECTS THAT IT MUST REPLACE THESE COMPONENTS SOON AND BOTH PARTIES WISH TO EXPAND THE CAPACITY AND IMPROVE THE DEPENDABILTY OF THE SYSTEM. THE DATE OF REPLACEMENT AND EXACT WORK TO BE DONE ARE PENDING STUDIES.

REFERENCE:
MINUTES OF MTS/MH PLANNING COMMITTEE MEETING #6

REVISION:
INSERVICE DATE DEFERRED FROM 2002 03 31 TO 2002 12 31 DUE TO MTS PLANNING CHANGES. REFLECTS REVISED ACTIVITY AND OVERHEAD RATES.

CONTINGENCY: $1,000,000

IN SERVICE DATES				Base estimate
2002 12 31	12 437			199901 L2
				Work start date 1999 04 01

	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
PREV. AUTHORITY Authorized to date:						
1999/00	300	14	13			327
2000/01	324	23	43			390
2001/02	9 834	936	365			11 135
2002/03	262	28				290
TOTAL	10 720	1 001	421			12 142
REV. AMOUNTS: Authorized to date: Over(under)expend:						
Auth 1999/00	15		1			16
Req.: 2000/01	519	15	19			553
2001/02	4 699	225	238			5 162
2002/03	5 799	398	509			6 706
TOTAL	11 032	638	767			12 437

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number: 05-00-4500

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1993 10	12 721	NEW ITEM.
1994 10	12 503	IN-SERVICE DATE DEFERRED ONE YEAR FROM 1999 03 31 TO 2000 03 31. REVISED INTEREST AND ESCALATION RATES.
1995 10	12 484	REVISED INTEREST AND ESCALATION RATES.
1996 10	13 105	REVISED INTEREST RATES. DEFERRED TWO YEARS TO 2002.
1997 04	12 265	ESTIMATE REFLECTS REVISED COSTING METHODOLOGY WITH THE NEW FINANCIAL REPORTING SYSTEM. IT ALSO REFLECTS REVISED INTEREST AND ESCALATION RATES.
1998 10	12 142	NO CHANGE.

ASSOCIATED PROJECTS

Budget reference number	Description
05-00-3207	MINNEDOSA AREA 71E3 MICROWAVE REPLACEMENT (MINNTE)
05-00-6550	WINNIPEG RIVER MICROWAVE SYSTEM REPLACEMENT
05-00-6561	MICROWAVE FREQUENCY DISPLACEMENT (2 GHZ)
05-00-6562	THOMPSON-KELSEY-RADISSON COMMUNICATIONS REPLACEMENT
05-00-6567	WINNIPEG AREA TO BRANDON AREA FIBRE OPTIC COMMUNICATIONS
05-00-7577	JENPEG-WHISKEY JACK-WABOWDEN M/W REPLACEMENT
05-00-8589	INTERLAKE DIGITAL MICROWAVE REPLACEMENT
05-00-8598	THOMPSON COMMUNICATIONS CABLES REPLACEMENT
05-00-8599	GRAND RAPIDS TO TYRELL RCA 9202 MICROWAVE REPLACEMENT

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	1					1	1
May	1					1	2
Jun	1					1	3
Jul	1					1	4
Aug	1					1	5
Sep	1					1	6
Oct	1					1	7
Nov	1					1	8
Dec	1					1	9
Jan	1					1	10
Feb	1					1	11
Mar	4		1			5	16
TOTAL	15		1			16	16
2000/01 Apr							
May							
Jun	52	2				54	54
Jul	52	2				54	108
Aug	52	1	1			54	162
Sep	52	2	1			55	217
Oct	52	1	2			55	272
Nov	52	1	2			55	327
Dec	52	2	2			56	383
Jan	52	1	3			56	439
Feb	52	2	3			57	496
Mar	51	1	5			57	553
TOTAL	519	15	19			553	553

1999-09-28 11:49 AM

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item

330

Title			Budget reference number
WINNIPEG RIVER MICROWAVE SYSTEM REPLACEMENT			05-00-6550
Originating division Planning & Control	Coordinating division Planning & Control	Constructing division Construction	Project Order Group (Range): 71041

DESCRIPTION:
REPLACEMENT OF THE WINNIPEG RIVER MICROWAVE SYSTEM.

JUSTIFICATION:
THE WINNIPEG RIVER MICROWAVE SYSTEM PROVIDES PROTECTION, CONTROL AND TELEPHONE CIRCUITS BETWEEN THE WINNIPEG RIVER GENERATING STATIONS AND THE SYSTEM CONTROL CENTRE IN WINNIPEG. THIS SYSTEM WAS ORIGINALLY INSTALLED IN 1958 AND THE RADIO EQUIPMENT WAS SUBSEQUENTLY REPLACED IN 1975. THE RADIO EQUIPMENT MUST BE REPLACED AGAIN DUE TO THE LOSS OF THE MANUFACTURER'S REPAIR SERVICE. SPARE PARTS ARE DEPLETED. ADDITIONAL SPARE PARTS WERE SALVAGED BY REPLACING THE TAYLOR-RIDGEWAY COMMUNICATIONS LINK MICROWAVE EQUIPMENT SO THAT THE REMAINING SYSTEM CAN BE KEPT IN OPERATION UNTIL REPLACEMENT. DELAYING REPLACEMENT MAY CAUSE THE WINNIPEG RIVER GENERATING STATIONS AND THE INTEGRATED POWER SYSTEM TO EXPERIENCE UNACCEPTABLY LONG SERVICE OUTAGES TO CRITICAL PROTECTION AND CONTROL CIRCUITS.

REFERENCE:
PRODUCTION DIVISION SOUTH REPORT PS94-07 REPLACEMENT OF WINNIPEG RIVER MICROWAVE SYSTEM.

REVISION:
ISD DEFERRED FROM 19991031 TO 20000331. THE FOLLOWING ITEMS HAVE BEEN ADDED:

NEW TOWER AND SITE AT GULL LAKE, TEST EQUPMENT FOR MICROWAVE & T1 TRANSMISSION, 48V UPGRADES FOR SEVEN SISTERS, WHITESHELL, AND LAC DU BONNET; POINTE DU BOIS & SCOTLAND FIBRE CABLE AND MUX, AND SEVEN SISTERS COMM ROOM RELOCATION.

CONTINGENCIES $94,000

IN SERVICE DATES				Base estimate
2000 03 31	9 259			199901 L2
				Work start date 1995 10 01

	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
PREV. AUTHORITY Authorized to date:	2 156		153			2 309
1999/00	3 941	88	148			4 177
2000/01	555					555
TOTAL	6 652	88	301			7 041
REV. AMOUNTS: Authorized to date:	2 156		153			2 309
Over(under)expend:						
Auth 1999/00	6 388	48	514			6 950
Req.:						
TOTAL	8 544	48	667			9 259

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 05-00-6550

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1995 10	7 265	NEW ITEM.
1996 10	7 265	REVISED INTEREST RATES.
1997 10	7 808	SELECTIVE REVISION: ISD DEFERRED 15 MONTHS FROM 1998 01 01 TO 1999 03 31. REVISED INTEREST AND ESCALATION RATES.
1998 10	7 042	ISD DEFERRED FROM 1999 03 31 TO 1999 10 31. RE-ESTIMATE REFLECTS CURRENT COSTS.

ASSOCIATED PROJECTS

Budget reference number	Description
05-00-3207	MINNEDOSA AREA 71E3 MICROWAVE REPLACEMENT (MINNTE)
05-00-4500	LAKE WINNIPEG MICROWAVE UPGRADE
05-00-6561	MICROWAVE FREQUENCY DISPLACEMENT (2 GHZ)
05-00-6562	THOMPSON-KELSEY-RADISSON COMMUNICATIONS REPLACEMENT
05-00-6567	WINNIPEG AREA TO BRANDON AREA FIBRE OPTIC COMMUNICATIONS
05-00-7577	JENPEG-WHISKEY JACK-WABOWDEN M/W REPLACEMENT
05-00-8589	INTERLAKE DIGITAL MICROWAVE REPLACEMENT
05-00-8598	THOMPSON COMMUNICATIONS CABLES REPLACEMENT
05-00-8599	GRAND RAPIDS TO TYRELL RCA 9202 MICROWAVE REPLACEMENT

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	460	2	16			478	478
May	689	4	19			712	1 190
Jun	871	7	24			902	2 092
Jul	837	5	31			873	2 965
Aug	883	8	37			928	3 893
Sep	1 071	11	43			1 125	5 018
Oct	385	4	51			440	5 458
Nov	314	3	54			371	5 829
Dec	269	1	57			327	6 156
Jan	203	1	59			263	6 419
Feb	203	1	61			265	6 684
Mar	203	1	62			266	6 950
TOTAL	6 388	48	514			6 950	6 950
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item

331

Title			Budget reference number
MICROWAVE FREQUENCY DISPLACEMENT (2 GHZ)			05-00-6561
riginating division lanning & Control	Coordinating division Planning & Control	Constructing division Construction	Project Order Group (Range): 70494:72032

DESCRIPTION:
PROVIDE REPLACEMENT COMMUNICATIONS FOR MICROWAVE EQUIPMENT IN VARIOUS MICROWAVE SYSTEMS WHICH MUST BE REMOVED FROM SERVICE.

JUSTIFICATION:
VARIOUS MICROWAVE EQUIPMENT MUST BE REMOVED FROM SERVICE AS IT WILL NO LONGER BE LICENSEABLE. THE FREQUENCIES ARE BEING RE-ALLOCATED BY INDUSTRY CANADA AS PER A DIRECTIVE MEMO DATED 95-02-02.

REFERENCE:
TELECONTROL REPORT 95-T1 FORECAST OF BUDGET AND SCHEDULE OF MICROWAVE SYSTEM CHANGES DUE TO FREQUENCY DISPLACEMENT DATED 95-06-22.

REVISION:
REVISED TO REFLECT BUDGET RESTRAINTS FOR SPENDING IN 1999/2000.

CONTINGENCY: $500,000

This BRN contains Deleted, Blocked, or Closed Orders.

IN SERVICE DATES				Base estimate
1999 03 31	- 150			199901 L2
2002 03 31	6 897			Work start date
				1996 10 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:	1 209		75		- 142	1 142
1999/00	675	15	137			827
2000/01	361	68	232			661
2001/02	439	102	293			834
2002/03	3 099	39				3 138
TOTAL	5 783	224	737		- 142	6 602
REV. AMOUNTS:						
Authorized to date:	1 209		75		- 142	1 142
Over(under)expend:						
Auth 1999/00	81		115			196
Req.: 2000/01	1 442	37	190			1 669
2001/02	1 811	58	333			2 202
2002/03	1 309	87				1 396
TOTAL	5 852	182	713		- 142	6 605

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number: 05-00-6561

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1995 10	6 618	NEW ITEM.
1996 10	6 773	IN-SERVICE DATE DEFERRED 1 YEAR.
1997 10	6 824	SCOPE UNCHANGED, ESTIMATE REFLECTS REVISED COSTING METHODOLOGY IMPLEMENTED WITH THE NEW FINANCIAL REPORTING SYSTEM. ALSO REFLECTS REVISED INTEREST AND ESCALATION RATES.
1998 10	6 602	REVISED TO REFLECT CURRENT COSTS & SCHEDULE.

ASSOCIATED PROJECTS

Budget reference number	Description
05-00-3207	MINNEDOSA AREA 71E3 MICROWAVE REPLACEMENT (MINNTE)
05-00-4500	LAKE WINNIPEG MICROWAVE UPGRADE
05-00-6550	WINNIPEG RIVER MICROWAVE SYSTEM REPLACEMENT
05-00-6562	THOMPSON-KELSEY-RADISSON COMMUNICATIONS REPLACEMENT
05-00-6567	WINNIPEG AREA TO BRANDON AREA FIBRE OPTIC COMMUNICATIONS
05-00-7577	JENPEG-WHISKEY JACK-WABOWDEN M/W REPLACEMENT
05-00-8589	INTERLAKE DIGITAL MICROWAVE REPLACEMENT
05-00-8598	THOMPSON COMMUNICATIONS CABLES REPLACEMENT
05-00-8599	GRAND RAPIDS TO TYRELL RCA 9202 MICROWAVE REPLACEMENT

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	7		9			16	16
May	7		9			16	32
Jun	7		9			16	48
Jul	7		9			16	64
Aug	7		9			16	80
Sep	7	-1	10			16	96
Oct	7	-1	10			16	112
Nov	7		10			17	129
Dec	7		10			17	146
Jan	7		10			17	163
Feb	7		10			17	180
Mar	4	2	10			16	196
TOTAL	81		115			196	196
2000/01 Apr	121	2	10			133	133
May	120	3	11			134	267
Jun	120	3	12			135	402
Jul	120	3	13			136	538
Aug	120	3	14			137	675
Sep	120	3	15			138	813
Oct	120	4	16			140	953
Nov	120	4	17			141	1 094
Dec	120	4	18			142	1 236
Jan	120	4	19			143	1 379
Feb	120	4	20			144	1 523
Mar	121		25			146	1 669
TOTAL	1 442	37	190			1 669	1 669

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item

332

Title			Budget reference number
THOMPSON-KELSEY-RADISSON COMMUNICATIONS REPLACEMENT			05-00-6562
Originating division Planning & Control	Coordinating division Planning & Control	Constructing division Construction	Project Order Group (Range): 70370

DESCRIPTION:
PROVISION OF COMMUNICATIONS TO REPLACE THE MTS RCA 9202 MICROWAVE CHANNELS BETWEEN THOMPSON, KELSEY, AND RADISSON.

JUSTIFICATION:
MTS WILL BE REMOVING THE RCA 9202 MICROWAVE SYSTEM FROM SERVICE AND WE MUST REPLACE THE CHANNELS ON THIS SYSTEM.

REFERENCE:
TELECONTROL REPORT 95-T2 'FORECAST OF BUDGET AND SCHEDULE - THOMPSON-KELSEY-RADISSON COMMUNICATIONS REPLACEMENT' DATED 95 -06-29

REVISION:
SCOPE OF JOB CHANGED. MTS TO REPLACE 9202 MW. START DATE CHANGED.

CONTINGENCY $8,000

IN SERVICE DATES				Base estimate
1999 08 31	109			199901 L2
				Work start date 1999 04 01

	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
PREV. AUTHORITY Authorized to date: 1999/00	255	4	5			264
TOTAL	255	4	5			264
REV. AMOUNTS: Authorized to date: Over(under)expend: Auth Req.: 1999/00	108		1			109
TOTAL	108		1			109

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 05-00-6562

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1995 10	2 254	NEW ITEM.
1996 10	2 364	ISD DEFERRED FROM 1999 03 30 TO 2001 03 30
1997 04	2 449	CONTINGENCY $200,000.
1998 10	263	CHANGE OF SCOPE - MTS WILL REPLACE THE RCA 9202 MICROWAVE AND MH MUST PURCHASE AND INSTALL MULTIPLEX FOR ITS OWN USE.

ASSOCIATED PROJECTS

Budget reference number	Description
05-00-3207	MINNEDOSA AREA 71E3 MICROWAVE REPLACEMENT (MINNTE)
05-00-4500	LAKE WINNIPEG MICROWAVE UPGRADE
05-00-6550	WINNIPEG RIVER MICROWAVE SYSTEM REPLACEMENT
05-00-6561	MICROWAVE FREQUENCY DISPLACEMENT (2 GHZ)
05-00-6567	WINNIPEG AREA TO BRANDON AREA FIBRE OPTIC COMMUNICATIONS
05-00-7577	JENPEG-WHISKEY JACK-WABOWDEN M/W REPLACEMENT
05-00-8589	INTERLAKE DIGITAL MICROWAVE REPLACEMENT
05-00-8598	THOMPSON COMMUNICATIONS CABLES REPLACEMENT
05-00-8599	GRAND RAPIDS TO TYRELL RCA 9202 MICROWAVE REPLACEMENT

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	2					2	2
May	16					16	18
Jun	15	1				16	34
Jul	23	1				24	58
Aug	15	1				16	74
Sep	15					15	89
Oct	15					15	104
Nov	1					1	105
Dec	1					1	106
Jan	1					1	107
Feb	1					1	108
Mar	3	-3	1			1	109
TOTAL	108		1			109	109
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item

333

Title			Budget reference number
WINNIPEG AREA TO BRANDON AREA FIBRE OPTIC COMMUNICATIONS			05-00-6567
Originating division Planning & Control	Coordinating division Planning & Control	Constructing division Construction	Project Order Group (Range): 70004:70628

DESCRIPTION:
PROVIDE A FIBRE OPTIC CABLE SYSTEM TO MEET COMMUNICATIONS REQUIREMENTS BETWEEN THE WINNIPEG AREA AND THE BRANDON AREA.

JUSTIFICATION:
FORECAST REQUIREMENTS FOR COMMUNICATIONS BETWEEN THE WINNIPEG AREA AND THE BRANDON AREA. REQUIRE THAT CHANNEL CAPACITY BE INCREASED AND THAT DIGITAL CAPACITY BE PROVIDED BETWEEN THESE POINTS. THE REQUIRED EXPANSION IS THE RESULT OF MANY REQUIREMENTS, INCLUDING BUT NOT EXCLUSIVE OF TRANSMISSION LINE PROTECTION, AGC/SCADA, THE VHF MOBILE RADIO SYSTEM, TRANSIENT FAULT RECORDERS, RUCUS, MAPINFO, CSS, TRAINING AND DISPATCH AND ADMINISTRATIVE TELEPHONE REQUIREMENTS.

REFERENCE:
TELECONTROL REPORT 94-T2 REPORT ON TELECONTROL COMMUNICATIONS OPTION, WINNIPEG AREA TO BRANDON AREA, 1994 - 2014.

REVISION:
INSERVICE DATE REVISED FROM 199811 TO 199904 (PHASE I) AND PHASE II - 200003. INCREASED COSTS DUE TO THE ADDITION OF THE FOLLOWING: GREAT PLAINS MICROWAVE SITE UPGRADE, NEW 48V POWER SYSTEM AT PORTAGE RADIO AND NEW DIESEL GENERATORS AT PORTAGE, PINKERTON LAKE, AND BRANDON SOUTH.

CONTINGENCIES:
$125,000

IN SERVICE DATES				Base estimate
1999 04 30 2000 03 31	6 911 359			199901 L3 Work start date 1996 01 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:	5 183		449			5 632
1999/00	142					142
TOTAL	5 325		449			5 774
REV. AMOUNTS:						
Authorized to date:	5 183		449			5 632
Over(under)expend:						
Auth 1999/00 Req.:	1 567	19	52	-5	- 500	1 133
TOTAL	6 750	19	501	-5	- 500	6 765

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 05-00-6567

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1995 10	7 426	NEW ITEM.
1996 10	7 759	ISD DEFERRED FROM 97 03 TO 97 11 DUE TO SCHEDULING PRIORITIES. INCREASED COST DUE TO SCHEDULING DELAY. REVISED CASHFLOW TO THE NEW ISD.
1997 10	9 175	REDUCTION IN OVERALL COSTS DUE TO SCOPE CHANGE IN MICROWAVE WORK. A REDUCTION IN THE NUMBER OF REPEATER BUILDINGS RESULTED IN LOWER ENGINEERING, MATERIAL, AND LABOUR COSTS.
1998 10	5 773	TO UPDATE THE COST AND CHANGE THE IN-SERVICE FROM THAT STATED IN A PREVIOUS SUBMISSION. A BETTER DEFINITION OF THE SCOPE OF THE ENGINEERING AND CONSTRUCTION WORK HAS RESULTED IN SIGNIFICANT COST REDUCTIONS IN THESE COST ELEMENTS. $500 000 CAPITAL CONTRIBUTION FROM WESTMAN MEDIA COOPERATIVE LTD. CONTINGENCY: $100,000

ASSOCIATED PROJECTS

Budget reference number	Description
05-00-3207	MINNEDOSA AREA 71E3 MICROWAVE REPLACEMENT (MINNTE)
05-00-4500	LAKE WINNIPEG MICROWAVE UPGRADE
05-00-6550	WINNIPEG RIVER MICROWAVE SYSTEM REPLACEMENT
05-00-6561	MICROWAVE FREQUENCY DISPLACEMENT (2 GHZ)
05-00-6562	THOMPSON-KELSEY-RADISSON COMMUNICATIONS REPLACEMENT
05-00-7577	JENPEG-WHISKEY JACK-WABOWDEN M/W REPLACEMENT
05-00-8589	INTERLAKE DIGITAL MICROWAVE REPLACEMENT
05-00-8598	THOMPSON COMMUNICATIONS CABLES REPLACEMENT
05-00-8599	GRAND RAPIDS TO TYRELL RCA 9202 MICROWAVE REPLACEMENT

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	99		39	- 500		- 362	- 362
May	99	1				100	- 262
Jun	215	2				217	-45
Jul	68	1	1			70	25
Aug	50		1			51	76
Sep	36	1	1			38	114
Oct	189	3	1			193	307
Nov	188	3	1			192	499
Dec	188	2	2			192	691
Jan	213	3	2		-5	213	904
Feb	187	4	2			193	1 097
Mar	35	-1	2			36	1 133
TOTAL	1 567	19	52	- 500	-5	1 133	1 133
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item

334

Title	Budget reference number
MINNEDOSA AREA 71E3 MICROWAVE REPLACEMENT (MINNTE)	05-00-3207

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
anning & Control	Planning & Control	Construction	70371

DESCRIPTION:
REPLACE THE MINNEDOSA AREA MICROWAVE SYSTEM WITH A 7GHZ DIGITAL SYSTEM.

JUSTIFICATION:
CHANGES IN MICROWAVE RADIO FREQUENCY SPECTRUM ASSIGNMENTS BY INDUSTRY CANADA HAVE MADE CONTINUATION OF USE OF THE MINNEDOSA AREA MICROWAVE SYSTEM UNCERTAIN. THIS ITEM COVERS THE COST OF REPLACING EQUIPMENT TO MOVE TO ANOTHER FREQUENCY BAND AS REQUIRED.

REF. PLANNING REPORT 92-T3 'BRANDON - RAPID CITY - MINNEDOSA - NEEPAWA - RAVEN LAKE MICROWAVE SYSTEM REPLACEMENT'

REVISION:
SCOPE OF JOB HAS CHANGED TO PARTICIPATE WITH WESTMAN'S INSTALLATION OF FIBRE OPTIC CABLE.

CONTINGENCY: $120,000

IN SERVICE DATES				Base estimate
2002 01 31	1 987			199704 L2
				Work start date 1999 07 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:						
1999/00	6					6
2000/01	831	61	26			918
2001/02	820	62	96			978
TOTAL	1 657	123	122			1 902
REV. AMOUNTS:						
Authorized to date:						
Over(under)expend:						
Auth 1999/00	135	1	6			142
Req.: 2000/01	862	52	39			953
2001/02	745	47	100			892
TOTAL	1 742	100	145			1 987

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number: 05-00-3207

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1996 10	1 716	NEW ITEM. PREVIOUSLY A DOMESTIC ITEM.
1997 04	1 855	ISD DATE DEFERRED 1 YEAR FROM 2000 10 31. SCOPE UNCHANGED, ESTIMATE REFLECTS REVISED COSTING METHODOLOGY IMPLEMENTED WITH THE NEW FINANCIAL REPORTING SYSTEM. ESTIMATE ALSO REFLECTS REVISED INTEREST AND ESCALATION RATES.
1998 10	1 902	DEFERED FROM 2001 01 31 TO 2002 01 31.

ASSOCIATED PROJECTS

Budget reference number	Description
05-00-4500	LAKE WINNIPEG MICROWAVE UPGRADE
05-00-6550	WINNIPEG RIVER MICROWAVE SYSTEM REPLACEMENT
05-00-6561	MICROWAVE FREQUENCY DISPLACEMENT (2 GHZ)
05-00-6562	THOMPSON-KELSEY-RADISSON COMMUNICATIONS REPLACEMENT
05-00-6567	WINNIPEG AREA TO BRANDON AREA FIBRE OPTIC COMMUNICATIONS
05-00-7577	JENPEG-WHISKEY JACK-WABOWDEN M/W REPLACEMENT
05-00-8589	INTERLAKE DIGITAL MICROWAVE REPLACEMENT
05-00-8598	THOMPSON COMMUNICATIONS CABLES REPLACEMENT
05-00-8599	GRAND RAPIDS TO TYRELL RCA 9202 MICROWAVE REPLACEMENT

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul	103					103	103
Aug	3		1			4	107
Sep	3		1			4	111
Oct	3		1			4	115
Nov	3		1			4	119
Dec	3		1			4	123
Jan	3		1			4	127
Feb	3		1			4	131
Mar	11	1	-1			11	142
TOTAL	135	1	6			142	142
2000/01 Apr	17		1			18	18
May	17	1	1			19	37
Jun	17	1	1			19	56
Jul	17	1	1			19	75
Aug	17		2			19	94
Sep	132	7	2			141	235
Oct	132	7	3			142	377
Nov	132	7	4			143	520
Dec	131	8	5			144	664
Jan	131	9	6			146	810
Feb	61	3	7			71	881
Mar	58	8	6			72	953
TOTAL	862	52	39			953	953

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item

335

Title			Budget reference number
JENPEG-WHISKEY JACK-WABOWDEN M/W REPLACEMENT			05-00-7577
Originating division anning & Control	Coordinating division Planning & Control	Constructing division Construction	Project Order Group (Range): 70166

DESCRIPTION:
REPLACEMENT OF JENPEG TO WHISKEY JACK MICROWAVE RADIO.

JUSTIFICATION:
MTS REPLACEMENT OF THE WHISKEY JACK TO WABOWDEN MICROWAVE WITH A DIGITAL SYSTEM, REQUIRES THAT MANITOBA HYDRO CHANGE ITS ELDERLY JENPEG TO WHISKEY JACK SYSTEM TO BE COMPATIBLE.

REVISION:
REVISED START DATE

CONTINGENCY: $25,000.

IN SERVICE DATES				Base estimate
1999 12 31	448			199803 L2
				Work start date 1998 09 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:	28					28
1999/00	370	8	15			393
TOTAL	398	8	15			421
REV. AMOUNTS:						
Authorized to date:	28					28
Over(under)expend:						
Auth 1999/00 Req.:	397	12	11			420
TOTAL	425	12	11			448

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 05-00-7577

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1996 10	366	NEW ITEM
1997 10	420	ESTIMATE REFLECTS REVISED COSTING METHODOLOGY IMPLEMENTED WITH THE NEW FINANCIAL REPORTING SYSTEM. ALSO REVISED INTEREST AND ESCALATION RATES REFLECTED.
1998 10	421	START DATE DEFERRED FROM 1998 01 TO 1998 06. ALSO THE INSERVICE DATE CHANGED FROM 1999 04 31 TO 1999 12 31.

ASSOCIATED PROJECTS

Budget reference number	Description
05-00-3207	MINNEDOSA AREA 71E3 MICROWAVE REPLACEMENT (MINNTE)
05-00-4500	LAKE WINNIPEG MICROWAVE UPGRADE
05-00-6550	WINNIPEG RIVER MICROWAVE SYSTEM REPLACEMENT
05-00-6561	MICROWAVE FREQUENCY DISPLACEMENT (2 GHZ)
05-00-6562	THOMPSON-KELSEY-RADISSON COMMUNICATIONS REPLACEMENT
05-00-6567	WINNIPEG AREA TO BRANDON AREA FIBRE OPTIC COMMUNICATIONS
05-00-8589	INTERLAKE DIGITAL MICROWAVE REPLACEMENT
05-00-8598	THOMPSON COMMUNICATIONS CABLES REPLACEMENT
05-00-8599	GRAND RAPIDS TO TYRELL RCA 9202 MICROWAVE REPLACEMENT

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	35	1				36	36
May	35	2				37	73
Jun	45	1	1			47	120
Jul	33	1	1			35	155
Aug	33	1	1			35	190
Sep	33		2			35	225
Oct	33	1	2			36	261
Nov	57	2	2			61	322
Dec	32	1	2			35	357
Jan	21					21	378
Feb	20	1				21	399
Mar	20	1				21	420
TOTAL	397	12	11			420	420
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item

336

Title			Budget reference number
INTERLAKE DIGITAL MICROWAVE REPLACEMENT			05-00-8589
riginating division anning & Control	Coordinating division Planning & Control	Constructing division Construction	Project Order Group (Range): 70519

DESCRIPTION:
REPLACE THE INTERLAKE DIGITAL MICROWAVE COMMUNICATION SYSTEM FROM DORSEY T.S. TO THE LOWER NELSON RIVER.

JUSTIFICATION:
THIS SYSTEM WAS INSTALLED IN 1977 AND WILL REQUIRE REPLACEMENT DUE TO LACK OF:

1. AVAILABILITY OF SPARE PARTS AND FACTORY SUPPORT.
2. PERFORMANCE OF THE SYSTEM.
3. THE NEED FOR MORE COMMUNICATIONS CAPACITY AND/OR
4. THE LICENSED FREQUENCIES BEING GIVEN TO THE PCS INDUSTRY.

REVISION:
REFLECTS REVISED ACTIVITY AND OVERHEAD RATES.

CONTINGENCY: $1,500,000

IN SERVICE DATES				Base estimate
2005 10 31	18 124			199803 L2
				Work start date 2004 04 01

	PREV. AUTHORITY Authorized to date:	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
	2004/05	1 263	175	57			1 495
	2005/06	13 707	1 952	250			15 909
	TOTAL	14 970	2 127	307			17 404
	REV. AMOUNTS: Authorized to date: Over(under)expend:						
Auth	2004/05	1 384	185	63			1 632
Req.	2005/06	14 252	1 974	266			16 492
	TOTAL	15 636	2 159	329			18 124

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 05-00-8589

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1998 10	17 404	NEW ITEM

ASSOCIATED PROJECTS

Budget reference number	Description
05-00-3207	MINNEDOSA AREA 71E3 MICROWAVE REPLACEMENT (MINNTE)
05-00-4500	LAKE WINNIPEG MICROWAVE UPGRADE
05-00-6550	WINNIPEG RIVER MICROWAVE SYSTEM REPLACEMENT
05-00-6561	MICROWAVE FREQUENCY DISPLACEMENT (2 GHZ)
05-00-6562	THOMPSON-KELSEY-RADISSON COMMUNICATIONS REPLACEMENT
05-00-6567	WINNIPEG AREA TO BRANDON AREA FIBRE OPTIC COMMUNICATIONS
05-00-7577	JENPEG-WHISKEY JACK-WABOWDEN M/W REPLACEMENT
05-00-8598	THOMPSON COMMUNICATIONS CABLES REPLACEMENT
05-00-8599	GRAND RAPIDS TO TYRELL RCA 9202 MICROWAVE REPLACEMENT

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item

337

Title			Budget reference number
THOMPSON COMMUNICATIONS CABLES REPLACEMENT			05-00-8598
iginating division anning & Control	Coordinating division Planning & Control	Constructing division Planning & Control	Project Order Group (Range): 70622:70623

DESCRIPTION:
REPLACE COMMUNICATION CABLES BETWEEN THOMPSON MYSTERY LAKE ROAD T.S AND THOMPSON STATION ROAD OFFICE AND BETWEEN THOMPSON MYSTERY LAKE ROAD T.S. AND THOMPSON SERVICE CENTER WITH FIBRE OPTIC CABLES.

JUSTIFICATION:
SAFETY CONSIDERATIONS REQUIRE THAT THESE TWO CABLES BE MODIFIED OR REPLACED. CONSIDERING THEIR CONDITION, REMAINING LIFE AND LACK OF CAPACITY, A REPLACEMENT WITH FIBRE OPTIC CABLES IS RECOMMENDED.

REVISION:
NEW ITEM

CONTINGENCY $33,000

IN SERVICE DATES				Base estimate
2001 12 31	706			199901 L2
				Work start date 2000 08 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:						
TOTAL						
REV. AMOUNTS:						
Authorized to date:						
Over(under)expend:						
Auth 2000/01	80	3	2			85
Req.: 2001/02	570	25	26			621
TOTAL	650	28	28			706

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number: 05-00-8598

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS

ASSOCIATED PROJECTS

Budget reference number	Description
05-00-3207	MINNEDOSA AREA 71E3 MICROWAVE REPLACEMENT (MINNTE)
05-00-4500	LAKE WINNIPEG MICROWAVE UPGRADE
05-00-6550	WINNIPEG RIVER MICROWAVE SYSTEM REPLACEMENT
05-00-6561	MICROWAVE FREQUENCY DISPLACEMENT (2 GHZ)
05-00-6562	THOMPSON-KELSEY-RADISSON COMMUNICATIONS REPLACEMENT
05-00-6567	WINNIPEG AREA TO BRANDON AREA FIBRE OPTIC COMMUNICATIONS
05-00-7577	JENPEG-WHISKEY JACK-WABOWDEN M/W REPLACEMENT
05-00-8589	INTERLAKE DIGITAL MICROWAVE REPLACEMENT
05-00-8599	GRAND RAPIDS TO TYRELL RCA 9202 MICROWAVE REPLACEMENT

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug	10					10	10
Sep	10					10	20
Oct	10					10	30
Nov	10	1				11	41
Dec	10	1				11	52
Jan	10	1				11	63
Feb	10	1				11	74
Mar	10	-1	2			11	85
TOTAL	80	3	2			85	85

1999-09-28 11:49 AM

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item

338

Title			Budget reference number
GRAND RAPIDS TO TYRELL RCA 9202 MICROWAVE REPLACEMENT			05-00-8599
Originating division Planning & Control	Coordinating division Planning & Control	Constructing division Planning & Control	Project Order Group (Range): 70624

DESCRIPTION:
GRAND RAPIDS TO TYRELL RCA 9202 MICROWAVE REPLACEMENT

JUSTIFICATION:
TO PROVIDE SATISFACTORY COMMUNICATION TO THOMPSON AND BEYOND IN THE FACE OF MTS MICROWAVE DELETIONS AND CHANGES, IT IS EXPECTED THAT WE WILL BE REQUIRED TO MODIFY 2 HOPS AND REPLACE 2 HOPS OF MICROWAVE RADIO.

REVISION:
NEW ITEM

CONTINGENCY $60,000

IN SERVICE DATES				Base estimate
2001 12 31	777			199901 L2
				Work start date 2000 01 01

	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
PREV. AUTHORITY Authorized to date:						
TOTAL						
REV. AMOUNTS: Authorized to date: Over(under)expend:						
Auth 2000/01	24	1				25
Req.: 2001/02	699	32	21			752
TOTAL	723	33	21			777

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number: 05-00-8599

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS

ASSOCIATED PROJECTS

Budget reference number	Description
05-00-3207	MINNEDOSA AREA 71E3 MICROWAVE REPLACEMENT (MINNTE)
05-00-4500	LAKE WINNIPEG MICROWAVE UPGRADE
05-00-6550	WINNIPEG RIVER MICROWAVE SYSTEM REPLACEMENT
05-00-6561	MICROWAVE FREQUENCY DISPLACEMENT (2 GHZ)
05-00-6562	THOMPSON-KELSEY-RADISSON COMMUNICATIONS REPLACEMENT
05-00-6567	WINNIPEG AREA TO BRANDON AREA FIBRE OPTIC COMMUNICATIONS
05-00-7577	JENPEG-WHISKEY JACK-WABOWDEN M/W REPLACEMENT
05-00-8589	INTERLAKE DIGITAL MICROWAVE REPLACEMENT
05-00-8598	THOMPSON COMMUNICATIONS CABLES REPLACEMENT

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan	8					8	8
Feb	8					8	16
Mar	8	1				9	25
TOTAL	24	1				25	25

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

COMPLEX STATUS: ☐ Planned ☒ In progress

Complex no. 219

REVISION STATUS: ☐ New complex ☒ In service change ☐ Concept change ☒ Estimate change only

COMPLEX	MAPINFO IMPLEMENTATION

Proposal

Design, implement and provide training and data conversion for a geographic information system.

JUSTIFICATION

☐ Load ☐ Service ☐ Safety ☒ Efficiency ☐ Reliability ☐ Other

Explanation

Based on a favourable benefit/cost analysis completed in 1990, the decision was made to proceed with the development of a geographical information system for Manitoba Hydro.

Estimate Level	COMPLEX START (yyyy mm)
L3	1995 04

IN SERVICE DATES AND AMOUNTS						
To 1997 12	$5864	1998 01	$1491	1999 02	$4728	1999 07	$3780
2000 01	$3780	2000 07	$3780	2001 12	$3780		

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	16,525		947		17,472	17,023	449	3
Year 99/00	4,107	42	281		4,430	4,692	-262	-6
00/01	4,128	109	68		4,305	2,795	1,510	54
01/02	1,753	75	166		1,994	2,346	-352	-15
02/03								
03/04								
04/05								
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	26,513	226	1,462		28,201	26,856	1,345	5

REVISION	Reflects addition of transmission line maintenance, revision of cashflow, and 9 Mo. deferral of final ISD

Reviewed by	yyyy mm dd	Reviewed by	yyyy mm dd
ORIGINATOR	99 11 03	COORDINATOR	99 11 03
Reviewed by	yyyy mm dd	Approved by	yyyy mm dd
INSTRUCTOR	99 11 03	VICE PRESIDENT	99 11 16

H2856/r Rev 99 03

Complex no. 219

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Advance or deferral impact

Factors affecting timing or viability

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Mapinfo Implementation Part II	23,169	25,281	25,787	26,513	726	3
TOTAL	23,169	25,281	25,787	26,513	726	3

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
96 10	25,079	New complex transferred from domestic.
9710	25,252	SCOPE UNCHANGED, ESTIMATE REFLECTS REVISED COSTING METHODOLOGY IMPLEMENTED WITH THE NEW FINANCIAL REPORTING SYSTEM.
1998 10	26,856	Reflects 97/98 underexpenditure 0.8M, in service deferred 8 months, and cash flow revised.
1999 10	28,201	Reflects addition of transmission line maintenance, revision of cashflow, and 9 Mo. deferral of final ISD

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item

339

Title			Budget reference number
MAPINFO IMPLEMENTATION PART II			09-00-7807
Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Design	Design	Design	72000:72001

DESCRIPTION:
DESIGN, IMPLEMENT AND PROVIDE TRAINING AND DATA CONVERSION FOR A GEOGRAPHIC INFORMATION SYSTEM.

EXECUTIVE COMMITTEE MEETING HELD ON 96/01/23 RECOMMENDED APPROVAL TO BE GRANTED TO PROCEED WITH THE PROJECT AT A COST NOT TO EXCEED 25.1 MILLION.

JUSTIFICATION:
BASED ON A FAVOURABLE BENEFIT/COST ANALYSIS COMPLETED IN 1990, THE DECISION WAS MADE TO PROCEED WITH THE DEVELOPMENT OF A GEOGRAPHICAL INFORMATION SYSTEM FOR MANITOBA HYDRO

REVISION:
CASHFLOWS REVISEDTO BALANCE CONVERSION RESOURCES TO APPROXIMATELY $1.6M PER YEAR. TRANSMISSION LINE MAINTENANCE WAS PROJECT INITIATED AND ADDED AT A COST OF $1.6M OF ADDITIONAL FUNDS. LAST ISD DELAYED FROM 2001 03 TO 2001 12.

CONTINGENCY: $100,000

This BRN contains Deleted, Blocked, or Closed Orders.

IN SERVICE DATES						Base estimate
Prior Total	5 854	1997 12 31	3	1999 07 31	3 780	199902 L3
1997 09 30	3	1998 01 31	1 491	2000 01 31	3 780	
1997 10 31	3	1999 02 28	4 728	2000 07 31	3 780	Work start date
1997 11 30	3	1999 04 30	0	2001 12 31	4 777	1995 04 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:	16 525		947			17 472
1999/00	3 821	136	286			4 243
2000/01	2 507	136	153			2 796
2001/02	2 346					2 346
TOTAL	25 199	272	1 386			26 857
REV. AMOUNTS:						
Authorized to date:	16 525		947			17 472
Over(under)expend:						
Auth 1999/00	4 107	42	281			4 430
Req.: 2000/01	4 128	110	68			4 306
2001/02	1 753	75	166			1 994
TOTAL	26 513	227	1 462			28 202

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

1999-10-14 01:48 PM

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number: 09-00-7807

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1996 10	25 079	NEW ITEM. TRANSFERRED FROM DOMESTIC BRN# 9609-00-2007 AND 9609-00-2008. PROGRAM EXTENDED AND CASH FLOWS REVISED TO ASSIST IN ACHIEVING 1998/99 CAPITAL CAP.
1997 10	25 251	SCOPE UNCHANGED, CASHFLOWS REVISED TO REFLECT UNDEREXPENDITURES IN PAST 2 YEARS AND TO ADVANCE PACE OF CONVERSION COMPLETION IN FINAL YEAR. MORE ISD'S ADDED TO CAPITALIZE MORE FREQUENT STAGES OF WORK COMPLETION.
1998 10	25 855	CASH FLOW REVISED. IN-SERVICE DATE CHANGED FROM 2000 07 TO 2001 03.

ASSOCIATED PROJECTS

Budget reference number	Description

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	509		31			540	540
May	313	2	34			349	889
Jun	328	2	37			367	1 256
Jul	328	2	39			369	1 625
Aug	328	2	16			346	1 971
Sep	326	3	18			347	2 318
Oct	327	4	20			351	2 669
Nov	328	4	23			355	3 024
Dec	331	5	25			361	3 385
Jan	336	5	28			369	3 754
Feb	334	6	4			344	4 098
Mar	319	7	6			332	4 430
TOTAL	4 107	42	281			4 430	4 430
2000/01 Apr	366	7	9			382	382
May	376	7	12			395	777
Jun	369	9	14			392	1 169
Jul	368	9	17			394	1 563
Aug	354	9	-7			356	1 919
Sep	354	9	-4			359	2 278
Oct	354	10	-2			362	2 640
Nov	353	11	1			365	3 005
Dec	324	10	3			337	3 342
Jan	324	10	6			340	3 682
Feb	324	11	8			343	4 025
Mar	262	8	11			281	4 306
TOTAL	4 128	110	68			4 306	4 306

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

COMPLEX STATUS: ☐ Planned ☒ In progress

Complex no. 2

REVISION STATUS: ☐ New complex ☐ In service change ☐ Concept change ☒ Estimate change only

COMPLEX: SITE REMEDIATION

Proposal

Implement programs designed to minimize or ameliorate the impact of the Corporation's operations on the environment, such as;
Conduct geotechnical investigations and remediate any hydrocarbon contaminated sites at 26 former isolated diesel generating stations in; Dauphin River, Bloodvien, Berens River, Jackhead, Little Grand Rapids, Manigotogan, Matheson Island, Pauingassi, Pine Dock, Poplar River, Pukatawagan, Gods Lake Narrows, Tadoule, The Pas, Moose Lake, Norway House, Cross Lake, Ilford, Nelson House, Split Lake, Wanless, Granville Lake, Bakers Narrows, Cormorant and Cranberry Portage.
Conduct geotechnical investigation for the various contaminated Corporate facilities, prepare a report with cleanup recommendations, remediate any contaminated areas identified and issue a final report confirming the facility and surrounding area were remediated and all areas of the work were left in accordance with applicable environmental regulations.

JUSTIFICATION

☐ Load ☐ Service
☒ Safety ☐ Efficiency
☐ Reliability ☒ Other

Explanation

Due to concerns and in compliance with current environmental regulations and standards applicable to unrestricted use of abandoned former diesel sites, the sites must be investigated, remediated and restored to equivalency of the surrounding area.
Various existing Corporate contaminated facilities should be brought into compliance with current environmental regulations and standards.

Estimate Level	COMPLEX START (yyyy mm)
L1-3	1991 10

IN SERVICE DATES AND AMOUNTS

Up To 96/97	$3278	1999 04	$93	1999 08	$611	1999 10	$1574
1999 12	$99	2000 08	$373	2000 09	$299	2000 11	$992
2000 12	$1239	2001 10	$209	2001 11	$1186	2002 ON	$1736

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	4,728		283	2,032	2,979	5,332	-2,353	-44
Year 99/00	1,514	35	7	245	1,311	1,003	308	31
00/01	2,331	129	27	251	2,236	1,439	797	55
01/02	835	66	16	51	866	861	5	1
02/03	1,574	144		649	1,069	1,051	18	2
03/04								
04/05								
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	10,982	374	333	3,228	8,461	9,686	-1,225	-13

REVISION: Reflects increases for Nelson House remediation , trailors and advancement at First Nation request, and Cormorant as req'd by MB Environmen t. Four sites deferred, & 5 completed.

Reviewed by ORIGINATOR	yyyy mm dd 99 11 09	Reviewed by COORDINATOR	yyyy mm dd 99 11 09
Reviewed by CONSTRUCTOR	yyyy mm dd 99 11 03	Approved by VICE PRESIDENT	yyyy mm dd 99 11 1995

H2856/r Rev 99 03

Complex no. 2

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Advance or deferral impact

POTENTIAL FOR LEGAL ACTIONS.

Factors affecting timing or viability

SUBJECT TO ENVIRONMENTAL REGULATIONS

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Diesel Site Clean-ups (19 abandoned sites)	24,030	12,143	12,386	10,982	-1,404	-11
TOTAL	24,030	12,143	12,386	10,982	-1,404	-11

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
9510	37,841	Oil containment items transferred to complex 81. Site remediation items do not reflect Federal Contribution.
9610	13,783	Estimates revised to reflect new overall work plan for remediation of diesel sites, with contributions based on 35 - 50% of all costs.
9710	12,016	Reflects receipt of federal contributions, results of latest comprehensive investigations, and adjustment of spent to date for closed out sites.
1998 10	9,686	Reflects cancellation of soil remediation work at Churchill DGS.
1999 10	8,461	Reflects increases for Nelson House remediation , trailors and advancement at First Nation request, and Cormorant as req'd by MB Environmen t. Four sites deferred, & 5 completed.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item

340

Title
LITTLE GRAND RAPIDS D.G.S. - SITE CLEAN-UP

Budget reference number
04-00-5462

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Operating & Maintenance	Construction	Construction	72025

DESCRIPTION:
1. CONDUCT GEOTECHNICAL INVESTIGATION OF THE DECOMMISSIONED DIESEL GENERATING STATION TO PREPARE A SITE INVESTIGATION REPORT ON THE INVESTIGATION INCLUDING RECOMMENDATIONS FOR REMEDIAL ACTION TO CLEAN UP ANY CONTAMINANTS. (W.O.# 43331 CLOSED OUT)
2. REMEDIATE TO ENVIRONMENTALLY ACCEPTABLE LIMITS ANY CONTAMINATED AREAS IDENTIFIED IN THE SITE INVESTIGATION REPORT.
3. ISSUE A FINAL REPORT ON THE PROJECT CONFIRMING THE DIESEL SITE AND SURROUNDING AREA WERE REMEDIATED AND ALL AREAS OF THE WORK WERE LEFT IN ACCORDANCE WITH APPLICABLE ENVIRONMENTAL REGULATIONS

JUSTIFICATION:
DUE TO ENVIRONMENTAL CONCERNS AND/OR REGULATIONS THE SITE MUST BE INVESTIGATED, REMEDIATED AS REQUIRED, AND RESTORED TO A LEVEL WHICH PERMITS UNRESTRICTED USE OF THE SITE AND THE SURROUNDING AREA.

REVISION:
REFLECTS REVISED ACTIVITY AND OVERHEAD RATES.

CONTINGENCY AMOUNT: $58,000

IN SERVICE DATES

1997 03 31	90
2002 11 30	713

Base estimate
199704 L2

Work start date
1993 06 01

	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
PREV. AUTHORITY						
Authorized to date:	85		6		-20	71
1999/00	16					16
2002/03	627	63			- 146	544
TOTAL	728	63	6		- 166	631
REV. AMOUNTS:						
Authorized to date:	85		6		-20	71
Over(under)expend:						
Auth 2002/03 Req.:	653	59			- 146	566
TOTAL	738	59	6		- 166	637

Prepared by	yy mm dd	Approved by	yy mm dd	Approved by	yy mm dd
COORDINATOR					
Estimated by					
ORIGINATOR		COORDINATING MANAGER		ORIGINATING MANAGER	

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 04-00-5462

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1994 10	338	TRSF FROM DOMESTIC ITEM (PREV BRN 9404-00-4424). STAGE 1 REFLECTS COSTS TO COMPLETION; REVISED INT & ESC FOR PROJECT.
1995 10	1 152	ACTUALS TO DATE REFLECT EXPLORATION. NO REMEDIATION ACTION PLAN ESTABLISHED TO DATE. ESCALATION AND INTEREST ADJUSTED.
1996 10	380	ESTIMATE AND SCHEDULE REVISED TO REFLECT NEW OVERALL WORK PLAN FOR REMEDIATION OF DIESEL SITES.
1997 10	594	ESTIMATE AND SCHEDULE UNCHANGED. CONTRIBUTIONS BASED ON 22.3% OF ALL COSTS EXCEPT FUTURE INTEREST, AS PER COST SHARING AGREEMENT WITH INAC.
1998 10	631	SCHEDULE DELAYED 1998 11 03 TO 2002 11 30. CASH FLOWS MOVED FROM 99/00 TO 02/03.

ASSOCIATED PROJECTS

Budget reference number	Description
04-00-5459	BLOODVEIN D.G.S. - SITE INVESTIGATION & CLEAN-UP
04-00-5460	BERENS RIVER D.G.S. - SITE INVESTIGATION & CLEAN-UP
04-00-5461	JACKHEAD D.G.S. - SITE CLEAN-UP
04-00-5463	MANIGOTAGAN D.G.S. - SITE CLEAN-UP
04-00-5465	PAUINGASSI D.G.S. - SITE CLEAN-UP
04-00-5467	POPLAR RIVER D.G.S. - SITE CLEAN-UP
04-00-5468	PUKATAWAGAN DIESEL SITE CLEAN-UP
04-00-5471	THE PAS D.G.S. - SITE INVESTIGATION & CLEAN-UP
04-00-5472	MOOSE LAKE D.G.S. - SITE INVESTIGATION & CLEAN-UP
04-00-5473	NORWAY HOUSE D.G.S. - SITE CLEAN-UP
04-00-5475	ILFORD D.G.S. - SITE CLEAN-UP
04-00-5476	NELSON HOUSE D.G.S. - SITE CLEAN-UP
04-00-5478	WANLESS D.G.S. - SITE CLEAN-UP
04-00-5479	CHURCHILL D.G.S. - SITE CLEAN-UP
04-00-5480	GRANVILLE LAKE D.G.S. - SITE INVESTIGATION & CLEAN-UP
04-00-5481	BAKERS NARROWS D.G.S. - SITE CLEAN-UP
04-00-5482	CORMORANT D.G.S. - SITE CLEAN-UP
04-00-5483	CRANBERRY PORTAGE D.G.S. - SITE CLEAN-UP

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item ___ Domestic Item 341

Title: MANIGOTAGAN D.G.S. - SITE CLEAN-UP

Budget reference number: 04-00-5463

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Operating & Maintenance	Construction	Construction	72026:72027

DESCRIPTION:
1. CONDUCT GEOTECHNICAL INVESTIGATION OF THE DECOMMISSIONED DIESEL GENERATING STATION TO DELINEATE THE EXTENT OF ANY HYDROCARBON CONTAMINATION ON AND/OR AROUND THE SITE AND PREPARE A SITE INVESTIGATION REPORT ON THE INVESTIGATION INCLUDING RECOMMENDATIONS FOR REMEDIAL ACTION TO CLEAN UP ANY CONTAMINANTS.
(WO #43364)

2. REMEDIATE TO ENVIRONMENTALLY ACCEPTABLE LIMITS ANY CONTAMINATED AREAS IDENTIFIED IN THE SITE INVESTIGATION REPORT.

3. ISSUE A FINAL REPORT ON THE PROJECT CONFIRMING THE DIESEL SITE AND SURROUNDING AREA WERE REMEDIATED AND ALL AREAS OF THE WORKS WERE LEFT IN ACCORDANCE WITH APPLICABLE ENVIRONMENTAL REGULATIONS.

JUSTIFICATION:
DUE TO ENVIRONMENTAL CONCERNS AND/OR REGULATIONS THE SITE MUST BE INVESTIGATED, REMEDIATED AS REQUIRED, AND RESTORED TO A LEVEL WHICH PERMITS UNRESTRICTED USE OF THE SITE AND THE SURROUNDING AREA.

REVISION:
REFLECTS REVISED ACTIVITY AND OVERHEAD RATES.

CONTINGENCY: $59,000.

IN SERVICE DATES

1999 12 31	99
2001 11 30	722

Base estimate: 199704 L2

Work start date: 1993 10 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:	5		1			6
1999/00	86	4	3			93
2000/01	17	1				18
2001/02	629	56	16			701
TOTAL	737	61	20			818
REV. AMOUNTS:						
Authorized to date:	5		1			6
Over(under)expend:						
Auth 1999/00	87	3	3			93
Req. 2000/01	19	1				20
2001/02	636	50	16			702
TOTAL	747	54	20			821

Prepared by	yy mm dd	Approved by	yy mm dd	Approved by	yy mm dd
COORDINATOR					
Estimated by					
ORIGINATOR		COORDINATING MANAGER		ORIGINATING MANAGER	

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 04-00-5463

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1994 10	566	TRSF FROM DOMESTIC ITEM (PREV BRN 9404-00-4425). STAGE 1 REFLECTS COSTS TO COMPLETION; REVISED INT & ESC FOR PROJECT.
1995 10	569	WORK HAS NOT COMMENCED ON EXPLORATION AT SITE. ACTUALS REFLECT ORGANIZATIONAL ENGINEERING COSTS TO DATE. ESCALATION AND INTEREST ADJUSTED.
1996 10	849	ESTIMATE AND SCHEDULE REVISED TO REFLECT NEW OVERALL WORK PLAN FOR REMEDIATION OF DIESEL SITES.
1997 10	824	SCOPE UNCHANGED. ESTIMATE REFLECTS REVISED COSTING METHODOLOGY IMPLEMENTED WITH THE NEW FINANCIAL REPORTING SYSTEM. ESTIMATE ALSO REFLECTS REVISED INTEREST AND ESCALATION RATES. IN SERVICE DATE ADDED FOR COMPLETION OF SITE INVESTIGATION.
1998 10	819	ESTIMATE AND SCHEDULE UNCHANGED.

ASSOCIATED PROJECTS

Budget reference number	Description
04-00-5459	BLOODVEIN D.G.S. - SITE INVESTIGATION & CLEAN-UP
04-00-5460	BERENS RIVER D.G.S. - SITE INVESTIGATION & CLEAN-UP
04-00-5461	JACKHEAD D.G.S. - SITE CLEAN-UP
04-00-5462	LITTLE GRAND RAPIDS D.G.S. - SITE CLEAN-UP
04-00-5465	PAUINGASSI D.G.S. - SITE CLEAN-UP
04-00-5467	POPLAR RIVER D.G.S. - SITE CLEAN-UP
04-00-5468	PUKATAWAGAN DIESEL SITE CLEAN-UP
04-00-5471	THE PAS D.G.S. - SITE INVESTIGATION & CLEAN-UP
04-00-5472	MOOSE LAKE D.G.S. - SITE INVESTIGATION & CLEAN-UP
04-00-5473	NORWAY HOUSE D.G.S. - SITE CLEAN-UP
04-00-5475	ILFORD D.G.S. - SITE CLEAN-UP
04-00-5476	NELSON HOUSE D.G.S. - SITE CLEAN-UP
04-00-5478	WANLESS D.G.S. - SITE CLEAN-UP
04-00-5479	CHURCHILL D.G.S. - SITE CLEAN-UP
04-00-5480	GRANVILLE LAKE D.G.S. - SITE INVESTIGATION & CLEAN-UP
04-00-5481	BAKERS NARROWS D.G.S. - SITE CLEAN-UP
04-00-5482	CORMORANT D.G.S. - SITE CLEAN-UP
04-00-5483	CRANBERRY PORTAGE D.G.S. - SITE CLEAN-UP

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun	21	1				22	22
Jul	24	1				25	47
Aug	25	1				26	73
Sep	4		1			5	78
Oct	4		1			5	83
Nov	4		1			5	88
Dec	5					5	93
Jan							93
Feb							93
Mar							93
TOTAL	87	3	3			93	93
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep	3					3	3
Oct	3					3	6
Nov	3					3	9
Dec	3					3	12
Jan	3					3	15
Feb	3					3	18
Mar	1	1				2	20
TOTAL	19	1				20	20

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item __ Domestic Item 342

Title
PAUINGASSI D.G.S. - SITE CLEAN-UP

Budget reference number
04-00-5465

ginating division	Coordinating division	Constructing division	Project Order Group (Range):
erating & Maintenance	Construction	Construction	70123

DESCRIPTION:
1. CONDUCT GEOTECHNICAL INVESTIGATION OF THE DECOMMISSIONED DIESEL GENERATING STATION TO DELINEATE THE EXTENT OF ANY HYDROCARBON CONTAMINATION ON AND/OR AROUND THE SITE AND PREPARE A SITE INVESTIGATION REPORT ON THE INVESTIGATION INCLUDING RECOMMENDATIONS FOR REMEDIAL ACTION TO CLEAN UP ANY CONTAMINANTS. (W.O.# 43612 CLOSED OUT)
2. REMEDIATE TO ENVIRONMENTALLY ACCEPTABLE LIMITS ANY CONTAMINATED AREAS IDENTIFIED IN THE SITE INVESTIGATION REPORT.
3. ISSUE A FINAL REPORT ON THE PROJECT CONFIRMING THE DIESEL SITE AND SURROUNDING AREA WERE REMEDIATED AND ALL AREAS OF THE WORK WERE LEFT IN ACCORDANCE WITH APPLICABLE ENVIRONMENTAL REGULATIONS.

JUSTIFICATION:
DUE TO ENVIRONMENTAL CONCERNS AND/OR REGULATIONS THE SITE MUST BE INVESTIGATED, REMEDIATED AS REQUIRED, AND RESTORED TO A LEVEL WHICH PERMITS UNRESTRICTED USE OF THE SITE AND THE SURROUNDING AREA.

REVISION:
ISD DEFERRED FROM 1999 03 31 TO 2000 11 30 AS SURFACING MATERIALS WILL BE HAULED VIA 99/00 WINTER ROAD AND BE PLACED IN THE SUMMER OF 2000. REFLECTS REVISED ACTIVITY AND OVERHEAD RATES.

CONTINGENCY AMOUNT: $ 38,000

IN SERVICE DATES		Base estimate
1997 03 31	77	199704 L2
2000 11 30	272	Work start date
		1993 06 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:	137		4		-31	110
1999/00	216					216
TOTAL	353		4		-31	326
REV. AMOUNTS:						
Authorized to date:	137		4		-31	110
Over(under)expend:						
Auth 1999/00	195	3			-30	168
Req. 2000/01	10					10
TOTAL	342	3	4		-61	288

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 04-00-5465

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1994 10	810	TRSF FROM DOMESTIC ITEM (PREV BRN 9404-00-4427). STAGE 1 REFLECTS COSTS TO COMPLETION; REVISED INT & ESC FOR PROJECT.
1995 10	825	GEOTECHNICAL EXPLORATION WORK UNDER WAY. NO REMEDIATION ACTION PLAN ISSUED TO DATE. ESCALATION AND INTEREST ADJUSTED.
1996 10	260	ESTIMATE AND SCHEDULE REVISED TO REFLECT NEW OVERALL WORK PLAN FOR REMEDIATION OF DIESEL SITES.
1997 10	408	ESTIMATE AND SCHEDULE UNCHANGED.
1998 10	325	SCHEDULE ADVANCED FROM 1999 11 TO 1998 11. COST REDUCED WITH A BETTER COST-EFFECTIVE CLEAN-UP METHOD. CONTRIBUTIONS BASED ON 22.3% OF ALL COSTS EXCEPT FUTURE INTEREST, AS PER COST SHARING AGREEMENT WITH INAC. CONTINGENCY: $38,000

ASSOCIATED PROJECTS

Budget reference number	Description
04-00-5459	BLOODVEIN D.G.S. - SITE INVESTIGATION & CLEAN-UP
04-00-5460	BERENS RIVER D.G.S. - SITE INVESTIGATION & CLEAN-UP
04-00-5461	JACKHEAD D.G.S. - SITE CLEAN-UP
04-00-5462	LITTLE GRAND RAPIDS D.G.S. - SITE CLEAN-UP
04-00-5463	MANIGOTAGAN D.G.S. - SITE CLEAN-UP
04-00-5467	POPLAR RIVER D.G.S. - SITE CLEAN-UP
04-00-5468	PUKATAWAGAN DIESEL SITE CLEAN-UP
04-00-5471	THE PAS D.G.S. - SITE INVESTIGATION & CLEAN-UP
04-00-5472	MOOSE LAKE D.G.S. - SITE INVESTIGATION & CLEAN-UP
04-00-5473	NORWAY HOUSE D.G.S. - SITE CLEAN-UP
04-00-5475	ILFORD D.G.S. - SITE CLEAN-UP
04-00-5476	NELSON HOUSE D.G.S. - SITE CLEAN-UP
04-00-5478	WANLESS D.G.S. - SITE CLEAN-UP
04-00-5479	CHURCHILL D.G.S. - SITE CLEAN-UP
04-00-5480	GRANVILLE LAKE D.G.S. - SITE INVESTIGATION & CLEAN-UP
04-00-5481	BAKERS NARROWS D.G.S. - SITE CLEAN-UP
04-00-5482	CORMORANT D.G.S. - SITE CLEAN-UP
04-00-5483	CRANBERRY PORTAGE D.G.S. - SITE CLEAN-UP

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	15			-2		13	13
May	15			-2		13	26
Jun	15			-2		13	39
Jul	15			-2		13	52
Aug	15			-2		13	65
Sep	15			-2		13	78
Oct	15			-2		13	91
Nov	53			-2		51	142
Dec	9	-1		-2		6	148
Jan	9	-1		-2		6	154
Feb	9	-1		-2		6	160
Mar	10	6		-8		8	168
TOTAL	195	3		-30		168	168
2000/01 Apr	1					1	1
May	1					1	2
Jun	1					1	3
Jul	1					1	4
Aug	1					1	5
Sep	1					1	6
Oct	1					1	7
Nov	1					1	8
Dec	1					1	9
Jan	1					1	10
Feb	1					1	11
Mar	-1					-1	10
TOTAL	10					10	10

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item

343

Title: POPLAR RIVER D.G.S. - SITE CLEAN-UP

Budget reference number: 04-00-5467

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Operating & Maintenance	Construction	Construction	70124

DESCRIPTION:
1. CONDUCT GEOTECHNICAL INVESTIGATION OF THE DECOMMISSIONED DIESEL GENERATING STATION TO DELINEATE THE EXTENT OF ANY HYDROCARBON CONTAMINATION ON AN/OR AROUND THE SITE AND PREPARE A SITE INVESTIGATION REPORT ON THE INVESTIGATION INCLUDING RECOMMENDATIONS FOR REMEDIAL ACTION TO CLEAN UP ANY CONTAMINANTS. (W.O.# 44099 CLOSED OUT)
2. REMEDIATE TO ENVIRONMENTALLY ACCEPTABLE LIMITS ANY CONTAMINATED AREAS IDENTIFIED IN THE SITE INVESTIGATION REPORT.

3. ISSUE A FINAL REPORT ON THE PROJECT CONFIRMING THE DIESEL SITE AND SURROUNDING AREA WERE REMEDIATED AND ALL AREAS OF THE WORK WERE LEFT IN ACCORDANCE WITH APPLICABLE ENVIRONMENTAL REGULATIONS.

JUSTIFICATION:
DUE TO ENVIRONMENTAL CONCERNS AND/OR REGULATIONS THE SITE MUST BE INVESTIGATED, REMEDIATED AS REQUIRED, AND RESTORED TO A LEVEL WHICH PERMITS UNRESTRICTED USE OF THE SITE AND THE SURROUNDING AREA.

REVISION:
REFLECTS REVISED ACTIVITY AND OVERHEAD RATES.

CONTINGENCY AMOUNT: $100,000

IN SERVICE DATES

1997 03 31	247
2000 12 31	1 238

Base estimate: 199704 L2

Work start date: 1993 09 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:	264		26		-65	225
1999/00	-8	1	1		-4	-10
2000/01	1 077	67	25		- 255	914
TOTAL	1 333	68	52		- 324	1 129
REV. AMOUNTS:						
Authorized to date:	264		26		-65	225
Over(under)expend:						
Auth 1999/00	18	1	3		-4	18
Req.: 2000/01	1 087	59	27		- 248	925
TOTAL	1 369	60	56		- 317	1 168

Prepared by: yy mm dd COORDINATOR

Approved by: yy mm dd Approved by:

Estimated by: ORIGINATOR — COORDINATING MANAGER — ORIGINATING MANAGER

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 04-00-5467

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1994 10	1 124	TRSF FROM DOMESTIC ITEM (PREV BRN 9404-00-4429). STAGE 1 REFLECTS COST TO COMPLETION; REVISED INT & ESC FOR PROJECT.
1995 10	1 101	ACTUALS TO DATE REFLECT EXPLORATION. NO REMEDIATION ACTION PLAN ESTABLISHED TO DATE. ESCALATION AND INTEREST ADJUSTED.
1996 10	742	ESTIMATE REVISED TO REFLECT NEW OVERALL WORK PLAN FOR REMEDIATION OF DIESEL SITES.
1997 10	1 131	ESTIMATE AND SCHEDULE UNCHANGED. CONTRIBUTIONS BASED ON 22.3% OF ALL COSTS EXCEPT FUTURE INTEREST, AS PER COST SHARING AGREEMENT WITH INAC.
1998 10	1 129	ESTIMATE AND SCHEDULE UNCHANGED.

ASSOCIATED PROJECTS

Budget reference number	Description
04-00-5459	BLOODVEIN D.G.S. - SITE INVESTIGATION & CLEAN-UP
04-00-5460	BERENS RIVER D.G.S. - SITE INVESTIGATION & CLEAN-UP
04-00-5461	JACKHEAD D.G.S. - SITE CLEAN-UP
04-00-5462	LITTLE GRAND RAPIDS D.G.S. - SITE CLEAN-UP
04-00-5463	MANIGOTAGAN D.G.S. - SITE CLEAN-UP
04-00-5465	PAUINGASSI D.G.S. - SITE CLEAN-UP
04-00-5468	PUKATAWAGAN DIESEL SITE CLEAN-UP
04-00-5471	THE PAS D.G.S. - SITE INVESTIGATION & CLEAN-UP
04-00-5472	MOOSE LAKE D.G.S. - SITE INVESTIGATION & CLEAN-UP
04-00-5473	NORWAY HOUSE D.G.S. - SITE CLEAN-UP
04-00-5475	ILFORD D.G.S. - SITE CLEAN-UP
04-00-5476	NELSON HOUSE D.G.S. - SITE CLEAN-UP
04-00-5478	WANLESS D.G.S. - SITE CLEAN-UP
04-00-5479	CHURCHILL D.G.S. - SITE CLEAN-UP
04-00-5480	GRANVILLE LAKE D.G.S. - SITE INVESTIGATION & CLEAN-UP
04-00-5481	BAKERS NARROWS D.G.S. - SITE CLEAN-UP
04-00-5482	CORMORANT D.G.S. - SITE CLEAN-UP
04-00-5483	CRANBERRY PORTAGE D.G.S. - SITE CLEAN-UP

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep	2	1		-1		2	2
Oct	2	1		-1		2	4
Nov	2					2	6
Dec	2					2	8
Jan	2					2	10
Feb	2					2	12
Mar	6	-1	3	-2		6	18
TOTAL	18	1	3	-4		18	18
2000/01 Apr	3	1		-1		3	3
May	13	1		-3		11	14
Jun	190	12		-44		158	172
Jul	190	11	2	-44		159	331
Aug	190	11	3	-44		160	491
Sep	190	12	4	-44		162	653
Oct	190	12	5	-44		163	816
Nov	10	1	6	-2		15	831
Dec	111	-2	7	-22		94	925
Jan							925
Feb							925
Mar							925
TOTAL	1 087	59	27	- 248		925	925

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item

Title: PUKATAWAGAN DIESEL SITE CLEAN-UP

Budget reference number: 04-00-5468

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Operating & Maintenance	Construction	Construction	70482

DESCRIPTION:
GEOTECHNICAL SURVEY CONDUCTED AT PUKATAWAGAN DIESEL SITE TO DETERMINE THE EXTENT OF FUEL CONTAMINATION AND SUBSEQUENT CLEANUP OF CONTAMINATED AREAS. THE SURVEY WAS COMPLETED IN EARLY 1991 AND CLEANUP WILL COMMENCE IN THE 1991/92 FISCAL YEAR AND CONTINUE THRU 1994/95.

JUSTIFICATION:
DUE TO CRITICAL ENVIRONMENTAL CONCERNS, CONTAMINATED AREAS WILL BE EXCAVATED AND RESTORED TO A LEVEL THAT IS CONSIDERED SUITABLE FOR UNRESTRICTED USE AT PUKATAWAGAN.

REVISION:
REFLECTS COSTS TO COMPLETION.

IN SERVICE DATES				Base estimate
1993 10 31	1 632			199802 L5
1994 04 30	90			Work start date
1999 04 30	72			1991 10 01

PREV. AUTHORITY	GROSS	ESCALATION	INT CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:	1 658		135		-1 240	553
1999/00	-24					-24
TOTAL	1 634		135		-1 240	529
REV. AMOUNTS:						
Authorized to date:	1 658		135		-1 240	553
Over(under)expend:						
Auth Req.: 1999/00			1			1
TOTAL	1 658		136		-1 240	554

Prepared by: yy mm dd COORDINATOR — Approved by: yy mm dd Approved by: yy mm dd

Estimated by: ORIGINATOR — COORDINATING MANAGER — ORIGINATING MANAGER

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 04-00-5468

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1994 10	1 802	TRSF FROM DOMESTIC ITEM (PREV BRN 9204-00-2309). REVISION REFLECTS COST TO COMPLETE THIS ITEM.
1995 10	1 722	REFLECTS ACTUAL COSTS TO COMPLETION
1996 10	861	CONTRIBUTIONS ADDED AT 50% OF ALL COSTS. ITEM COMPLETE.
1997 10	510	ITEM RE-OPENED TO COVER MANITOBA HYDRO'S PORTION OF THE ESTIMATED COSTS FOR DEALING WITH ADDITIONAL CONTAMINATION DISCOVERED DURING UN-RELATED EXCAVATION ADJACENT TO THE ORIGINALLY-REMEDIATED AREA. WORK WILL BE COMPLETED THROUGH AN AGENT OF INDIAN AND NORTHERN AFFAIRS CANADA AND BILLED TO MANITOBA HYDRO AT A RATE OF 28% OF THEIR COSTS, WHICH IS IN KEEPING WITH THE COST SHARING AGREEMENT WITH INAC FOR SOIL REMEDIATION AT THIS SITE.
1998 10	529	WORK HAS BEEN COMPLETED THROUGH AN AGENT OF INDIAN AND NORTHERN AFFAIRS CANADA AND BILLED TO MANITOBA HYDRO AT A RATE OF 28% OF THEIR COSTS, WHICH IS IN KEEPING WITH THE COST SHARING AGREEMENT WITH INAC FOR SOIL REMEDIATION AT THIS SITE.

ASSOCIATED PROJECTS

Budget reference number	Description
04-00-5459	BLOODVEIN D.G.S. - SITE INVESTIGATION & CLEAN-UP
04-00-5460	BERENS RIVER D.G.S. - SITE INVESTIGATION & CLEAN-UP
04-00-5461	JACKHEAD D.G.S. - SITE CLEAN-UP
04-00-5462	LITTLE GRAND RAPIDS D.G.S. - SITE CLEAN-UP
04-00-5463	MANIGOTAGAN D.G.S. - SITE CLEAN-UP
04-00-5465	PAUINGASSI D.G.S. - SITE CLEAN-UP
04-00-5467	POPLAR RIVER D.G.S. - SITE CLEAN-UP
04-00-5471	THE PAS D.G.S. - SITE INVESTIGATION & CLEAN-UP
04-00-5472	MOOSE LAKE D.G.S. - SITE INVESTIGATION & CLEAN-UP
04-00-5473	NORWAY HOUSE D.G.S. - SITE CLEAN-UP
04-00-5475	ILFORD D.G.S. - SITE CLEAN-UP
04-00-5476	NELSON HOUSE D.G.S. - SITE CLEAN-UP
04-00-5478	WANLESS D.G.S. - SITE CLEAN-UP
04-00-5479	CHURCHILL D.G.S. - SITE CLEAN-UP
04-00-5480	GRANVILLE LAKE D.G.S. - SITE INVESTIGATION & CLEAN-UP
04-00-5481	BAKERS NARROWS D.G.S. - SITE CLEAN-UP
04-00-5482	CORMORANT D.G.S. - SITE CLEAN-UP
04-00-5483	CRANBERRY PORTAGE D.G.S. - SITE CLEAN-UP

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr			1			1	1
May							1
Jun							1
Jul							1
Aug							1
Sep							1
Oct							1
Nov							1
Dec							1
Jan							1
Feb							1
Mar							1
TOTAL			1			1	1
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item

345

Title			Budget reference number
THE PAS D.G.S. - SITE INVESTIGATION & CLEAN-UP			04-00-5471
Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Operating & Maintenance	Construction	Construction	70125

DESCRIPTION:
1. CONDUCT GEOTECHNICAL INVESTIGATION OF THE DECOMMISSIONED DIESEL GENERATING STATION TO DELINEATE THE EXTENT OF ANY HYDROCARBON CONTAMINATION ON AND/OR AROUND THE SITE AND PREPARE A SITE INVESTIGATION REPORT ON THE INVESTIGATION INCLUDING RECOMMENDATIONS FOR REMEDIAL ACTION TO CLEAN UP ANY CONTAMINANTS. (W.O.# 45419, CLOSED OUT)
2. RISK MANAGE OR REMEDIATE TO ENVIRONMENTALLY ACCEPTABLE LIMITS ANY CONTAMINATED AREAS IDENTIFIED IN THE SITE INVESTIGATION REPORT.
3. ISSUE A FINAL REPORT ON THE PROJECT CONFIRMING THE DIESEL SITE AND SURROUNDING AREA WERE REMEDIATED AND ALL AREAS OF THE WORKS WERE LEFT IN ACCORDANCE WITH APPLICABLE ENVIRONMENTAL REGULATIONS.

JUSTIFICATION:
DUE TO ENVIRONMENTAL CONCERNS AND/OR REGULATIONS THE SITE MUST BE INVESTIGATED, REMEDIATED AS REQUIRED, AND RESTORED TO A LEVEL WHICH PERMITS UNRESTRICTED USE OF THE SITE AND SURROUNDING AREA.

REVISION:
ISD DEFERRED FROM 1999/09/30 TO 2000/09/30 FOR CAPITAL CONSTRAINT IN DEMOLITION OF THE BUILDING. REFLECTS REVISED ACTIVITY AND OVERHEAD RATES.

CONTINGENCY AMOUNT: $ 20,000

IN SERVICE DATES				Base estimate
1997 03 31	217			199704 L2
2000 09 30	249			Work start date
				1993 05 01

	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
PREV. AUTHORITY						
Authorized to date:	203		14			217
1999/00	231	10				241
TOTAL	434	10	14			458
REV. AMOUNTS:						
Authorized to date:	203		14			217
Over(under)expend:						
Auth 1999/00						
Req.: 2000/01	235	14				249
TOTAL	438	14	14			466

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 04-00-5471

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1994 10	1 625	TRSF FROM DOMESTIC ITEM (PREV BRN 9404-00-4420). STAGE 1 REFLECTS COST TO COMPLETION; REVISED INT & ESC FOR PROJECT.
1995 10	1 631	REMEDIATION ACTION PLAN PENDING UNTIL DECISION REACHED ON FINAL DISPOSAL OF SITE. ESCALATION AND INTEREST ADJUSTED.
1996 10	462	ESTIMATE AND SCHEDULE REVISED TO REFLECT NEW OVERALL WORK PLAN FOR REMEDIATION OF DIESEL SITES.
1997 10	453	ESTIMATE UNCHANGED. ISD ADVANCED ONE MONTH.
1998 10	459	RE-ESTIMATED TO REFLECT THE REQUIREMENTS OF A SPECIFICATION AND CO-ORDINATION WITH CUSTOMER SERVICE FOR THE DEMOLITION OF THE EXISTING BUILDING.

ASSOCIATED PROJECTS

Budget reference number	Description
04-00-5459	BLOODVEIN D.G.S. - SITE INVESTIGATION & CLEAN-UP
04-00-5460	BERENS RIVER D.G.S. - SITE INVESTIGATION & CLEAN-UP
04-00-5461	JACKHEAD D.G.S. - SITE CLEAN-UP
04-00-5462	LITTLE GRAND RAPIDS D.G.S. - SITE CLEAN-UP
04-00-5463	MANIGOTAGAN D.G.S. - SITE CLEAN-UP
04-00-5465	PAUINGASSI D.G.S. - SITE CLEAN-UP
04-00-5467	POPLAR RIVER D.G.S. - SITE CLEAN-UP
04-00-5468	PUKATAWAGAN DIESEL SITE CLEAN-UP
04-00-5472	MOOSE LAKE D.G.S. - SITE INVESTIGATION & CLEAN-UP
04-00-5473	NORWAY HOUSE D.G.S. - SITE CLEAN-UP
04-00-5475	ILFORD D.G.S. - SITE CLEAN-UP
04-00-5476	NELSON HOUSE D.G.S. - SITE CLEAN-UP
04-00-5478	WANLESS D.G.S. - SITE CLEAN-UP
04-00-5479	CHURCHILL D.G.S. - SITE CLEAN-UP
04-00-5480	GRANVILLE LAKE D.G.S. - SITE INVESTIGATION & CLEAN-UP
04-00-5481	BAKERS NARROWS D.G.S. - SITE CLEAN-UP
04-00-5482	CORMORANT D.G.S. - SITE CLEAN-UP
04-00-5483	CRANBERRY PORTAGE D.G.S. - SITE CLEAN-UP

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr	2					2	2
May	13					13	15
Jun	51	3				54	69
Jul	50	3				53	122
Aug	50	3				53	175
Sep	69	5				74	249
Oct							249
Nov							249
Dec							249
Jan							249
Feb							249
Mar							249
TOTAL	235	14				249	249

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item ___ Domestic Item

346

Title: MOOSE LAKE D.G.S. - SITE INVESTIGATION & CLEAN-UP

Budget reference number: 04-00-5472

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Operating & Maintenance	Construction	Construction	70126:70219

DESCRIPTION:
1. CONDUCT GEOTECHNICAL INVESTIGATION OF THE DECOMMISSIONED DIESEL GENERATING STATION TO DELINEATE THE EXTENT OF ANY HYDROCARBON CONTAMINATION ON AND/OR AROUND THE SITE AND PREPARE A SITE INVESTIGATION REPORT ON THE INVESTIGATION INCLUDING RECOMMENDATIONS FOR REMEDIAL ACTION TO CLEAN UP ANY CONTAMINANTS. (W.O.# 40238 CLOSED OUT)

2. CONDUCT RISK MANAGEMENT STUDY AND, BASED ON RESULTS , EITHER RISK MANAGE THE SITE OR REMEDIATE TO ENVIRONMENTALLY ACCEPTABLE LIMITS. (POG 70126)

3. REMEDIATE, IF NECESSARY, IN 2002/03 (POG 70219).

4. ISSUE FINAL REPORT ON THE PROJECT CONFIRMING THE DIESEL SITE AND SURROUNDING AREA WERE LEFT IN ACCORDANCE WITH APPLICABLE ENVIRONMENTAL REGULATIONS.

JUSTIFICATION:
DUE TO ENVIRONMENTAL CONCERNS AND/OR REGULATIONS THE SITE MUST BE INVESTIGATED, REMEDIATED AS REQUIRED, AND RESTORED TO A LEVEL WHICH PERMITS UNRESTRICTED USE OF THE SITE AND SURROUNDING AREA.

REVISION:
REFLECTS REVISED ACTIVITY AND OVERHEAD RATES. CONTINUE MONITORING AND TESTING IN 99/00 BEFORE DECIDING IF SOIL REMEDIATION IS REQUIRED IN 2002/03.

CONTINGENCY: $77,000

IN SERVICE DATES

1997 03 31	159
2000 08 31	324
2002 12 31	944

Base estimate: 199704 L3

Work start date: 1993 10 01

PREV AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:	369		17		-86	300
1999/00	63	3			-7	59
2000/01	24	1			-3	22
2001/02	12	2			-7	7
2002/03	841	85			- 463	463
TOTAL	1 309	91	17		- 566	851
REV. AMOUNTS:						
Authorized to date:	369		17		-86	300
Over(under)expend.						
Auth 1999/00	66	3			-2	67
Req.: 2000/01	27	2			-1	28
2001/02	14	2			-7	9
2002/03	849	78			- 463	464
TOTAL	1 325	85	17		- 559	868

Prepared by: yy mm dd COORDINATOR — Approved by: yy mm dd — Approved by: yy mm dd

Estimated by: ORIGINATOR — COORDINATING MANAGER — ORIGINATING MANAGER

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 04-00-5472

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1994 10	459	TRSF FROM DOMESTIC ITEM PREV BRN 9404-00-4421. STAGE 1 REFLECTS COSTS TO COMPLETION; REVISED INT & ESC FOR THE PROJECT.
1995 10	1 226	REDUCTION DUE TO COST ESTIMATE REFLECTING EXPLORATION RESULTS WHICH ASSISTS IN QUANTIFYING SCOPE OF WORK. AUTH. TO DATE DO NOTMATCH DUE TO WORK ORDER 44149 TRANSFERRED TO BRN 9304-00-0369. ESCALATION AND INTEREST ADJUSTED. CONTRIBUTIONS NO LONGER APPLY DIESEL SITE OFF RESERVE.
1996 10	751	ESTIMATE AND SCHEDULE REVISED TO REFLECT NEW OVERALL WORK PLAN FOR REMEDIATION OF DIESEL SITES.
1997 10	836	ESTIMATE AND SCHEDULE UNCHANGED. CASHFLOW REVISED TO REFLECT RISK MANAGEMENT STUDY COSTS UNTIL 2000/01.
1998 10	850	SCHEDULE UNCHANGED. ESTIMATE FOR CONSULTANT COSTS INCREASED TO REFLECT INCREASED MONITORING AND TESTING REQUIRED. 22.3% FOR RISK MANAGEMENT COSTS, AND 50%FOR REMEDIATION COSTS, EXLUDING FUTURE INTEREST, AS PER COST SHARING AGREEMENT WITH INAC.

ASSOCIATED PROJECTS

Budget reference number	Description
04-00-5459	BLOODVEIN D.G.S. - SITE INVESTIGATION & CLEAN-UP
04-00-5460	BERENS RIVER D.G.S. - SITE INVESTIGATION & CLEAN-UP
04-00-5461	JACKHEAD D.G.S. - SITE CLEAN-UP
04-00-5462	LITTLE GRAND RAPIDS D.G.S. - SITE CLEAN-UP
04-00-5463	MANIGOTAGAN D.G.S. - SITE CLEAN-UP
04-00-5465	PAUINGASSI D.G.S. - SITE CLEAN-UP
04-00-5467	POPLAR RIVER D.G.S. - SITE CLEAN-UP
04-00-5468	PUKATAWAGAN DIESEL SITE CLEAN-UP
04-00-5471	THE PAS D.G.S. - SITE INVESTIGATION & CLEAN-UP
04-00-5473	NORWAY HOUSE D.G.S. - SITE CLEAN-UP
04-00-5475	ILFORD D.G.S. - SITE CLEAN-UP
04-00-5476	NELSON HOUSE D.G.S. - SITE CLEAN-UP
04-00-5478	WANLESS D.G.S. - SITE CLEAN-UP
04-00-5479	CHURCHILL D.G.S. - SITE CLEAN-UP
04-00-5480	GRANVILLE LAKE D.G.S. - SITE INVESTIGATION & CLEAN-UP
04-00-5481	BAKERS NARROWS D.G.S. - SITE CLEAN-UP
04-00-5482	CORMORANT D.G.S. - SITE CLEAN-UP
04-00-5483	CRANBERRY PORTAGE D.G.S. - SITE CLEAN-UP

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	6					6	6
May	6					6	12
Jun	6					6	18
Jul	5	1				6	24
Aug	5	1				6	30
Sep	5	1				6	36
Oct	5	1				6	42
Nov	5	1				6	48
Dec	5	1				6	54
Jan	5	1				6	60
Feb	5	1				6	66
Mar	8	-5		-2		1	67
TOTAL	66	3		-2		67	67
2000/01 Apr	6					6	6
May	6					6	12
Jun	5	1				6	18
Jul	5	1				6	24
Aug	5			-1		4	28
Sep							28
Oct							28
Nov							28
Dec							28
Jan							28
Feb							28
Mar							28
TOTAL	27	2		-1		28	28

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item

347

Title
NORWAY HOUSE D.G.S. - SITE CLEAN-UP

Budget reference number
04-00-5473

riginating division	Coordinating division	Constructing division	Project Order Group (Range):
perating & Maintenance	Construction	Construction	70127

DESCRIPTION:
1. CONDUCT GEOTECHNICAL INVESTIGATION OF THE DECOMMISSIONED DIESEL GENERATING STATION TO DELINEATE THE EXTENT OF ANY HYDROCARBON CONTAMINATION ON AND/OR AROUND THE SITE AND PREPARE A SITE INVESTIGATION REPORT ON THE INVESTIGATION INCLUDING RECOMMENDATIONS FOR REMEDIAL ACTION TO CLEAN UP ANY CONTAMINANTS. (WORK ORDER 44842 CLOSED OUT)

2. RISK MANAGE THE SITE. REMEDIATION, IF REQUIRED, WILL BE COMPLETED IN 2001/02.

3. ISSUE A FINAL REPORT ON THE PROJECT CONFIRMING THE DIESEL SITE AND SURROUNDING AREA WERE LEFT IN ACCORDANCE WITH APPLICABLE ENVIRONMENTAL REGULATIONS.

JUSTIFICATION:
DUE TO ENVIRONMENTAL CONCERNS AND/OR REGULATIONS THE SITE MUST BE INVESTIGATED, REMEDIATED AS REQUIRED, AND RESTORED TO A LEVEL WHICH PERMITS UNRESTRICTED USE OF THE SITE AND THE SURROUNDING AREA.

REVISION:
REFLECTS REVISED ACTIVITY AND OVERHEAD RATES.

CONTINGENCY AMOUNT: $ 17,000

IN SERVICE DATES

1997 03 31	126
2001 10 31	209

Base estimate
199704 L2

Work start date
1993 06 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date	122		4		-28	98
2000/01	8	1			-2	7
2001/02	181	16			-44	153
TOTAL	311	17	4		-74	258
REV. AMOUNTS:						
Authorized to date	122		4		-28	98
Over(under)expend:						
Auth 2000/01	9	1			-2	8
Req. 2001/02	185	14			-44	155
TOTAL	316	15	4		-74	261

Prepared by — yy mm dd — COORDINATOR
Approved by — yy mm dd — COORDINATING MANAGER
Approved by — yy mm dd — ORIGINATING MANAGER
Estimated by — ORIGINATOR

1999-08-21 05:26 PM

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 04-00-5473

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1994 10	370	TRSF FROM DOMESTIC ITEM (PREV BRN 9404-00-4430). STAGE 1 REFLECTS COST TO COMPLETION; REVISED INT & ESC FOR THE PROJECT.
1995 10	1 204	EXPLORATION COMPLETE. UNRESOLVED ON REMEDIATION REQUIREMENTSAS MANITOBA HYDRO MAY RISK MANAGE SITE. IF THIS IS THE CASE THE ESTIMATECOULD BE REDUCED BY APPROXIMATELY $950,000. ESCALATION AND INTEREST ADJUSTED.
1996 10	168	ESTIMATE AND SCHEDULE REVISED TO REFLECT NEW OVERALL WORK PLAN FOR REMEDIATION OF DIESEL SITES.
1997 10	261	ESTIMATE AND SCHEDULE UNCHANGED.
1998 10	258	ESTIMATE AND SCHEDULE UNCHANGED. ALL COSTS EXCEPT FOR FUTURE INTEREST, AS PER COST SHARING AGREEMENT WITH INAC.

ASSOCIATED PROJECTS

Budget reference number	Description
04-00-5459	BLOODVEIN D.G.S. - SITE INVESTIGATION & CLEAN-UP
04-00-5460	BERENS RIVER D.G.S. - SITE INVESTIGATION & CLEAN-UP
04-00-5461	JACKHEAD D.G.S. - SITE CLEAN-UP
04-00-5462	LITTLE GRAND RAPIDS D.G.S. - SITE CLEAN-UP
04-00-5463	MANIGOTAGAN D.G.S. - SITE CLEAN-UP
04-00-5465	PAUINGASSI D.G.S. - SITE CLEAN-UP
04-00-5467	POPLAR RIVER D.G.S. - SITE CLEAN-UP
04-00-5468	PUKATAWAGAN DIESEL SITE CLEAN-UP
04-00-5471	THE PAS D.G.S. - SITE INVESTIGATION & CLEAN-UP
04-00-5472	MOOSE LAKE D.G.S. - SITE INVESTIGATION & CLEAN-UP
04-00-5475	ILFORD D.G.S. - SITE CLEAN-UP
04-00-5476	NELSON HOUSE D.G.S. - SITE CLEAN-UP
04-00-5478	WANLESS D.G.S. - SITE CLEAN-UP
04-00-5479	CHURCHILL D.G.S. - SITE CLEAN-UP
04-00-5480	GRANVILLE LAKE D.G.S. - SITE INVESTIGATION & CLEAN-UP
04-00-5481	BAKERS NARROWS D.G.S. - SITE CLEAN-UP
04-00-5482	CORMORANT D.G.S. - SITE CLEAN-UP
04-00-5483	CRANBERRY PORTAGE D.G.S. - SITE CLEAN-UP

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep	1					1	1
Oct	1					1	2
Nov	1					1	3
Dec	1					1	4
Jan	1					1	5
Feb	1					1	6
Mar	3	1		-2		2	8
TOTAL	9	1		-2		8	8

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item

348

Title
NELSON HOUSE D.G.S. - SITE CLEAN-UP

Budget reference number
04-00-5476

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Operating & Maintenance	Construction	Construction	70147:70439

DESCRIPTION:
1. CONDUCT GEOTECHNICAL INVESTIGATION OF THE DECOMMISSIONED DIESEL GENERATING STATION TO DELINEATE THE EXTENT OF ANY HYDROCARBON CONTAMINATION ON AND/OR AROUND THE SITE AND PREPARE A SITE INVESTIGATION REPORT ON THE INVESTIGATION INCLUDING RECOMMENDATIONS FOR REMEDIAL ACTION TO CLEAN UP ANY CONTAMINANTS. (POG 70147)

2. CONDUCT RISK MANAGE STUDY AND IDENTIFY ANY AREAS OF CONCERN. (REMEDIATION, IF REQ'D, TO BE COMPLETED IN 2002\03. (POG 70439)

3. ISSUE A FINAL REPORT ON THE PROJECT CONFIRMING THE DIESEL SITE AND SURROUNDING AREA WERE LEFT IN ACCORDANCE WITH APPLICABLE ENVIRONMENTAL REGULATIONS

JUSTIFICATION:
DUE TO ENVIRONMENTAL CONCERNS AND/OR REGULATIONS THE SITE MUST BE INVESTIGATED, REMEDIATED AS REQUIRED, AND RESTORED TO A LEVEL WHICH PERMITS UNRESTRICTED USE OF THE SITE AND THE SURROUNDING AREA.

REVISION:
INCREASE DUE TO SITE WORK REQUIRED FOR REMEDIATION AND ALSO PROVIDING TEMPORARY TRAILERS/ACCOMODATIONS FOR THE MEDICINE LODGE OPERATION. REFLECTS REVISED ACTIVITY AND OVERHEAD RATES. SCHEDULE ADVANCED TO REFLECT REQUEST FROM THE FIRST NATION.

CONTINGENCY: $100,000

IN SERVICE DATES

1997 03 31	152
1999 04 30	23
1999 10 31	413
2002 09 30	79

Base estimate
199903 L2

Work start date
1994 05 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:	170		8		-89	89
1999/00						
2000/01						
2001/02						
2002/03	80	9			-44	45
TOTAL	250	9	8		- 133	134
REV. AMOUNTS:						
Authorized to date:	170		8		-89	89
Over(under)expend:						
Auth 1999/00	408	2			- 206	204
Req.: 2002/03	72	7			-40	39
TOTAL	650	9	8		- 335	332

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 04-00-5476

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1994 10	450	TRSF FROM DOMESTIC ITEM (PREV BRN 9504-00-4438.) REVISED INT & ESC FOR THE PROJECT.
1995 10	1 493	EXPLORATION REPORT BEING PREPARED. REMEDIATION ACTION PLAN NOT ISSUED TO DATE. ESCALATION AND INTEREST ADJUSTED. THERE IS A POSSIBILITY THAT NO CONSTRUCTION ACTIVITY MAY BE REQUIRED BASED ON PRELIMINARY INVESTIGATIONS.
1996 10	120	ESTIMATE AND SCHEDULE REVISED TO REFLECT NEW OVERALL WORK PLAN FOR REMEDIATION OF DIESEL SITES.
1997 10	133	ESTIMATE UNCHANGED. REMEDIATION (IF REQUIRED) DEFERRED TO 2002 03.
1998 10	134	NO CHANGE

ASSOCIATED PROJECTS

Budget reference number	Description
04-00-5459	BLOODVEIN D.G.S. - SITE INVESTIGATION & CLEAN-UP
04-00-5460	BERENS RIVER D.G.S. - SITE INVESTIGATION & CLEAN-UP
04-00-5461	JACKHEAD D.G.S. - SITE CLEAN-UP
04-00-5462	LITTLE GRAND RAPIDS D.G.S. - SITE CLEAN-UP
04-00-5463	MANIGOTAGAN D.G.S. - SITE CLEAN-UP
04-00-5465	PAUINGASSI D.G.S. - SITE CLEAN-UP
04-00-5467	POPLAR RIVER D.G.S. - SITE CLEAN-UP
04-00-5468	PUKATAWAGAN DIESEL SITE CLEAN-UP
04-00-5471	THE PAS D.G.S. - SITE INVESTIGATION & CLEAN-UP
04-00-5472	MOOSE LAKE D.G.S. - SITE INVESTIGATION & CLEAN-UP
04-00-5473	NORWAY HOUSE D.G.S. - SITE CLEAN-UP
04-00-5475	ILFORD D.G.S. - SITE CLEAN-UP
04-00-5478	WANLESS D.G.S. - SITE CLEAN-UP
04-00-5479	CHURCHILL D.G.S. - SITE CLEAN-UP
04-00-5480	GRANVILLE LAKE D.G.S. - SITE INVESTIGATION & CLEAN-UP
04-00-5481	BAKERS NARROWS D.G.S. - SITE CLEAN-UP
04-00-5482	CORMORANT D.G.S. - SITE CLEAN-UP
04-00-5483	CRANBERRY PORTAGE D.G.S. - SITE CLEAN-UP

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	9					9	9
May	9					9	18
Jun	91					91	109
Jul	91					91	200
Aug	91		1			92	292
Sep	9					9	301
Oct	108		1	- 206		-97	204
Nov							204
Dec							204
Jan							204
Feb							204
Mar							204
TOTAL	408		2	- 206		204	204
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

1999-08-21 05:27 PM

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item ___ Domestic Item

349

Title
WANLESS D.G.S. - SITE CLEAN-UP

Budget reference number
04-00-5478

riginating division	Coordinating division	Constructing division	Project Order Group (Range):
perating & Maintenance	Construction	Construction	70128:70440

DESCRIPTION:
1. CONDUCT GEOTECHNICAL INVESTIGATION OF THE DECOMMISSIONED DIESEL GENERATING STATION TO DELINEATE THE EXTENT OF ANY HYDROCARBON CONTAMINATION ON AND/OR AROUND THE SITE AND PREPARE A SITE INVESTIGATION REPORT ON THE INVESTIGATION INCLUDING RECOMMENDATIONS FOR REMEDIAL ACTION TO CLEAN UP ANY CONTAMINANTS.
2. REMEDIATE TO ENVIRONMENTALLY ACCEPTABLE LIMITS ANY CONTAMINATED AREAS IDENTIFIED IN THE SITE INVESTIGATION REPORT.
3. ISSUE A FINAL REPORT ON THE PROJECT CONFIRMING THE DIESEL SITE AND SURROUNDING AREA WERE REMEDIATED AND ALL AREAS OF THE WORKS LEFT IN ACCORDANCE WITH APPLICABLE ENVIRONMENTAL REGULATIONS.

JUSTIFICATION:
DUE TO ENVIRONMENTAL CONCERNS AND/OR REGULATIONS THE SITE MUST BE INVESTIGATED, REMEDIATED AS REQUIRED, AND RESTORED TO A LEVEL WHICH PERMITS UNRESTRICTED USE OF THE SITE AND THE SURROUNDING AREA.

REVISION:
ISD DEFERRED TO 2000/11/30 FOR CAPITAL CONSTRAINT REASONS AND SCHEDULING OF WORK. REFLECTS REVISED ACTIVITY AND OVERHEAD RATES.

CONTINGENCY: $ 25,000

IN SERVICE DATES

2000 03 31	49
2000 11 30	299

Base estimate
199704 L2

Work start date
1994 05 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date	42		7			49
1999/00	278	13				291
TOTAL	320	13	7			340
REV. AMOUNTS:						
Authorized to date:	42		7			49
Over(under)expend:						
Auth 1999/00 Req. 2000/01	282	17				299
TOTAL	324	17	7			348

Prepared by yy mm dd COORDINATOR Approved by yy mm dd Approved by yy mm dd

Estimated by ORIGINATOR COORDINATING MANAGER ORIGINATING MANAGER

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 04-00-5478

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1994 10	492	TRSF FROM DOMESTIC ITEM (PREV BRN 9404-00-4440). REVISED INTEREST & ESCALATION FOR THE PROJECT.
1995 10	494	EXPLORATION REPORT BEING PREPARED. REMEDIATION ACTION PLAN NOT ISSUED TO DATE. ESCALATION AND INTEREST ADJUSTED.
1996 10	352	ESTIMATE AND SCHEDULE REVISED TO REFLECT NEW OVERALL WORK PLAN FOR REMEDIATION OF DIESEL SITES.
1997 10	337	SCOPE UNCHANGED. ESTIMATE REFLECTS REVISED COSTING METHODOLOGY IMPLEMENTED WITH THE NEW FINANCIAL REPORTING SYSTEM. ESTIMATE ALSO REFLECTS REVISED INTEREST AND ESCALATION RATES.
1998 10	340	ESTIMATE INCREASED SLIGHTLY TO REFLECT THE REQUIREMENT FOR A CONSULTANT'S REPORT.

ASSOCIATED PROJECTS

Budget reference number	Description
04-00-5459	BLOODVEIN D.G.S. - SITE INVESTIGATION & CLEAN-UP
04-00-5460	BERENS RIVER D.G.S. - SITE INVESTIGATION & CLEAN-UP
04-00-5461	JACKHEAD D.G.S. - SITE CLEAN-UP
04-00-5462	LITTLE GRAND RAPIDS D.G.S. - SITE CLEAN-UP
04-00-5463	MANIGOTAGAN D.G.S. - SITE CLEAN-UP
04-00-5465	PAUINGASSI D.G.S. - SITE CLEAN-UP
04-00-5467	POPLAR RIVER D.G.S. - SITE CLEAN-UP
04-00-5468	PUKATAWAGAN DIESEL SITE CLEAN-UP
04-00-5471	THE PAS D.G.S. - SITE INVESTIGATION & CLEAN-UP
04-00-5472	MOOSE LAKE D.G.S. - SITE INVESTIGATION & CLEAN-UP
04-00-5473	NORWAY HOUSE D.G.S. - SITE CLEAN-UP
04-00-5475	ILFORD D.G.S. - SITE CLEAN-UP
04-00-5476	NELSON HOUSE D.G.S. - SITE CLEAN-UP
04-00-5479	CHURCHILL D.G.S. - SITE CLEAN-UP
04-00-5480	GRANVILLE LAKE D.G.S. - SITE INVESTIGATION & CLEAN-UP
04-00-5481	BAKERS NARROWS D.G.S. - SITE CLEAN-UP
04-00-5482	CORMORANT D.G.S. - SITE CLEAN-UP
04-00-5483	CRANBERRY PORTAGE D.G.S. - SITE CLEAN-UP

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr	3					3	3
May	3					3	6
Jun	12	1				13	19
Jul	73	5				78	97
Aug	73	5				78	175
Sep	73	5				78	253
Oct	10	1				11	264
Nov	35	2				37	301
Dec							301
Jan							301
Feb							301
Mar		-2				-2	299
TOTAL	282	17				299	299

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item

350

Title	Budget reference number
CHURCHILL D.G.S. - SITE CLEAN-UP	04-00-5479

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Operating & Maintenance	Construction	Construction	70129:70148

DESCRIPTION:
1. REMOVE TANKS FROM DIESEL TANK FARM. (W.O.# 27045, CLOSED OUT)
2. CONDUCT GEOTECHNICAL INVESTIGATION OF THE DECOMMISSIONED DIESEL GENERATING STATION TO DELINEATE THE EXTENT OF ANY HYDROCARBON CONTAMINATION ON AND/OR AROUND THE SITE; PREPARE SITE INVESTIGATION REPORT INCLUDING RECOMMENDATIONS FOR CLEAN UP. (W.O.# 46672)
3. REMEDIATE TO ENVIRONMENTALLY ACCEPTABLE LIMITS ANY CONTAMINATED AREAS IDENTIFIED IN THE SITE INVESTIGATION REPORT.
4. ISSUE A FINAL REPORT ON THE PROJECT CONFIRMING THE DIESEL SITE AND SURROUNDING AREA WERE REMEDIATED AND ALL AREAS OF THE WORKS WERE LEFT IN ACCORDANCE WITH APPLICABLE ENVIRONMENTAL REGULATIONS.

JUSTIFICATION:
DUE TO ENVIRONMENTAL CONCERNS AND/OR REGULATIONS THE SITE MUST BE INVESTIGATED, REMEDIATED AS REQUIRED, AND RESTORED TO A LEVEL WHICH PERMITS UNRESTRICTED USE OF THE SITE AND THE SURROUNDING AREA.

REVISION:
ISD DEFERRED FROM 1998/10/31 TO 1999/10/31 FOR CAPITAL CONSTRAINT REASONS. REFLECTS REVISED ACTIVITY AND OVERHEAD RATES.

CONTINGENCY: $100,000

IN SERVICE DATES				Base estimate
1997 03 31	146			199802 L2
1999 10 31	1 160			Work start date 1994 06 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:	621		52			673
1999/00	591					591
TOTAL	1 212		52			1 264
REV. AMOUNTS:						
Authorized to date:	621		52			673
Over(under)expend:						
Auth 1999/00 Req.:	616	17				633
TOTAL	1 237	17	52			1 306

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

1999-09-28 11:50 AM

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number: 04-00-5479

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1994 10	1 635	NEW ITEM.
1995 10	1 786	ACTUALS TO DATE REPRESENT REMOVAL OF TANKS. ESCALATION AND INTEREST ADJUSTED.
1996 10	3 485	ESTIMATE AND SCHEDULE REVISED TO REFLECT NEW OVERALL WORK PLAN FOR REMEDIATION OF DIESEL SITES.
1997 10	3 399	SCOPE UNCHANGED, ESTIMATE REFLECTS REVISED COSTING METHODOLOGY IMPLEMENTED WITH THE NEW FINANCIAL REPORTING SYSTEM. ESTIMATE ALSO REFLECTS REVISED INTEREST AND ESCALATION RATES.
1998 10	1 264	SOIL REMEDIATION WORK CANCELLED.

ASSOCIATED PROJECTS

Budget reference number	Description
04-00-5459	BLOODVEIN D.G.S. - SITE INVESTIGATION & CLEAN-UP
04-00-5460	BERENS RIVER D.G.S. - SITE INVESTIGATION & CLEAN-UP
04-00-5461	JACKHEAD D.G.S. - SITE CLEAN-UP
04-00-5462	LITTLE GRAND RAPIDS D.G.S. - SITE CLEAN-UP
04-00-5463	MANIGOTAGAN D.G.S. - SITE CLEAN-UP
04-00-5465	PAUINGASSI D.G.S. - SITE CLEAN-UP
04-00-5467	POPLAR RIVER D.G.S. - SITE CLEAN-UP
04-00-5468	PUKATAWAGAN DIESEL SITE CLEAN-UP
04-00-5471	THE PAS D.G.S. - SITE INVESTIGATION & CLEAN-UP
04-00-5472	MOOSE LAKE D.G.S. - SITE INVESTIGATION & CLEAN-UP
04-00-5473	NORWAY HOUSE D.G.S. - SITE CLEAN-UP
04-00-5475	ILFORD D.G.S. - SITE CLEAN-UP
04-00-5476	NELSON HOUSE D.G.S. - SITE CLEAN-UP
04-00-5478	WANLESS D.G.S. - SITE CLEAN-UP
04-00-5480	GRANVILLE LAKE D.G.S. - SITE INVESTIGATION & CLEAN-UP
04-00-5481	BAKERS NARROWS D.G.S. - SITE CLEAN-UP
04-00-5482	CORMORANT D.G.S. - SITE CLEAN-UP
04-00-5483	CRANBERRY PORTAGE D.G.S. - SITE CLEAN-UP

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May	47	1				48	48
Jun	47	1				48	96
Jul	47	1				48	144
Aug	47	1				48	192
Sep	47	1				48	240
Oct	64	1				65	305
Nov	64	1				65	370
Dec	64	1				65	435
Jan	64	1				65	500
Feb	64	1				65	565
Mar	61	7				68	633
TOTAL	616	17				633	633
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item

351

Title: GRANVILLE LAKE D.G.S. - SITE INVESTIGATION & CLEAN-UP

Budget reference number: 04-00-5480

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Operating & Maintenance	Construction	Construction	70108:70109

DESCRIPTION:
1. CONDUCT GEOTECHNICAL INVESTIGATION OF THE DECOMMISSIONED DIESEL GENERATING STATION IN ORDER TO DELINEATE THE EXTENT OF HYDROCARBON CONTAMINATION ON AND/OR AROUND THE SITE AND PREPARE A SITE INVESTIGATION REPORT ON THE INVESTIGATION INCLUDING RECOMMENDATIONS FOR REMEDIAL ACTION TO CLEAN UP ANY CONTAMINANTS. (WORK ORDER 46664 CLOSED OUT)

2. REMEDIATE ANY CONTAMINATED AREAS IDENTIFED IN THE SITE INVESTIGATION REPORT TO ENVIRONMENTALLY ACCEPTABLE LIMITS AND DEVELOP ANY LANDFARM AREAS NECESSARY FOR THE REMEDIATION PROCESS.

3. LAND FARM ANY CONTAMINATED SOILS REMOVED FROM THE DIESEL SITE AREA UNTIL CONTAMINATION IS REDUCED TO ENVIRONMENTALLY ACCEPTABLE LEVELS.

4. ISSUE A FINAL REPORT ON THE PROJECT CONFIRMING THE DIESEL SITE AND SURROUNDING AREA WERE REMEDIATED AND ALL AREAS OF THE WORKS WERE LEFT IN ACCORDANCE WITH APPLICABLE ENVIRONMENTAL REGULATIONS.

JUSTIFICATION:
DUE TO ENVIRONMENTAL CONCERNS AND/OR REGULATIONS THE SITE MUST BE INVESTIGATED, REMEDIATED AS REQUIRED, AND RESTORED TO A LEVEL WHICH PERMITS UNRETRICTED USE OF THE SITE AND THE SURROUNDING AREA.

REVISION:
REFLECTS ACTUAL COSTS TO COMPLETION.

IN SERVICE DATES		Base estimate
1997 03 31	342	199704 L4
1999 08 31	610	Work start date 1995 05 01

	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
PREV. AUTHORITY						
Authorized to date	938		6		- 473	471
1999/00	15					15
TOTAL	953		6		- 473	486
REV. AMOUNTS:						
Authorized to date	938		6		- 473	471
Over(under)expend.						
Auth 1999/00	8				-3	5
Req.:						
TOTAL	946		6		- 476	476

Prepared by: yy mm dd COORDINATOR — Approved by: yy mm dd — Approved by: yy mm dd

Estimated by: ORIGINATOR — COORDINATING MANAGER — ORIGINATING MANAGER

1999-08-21 05:27 PM

CAPITAL EXPENDITURE REVISION

Budget reference number 04-00-5480

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1994 10	573	NEW ITEM.
1995 10	575	EXPLORATION PLANNED FOR 95/96. ESCALATION AND INTEREST ADJUSTED.
1996 10	320	ESTIMATE AND SCHEDULE REVISED TO REFLECT NEW OVERALL WORK PLAN FOR REMEDIATION OF DIESEL SITES.
1997 10	498	ESTIMATE INCREASED BASED ON FINDINGS OF INVESTIGATION.
1998 10	488	ADDITIONAL COSTS TO BE INCURRED FOR MONITORING/TESTING. CONTRIBUITIONS BASED ON 50% OF ALL COSTS EXCEPT FUTURE INTEREST, AS PER COST SHARING AGREEMENT WITH INAC.

ASSOCIATED PROJECTS

Budget reference number	Description
04-00-5459	BLOODVEIN D.G.S. - SITE INVESTIGATION & CLEAN-UP
04-00-5460	BERENS RIVER D.G.S. - SITE INVESTIGATION & CLEAN-UP
04-00-5461	JACKHEAD D.G.S. - SITE CLEAN-UP
04-00-5462	LITTLE GRAND RAPIDS D.G.S. - SITE CLEAN-UP
04-00-5463	MANIGOTAGAN D.G.S. - SITE CLEAN-UP
04-00-5465	PAUINGASSI D.G.S. - SITE CLEAN-UP
04-00-5467	POPLAR RIVER D.G.S. - SITE CLEAN-UP
04-00-5468	PUKATAWAGAN DIESEL SITE CLEAN-UP
04-00-5471	THE PAS D.G.S. - SITE INVESTIGATION & CLEAN-UP
04-00-5472	MOOSE LAKE D.G.S. - SITE INVESTIGATION & CLEAN-UP
04-00-5473	NORWAY HOUSE D.G.S. - SITE CLEAN-UP
04-00-5475	ILFORD D.G.S. - SITE CLEAN-UP
04-00-5476	NELSON HOUSE D.G.S. - SITE CLEAN-UP
04-00-5478	WANLESS D.G.S. - SITE CLEAN-UP
04-00-5479	CHURCHILL D.G.S. - SITE CLEAN-UP
04-00-5481	BAKERS NARROWS D.G.S. - SITE CLEAN-UP
04-00-5482	CORMORANT D.G.S. - SITE CLEAN-UP
04-00-5483	CRANBERRY PORTAGE D.G.S. - SITE CLEAN-UP

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul		4				4	4
Aug		4		-3		1	5
Sep							5
Oct							5
Nov							5
Dec							5
Jan							5
Feb							5
Mar							5
TOTAL		8		-3		5	5
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item

352

Title
CORMORANT D.G.S. - SITE CLEAN-UP

Budget reference number
04-00-5482

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Operating & Maintenance	Construction	Construction	70130:70131

DESCRIPTION:
1. CONDUCT GEOTECHNICAL INVESTIGATION OF THE DECOMMISSIONED DIESEL GENERATING STATION TO DELINEATE THE EXTENT OF ANY HYDROCARBON CONTAMINATION ON AND/OR AROUND THE SITE AND PREPARE A SITE INVESTIGATION REPORT ON THE INVESTIGATION INCLUDING RECOMMENDATIONS FOR REMEDIAL ACTION TO CLEAN UP ANY CONTAMINANTS. COMPLETION: 1997 07 31 (WORK ORDER #46383/POG 70130).

2. REMEDIATE TO ENVIRONMENTALLY ACCEPTABLE LIMITS ANY CONTAMINATED AREAS IDENTIFIED IN THE SITE INVESTIGATION REPORT. COMPLETION: 2000 09 30 (POG 70131).

3. ISSUE A FINAL REPORT ON THE PROJECT CONFIRMING THE DIESEL SITE AND SURROUNDING AREA WERE REMEDIATED AND ALL AREAS OF THE WORKS WERE LEFT IN ACCORDANCE WITH APPLICABLE ENVIRONMENTAL REGULATIONS. COMPLETION: 2000 11 30 (POG 70131).

JUSTIFICATION:
DUE TO ENVIRONMENTAL CONCERNS AND/OR REGULATIONS THE SITE MUST BE INVESTIGATED, REMEDIATED AS REQUIRED, AND RESTORED TO A LEVEL WHICH PERMITS UNRESTRICTED USE OF THE SITE AND THE SURROUNDING AREAS.

REVISION:
FUNDS REQUIRED IN 1999/00 FOR SITE INVESTIGATION WORK AS REQUIRED BY MANITOBA ENVIRIONMENT. RELFECTS REVISED ACTIVITY AND OVERHEAD RATES.

CONTINGENCY AMOUNT: $ 36,000

IN SERVICE DATES		Base estimate
2000 09 30	50	199704 L2
2000 11 30	421	Work start date
		1996 09 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:	44		1			45
1999/00	285	12				297
2000/01	98	6				104
TOTAL	427	18	1			446
REV. AMOUNTS:						
Authorized to date:	44		1			45
Over(under)expend:						
Auth 1999/00	104	4				108
Req 2000/01	302	16				318
TOTAL	450	20	1			471

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 04-00-5482

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1994 10	928	NEW ITEM
1995 10	928	NO ACTIVITY TO DATE. ESCALATION AND INTERST ADJUSTED.
1996 10	448	ESTIMATE AND SCHEDULE REVISED TO REFLECT NEW OVERALL WORK PLAN FOR REMEDIATION OF DIESEL SITES.
1997 10	453	ESTIMATE UNCHANGED. ISD FOR SITE INVESTIGATION DELAYED BY SIX MONTHS.
1998 10	446	ITEM 1 - ISD DELAYED FROM 1997 07 TO 1998 03. ESTIMATE INCREASED TO REFLECT THE REQUIREMENT FOR A CONSULTANT'S REPORT IN GEOTECHNICAL INVESTIGATION. ITEM 2 - MAJORITY OF SITE CLEAN-UP WORK ADVANCED TO 1999/00 FISCAL YEAR TO FACILITATE WORK LOAD SCHEDULE AND CASH FLOW.

ASSOCIATED PROJECTS

Budget reference number	Description
04-00-5459	BLOODVEIN D.G.S. - SITE INVESTIGATION & CLEAN-UP
04-00-5460	BERENS RIVER D.G.S. - SITE INVESTIGATION & CLEAN-UP
04-00-5461	JACKHEAD D.G.S. - SITE CLEAN-UP
04-00-5462	LITTLE GRAND RAPIDS D.G.S. - SITE CLEAN-UP
04-00-5463	MANIGOTAGAN D.G.S. - SITE CLEAN-UP
04-00-5465	PAUINGASSI D.G.S. - SITE CLEAN-UP
04-00-5467	POPLAR RIVER D.G.S. - SITE CLEAN-UP
04-00-5468	PUKATAWAGAN DIESEL SITE CLEAN-UP
04-00-5471	THE PAS D.G.S. - SITE INVESTIGATION & CLEAN-UP
04-00-5472	MOOSE LAKE D.G.S. - SITE INVESTIGATION & CLEAN-UP
04-00-5473	NORWAY HOUSE D.G.S. - SITE CLEAN-UP
04-00-5475	ILFORD D.G.S. - SITE CLEAN-UP
04-00-5476	NELSON HOUSE D.G.S. - SITE CLEAN-UP
04-00-5478	WANLESS D.G.S. - SITE CLEAN-UP
04-00-5479	CHURCHILL D.G.S. - SITE CLEAN-UP
04-00-5480	GRANVILLE LAKE D.G.S. - SITE INVESTIGATION & CLEAN-UP
04-00-5481	BAKERS NARROWS D.G.S. - SITE CLEAN-UP
04-00-5483	CRANBERRY PORTAGE D.G.S. - SITE CLEAN-UP

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec	3					3	3
Jan	3					3	6
Feb	3					3	9
Mar	95	4				99	108
TOTAL	104	4				108	108
2000/01 Apr	7					7	7
May	7					7	14
Jun	17	1				18	32
Jul	80	4				84	116
Aug	80	4				84	200
Sep	80	5				85	285
Oct	14	1				15	300
Nov	14	1				15	315
Dec	3					3	318
Jan							318
Feb							318
Mar							318
TOTAL	302	16				318	318

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item

353

Title: CRANBERRY PORTAGE D.G.S. - SITE CLEAN-UP

Budget reference number: 04-00-5483

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Operating & Maintenance	Construction	Construction	70132:70133

DESCRIPTION:
1. CONDUCT GEOTECHNICAL INVESTIGATION OF THE DECOMMISSIONED DIESEL GENERATING STATION TO DELINEATE THE EXTENT OF ANY HYDROCARBON CONTAMINATION ON AND/OR AROUND THE SITE AND PREPARE A SITE INVESTIGATION REPORT ON THE INVESTIGATION INCLUDING RECOMMENDATIONS FOR REMEDIAL ACTION TO CLEAN UP ANY CONTAMINANTS. COMPLETION: 1997 07 31 (WORK ORDER#46466/POG 70132).

2. RISK MANAGE OR REMEDIATE TO ENVIRONMENTALLY ACCEPTABLE LIMITS ANY CONTAMINATED AREAS IDENTIFIED IN THE SITE INVESTIGATION REPORT. COMPLETION: 2000 09 30 (POG 70133).
3. ISSUE A FINAL REPORT ON THE PROJECT CONFIRMING THE DIESEL SITE AND SURROUNDING AREA WERE LEFT IN ACCORDANCE WITH APPLICABLE ENVIRONMENTAL REGULATIONS. COMPLETION: 2000 11 30 (POG 70133).

JUSTIFICATION:
DUE TO ENVIRONMENTAL CONCERNS AND/OR REGULATIONS THE SITE MUST BE INVESTIGATED, REMEDIATED AS REQUIRED, AND RESTORED TO A LEVEL WHICH PERMITS UNRESTRICTED USE OF THE SITE AND THE SURROUNDING AREA.

REVISION:
REFLECTS REVISED ACTIVITY AND OVERHEAD RATES.

CONTINGENCY: $33,000

IN SERVICE DATES			Base estimate
2001 11 30	464		199704 L2
			Work start date: 1996 09 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:	69		2			71
1999/00	15	1				16
2000/01	353	22				375
TOTAL	437	23	2			462
REV. AMOUNTS:						
Authorized to date:	69		2			71
Over(under)expend:						
Auth 1999/00	14	1				15
Req. 2000/01	359	19				378
TOTAL	442	20	2			464

Prepared by: yy mm dd COORDINATOR — Approved by: yy mm dd Approved by:

Estimated by: ORIGINATOR — COORDINATING MANAGER — ORIGINATING MANAGER

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 04-00-5483

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1994 10	928	NEW ITEM
1995 10	928	NO ACTIVITY TO DATE. ESCALATION AND INTEREST ADJUSTED.
1996 10	455	ESTIMATE AND SCHEDULE REVISED TO REFLECT NEW OVERALL WORK PLAN FOR REMEDIATION OF DIESEL SITES.
1997 10	458	ESTIMATE UNCHANGED. ISD FOR SITE INVESTIGATION DELAYED BY SIX MONTHS.
1998 10	462	ISD DELAYED BY TWELVE MONTHS, FROM 2000 11 TO 2001 11. INCREASED TO REFLECT THE REQUIREMENT FOR A REPORT BY A CONSULTANT.

ASSOCIATED PROJECTS

Budget reference number	Description
04-00-5459	BLOODVEIN D.G.S. - SITE INVESTIGATION & CLEAN-UP
04-00-5460	BERENS RIVER D.G.S. - SITE INVESTIGATION & CLEAN-UP
04-00-5461	JACKHEAD D.G.S. - SITE CLEAN-UP
04-00-5462	LITTLE GRAND RAPIDS D.G.S. - SITE CLEAN-UP
04-00-5463	MANIGOTAGAN D.G.S. - SITE CLEAN-UP
04-00-5465	PAUINGASSI D.G.S. - SITE CLEAN-UP
04-00-5467	POPLAR RIVER D.G.S. - SITE CLEAN-UP
04-00-5468	PUKATAWAGAN DIESEL SITE CLEAN-UP
04-00-5471	THE PAS D.G.S. - SITE INVESTIGATION & CLEAN-UP
04-00-5472	MOOSE LAKE D.G.S. - SITE INVESTIGATION & CLEAN-UP
04-00-5473	NORWAY HOUSE D.G.S. - SITE CLEAN-UP
04-00-5475	ILFORD D.G.S. - SITE CLEAN-UP
04-00-5476	NELSON HOUSE D.G.S. - SITE CLEAN-UP
04-00-5478	WANLESS D.G.S. - SITE CLEAN-UP
04-00-5479	CHURCHILL D.G.S. - SITE CLEAN-UP
04-00-5480	GRANVILLE LAKE D.G.S. - SITE INVESTIGATION & CLEAN-UP
04-00-5481	BAKERS NARROWS D.G.S. - SITE CLEAN-UP
04-00-5482	CORMORANT D.G.S. - SITE CLEAN-UP

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep	2					2	2
Oct	2					2	4
Nov	2					2	6
Dec	2					2	8
Jan	2					2	10
Feb	2					2	12
Mar	2	1				3	15
TOTAL	14	1				15	15
2000/01 Apr	2	1				3	3
May	2	1				3	6
Jun	13					13	19
Jul	96	5				101	120
Aug	96	5				101	221
Sep	96	6				102	323
Oct	10	1				11	334
Nov	44					44	378
Dec							378
Jan							378
Feb							378
Mar							378
TOTAL	359	19				378	378

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

COMPLEX STATUS: ☐ Planned ☒ In progress

Complex no. 81

REVISION STATUS: ☐ New complex ☐ In service change ☐ Concept change ☒ Estimate change only

COMPLEX: OIL CONTAINMENT

Proposal

Implement programs designed to minimize or ameliorate the impact of the Corporation's operations on the environment, such as;

Design and construct oil containment systems to collect and recover any oil spilled within the system.

JUSTIFICATION

☐ Load ☐ Service
☒ Safety ☐ Efficiency
☐ Reliability ☒ Other

Explanation

Previous experience with oil spills requires the Corporation to demonstrate "due diligence" with respect to containing and minimizing the potential for any further occurances.

Estimate Level	COMPLEX START (yyyy mm)
L1	1995 02

IN SERVICE DATES AND AMOUNTS

1997 03	$70	1999 05	$192	2002 03	$266	2002 10	$3341

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	421		63		484	474	10	2
Year 99/00	54		24		78	33	45	136
00/01	722	32	51		805	694	111	16
01/02	1,020	70	138		1,228	1,085	143	13
02/03	825	67	115		1,007	857	150	18
03/04	244	23			267	233	34	15
04/05								
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	3,286	192	391		3,869	3,376	493	15

REVISION: Scope unchanged.

Reviewed by ORIGINATOR	yyyy mm dd 99 11 09	Reviewed by COORDINATOR	yyyy mm dd 99 11 03
Reviewed by CONSTRUCTOR	yyyy mm dd 99 11 03	Approved by VICE-PRESIDENT	yyyy mm dd 99 11

H2856/r Rev 99 03

Complex no. 81

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Advance or deferral impact

POTENTIAL FOR LEGAL ACTIONS.

Factors affecting timing or viability

SUBJECT TO ENVIRONMENTAL REGULATIONS

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE	
					Amount	%
AC Sub- Station Oil Containment - Central Area	747	637	650	747	97	15
AC Sub- Station Oil Containment - Western Area	879	749	764	879	115	15
AC Sub- Station Oil Containment - Eastern Area	901	772	787	901	114	14
AC Sub- Station Oil Containment - Northern Area	280	241	246	280	34	14
Microwave & VHF Sites Oil Spill Containment		230	235	230	-5	-2
Thompson Service Ctr Oil Spill Containment	70	70	71	70	-1	-1
Operations & Maintenance spill response equipment	150	155	158	179	21	13
TOTAL	3,027	2,854	2,911	3,286	375	13

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
95 10	19,780	NewComplex. (previously part of ENVIRONMENTAL INITIATIVES complex) .
96 10	3,363	Reflects Transmission & Distribution portion of previous oil containment item and addition of a spill response equipment purchase item, base year 1996.
9710	3,409	ESTIMATE REFLECTS REVISED COSTING METHODOLOGY IMPLEMENTED WITH THE NEW FINANCIAL REPORTING SYSTEM.
1998 10	3,376	Estimates revised to reflect actual site assessments completed, and balance of deferred equipment purchase requirements.
1999 10	3,869	Scope unchanged.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION
95 - M5	Oil spill containment in Corporate Facilities.

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item ___ Domestic Item

354

Title
AC SUB-STATION OIL CONTAINMENT - CENTRAL AREA

Budget reference number
03-00-6110

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Operating & Maintenance	Design	Construction	70024

DESCRIPTION:
IMPLEMENT NECESSARY OIL CONTAINMENT SYSTEMS AT EACH STATION. ALL STATIONS WILL BE ASSESSED AND CONTAINMENT INSTALLED WHERE REQUIRED.

JUSTIFICATION:
EACH STATION REQUIRES AN ASSESSMENT AND IMPLEMENTATION OF NECESSARY OIL CONTAINMENT SYSTEMS FOR ENVIRONMENTAL PROTECTION IN THE EVENT OF AN OIL SPILL, AS WELL AS MEETING FEDERAL AND PROVINCIAL LEGISLATION AND MANITOBA HYDRO GUIDELINES.

REFERENCE:
OIL SPILL CONTAINMENT WORKING GROUP REPORT 95-M5 ON OIL SPILL CONTAINMENT IN CORPORATE FACILITIES.

REVISION:
REFLECTS REVISED ACTIVITY AND OVERHEAD RATES.

CONTINGENCY: $10 000.

IN SERVICE DATES

2002 10 31 885

Base estimate
199807 L2

Work start date
1995 10 01

PREV AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date	54		12			66
1999/00	-4		5			1
2000/01	156	8	11			175
2001/02	187	12	29			228
2002/03	187	16	26			229
2003/04	57	6				63
TOTAL	637	42	83			762
REV. AMOUNTS.						
Authorized to date	54		12			66-
Over(under)expend:						
Auth 1999/00	2	-1	6			7
Req.: 2000/01	184	7	13			204
2001/02	221	13	33			267
2002/03	221	18	30			269
2003/04	65	7				72
TOTAL	747	44	94			885

Prepared by: yy mm dd COORDINATOR — Approved by: yy mm dd — Approved by: yy mm dd

Estimated by: ORIGINATOR — COORDINATING MANAGER — ORIGINATING MANAGER

1999-08-21 05:21 PM

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number: 03-00-6110

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1995 10	906	NEW ITEM
1996 10	793	REDUCED ESTIMATE AND DELAYED CONTINUATION OF WORK TO 2000, TO ASSIST IN REDUCING FORECAST TO ACHIEVE 98/99 CAPITAL TARGET.
1997 10	776	CHANGED TITLE WORDING. ESTIMATE REFLECTS REVISED COSTING METHODOLOGY IMPLEMENTED WITH THE NEW FINANCIAL REPORTING SYSTEM. ALSO, REFLECTS REVISED INTEREST AND ESCALATION RATES.
1998 10	762	ESTIMATE REVISED TO REFLECT ACTUAL SITE ASSESSMENTS COMPLETED.

ASSOCIATED PROJECTS

Budget reference number	Description
03-00-6111	AC SUB-STATION OIL CONTAINMENT - WESTERN AREA
03-00-6112	AC SUB-STATION OIL CONTAINMENT - EASTERN AREA
03-00-6113	AC SUB-STATION OIL CONTAINMENT - NORTHERN AREA
05-00-6566	MICROWAVE AND VHF SITES OIL SPILL CONTAINMENT
08-00-6585	THOMPSON SERVICE CENTRE OIL SPILL CONTAINMENT
09-00-7697	OPERATIONS AND MAINTENANCE SPILL RESPONSE EQUIPMENT

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr		1				1	1
May		1				1	2
Jun		1				1	3
Jul		1				1	4
Aug		1				1	5
Sep		1				1	6
Oct		1				1	7
Nov		1				1	8
Dec		1				1	9
Jan		1				1	10
Feb		1				1	11
Mar	2	-12	6			-4	7
TOTAL	2	-1	6			7	7
2000/01 Apr			1			1	1
May			1			1	2
Jun	18	1	1			20	22
Jul	18	1	1			20	42
Aug	18	1	1			20	62
Sep	18	1	1			20	82
Oct	18	1	1			20	102
Nov	18	1	1			20	122
Dec	18	2	1			21	143
Jan	18	1	2			21	164
Feb	18	1	2			21	185
Mar	22	-3				19	204
TOTAL	184	7	13			204	204

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item ___ Domestic Item 355

Title
AC SUB-STATION OIL CONTAINMENT - WESTERN AREA

Budget reference number
03-00-6111

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Operating & Maintenance	Design	Construction	70025

DESCRIPTION:
IMPLEMENT NECESSARY OIL CONTAINMENT SYSTEMS AT EACH STATION. ALL STATIONS WILL BE ASSESSED AND CONTAINMENT INSTALLED WHERE REQUIRED.

JUSTIFICATION:
EACH STATION REQUIRES AN ASSESSMENT AND IMPLEMENTATION OF NECESSARY OIL CONTAINMENT SYSTEMS FOR ENVIRONMENTAL PROTECTION IN THE EVENT OF AN OIL SPILL, AS WELL AS MEETING FEDERAL AND PROVINCIAL LEGISLATION AND MANITOBA HYDRO GUIDELINES.

REFERENCE:
OIL SPILL CONTAINMENT WORKING GROUP REPORT 95-M5 ON OIL SPILL CONTAINMENT IN CORPORATE FACILITIES.

REVISION:
REFLECTS REVISED ACTIVITY AND OVERHEAD RATES.

CONTINGENCY: $11 000

IN SERVICE DATES		Base estimate
2002 10 31	1 042	199807 L2
		Work start date
		1995 10 01

PREV AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:	59		13			72
1999/00	-3		6			3
2000/01	184	9	13			206
2001/02	221	14	34			269
2002/03	221	20	30			271
2003/04	66	7				73
TOTAL	748	50	96			894
REV. AMOUNTS:						
Authorized to date:	59		13			72
Over(under)expend:						
Auth 1999/00	2	1	6			9
Req. 2000/01	218	10	14			242
2001/02	262	15	39			316
2002/03	262	21	36			319
2003/04	76	8				84
TOTAL	879	55	108			1 042

Prepared by: yy mm dd COORDINATOR — Approved by: yy mm dd — Approved by: yy mm dd

Estimated by: ORIGINATOR — COORDINATING MANAGER — ORIGINATING MANAGER

1999-08-21 05:21 PM

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number: 03-00-6111

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1995 10	978	NEW ITEM.
1996 10	852	REDUCED ESTIMATE AND DELAYED CONTINUATION OF WORK TO 2000, TO ASSIST IN REDUCING FORECAST TO ACHIEVE 98/99 CAPITAL TARGET.
1997 10	833	CHANGED TITLE WORDING. ESTIMATE REFLECTS REVISED COSTING METHODOLOGY IMPLEMENTED WITH THE NEW FINANCIAL REPORTING SYSTEM. ALSO, REFLECTS REVISED INTEREST AND ESCALATION RATES.
1998 10	894	ESTIMATE REVISED TO REFLECT ACTUAL SITE ASSESSMENTS COMPLETED.

ASSOCIATED PROJECTS

Budget reference number	Description
03-00-6110	AC SUB-STATION OIL CONTAINMENT - CENTRAL AREA
03-00-6112	AC SUB-STATION OIL CONTAINMENT - EASTERN AREA
03-00-6113	AC SUB-STATION OIL CONTAINMENT - NORTHERN AREA
05-00-6566	MICROWAVE AND VHF SITES OIL SPILL CONTAINMENT
08-00-6585	THOMPSON SERVICE CENTRE OIL SPILL CONTAINMENT
09-00-7697	OPERATIONS AND MAINTENANCE SPILL RESPONSE EQUIPMENT

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr		1				1	1
May			1			1	2
Jun			1			1	3
Jul			1			1	4
Aug			1			1	5
Sep			1			1	6
Oct			1			1	7
Nov			1			1	8
Dec			1			1	9
Jan			1			1	10
Feb			1			1	11
Mar	2		-4			-2	9
TOTAL	2	1	6			9	9
2000/01 Apr			1			1	1
May			1			1	2
Jun	22		1			23	25
Jul	22		1			23	48
Aug	22	1	1			24	72
Sep	22	1	1			24	96
Oct	22	1	1			24	120
Nov	22	1	1			24	144
Dec	22		2			24	168
Jan	22		2			24	192
Feb	22	1	2			25	217
Mar	20	5				25	242
TOTAL	218	10	14			242	242

1999-08-21 05:21 PM

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item

356

Title: AC SUB-STATION OIL CONTAINMENT - EASTERN AREA

Budget reference number: 03-00-6112

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
erating & Maintenance	Design	Construction	70026

DESCRIPTION:
IMPLEMENT NECESSARY OIL CONTAINMENT SYSTEMS AT EACH STATION. ALL STATIONS WILL BE ASSESSED AND CONTAINMENT INSTALLED WHERE INSTALLED.

JUSTIFICATION:
EACH STATION REQUIRES AN ASSESSMENT AND IMPLEMENTATION OF NECESSARY OIL CONTAINMENT SYSTEMS FOR ENVIRONMENTAL PROTECTION IN THE EVENT OF AN OIL SPILL, AS WELL AS MEETING FEDERAL AND PROVINCIAL LEGISLATION AND MANITOBA HYDRO GUIDELINES.

REFERENCE:
OIL SPILL CONTAINMENT WORKING GROUP REPORT 95-M5 ON OIL SPILL CONTAINMENT IN CORPORATE FACILITIES.

REVISION:
REFLECTS REVISED ACTIVITY AND OVERHEAD RATES.

CONTINGENCY: $11 000

IN SERVICE DATES: 2002 10 31 — 1 078

Base estimate: 199807 L2

Work start date: 1995 10 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date	79		19			98
1999/00	-2		8			6
2000/01	185	8	16			209
2001/02	221	14	37			272
2002/03	221	19	32			272
2003/04	67	6				73
TOTAL	771	47	112			930
REV. AMOUNTS:						
Authorized to date:	79		19			98
Over(under)expend:						
Auth 1999/00	3	-1	9			11
Req 2000/01	218	10	17			245
2001/02	262	16	41			319
2002/03	262	22	37			321
2003/04	77	7				84
TOTAL	901	54	123			1 078

Prepared by: yy mm dd — COORDINATOR — Approved by: yy mm dd — COORDINATING MANAGER — Approved by: yy mm dd — ORIGINATING MANAGER

Estimated by: ORIGINATOR

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 03-00-6112

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1995 10	994	NEW ITEM.
1996 10	877	REDUCED E STIMATE AND DELAYED CONTINUATION OF WORK TO 2000, TO ASSIST IN REDUCING FORECAST TO ACHIEVE 98/99 CAPITAL TARGET.
1997 10	885	CHANGED TITLE WORDING. ESTIMATE REFLECTS REVISED COSTING METHODOLOGY IMPLEMENTED WITH THE NEW FINANCIAL REPORTING SYSTEM. ALSO, REFLECTS REVISED INTEREST AND ESCALATION RATES.
1998 10	931	ESTIMATE REVISED TO REFLECT ACTUAL SITE ASSESSMENTS COMPLETED.

ASSOCIATED PROJECTS

Budget reference number	Description
03-00-6110	AC SUB-STATION OIL CONTAINMENT - CENTRAL AREA
03-00-6111	AC SUB-STATION OIL CONTAINMENT - WESTERN AREA
03-00-6113	AC SUB-STATION OIL CONTAINMENT - NORTHERN AREA
05-00-6566	MICROWAVE AND VHF SITES OIL SPILL CONTAINMENT
08-00-6585	THOMPSON SERVICE CENTRE OIL SPILL CONTAINMENT
09-00-7697	OPERATIONS AND MAINTENANCE SPILL RESPONSE EQUIPMENT

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr			1			1	1
May			1			1	2
Jun			1			1	3
Jul			1			1	4
Aug			1			1	5
Sep			1			1	6
Oct			1			1	7
Nov			1			1	8
Dec			1			1	9
Jan			1			1	10
Feb			1			1	11
Mar	3	-1	-2				11
TOTAL	3	-1	9			11	11
2000/01 Apr			1			1	1
May			1			1	2
Jun	22		1			23	25
Jul	22	1	1			24	49
Aug	22	1	1			24	73
Sep	22	1	1			24	97
Oct	22	1	1			24	121
Nov	22		2			24	145
Dec	22	1	2			25	170
Jan	22	1	2			25	195
Feb	22	1	2			25	220
Mar	20	3	2			25	245
TOTAL	218	10	17			245	245

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item

357

Title
AC SUB-STATION OIL CONTAINMENT - NORTHERN AREA

Budget reference number
03-00-6113

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Operating & Maintenance	Design	Construction	70027

DESCRIPTION:
IMPLEMENT NECESSARY OIL CONTAINMENT SYSTEMS AT EACH STATION. ALL STATIONS WILL BE ASSESSED AND CONTAINMENT INSTALLED WHERE REQUIRED.

JUSTIFICATION:
EACH STATION REQUIRES AN ASSESSMENT AND IMPLEMENTATION OF NECESSARY OIL CONTAINMENT SYSTEMS FOR ENVIRONMENTAL PROTECTION IN THE EVENT OF AN OIL SPILL, AS WELL AS MEETING FEDERAL AND PROVINCIAL LEGISLATION AND MANITOBA HYDRO GUIDELINES.

REFERENCE:
OIL SPILL CONTAINMENT WORKING GROUP REPORT 95-M5 ON OIL SPILL CONTAINMENT IN CORPORATE FACILITIES.

REVISION:
REFLECTS REVISED ACTIVITY AND OVERHEAD RATES.

CONTINGENCY: $5 000

IN SERVICE DATES

2002 10 31 — 336

Base estimate
199807 L2

Work start date
1995 10 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date	26		6			32
1999/00	-1	-1	3			1
2000/01	57	2	5			64
2001/02	68	4	12			84
2002/03	68	6	10			84
2003/04	23	2				25
TOTAL	241	13	36			290
REV. AMOUNTS:						
Authorized to date	26		6			32-
Over(under)expend.						
Auth 1999/00	1		3			4
Req. 2000/01	67	2	6			75
2001/02	80	5	13			98
2002/03	80	7	12			99
2003/04	26	2				28
TOTAL	280	16	40			336

Prepared by — yy mm dd — COORDINATOR — Approved by — yy mm dd — Approved by — yy mm dd

Estimated by — ORIGINATOR — COORDINATING MANAGER — ORIGINATING MANAGER

1999-08-21 05:21 PM

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 03-00-6113

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1995 10	492	NEW ITEM.
1996 10	433	REDUCED ESTIMATE AND DELAYED CONTINUATION OF WORK TO 2000, TO ASSIST IN REDUCING FORECAST TO ACHIEVE 98/99 CAPITAL FORECAST.
1997 10	428	CHANGED TITLE WORDING. ESTIMATE REFLECTS REVISED COSTING METHODOLOGY IMPLEMENTED WITH THE NEW FINANCIAL REPORTING SYSTEM. ALSO, REFLECTS REVISED INTEREST AND ESCALATION RATES.
1998 10	291	ESTIMATE REVISED TO REFLECT ACTUAL SITE ASSESSMENTS COMPLETED.

ASSOCIATED PROJECTS

Budget reference number	Description
03-00-6110	AC SUB-STATION OIL CONTAINMENT - CENTRAL AREA
03-00-6111	AC SUB-STATION OIL CONTAINMENT - WESTERN AREA
03-00-6112	AC SUB-STATION OIL CONTAINMENT - EASTERN AREA
05-00-6566	MICROWAVE AND VHF SITES OIL SPILL CONTAINMENT
08-00-6585	THOMPSON SERVICE CENTRE OIL SPILL CONTAINMENT
09-00-7697	OPERATIONS AND MAINTENANCE SPILL RESPONSE EQUIPMENT

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar	1		3			4	4
TOTAL	1		3			4	4
2000/01 Apr							
May							
Jun	7					7	7
Jul	7					7	14
Aug	7					7	21
Sep	7					7	28
Oct	7					7	35
Nov	7	-1	1			7	42
Dec	7		1			8	50
Jan	7		1			8	58
Feb	7		1			8	66
Mar	4	3	2			9	75
TOTAL	67	2	6			75	75

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — 358 Domestic Item

Title
MICROWAVE AND VHF SITES OIL SPILL CONTAINMENT

Budget reference number
05-00-6566

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Operating & Maintenance	Power Planning & Operations	Construction	70374

DESCRIPTION:
DESIGN AND INSTALL APPROPRIATE OIL SPILL CONTAINMENT FACITILITES AT THE 47 MICROWAVE AND VHF SITES. FOR THOSE SITES WITH INDOOR STORAGE TANKS, IT IS RECOMMENDED THAT CONTAINMENT CURBING BE INSTALLED, WOODEN FLOORS BE UPGRADED, AND CONCRETE FLOORS BE SEALED. FOR THOSE SITES WITH OUTDOOR STORAGE TANKS, IT IS RECOMMENDED THE TANKS BE UPGRADED TO ABOVE GROUND REGULATION DOUBLE WALLED TANKS.

JUSTIFICATION:
EACH OF THESE SITES HAS A SMALL STANDBY GENERATOR WHICH OPERATES IN THE EVENT OF A POWER OUTAGE AND TYPICALLY HAS TWO FUEL TANKS LOCATED EITHER INSIDE OR OUTSIDE OF THE BUILDING. THE CONCERN IS FAILURE OF THE FUEL STORAGE TANKS AND RELEASE OF FUEL INTO THE BUILDING AND/OR INTO THE ENVIRONMENT.

REFERENCE:
OIL SPILL CONTAINMENT WORKING GROUP REPORT 95 -M5 'OIL SPILL CONTAINMENT IN CORPORATE FACILITIES'

REVISION:
REFLECTS REVISED ACTIVITY AND OVERHEAD RATES.

IN SERVICE DATES		Base estimate
2002 03 31	266	199704 L1
		Work start date 2000 04 01

PREV AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:						
2000/01	35	3	2			40
2001/02	195	23	12			230
TOTAL	230	26	14			270
REV. AMOUNTS:						
Authorized to date:						
Over(under)expend:						
Auth 2000/01	35	3	1			39
Req 2001/02	195	20	12			227
TOTAL	230	23	13			266

Prepared by: yy mm dd COORDINATOR — Approved by: yy mm dd Approved by: yy mm dd

Estimated by: ORIGINATOR — COORDINATING MANAGER — ORIGINATING MANAGER

1999-08-21 05:29 PM

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number: 05-00-6566

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1995 10	251	NEW ITEM.
1996 10	245	CASH FLOW AND ISD REVISED TO DELAY START OF WORK BY 3 YEARS AS APPROVED BY OSCWG TO REDUCE FORECAST TO ASSIST IN ACHIEVING 98/99 CAPITAL TARGET.
1997 10	269	ORIGINAL ESTIMATE ADJUSTED FOR SAP INPUT AND REVISED ACTIVITY RATES AND OVERHEADS.
1998 10	270	NO CHANGE

ASSOCIATED PROJECTS

Budget reference number	Description
03-00-6110	AC SUB-STATION OIL CONTAINMENT - CENTRAL AREA
03-00-6111	AC SUB-STATION OIL CONTAINMENT - WESTERN AREA
03-00-6112	AC SUB-STATION OIL CONTAINMENT - EASTERN AREA
03-00-6113	AC SUB-STATION OIL CONTAINMENT - NORTHERN AREA
08-00-6585	THOMPSON SERVICE CENTRE OIL SPILL CONTAINMENT
09-00-7697	OPERATIONS AND MAINTENANCE SPILL RESPONSE EQUIPMENT

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr	3					3	3
May	3					3	6
Jun	3					3	9
Jul	3					3	12
Aug	3					3	15
Sep	3					3	18
Oct	3					3	21
Nov	3					3	24
Dec	3					3	27
Jan	3					3	30
Feb	3					3	33
Mar	2	3	1			6	39
TOTAL	35	3	1			39	39

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — 359 Domestic Item

Title
THOMPSON SERVICE CENTRE OIL SPILL CONTAINMENT

Budget reference number
08-00-6585

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Operating & Maintenance	Design	Construction	70375

DESCRIPTION:
DESIGN AND INSTALL APPROPRIATE OIL SPILL CONTAINMENT AT THE THOMPSON SERVICE CENTRE BY REPLACING THE JET B FUEL TANKS WITH DOUBLE WALLED TANKS.

JUSTIFICATION:
OIL SPILL CONTAINMENT SYSTEMS FOR ENVIRONMENTAL PROTECTION REQUIRED TO COMPLY WITH MANITOBA REGULATION 97/88R 'GASOLINE AND ASSOCIATED PRODUCTS REGULATION'.

REFERENCE:
JULY 1995 REPORT 95-M5 'OIL SPILL CONTAINMENT WORKING GROUP REPORT ON OIL SPILL CONTAINMENT IN CORPORATE FACILITIES'.

REVISION:
ITEM COMPLETED.

IN SERVICE DATES			Base estimate
1997 03 31	70		199604 L5
			Work start date
			1996 08 01

	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
PREV. AUTHORITY Authorized to date:	70					70
TOTAL	70					70
REV. AMOUNTS: Authorized to date:	70					70
Over(under)expend:						
Auth Req.:						
TOTAL	70					70

Prepared by (yy mm dd) COORDINATOR	Approved by (yy mm dd) COORDINATING MANAGER	Approved by (yy mm dd) ORIGINATING MANAGER
Estimated by ORIGINATOR		

1999-08-21 05:30 PM

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 08-00-6585

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1995 10	81	NEW ITEM
1996 10	78	ADVANCED INTO 1996/1997 AS RECOMMENDED BY OSCWG DUE TO BEING IN NON-COMPLIANCE WITH REGULATION.
1997 10	70	ITEM COMPLETED.
1998 10	70	ITEM COMPLETE.

ASSOCIATED PROJECTS

Budget reference number	Description
03-00-6110	AC SUB-STATION OIL CONTAINMENT - CENTRAL AREA
03-00-6111	AC SUB-STATION OIL CONTAINMENT - WESTERN AREA
03-00-6112	AC SUB-STATION OIL CONTAINMENT - EASTERN AREA
03-00-6113	AC SUB-STATION OIL CONTAINMENT - NORTHERN AREA
05-00-6566	MICROWAVE AND VHF SITES OIL SPILL CONTAINMENT
09-00-7697	OPERATIONS AND MAINTENANCE SPILL RESPONSE EQUIPMENT

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — 360 Domestic Item

Title
OPERATIONS AND MAINTENANCE SPILL RESPONSE EQUIPMENT

Budget reference number
09-00-7697

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Operating & Maintenance	Operating & Maintenance	Operating & Maintenance	70251:94207

DESCRIPTION:
PURCHASE SPILL RESPONSE EQUIPMENT FOR THE OPERATIONS AND MAINTENANCE DIVISION IN ORDER TO MEET CORPORATE SPILL RESPONSE OBJECTIVES.

JUSTIFICATION:
THE CORPORATE OIL SPILL CONTAINMENT WORKING GROUP'S TERMS OF REFERENCE INCLUDED THE DEVELOPMENT OF EMERGENCY RESPONSE PROCEDURES AND EQUIPMENT PROCUREMENT, STAFFING AND TRAINING. THIS PUTS IN PLACE THE CORPORATE INITIATIVE TO PROVIDE SPILL RESPONSE EQUIPMENT AT VARIOUS FACILITIES.

REFERENCE:
OIL SPILL CONTAINMENT WORKING GROUP REPORT 95-M5 DATED 1996 01 30. OSC PROGRAM 6(C) SUB-COMMITTEE REPORT 96 E/M-01 DATED 1996 08 07.

REVISION:
REVISED TO ALLOW THE COMPLETION OF NECESSARY EQUIPMENT PURCHASES.

CONTINGENCY AMOUNT: $0

IN SERVICE DATES

1999 05 31	192		

Base estimate
199902 L4

Work start date
1997 04 01

	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
PREV. AUTHORITY						
Authorized to date	132		13			145
1999/00	12					12
TOTAL	144		13			157
REV. AMOUNTS						
Authorized to date	132		13			145
Over(under)expend:						
Auth Req.: 1999/00	47					47
TOTAL	179		13			192

Prepared by: yy mm dd COORDINATOR

Estimated by: ORIGINATOR

Approved by: yy mm dd COORDINATING MANAGER

Approved by: yy mm dd ORIGINATING MANAGER

1999-08-21 05:30 PM

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number: 09-00-7697

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1996 10	84	NEW ITEM
1998 10	178	REVISED TO ALLOW THE COMPLETION OF NECESSARY EQUIPMENT PURCHASES.

ASSOCIATED PROJECTS

Budget reference number	Description
03-00-6110	AC SUB-STATION OIL CONTAINMENT - CENTRAL AREA
03-00-6111	AC SUB-STATION OIL CONTAINMENT - WESTERN AREA
03-00-6112	AC SUB-STATION OIL CONTAINMENT - EASTERN AREA
03-00-6113	AC SUB-STATION OIL CONTAINMENT - NORTHERN AREA
05-00-6566	MICROWAVE AND VHF SITES OIL SPILL CONTAINMENT
08-00-6585	THOMPSON SERVICE CENTRE OIL SPILL CONTAINMENT

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	23					23	23
May	24					24	47
Jun							47
Jul							47
Aug							47
Sep							47
Oct							47
Nov							47
Dec							47
Jan							47
Feb							47
Mar							47
TOTAL	47					47	47
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

1999-08-21 05:30 PM

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

COMPLEX STATUS: ☐ Planned ☒ In progress

Complex no. 131 - 139

REVISION STATUS: ☐ New complex ☐ In service change ☒ Concept change ☐ Estimate change only

COMPLEX: DOMESTIC ITEM - TRANSMISSION & DISTRIBUTION

Proposal

This complex consists of several hundred projects which are not identified as Major Items and whose individual cost is of a relatively small amount. The majority of projects are required to extend sub-transmission, distribution and transformation facilities to supply service to residential, farm, commercial and industrial customers and to replace plant facilities whose useful life has been exceeded.

JUSTIFICATION: ☒ Load ☒ Service ☒ Safety ☒ Efficiency ☒ Reliability ☒ Other

Explanation

The system has incurred consistant expenditures in the past which are required to meet the load growth into the foredeeable future. The residential, farm, commercial and industrial loads are expected to grow at an 20 year average rate of 1.5% per annum and will require a program of additions to the System to accommodate these anticipated loads.

Estimate Level	COMPLEX START (yyyy mm)
L2	1996 04

IN SERVICE DATES AND AMOUNTS

1999 03 31	$74482	2000 03 31	$77560	2001 03 31	$78856	2002 03 31	$81652
2003 03 31	$83726	2004 03 31	$86027	2005 03 31	$88303	2006 03 31	$90580
2007 03 31	$92885	2008 03 31	$95198	2009 03 31	$97603	2010 03 31	$100092

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend						74,482	-74,482	-100
Year 99/00	89,187	310	3,043	14,984	77,556	77,560	-4	-0
00/01	89,966	1076	3,077	18,363	75,756	78,856	-3,100	-4
01/02	91,900	2321	3,134	18,803	78,552	81,652	-3,100	-4
02/03	93,110	3554	3,134	19,172	80,626	83,726	-3,100	-4
03/04	89,133	7055	1,713	14,175	83,726	86,027	-2,301	-3
04/05	89,837	8759	1,761	14,330	86,027	88,303	-2,276	-3
05/06	90,424	10508	1,829	14,458	88,303	90,580	-2,277	-3
06/07	90,953	12304	1,897	14,574	90,580	92,885	-2,305	-2
07/08	91,476	14153	1,946	14,690	92,885	95,198	-2,313	-2
08/09	91,925	16045	2,016	14,788	95,198	97,603	-2,405	-2
09/10	92,389	17992	2,112	14,890	97,603	100,092	-2,489	-2
10/11	92,901	20005	2,189	15,003	100,092	102,746	-2,654	-3
11/12	93,493	22093	2,293	15,133	102,746	105,352	-2,606	-2
12/13	93,996	24223	2,376	15,243	105,352	108,078	-2,726	-3
13/14	94,531	26422	2,486	15,361	108,078	110,760	-2,682	-2
14/15	95,009	28668	2,549	15,466	110,760	113,572	-2,812	-2
15/16	95,570	31002	2,589	15,589	113,572	116,517	-2,945	-3
16/17	96,165	33414	2,658	15,720	116,517	119,574	-3,057	-3
17/18	96,771	35901	2,755	15,853	119,574	122,718	-3,144	-3
18/19	97,409	38473	2,829	15,993	122,718		122,718	
Beyond								
TOTAL	1,856,145	354,278	48,386	312,588	1,946,221	1,946,281	-60	-0

REVISION: Reflects forecast costs for the Transmission & Distribution Group.

Reviewed by ORIGINATOR	yyyy mm dd 99 11 08	Reviewed by COORDINATOR	yyyy mm dd 99 11 03		
Reviewed by CONSTRUCTOR	yyyy mm dd 99 11 03	Approved by VICE-PRESIDENT	yyyy mm dd 99 11 16		

H2856/r Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Complex no.
131 - 139

Advance or deferral impact

Requirements are necessary to meet capacity and energy demands, in accordance with our system design criteria and/or commitments.

Factors affecting timing or viability

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE	
					Amount	%
TOTAL						

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
9510	2,681,204	Reflects reduced load growth.
9610	1,721,964	This item reflects forecast costs attributable to the Transmission & Distribution Group.
1997 10	1,635,878	REFLECTS TRANSMISSION AND DISTRIBUTION'S REVISED SHARE OF THE DOMESTIC FORECAST BASED ON CURRENT RATES.
1998 10	1,946,281	Annual forecast adjusted to reflect the revised costing methodology impacts based on experience to date.
1999 10	1,946,221	Reflects forecast costs for the Transmission & Distribution Group.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

Manitoba Hydro

Capital Forecast

Volume 1 of 2
Power Supply
Customer Service
Corporate Group

CEF 99-1
1999/00 – 2018/19

October 1999

CAPITAL EXPENDITURE FORECAST (CEF99-1)
(IN MILLIONS OF DOLLARS)
FOR THE YEARS 1999/00 TO 2018/19

		Total	Prev	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	20 year Forecast
POWER SUPPLY																								
	FUTURE ENERGY SUPPLY																							
24	WUSKWATIM GENERATING STATION	632.5														24.1	11.7	76.0	158.3	182.5	179.9			632.5
264	CONAWAPA GENERATING STATION	2,695.6												45.1	49.9	131.1	151.7	246.4	346.2	393.8	390.1	436.4	359.5	2,560.3
	HVDC FACILITIES																							
223	HVDC BIPOLE RELIABILITY ENHANCEMENTS	32.3	16.4	10.9	5.0																			15.9
88	BIPOLE I CONVERTER TRANSFORMERS	4.9	4.9																					
11	BIPOLE I MERCURY ARC VALVES STAGE 3	151.0				1.0	3.8	43.5	60.5	41.6	0.7													151.0
5	HVDC BIPOLE 2 THYRISTOR POLY PIPE REPLACEMENTS	5.5	3.4	1.4	0.8																			2.2
54	CONVERTER TRANSFORMER BUSHING REPLACEMENT	6.4	4.0	0.4	1.3	0.6	0.1																	2.4
203	DORSEY BIPOLE 1 SYNCH CONDENSER BREAKER REPLACEMENT	7.0	0.6	1.5	0.4	2.3	2.2																	6.4
216	BIPOLE 1 DC FILTER CAPACITOR REPLACEMENT	5.0	0.2	0.8	1.7	2.0	0.3																	4.7
213	S.E.R. REPLACEMENT	2.0	1.3	0.7																				0.7
214	BIPOLE 1 VALVE HALL WALL BUSHING REPLACEMENT	9.1	2.0	4.9	2.0	0.2																		7.1
249	DORSEY BRINE EFFLUENT DISPOSAL STUDY AND IMPROVEMENT	0.8	0.8																					
258	BIPOLE 1 &2 ELECTRODE LINE MONITORING	1.4				0.2	1.2																	1.4
259	HVDC SWITCHGEAR ARCPROOF/SAFETY UPGRADES (PHASE 1)	1.1			0.4	0.5	0.1																	1.1
260	HVDC AUXILIARY POWER SUPPLY UPGRADES	1.8			0.5	0.5	0.4	0.4																1.8
272	DORSEY SYNCHRONOUS CONDENSER REFURBISHMENT	7.3			1.1	1.3	1.3	1.3	1.2	1.2														7.3
	HYDRAULIC REHABILITATION																							
3	GREAT FALLS G.S. REHABILITATION	23.6	0.1	0.3	2.7	10.6	7.4	2.5																23.5
52	SEVEN SISTERS G.S. REHABILITATION	19.5	18.0	1.5																				1.5
32	PINE FALLS G.S. REHABILITATION	18.1	2.8	0.8	0.8	1.5	7.1	5.0	0.1															15.3
33	McARTHUR G.S. REHABILITATION	11.9	11.1	0.8																				0.8
1	LAURIE RIVER PLANT 1 AND 2 REHABILITATION	16.1	9.3	0.5	2.2		0.1	0.5	0.5						1.2	0.9	0.9							6.9
48	GRAND RAPIDS G.S. REHABILITATION	100.7	75.7	5.4	13.8	5.8																		25.0
25	JENPEG G.S. UNIT OVERHAULS (UNITS 1 - 6)	29.0	6.7	2.2	0.7	3.7	3.7	3.6	0.3	3.8	0.3	3.9												22.3
22	KETTLE & LONG SPRUCE G.S. STATOR REWEDGING	7.1	5.8	1.0	0.3																			1.3
82	PRODUCTION NORTH DAM SAFETY UPGRADES	14.8	3.3	2.1	1.7	2.2	2.2	2.3	1.1															11.6
26	WINNIPEG RIVER CONTROL SYSTEM	13.5	2.4	2.6	2.0	5.6	0.9																	11.1
234	LIMESTONE OUTSTANDING WORK	17.9	11.5	1.7	2.8	0.6	0.6	0.6																6.4
243	WINNIPEG RIVER RIVERBANK PROTECTION PROGRAM	8.3	2.0	0.8	0.7	0.7	0.8	0.8	0.8	0.8	0.8													6.2
246	KETTLE GS - STATOR REWIND	33.8			0.2	0.9	2.5	2.5	2.6	2.6	2.6	2.7	2.7	2.8	2.8	2.9	2.9	3.0						33.8
252	KELSEY G.S. GATE REHABILITATION	3.5				0.6		0.7		0.7		0.7		0.8										3.5
256	KETTLE ANNUNCIATION SYSTEM RENEWAL	1.5			1.0	0.5																		1.5
	THERMAL REHABILITATION																							
38	THERMAL G.S. ASSURANCE	134.1	129.2	4.0	0.9																			4.9
226	BRANDON G.S. UNIT 5 LCENSE RENEWAL	23.3						2.1	0.9	5.8	0.9	1.7	1.0	2.7	1.5	0.9	2.1	0.5	1.2	0.5	0.5	0.5	0.7	23.3
220	BRANDON G.S. SWITCHYARD JETAIRE BREAKER REPLACEMENT	3.6	2.2	1.4																				1.4
	OTHER																							
224	200MW ONTARIO HYDRO SALE - SYNC COND CONVERSION	7.7	4.2	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.5													3.5
227	SITE REMEDIATION OF CONTAMINATED CORPORATE FACILITIES	12.9	0.9	0.8	0.8	0.8	0.8	0.9	0.9	0.9	0.9	0.9	1.0	1.0	1.0	1.0	0.3							12.0
225	OIL CONTAINMENT	15.6	8.2	0.3	0.6	2.3	1.0	1.6	1.6															7.4
228	FIRE PROTECTION PROJECTS	6.7	2.6	0.5	3.1	0.6																		4.1
13	POWER SUPPLY BUILDINGS	35.4	19.1	5.7	2.3	2.8	3.6	1.8																16.2
990	PLANNING STUDY COSTS			16.1	16.5	3.1	2.7	0.9	2.8	2.8	9.7	9.1	18.9	(14.4)	2.8	(15.0)	2.6	2.6	2.8	2.8	2.9	3.0	3.0	75.7
	DOMESTIC ITEMS - POWER SUPPLY			10.0	10.2	10.5	10.7	11.0	11.2	11.5	11.7	12.0	12.2	12.5	12.8	13.1	13.4	13.7	14.0	14.3	14.6	14.9	15.3	249.5
	SUB-TOTAL POWER SUPPLY			79.4	77.1	61.8	54.0	82.3	84.9	72.1	28.1	30.9	35.8	50.4	72.0	159.0	185.6	342.2	522.5	593.9	588.1	454.8	378.5	3,953.2

CAPITAL EXPENDITU[illegible]AST (CEF99-1)
(IN MILLIONS O[illegible]LARS)
FOR THE YEARS 1999/00 TO 2018/19

		Total	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	20 year Forecast
TRANSMISSION AND DISTRIBUTION																							
	TRANSMISSION FOR GENERATION																						
58	WUSKWATIM TRANSMISSION	66.5												1.1	1.2	2.7	2.6	8.2	25.8	25.1			66.5
263	HVDC CONVERSION BIPOLE 3/CONAWAPA TRANSMISSION	1,896.2										2.6	9.2	15.3	15.8	41.5	55.3	215.8	412.4	509.3	372.7	186.7	1,836.6
	INTERCONNECTIONS																						
79	MANITOBA > MINNESOTA 500kV TRANSMISSION UPGRADE (MMTU)																						
95	200MW ONTARIO HYDRO SALE - T/L UPGRADE	0.8	0.8																				0.8
268	HARVEY-GLENBORO 230KV LINE	16.0		1.6	6.4	8.0																	16.0
	TRANSMISSION																						
87	KETTLE AC TRANSMISSION IMPROVEMENTS	10.6	0.1	0.0	0.2	1.0	4.3	5.0															10.6
16	NORTH CENTRAL MANITOBA PROJECT	0.8	0.0	0.3	0.4																		0.8
30	THOMPSON>HERBLET LAKE 230kV TRANSMISSION	57.1			0.2	0.2	0.8	5.4	21.5	14.1	14.9												57.1
40	FLIN FLON - CLIFF LAKE TRANSFORMER REPLACEMENT	1.5	0.6	0.9																			1.5
47	HERBLET LAKE > THE PAS 230kV TRANSMISSION	55.3				0.2	0.5	1.0	0.3	1.1	3.4	16.4	19.0	6.7									48.5
57	DORSEY > NEEPAWA > CORNWALLIS 230kV LINE	18.5	16.8	1.7																			18.5
60	WINNIPEG > BRANDON 230kV TRANSMISSION	73.0			0.1	3.0	4.8	7.4	13.7	18.7	15.1	10.3											73.0
45	FT GARRY - PERIMETER SOUTH BANK REPLACEMENT	4.4			0.4	2.5	1.5																4.4
84	RIDGEWAY TRANSFORMER ADDITION	9.2					0.3	0.6	0.8	4.1	3.4												9.2
78	RIDGEWAY > ST. VITAL 230kV TRANSMISSION	1.7	1.7																				1.7
64	ST. VITAL TRANSFORMER ADDITION	9.0	0.3	3.6	4.0	1.0																	9.0
42	DORSEY-ROSSER 230kV TRANSMISSION IMPROVEMENTS	1.8	0.0	1.4	0.4																		1.8
27	DORSEY > ST. VITAL 230kV AC TRANSMISSION	7.7	0.0	1.3	5.3	1.1	0.0																7.7
96	DORSEY > LAVERENDRYE > ST. VITAL 230kV TRANSMISSION	25.9														1.7	3.5	10.7	10.0				25.9
21	ROSSER > SILVER 230kV TRANSMISSION	27.6	3.6	0.4	0.5	3.3	9.9	10.0															27.6
9	RAVEN LAKE > BIRTLE 230kV TRANSMISSION																						
94	BRANDON 115kV LOOP																						
39	RAVEN LAKE STATION 230-66kV TRANSFORMATION	8.3																0.6	1.5	3.0	3.3		8.3
98	VERMILION STATION STATIC VAR GENERATOR																						
18	NEEPAWA 230 -115kV STN	17.5					0.1	1.0	7.4	9.1													17.5
201	ASSINIBOINE - WILKES AVE 115-24 KV BANK 1 ADDITION	7.2	7.1	0.1																			7.2
202	ROSSER > MCPHILLIPS 115kV TRANSMISSION IMPROVEMENTS	2.4	0.0	0.1	0.4	1.8																	2.4
204	RICHER SOUTH 230-66kV TRANSFORMER ADDITION	4.9				0.4	0.4	2.3	1.8														4.9
205	PINE FALLS > BLOODVEIN 115kV TRANSMISSION LINE	29.1								0.2	0.2	1.0	1.7	7.0	15.6	3.4							29.1
207	ST. VITAL > STEINBACH 230kV TRANSMISSION	22.3						0.3	0.3	0.6	3.3	4.2	13.6										22.3
208	RIDGEWAY > SELKIRK 230kV TRANSMISSION	25.1				0.6	2.0	3.3	4.5	7.0	7.6												25.1
210	SOURIS > PEMBINA VALLEY 230kV TRANSMISSION	32.6								0.6	0.9	1.4	1.6	12.0	16.1								32.6
4	WINNIPEG AREA TRANSMISSION REFURBISHMENT	4.0	1.1	0.6	0.4	0.8	1.1	0.0															4.0
28	DORSEY STATION 230kV BREAKER REPLACEMENT	1.6	1.6																				1.6
43	DORSEY > US BORDER D602F 500KV AC T/L INSULATOR REPL.	2.7	1.2	0.5	0.4	0.6																	2.7
7	BIPOLE 1 & 2 LINE SPACER DAMPERS REPLACEMENT	5.1	0.7	2.5	1.9	0.0																	5.1
247	DORSEY 230kV BUS ENHANCEMENTS	16.0	0.4	0.9	3.2	7.0	4.6																16.0
251	FLIN FLON AREA TRANSMISSION IMPROVEMENTS	17.3	0.3	2.0	5.2	1.6	5.2	2.9															17.3
257	PINE FALLS-GREAT FALLS 115-66kV SUPPLY	9.4		0.9	2.7	3.4	1.2	1.1															9.4
	SUBTRANSMISSION																						
55	JENPEG > NORWAY HOUSE 66 kV SUB TRANSMISSION LINE	12.5	0.0	0.0	0.3	0.9	4.9	6.3															12.5
53	RUTTAN > SOUTH INDIAN LAKE 66 kV LINE	5.5	0.3	0.3	0.3	1.6	3.0																5.5
17	CENTRAL SUPPLY > PIKWITONEI & THICKET PORTAGE	0.7	0.0	0.7																			0.7
206	PINEY > SPRAGUE 66kV LINE	1.7	1.7	0.0																			1.7
209	BIRTLE SOUTH > ROSSBURN 66kV LINE	5.4				0.1	0.2	3.6	1.5														5.4
237	ST. BONIFACE-PLESSIS ROAD 115-25KV STATION	16.4	7.8	8.3	0.3																		16.4
238	ROSSER - OAK POINT 115-24KV STATION	18.5			0.0	0.7	2.0	10.1	5.7														18.5
239	ROSSER - OAK POINT BANK 2 ADDITION	9.8										0.8	6.2	2.7									9.8
240	ST. BONIFACE - PLESSIS ROAD BANK 2 ADDITION	4.9	0.1	1.6	3.2																		4.9
241	NEEPAWA 66KV SYSTEM	3.4			0.2	3.3																	3.4
242	RESTON/GLENBORO CAPACITY INCREASE	4.9	0.5	2.8	1.6																		4.9
80	ST. LEON 230-66KV TRANSF. ADD'N AND IPL EXPANSION	8.9	0.2	0.9	1.6	5.0	0.7	0.5															8.9
253	BRANDON EAST 115kV IMPROVEMENTS	1.0	1.0																				1.0
250	BRANDON CROCUS PLAINS 115-24kV BANK ADDITION	7.2		0.1	0.6	3.9	2.3	0.4															7.2
	DISTRIBUTION																						
86	DIESEL UPGRADING ENHANCEMENT	10.3	2.1	1.7	4.4	2.0																	10.3
221	VIRDEN AREA DISTRIBUTION CHANGES	10.0	4.2	1.3	1.6	0.9	1.0	1.0															10.0
217	DEFECTIVE RINJ CABLE REPLACEMENT	7.8	0.8	1.2	1.8	1.9	2.1																7.8
261	BRERETON LAKE STATION AREA	6.6		2.6	2.2	0.7	0.5	0.5	0.1														6.6
267	PAINT LAKE NEW FEEDER	1.6			1.8	(0.2)																	1.6
	COMMUNICATIONS, CONTROLS AND INFO TECHNOLOGY																						
10	EMS SCADA	2.1	2.1																				2.1
12	MICROWAVE RADIO REPLACEMENTS	48.1	9.0	3.3	9.6	8.1		1.6	16.5														48.1
218	LAN NETWORK EXPANSION																						
219	MAPINFO IMPLEMENTATION	10.7	4.4	4.3	2.0																		10.7
	OTHER																						
2	SITE REMEDIATION	5.5	1.3	2.2	0.9	1.1																	5.5
81	OIL CONTAINMENT	3.4	0.1	0.8	1.2	1.0	0.3																3.4
92	FIRE PROTECTION PROJECTS																						

CAPITAL EXPENDIT[illegible]AST (CEF99-1)
(IN MILLIONS [illegible]LARS)
FOR THE YEARS 1999/00 TO 2018/19

	Total	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	20 year Forecast
DOMESTIC ITEMS - TRANMISSION AND DISTRIBUTION		77.6	75.8	78.6	80.6	86.0	88.3	90.6	92.9	95.2	97.6	100.1	102.7	105.4	108.1	110.8	113.6	116.5	119.6	122.7	125.8	1,988.3
SUB-TOTAL TRANSMISSION AND DISTRIBUTION		**149.5**	**126.6**	**144.5**	**148.0**	**139.7**	**152.6**	**164.7**	**148.3**	**143.8**	**134.2**	**151.4**	**147.5**	**154.1**	**157.4**	**172.1**	**348.8**	**566.1**	**657.0**	**498.7**	**312.5**	**4,617.7**

CAPITAL EXPENDI[illegible]ECAST (CEF99-1)
(IN MILLION[illegible]OLLARS)
FOR THE YEARS 1999/00 TO 2018/19

		Total	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	20 year Forecast
CUSTOMER SERVICE																							
991	DEMAND SIDE MANAGEMENT CAPITAL COSTS		8.2	10.1	10.4	9.2	9.3	7.2	7.3	7.2	7.4	7.5	5.3	5.4	5.5	5.6	5.7	5.8	5.7	5.8	5.9	6.0	140.7
97	AUTOMATIC METER READING IMPLEMENTATION	30.5		0.1	2.1	3.2	3.3	3.1	3.4	3.5	3.5	6.2	2.3										30.5
	DOMESTIC ITEMS - CUSTOMER SERVICE		33.7	30.3	31.3	32.5	35.0	36.1	37.1	38.1	39.1	40.2	41.3	42.5	43.7	44.9	46.1	47.4	48.8	50.2	51.6	52.9	823.0
	SUB-TOTAL CUSTOMER SERVICE		**41.9**	**40.5**	**43.8**	**44.9**	**47.6**	**46.3**	**47.8**	**48.8**	**50.1**	**54.0**	**49.0**	**47.9**	**49.2**	**50.5**	**51.8**	**53.2**	**54.4**	**56.0**	**57.5**	**58.9**	**994.2**

CAPITAL EXPENDITU[illegible]CAST (CEF99-1)
(IN MILLIONS [illegible]LLARS)
FOR THE YEARS 1999/00 TO 2018/19

		Total	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	20 year Forecast
CORPORATE GROUP																							
230	FIRE PROTECTION PROJECTS	1.0	0.7	0.3																			1.0
231	CORPORATE BUILDING PROGRAM	17.2	0.0				15.1	2.1															17.2
244	YEAR 2000 CONVERSION	8.8	6.8	2.0																			8.8
245	NEW CUSTOMER SERVICE SYSTEM	8.0			0.3	2.6	5.1																7.9
	DOMESTIC ITEMS - CORPORATE GROUP		23.0	23.6	22.2	24.8	25.7	26.2	26.8	27.3	27.9	28.4	29.0	29.6	30.2	30.8	31.5	32.1	32.8	33.4	34.1	35.0	574.4
	SUB-TOTAL CORPORATE GROUP		**30.5**	**25.9**	**22.6**	**27.3**	**45.9**	**28.3**	**26.8**	**27.3**	**27.9**	**28.4**	**29.0**	**29.6**	**30.2**	**30.8**	**31.5**	**32.1**	**32.8**	**33.4**	**34.1**	**35.0**	**609.3**
	TOTAL CAPITAL EXPENDITURES		**301.3**	**270.0**	**272.7**	**274.3**	**315.4**	**312.0**	**311.3**	**252.6**	**252.7**	**252.5**	**279.8**	**297.1**	**392.6**	**424.3**	**597.5**	**956.7**	**1,247.2**	**1,334.4**	**1,045.1**	**784.9**	**10,174.4**

CAPITAL EXPENDITURE FORECAST REVISIONS (CEF99-1)
(IN MILLIONS OF DOLLARS)
FOR THE YEARS 1999/00 TO 2018/19

		2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	20 year Forecast
POWER SUPPLY																						
	FUTURE ENERGY SUPPLY																					
24	WUSKWATIM GENERATING STATION											(31.0)	(24.8)	(30.4)	(159.9)	(118.2)	(30.2)	182.5	179.9			(32.1)
264	CONAWAPA GENERATING STATION											45.1	49.9	131.1	151.7	246.4	346.2	393.8	390.1	436.4	359.5	2,550.3
	HVDC FACILITIES																					
223	HVDC BIPOLE RELIABILITY ENHANCEMENTS	(4.2)	(4.1)	(2.1)																		(10.4)
88	BIPOLE 1 CONVERTER TRANSFORMERS	(1.6)																				(1.6)
11	BIPOLE 1 MERCURY ARC VALVES STAGE 3			0.0	0.1	0.7	1.0	0.7	0.0													2.5
5	HVDC BIPOLE 2 THYRISTOR POLY PIPE REPLACEMENTS	(0.8)	0.1																			(0.7)
54	CONVERTER TRANSFORMER BUSHING REPLACEMENT	(0.9)	0.7	0.4	0.1																	0.3
203	DORSEY BIPOLE 1 SYNCH CONDENSER BREAKER REPLACEMENT	0.2	(1.0)	(0.2)	(0.4)																	(1.3)
216	BIPOLE 1 DC FILTER CAPACITOR REPLACEMENT	0.1	0.7	1.0	0.3																	2.1
213	S.E.R. REPLACEMENT	0.7																				0.7
214	BIPOLE 1 VALVE HALL WALL BUSHING REPLACEMENT	1.8	(2.0)	0.2																		0.1
249	DORSEY BRINE EFFLUENT DISPOSAL STUDY AND IMPROVEMENT																					
258	BIPOLE 1 &2 ELECTRODE LINE MONITORING			0.2	1.2																	1.4
259	HVDC SWITCHGEAR ARCPROOF/SAFETY UPGRADES (PHASE 1 & 2)		0.4	0.5	0.1																	1.1
260	HVDC AUXILIARY POWER SUPPLY UPGRADES		0.5	0.5	0.4	0.4																1.8
272	DORSEY SYNCHRONOUS CONDENSER REFURBISHMENT		1.1	1.3	1.3	1.3	1.2	1.2														7.3
	HYDRAULIC REHABILITATION																					
3	GREAT FALLS G.S. REHABILITATION	(0.6)	(6.7)	(0.5)	5.1	2.5																(0.1)
52	SEVEN SISTERS G.S. REHABILITATION	0.8																				0.8
32	PINE FALLS G.S. REHABILITATION	(2.3)	(6.2)	(3.5)	6.9	5.0	0.1															0.1
33	McARTHUR G.S. REHABILITATION	0.1																				0.1
1	LAURIE RIVER PLANT 1 AND 2 REHABILITATION	(0.0)	0.1		(0.0)	(0.0)	(0.0)						(0.0)	(0.0)	(0.0)							0.0
48	GRAND RAPIDS G.S. REHABILITATION	(10.9)	8.8	1.3	(4.6)	(3.6)	(2.4)															(11.5)
25	JENPEG G.S. UNIT OVERHAULS (UNITS 1 - 6)	(1.7)	(3.2)	0.6	3.7	0.3	0.3	0.3	0.3	0.3												0.9
22	KETTLE & LONG SPRUCE G.S. STATOR REWEDGING	0.1	0.0																			0.1
82	PRODUCTION NORTH DAM SAFETY UPGRADES	0.8	1.6	2.2	2.2	2.3	1.1															10.2
26	WINNIPEG RIVER CONTROL SYSTEM	0.7	(4.7)	4.0	0.5																	0.6
234	LIMESTONE OUTSTANDING WORK	(2.2)	2.4	0.0	0.0	0.0																0.2
243	WINNIPEG RIVER RIVERBANK PROTECTION PROGRAM	0.4	0.1	0.1	0.2	0.2	0.2	0.2	0.2													1.5
246	KETTLE GS - STATOR REWIND	(0.9)	(1.2)	(1.3)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.3)	(0.3)	(0.3)	1.0	3.0						(1.6)
252	KELSEY G.S. GATE REHABILITATION		(0.6)	0.6	(0.7)	0.7	(0.7)	0.7	(0.7)	0.7	(0.7)	0.8										0.1
256	KETTLE ANNUNCIATION SYSTEM RENEWAL		1.0	0.5																		1.5
	THERMAL REHABILITATION																					
38	THERMAL G.S. ASSURANCE	3.2	0.9																			4.2
226	BRANDON G.S. UNIT 5 LCENSE RENEWAL		(1.1)	(3.6)	(2.5)	0.9	(0.4)	(1.7)	(1.3)	(0.3)	(0.8)	2.7	1.5	0.9	2.1	0.5	1.2	0.5	0.5	0.5	0.7	0.1
220	BRANDON G.S. SWITCHYARD JETAIRE BREAKER REPLACEMENT	(0.6)																				(0.6)
	OTHER																					
224	200MW ONTARIO HYDRO SALE - SYNC COND CONVERSION	(0.7)	(0.1)	(0.1)	(0.1)	0.1	0.4	0.4	0.5													0.6
227	SITE REMEDIATION OF CONTAMINATED CORPORATE FACILITIES	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0							0.4
225	OIL CONTAINMENT	(0.3)	(1.6)	(2.6)	0.1	1.6	1.6															(1.1)
228	FIRE PROTECTION PROJECTS	0.1	0.7	0.6																		1.3
13	POWER SUPPLY BUILDINGS	(0.2)	(1.6)	(1.1)	1.4	1.8																0.3
990	PLANNING STUDY COSTS	0.0	14.5	0.8	0.4	(1.4)	0.5	(0.2)	3.7	3.0	10.7	0.5	0.5	(17.4)	0.1	(0.2)	(0.1)	2.5	0.5	0.3	0.3	19.0
	DOMESTIC ITEMS - POWER SUPPLY	(0.0)	0.0	0.0																		(0.0)
	SUB-TOTAL POWER SUPPLY	(19.0)	(0.1)	0.0	15.6	12.6	2.7	1.4	2.5	3.5	8.9	17.8	26.8	84.0	(5.0)	131.6	317.1	579.2	571.1	437.2	360.5	2,548.4

CAPITAL EXPENDITURE FORECAST REVISIONS (CEF99-1)
(IN MILLIONS OF DOLLARS)
FOR THE YEARS 2000 TO 2018/19

		2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	19	20 year Forecast
TRANSMISSION AND DISTRIBUTION																						
	TRANSMISSION FOR GENERATION																					
58	WUSKWATIM TRANSMISSION										(0.8)	(0.9)	(2.1)	(2.1)	(7.2)	(24.2)	(23.5)					(60.8)
263	HVDC CONVERSION BIPOLE 3/CONAWAPA TRANSMISSION										2.6	9.2	15.3	15.8	41.5	55.3	215.8	412.4	509.3	372.7	186.7	1,836.6
	INTERCONNECTIONS																					
79	MANITOBA > MINNESOTA 500kV TRANSMISSION UPGRADE (MMTU)																					
95	200MW ONTARIO HYDRO SALE - T/L UPGRADE	0.8																				0.8
268	HARVEY-GLENBORO 230KV LINE		1.6	6.4	8.0																	16.0
	TRANSMISSION																					
87	KETTLE AC TRANSMISSION IMPROVEMENTS	(1.5)	(2.4)	(2.3)	(1.8)	4.3	5.0															1.4
16	NORTH CENTRAL MANITOBA PROJECT	(0.7)	0.0	(0.1)	(0.0)																	(0.8)
30	THOMPSON>HERBLET LAKE 230kV TRANSMISSION	(0.2)	(0.3)	(0.2)	(0.2)	(4.3)	(15.6)	8.0	(0.2)	14.9												1.9
40	FLIN FLON - CLIFF LAKE TRANSFORMER REPLACEMENT	0.3	0.9																			1.2
47	HERBLET LAKE > THE PAS 230kV TRANSMISSION				0.0	0.0	0.1	0.0	0.1	0.1	0.1	0.3	0.2									1.0
57	DORSEY > NEEPAWA > CORNWALLIS 230kV LINE	1.1	(4.9)																			(3.8)
60	WINNIPEG > BRANDON 230kV TRANSMISSION		(0.1)	(0.2)	(3.2)	(1.7)	(5.1)	(4.1)	2.7	5.2	10.3											3.9
45	FT GARRY - PERIMETER SOUTH BANK REPLACEMENT		(0.4)	0.2	(1.4)	1.5																(0.1)
84	RIDGEWAY TRANSFORMER ADDITION					0.0	0.1	0.1	0.1	0.0												0.3
78	RIDGEWAY > ST. VITAL 230kV TRANSMISSION	0.8																				0.8
64	ST. VITAL TRANSFORMER ADDITION	(2.9)	0.9	3.6	(1.0)																	0.5
42	DORSEY-ROSSER 230kV TRANSMISSION IMPROVEMENTS	0.0	(0.1)	0.0																		(0.0)
27	DORSEY > ST. VITAL 230kV AC TRANSMISSION	(5.1)	(0.2)	4.9	1.1	0.0																0.7
96	DORSEY > LAVERENDRYE > ST. VITAL 230kV TRANSMISSION														0.1	0.2	0.0	0.0				0.3
21	ROSSER > SILVER 230kV TRANSMISSION	0.6	(3.6)	(10.7)	(4.2)	9.9	10.0															2.0
9	RAVEN LAKE > BIRTLE 230kV TRANSMISSION																					
94	BRANDON 115kV LOOP																					
39	RAVEN LAKE STATION 230-66kV TRANSFORMATION																0.1	0.1	0.1	0.0		0.2
98	VERMILION STATION STATIC VAR GENERATOR	(0.0)	(0.1)	(0.5)	(8.5)	(8.6)	(3.9)															(21.7)
18	NEEPAWA 230-115kV STN	(0.3)	(0.4)	(1.0)	(10.1)	(10.5)	1.0	7.4	9.1													(4.8)
201	ASSINIBOINE - WILKES AVE 115-24 KV BANK 1 ADDITION	1.3	(1.2)																			0.1
202	ROSSER > MCPHILLIPS 115kV TRANSMISSION IMPROVEMENTS	(0.1)	(0.3)	(1.3)	1.8																	0.2
204	RICHER SOUTH 230-66kV TRANSFORMER ADDITION				0.0	0.1	0.0	0.0														0.1
205	PINE FALLS > BLOODVEIN 115kV TRANSMISSION LINE	(0.1)	(0.1)	(0.8)	(1.4)	(5.3)	(13.9)	(3.0)	0.2	0.2	1.0	1.7	7.0	15.6	3.4							4.4
207	ST. VITAL > STEINBACH 230kV TRANSMISSION						0.0	0.0	0.1	0.1	0.2	0.1										0.6
208	RIDGEWAY > SELKIRK 230kV TRANSMISSION				0.1	0.1	0.1	0.2	0.1	0.1												0.6
210	SOURIS > PEMBINA VALLEY 230kV TRANSMISSION								0.0	0.0	0.1	0.1	0.2	0.3								0.7
4	WINNIPEG AREA TRANSMISSION REFURBISHMENT	0.4	(0.2)	(0.3)	0.1	0.2	0.0															0.3
28	DORSEY STATION 230kV BREAKER REPLACEMENT	0.6																				0.6
43	DORSEY > US BORDER D602F 500KV AC T/L INSULATOR REPLACEMENT	0.4	(0.3)	(0.5)	(0.6)																	(1.0)
7	BIPOLE 1 & 2 LINE SPACER DAMPERS REPLACEMENT	(3.0)	(1.2)	(1.6)	0.0																	(5.7)
247	DORSEY 230kV BUS ENHANCEMENTS	0.0	0.1	0.6	0.6	0.2																1.5
251	FLIN FLON AREA TRANSMISSION IMPROVEMENTS	0.3	2.0	5.2	1.6	5.2	2.9															17.3
257	PINE FALLS-GREAT FALLS 115-66kV SUPPLY		0.9	2.7	3.4	1.2	1.1															9.4
	SUBTRANSMISSION																					
55	JENPEG > NORWAY HOUSE 66 kV SUB TRANSMISSION LINE	(0.2)	(1.7)	(2.0)	(6.3)	4.9	6.3															1.1
53	RUTTAN > SOUTH INDIAN LAKE 66 kV LINE	0.2	(0.4)	(1.8)	(0.7)	3.0																0.3
17	CENTRAL SUPPLY > PIKWITONEI & THICKET PORTAGE	0.0	0.0																			0.1
206	PINEY > SPRAGUE 66kV LINE	0.5	0.0																			0.5
209	BIRTLE SOUTH > ROSSBURN 66kV LINE				0.0	0.0	(0.1)	(0.1)														(0.2)
237	SPRINGFIELD-ST. BONIFACE 115-25KV STATION	2.8	5.0	(6.7)																		1.1
238	ROSSER - OAK POINT 115-24KV STATION		(0.0)	(0.5)	(0.2)	(8.5)	4.2	5.7														0.6
239	ROSSER - OAK POINT BANK 2 ADDITION										0.1	(0.0)	(0.0)									0.0
240	SPRINGFIELD-ST. BONIFACE BANK 2 ADDITION	0.0	(0.0)	0.5																		0.5
241	NEEPAWA 66KV SYSTEM			(0.0)	(0.1)																	(0.1)
242	RESTON/GLENBORO CAPACITY INCREASE	0.1	0.0	0.0																		0.1
80	ST. LEON 230-66KV TRANSFORMER ADD'N AND IPL EXPANSION	0.3	0.2	0.3	0.0	0.1	(0.6)															0.3
253	BRANDON EAST 115kV IMPROVEMENTS	0.1																				0.1
250	BRANDON CROCUS PLAINS 115-24kV BANK ADDITION		0.0	0.0	0.3	0.1	(0.0)															0.3
	DISTRIBUTION																					
86	DIESEL UPGRADING ENHANCEMENT	(0.9)	0.6	4.2	(3.5)																	0.4
221	VIRDEN AREA DISTRIBUTION CHANGES	0.9	(0.0)	0.1	0.1	0.1	0.1															1.2
217	DEFECTIVE RINJ CABLE REPLACEMENT	(0.1)	(0.1)	(0.2)	(0.2)	(0.3)																(0.8)
261	BRERETON LAKE STATION AREA STUDY		2.6	2.2	0.7	0.5	0.5	0.1														6.6
267	PAINT LAKE NEW FEEDER			1.8	(0.2)																	1.6
	COMMUNICATIONS, CONTROLS AND INFO TECHNOLOGY																					
10	EMS SCADA	1.6																				1.6
12	MICROWAVE RADIO REPLACEMENTS	3.2	0.8	(3.3)	4.7		0.1	0.6														6.0
218	LAN NETWORK EXPANSION																					
219	MAPINFO IMPLEMENTATION	(0.3)	1.5	(0.4)																		0.9

CAPITAL EXPENDITURE FORECAST REVISIONS (CEF99-1)
(IN MILLIO[illegible]LLARS)
FOR THE YEA[illegible]TO 2018/19

		2000	2001	2002	2003	2004	2005		2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	[illegible]2019	20 year Forecast
	OTHER																					
2	SITE REMEDIATION	0.3	0.8	0.0	0.0																	
81	OIL CONTAINMENT	0.0	0.1	0.1	0.2	0.0																1.1
92	FIRE PROTECTION PROJECTS											1.0	2.0	3.0	4.0	5.0	6.0	7.0	8.0	9.0	10.0	0.5 55.0
	DOMESTIC ITEMS - TRANMISSION AND DISTRIBUTION	(0.0)	(3.2)	(3.1)	(3.1)								(0.0)						(0.0)			(9.4)
	SUB-TOTAL TRANSMISSION AND DISTRIBUTION	**1.0**	**(3.0)**	**(4.5)**	**(23.9)**	**(7.8)**	**(7.8)**	**14.9**	**12.1**	**20.6**	**13.4**	**11.6**	**22.7**	**32.6**	**41.7**	**36.3**	**198.4**	**419.5**	**517.4**	**381.7**	**196.7**	**1,873.7**

CAPITAL EXPENDITURE FORECAST REVISIONS (CEF99-1)
(IN MILLIONS OF DOLLARS)
FOR THE YEARS 2000/01 TO 2018/19

		2000	2001	2002	2003	2004	2005	20..	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	19	20 year Forecast
CUSTOMER SERVICE																						
991	DEMAND SIDE MANAGEMENT CAPITAL COSTS	(0.0)	2.1	2.2	1.0	2.0	1.6	1.8	1.7	1.8	2.0	0.8	0.6	0.8	0.8	0.8	0.9	1.0	1.0	1.0	1.1	25 0
97	AUTOMATIC METER READING IMPLEMENTATION		(1.5)	(0.9)	(0.1)	(0.0)	(0.0)	(0.1)	(0.0)	(0.1)	(0.1)	2.3										(0 6)
	DOMESTIC ITEMS - CUSTOMER SERVICE	0.1	(1.4)	(1.5)	(1.5)																	(4 4)
	SUB-TOTAL CUSTOMER SERVICE	0.1	(0.8)	(0.2)	(0.6)	1.9	1.6	1.7	1.6	1.6	1.9	3.1	0.6	0.8	0.8	0.8	0.9	1.0	1.0	1.0	1.1	20.0

CAPITAL EXPENDITURE FORECAST REVISIONS (CEF99-1)
(IN MILLIONS OF DOLLARS)
FOR THE YEARS 2000 TO 2018/19

		2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	20 year Forecast
CORPORATE GROUP																					
230	FIRE PROTECTION PROJECTS	(0.0)	(0.0)																		(0.0)
231	CORPORATE BUILDING PROGRAM	0.0				(0.1)	(0.0)														(0.1)
244	YEAR 2000 CONVERSION	0.0	(0.7)																		(0.7)
245	NEW CUSTOMER SERVICE SYSTEM			(0.0)	(0.0)	(0.0)															(0.1)
	DOMESTIC ITEMS - CORPORATE GROUP	5.1	(0.4)	(0.4)	(0.4)																3.9
	SUB-TOTAL CORPORATE GROUP	5.1	(1.1)	(0.4)	(0.4)	(0.2)	(0.0)														3.0
	TOTAL CAPITAL EXPENDITURES	**(12.7)**	**(5.0)**	**(5.1)**	**(9.3)**	**6.5**	**(3.5)**	**18.1**	**16.2**	**25.7**	**24.2**	**32.5**	**50.0**	**117.4**	**37.6**	**168.7**	**516.3**	**999.7**	**1,089.5**	**819.9**	**454.3**	**4,341.1**

FALL 1999 FORECAST

SECTIONS

SUMMARY

POWER SUPPLY

FUTURE ENERGY SUPPLY

HVDC FACILITIES

HYDRAULIC REHABILITATION

THERMAL REHABILITATION

OTHER

DOMESTIC ITEM - POWER SUPPLY

CUSTOMER SERVICE

MAJOR ITEMS

DOMESTIC ITEM - CUSTOMER SERVICE

CORPORATE GROUP

MAJOR ITEMS

DOMESTIC ITEM - CORPORATE GROUP

TRANSMISSION & DISTRIBUTION

TRANSMISSION FOR GENERATION

INTERCONNECTIONS - T & D

TRANSMISSION

SUBTRANSMISSION

DISTRIBUTION

COMMUNICATIONS, CONTROLS AND INFO TECHNOLOGY

OTHER

DOMESTIC ITEM - T & D

VOLUME 1

POWER SUPPLY CUSTOMER SERVICE CORPORATE GROUP

COMPLEX	BUDGET REFERENCE DESCRIPTION	BRN #	PAGE
	FUTURE ENERGY SUPPLY		
24	WUSKWATIM GENERATING STATION	01-27-6001	1
264	CONAWAPA GENERATING STATION	01-26-8124	2
	HVDC FACILITIES		
223	HVDC BIPOLE RELIABILITY ENHANCEMENTS		
	RADISSON STATION SST1 RELOCATION & SST2 & 3 CABLE REPL	03-00-6119	3
	DORSEY BIPOLE 1 SPARE CONVERTER TRANSFORMER 300kV	03-00-5901	4
	DORSEY BIPOLE 1 SPARE CONVERTER TRANSFORMER 450kV	03-00-6129	5
	RADISSON BIPOLE 1 SPARE CONVERTER TRANSFORMER 450kV	03-00-5902	6
	DORSEY BIPOLE 2 SPARE CONVERTER TRANSFORMERS 375kV & 500kV	03-00-5903	7
	HENDAY BIPOLE 2 SPARE CONVERTER TRANSFORMER 500kV	03-00-5904	8
	DORSEY BIPOLE 2 SPARE SMOOTHING REACTOR	03-00-5905	9
	HENDAY BIPOLE 2 SPARE SMOOTHING REACTOR	03-00-5906	10
	DORSEY BIPOLE 2 COOLING UPGRADE	03-00-5907	11
	HENDAY BIPOLE 2 COOLING UPGRADE	03-00-5908	12
	DORSEY BIPOLE 1 SPARE CONVERTER TRANSFORMER 300kV (SP # 3)	03-00-8369	13
	HENDAY BIPOLE 2 SPARE CONVERTER TRANSFORMER 500kV (SP # 2)	03-00-8370	14
88	BIPOLE 1 CONVERTER TRANSFORMERS		
	DORSEY T21A PHASE CONVERTER TF REPAIR	03-00-8294	15
	DORSEY T13A PHASE CONVERTER TF REPAIR	03-00-8302	16
	RADISSON STATION CONVERTER TRANSFORMER	03-00-1685	17
11	BIPOLE 1 MERCURY ARC VALVES STAGE 3		
	DORSEY STATION BPI MERCURY ARC VALVES STAGE 3	03-00-2334	18
	RADISSON STATION BPI MERCURY ARC VALVES STAGE 3	03-00-2335	19
5	HVDC BIPOLE 2 THYRISTOR POLY PIPE REPLACEMENTS		
	DORSEY BP 2 THYRISTOR MODULES POLYAMIDE TUBING REPLACEMENT	03-00-4804	20
	HENDAY BP 2 THYRISTOR MODULES POLYAMIDE TUBING REPLACEMENT	03-00-5827	21
54	CONVERTER TRANSFORMER BUSHING REPLACEMENT		
	DORSEY AC CONVERTER TRANSFORMER BUSHING REPLACEMENT	03-00-6126	22
	RADISSON/HENDAY AC CONVERTER TRANSFORMER BUSHING REPLACEMENT	03-00-6127	23
203	DORSEY BIPOLE 1 SYNCH CONDENSER BREAKER REPLACEMENT	03-00-6185	24
216	BIPOLE 1 & 2 DC FILTER CAPACITOR REPLACEMENT	03-00-7223	25
213	S.E.R. REPLACEMENT		
	DORSEY BIPOLE 1 S.E.R. REPLACEMENT	03-00-7217	26
	RADISSON BIPOLE 1 S.E.R. REPLACEMENT	03-00-7218	27
214	BIPOLE 1 VALVE HALL WALL BUSHING REPLACEMENT		

COMPLEX	BUDGET REFERENCE DESCRIPTION	BRN #	PAGE
	DORSEY BIPOLE 1 VALVE HALL WALL BUSHING REPLACEMENT	03-00-7219	28
	RADISSON BIPOLE 1 VALVE HALL WALL BUSHING REPLACEMENT	03-00-7220	29
249	DORSEY BRINE EFFLUENT DISPOSAL STUDY AND IMPROVEMENT	03-00-8300	30
258	BIPOLE 1 & 2 ELECTRODE LINE MONITORING	03-00-8396	31
259	HVDC SWITCHGEAR ARCPROOF/SAFETY UPGRADES	03-00-8398	32
260	HVDC AUXILIARY POWER SUPPLY UPGRADES	03-00-8395	33
272	DORSEY SYNCHRONOUS CONDENSER REFURBISHMENT	03-00-8376	34
	HYDRAULIC REHABILITATION		
3	GREAT FALLS G.S. REHABILITATION		
	GREAT FALLS G.S. DRAFT TUBE LINER & RUNNER REPL	01-01-8057	35
	GREAT FALLS G.S. INTAKE GATES	01-01-8069	36
52	SEVEN SISTERS G.S. REHABILITATION		
	SEVEN SISTERS G.S. ELECTRICAL/MECHANICAL SYSTEMS	01-02-6017	37
	SEVEN SISTERS G.S. UNIT #4 REHABILITATION	01-02-5924	38
	SEVEN SISTERS G.S. MAJOR CONCRETE REHABILITATION	01-02-5925	39
	SEVEN SISTERS G.S. CRANES & SPILLWAY ANCHORS	01-02-5926	40
32	PINE FALLS G.S. REHABILITATION		
	PINE FALLS G.S. ELECTRICAL/MECHANICAL SYSTEMS	01-03-8024	41
	PINE FALLS G.S. UNIT 1&2 GENERATOR REWIND & RERUNNERING	01-03-8058	42
33	McARTHUR G.S. REHABILITATION	01-04-8005	43
1	LAURIE RIVER PLANT 1 AND 2 REHABILITATION		
	LAURIE RIVER PLANT 1 & 2 PHASE 1	01-10-9006	44
	LAURIE RIVER PLANT 1 & 2 PHASE 2	01-10-2110	45
	LAURIE RIVER PLANT 1 & 2 PHASE 3	01-10-2111	46
48	GRAND RAPIDS G.S. REHABILITATION		
	GRAND RAPIDS G.S. REHABILITATION UNIT 1 OVERHAUL	01-08-3011	47
	GRAND RAPIDS G.S. REHABILITATION UNIT 2 OVERHAUL	01-08-3012	48
	GRAND RAPIDS G.S. REHABILITATION UNIT 3 OVERHAUL	01-08-3013	49
	GRAND RAPIDS G.S. REHABILITATION UNIT 4 OVERHAUL	01-08-1068	50
	GRAND RAPIDS G.S. UNIT #1 REPAIRS	01-08-3009	51
	GRAND RAPIDS GEN BREAKERS & SYNCH CONDENSOR CONVERSION	01-08-5931	52
25	JENPEG G.S. UNIT OVERHAULS	01-23-4905	53
22	KETTLE & LONG SPRUCE G.S. STATOR REWEDGING		
	LONG SPRUCE STATOR REWEDGING	01-21-5941	54
	KETTLE STATOR REWEDGING	01-20-5942	55
82	DAM SAFETY UPGRADES		
	GENERATION NORTH DAM SAFETY UPGRADES	01-70-6971	56
	GENERATION SOUTH DAM SAFETY UPGRADES	01-08-7041	57

COMPLEX	BUDGET REFERENCE DESCRIPTION	BRN #	PAGE
26	WINNIPEG RIVER CONTROL SYSTEM		
	WINNIPEG RIVER CONTROL SYSTEM COMPLEX GREAT FALLS G.S.	01-01-6959	58
	WINNIPEG RIVER CONTROL SYSTEM COMPLEX SEVEN SISTERS G.S.	01-02-6960	59
	WINNIPEG RIVER CONTROL SYSTEM COMPLEX PINE FALLS G.S.	01-03-6961	60
	WINNIPEG RIVER CONTROL SYSTEM COMPLEX MC ARTHUR FALLS G.S.	01-04-6962	61
234	LIMESTONE OUTSTANDING WORK		
	LIMESTONE G.S. OUTSTANDING WORK	01-25-7044	62
	LIMESTONE G.S. MODIFICATIONS	01-25-7045	63
	LIMESTONE CHANNEL IMPROVEMENTS	01-25-8068	64
243	WPG RIVER RIVERBANK PROTECTION PROGRAM		
	WPG RIVER RIVERBANK PROTECTION PROGRAM - PINE FALLS	01-03-8055	65
	WPG RIVER RIVERBANK PROTECTION PROGRAM - MCARTHUR FALLS	01-04-8056	66
246	KETTLE G.S. STATOR REWIND	01-20-7046	67
252	KELSEY GS GATE REHABILITATION	01-07-8084	68
256	KETTLE CAS SYSTEM UPGRADES	01-20-8107	69
	THERMAL REHABILITATION		
38	THERMAL G.S. ASSURANCE		
	BRANDON G.S. UNITS 1 - 5 LIFE ASSURANCE PHASE 3	01-16-8023	70
	SELKIRK G.S. UNITS 1 & 2 LIFE ASSURANCE PHASE 3	01-16-8051	71
226	BRANDON G.S. LICENCE RENEWAL	01-16-7008	72
220	BRANDON G.S. SWITCHYARD JETAIRE BREAKER REPLACEMENT	01-05-7012	73
	OTHER		
224	200MW ONTARIO HYDRO SALE - SYNC COND CONVERSION		
	SEVEN SISTERS GEN 1-6 SYNC COND. CONVERSION	01-02-5933	74
	SEVEN SISTERS 115kV BRKR & WALL BUSHING UPGRADE	01-02-8071	75
227	SITE REMEDIATION OF CONTAMINATED CORPORATE FACILITIES	08-00-6586	76
225	OIL CONTAINMENT		
	GENERATION SOUTH G.S. OIL SPILL CONTAINMENT	01-01-6969	77
	GENERATION NORTH G.S. OIL SPILL CONTAINMENT	01-20-5940	78
	DORSEY STATION OIL CONTAINMENT SYSTEM	03-00-4810	79
	HENDAY STATION OIL CONTAINMENT SYSTEM	03-00-5923	80
	RADISSON STATION OIL CONTAINMENT SYSTEM	03-00-5924	81
	GENERATION NORTH SPILL RESPONSE EQUIPMENT	09-00-7805	82
	GENERATION SOUTH SPILL RESPONSE EQUIPMENT	09-00-7806	83
228	FIRE PROTECTION PROJECTS		
	KETTLE G.S. FIRE ALARM SYSTEM	01-20-7009	84
	LONG SPRUCE G.S. FIRE ALARM SYSTEM	01-21-7010	85
	LIMESTONE G.S. FIRE ALARM SYSTEM	01-25-7011	86
	JENPEG FIRE PREVENTION & PROTECTION	01-23-8108	87

COMPLEX	BUDGET REFERENCE DESCRIPTION	BRN #	PAGE
	SEVEN SISTERS G.S. FIRE PREVENTION/PROTECTION SYSTEM	01-02-8117	88
	MCARTHUR FALLS G.S. FIRE PREVENTION/PROTECTION SYSTEM	01-04-8118	89
	GREAT FALLS G.S. FIRE PREVENTION/PROTECTION SYSTEM	01-01-8119	90
	PINE FALLS G.S. FIRE PREVENTION/PROTECTION SYSTEM	01-03-8120	91
	DORSEY BP 1 & 2 ADDRESSABLE FIRE ALARM SYSTEM	03-00-4809	92
	RADISSON STATION ADDRESSABLE FIRE ALARM SYSTEM	03-00-5925	93
	HENDAY STATION ADDRESSABLE FIRE ALARM SYSTEM	03-00-5926	94
	DORSEY BIPOLE 1 THYRISTOR VALVES FIRE PROTECTION UPGRADE	03-00-7221	95
	RADISSON BIPOLE 1 THYRISTOR VALVES FIRE PROTECTION UPGRADE	03-00-7222	96
13	POWER SUPPLY BUILDINGS		
	WINNIPEG RIVER OPERATING CENTER	01-01-5943	97
	GILLAM INFRASTRUCTURE UPGRADE	01-20-6970	98
	GRAND RAPIDS INFRASTRUCTURE UPGRADE	01-08-8091	99
	GILLAM PERMANENT HOUSING	08-00-6581	100
	GRAND RAPIDS G.S. STAFFHOUSE REPLACEMENT	08-00-8029	101
990	PLANNING STUDY COSTS	01-50-1001	102
121-129	**DOMESTIC ITEM - POWER SUPPLY**		

CUSTOMER SERVICE

MAJOR ITEMS

991	DEMAND SIDE MANAGEMENT CAPITAL COSTS	01-98-1088	103
97	AUTOMATIC METER READING IMPLEMENTATION	05-00-3016	104
141-149	**DOMESTIC ITEM - CUSTOMER SERVICE**		

CORPORATE GROUP

MAJOR ITEMS

230	FIRE PROTECTION PROJECTS		
	FIRE PREVENTION AND PROTECTION H.O.	08-00-5564	105
	FIRE PREVENTION AND PROTECTION WSC	08-00-5565	106
231	CORPORATE BUILDING PROGRAM		
	INTEGRATED TRADES TRAINING CENTRE PROPERTY AND BUILDING	08-00-5568	107
	REFURBISH 820 TAYLOR AVENUE BUILDING	08-00-7058	108
244	YEAR 2000 CONVERSION	09-00-8822	109
245	NEW CUSTOMER SERVICE SYSTEM	09-00-8821	110
111-119	**DOMESTIC ITEM - CORPORATE GROUP**		

** Volume 2 contains Transmission & Distribution items

CAPITAL EXPENDITURE FORECAST (CEF99-1)
(IN MILLIONS OF DOLLARS)
FOR THE YEARS 1999/00 TO 2018/19

		Total	Prev	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	20 year Forecast
POWER SUPPLY																								
	FUTURE ENERGY SUPPLY																							
24	WUSKWATIM GENERATING STATION	632.5														24.1	11.7	76.0	158.3	182.5	179.9			632.5
264	CONAWAPA GENERATING STATION	2,695.6												45.1	49.9	131.1	151.7	246.4	346.2	393.8	390.1	436.4	359.5	2,550.3
	HVDC FACILITIES																							
223	HVDC BIPOLE RELIABILITY ENHANCEMENTS	32.3	16.4	10.9	5.0																			15.9
88	BIPOLE 1 CONVERTER TRANSFORMERS	4.9	4.9																					
11	BIPOLE 1 MERCURY ARC VALVES STAGE 3	151.0				1.0	3.8	43.5	60.5	41.6	0.7													151.0
5	HVDC BIPOLE 2 THYRISTOR POLY PIPE REPLACEMENTS	5.5	3.4	1.4	0.8																			2.2
54	CONVERTER TRANSFORMER BUSHING REPLACEMENT	6.4	4.0	0.4	1.3	0.6	0.1																	2.4
203	DORSEY BIPOLE 1 SYNCH CONDENSER BREAKER REPLACEMENT	7.0	0.6	1.5	0.4	2.3	2.2																	6.4
216	BIPOLE 1 DC FILTER CAPACITOR REPLACEMENT	5.0	0.2	0.8	1.7	2.0	0.3																	4.7
213	S.E.R. REPLACEMENT	2.0	1.3	0.7																				0.7
214	BIPOLE 1 VALVE HALL WALL BUSHING REPLACEMENT	9.1	2.0	4.9	2.0	0.2																		7.1
249	DORSEY BRINE EFFLUENT DISPOSAL STUDY AND IMPROVEMENT	0.8	0.8																					
258	BIPOLE 1 &2 ELECTRODE LINE MONITORING	1.4				0.2	1.2																	1.4
259	HVDC SWITCHGEAR ARCPROOF/SAFETY UPGRADES (PHASE 1)	1.1			0.4	0.5	0.1																	1.1
260	HVDC AUXILIARY POWER SUPPLY UPGRADES	1.8			0.5	0.5	0.4	0.4																1.8
272	DORSEY SYNCHRONOUS CONDENSER REFURBISHMENT	7.3			1.1	1.3	1.3	1.3	1.2	1.2														7.3
	HYDRAULIC REHABILITATION																							
3	GREAT FALLS G.S. REHABILITATION	23.6	0.1	0.3	2.7	10.6	7.4	2.5																23.5
52	SEVEN SISTERS G.S. REHABILITATION	19.5	18.0	1.5																				1.5
32	PINE FALLS G.S. REHABILITATION	18.1	2.8	0.8	0.8	1.5	7.1	5.0	0.1															15.3
33	McARTHUR G.S. REHABILITATION	11.9	11.1	0.8																				0.8
1	LAURIE RIVER PLANT 1 AND 2 REHABILITATION	16.1	9.3	0.5	2.2		0.1	0.5	0.5						1.2	0.9	0.9							6.9
48	GRAND RAPIDS G.S. REHABILITATION	100.7	75.7	5.4	13.8	5.8																		25.0
25	JENPEG G.S. UNIT OVERHAULS (UNITS 1 - 6)	29.0	6.7	2.2	0.7	3.7	3.7	3.6	0.3	3.8	0.3	3.9												22.3
22	KETTLE & LONG SPRUCE G.S. STATOR REWEDGING	7.1	5.8	1.0	0.3																			1.3
82	PRODUCTION NORTH DAM SAFETY UPGRADES	14.8	3.3	2.1	1.7	2.2	2.2	2.3	1.1															11.6
26	WINNIPEG RIVER CONTROL SYSTEM	13.5	2.4	2.6	2.0	5.6	0.9																	11.1
234	LIMESTONE OUTSTANDING WORK	17.9	11.5	1.7	2.8	0.6	0.6	0.6																6.4
243	WINNIPEG RIVER RIVERBANK PROTECTION PROGRAM	8.3	2.0	0.8	0.7	0.7	0.8	0.8	0.8	0.8	0.8													6.2
246	KETTLE GS - STATOR REWIND	33.8			0.2	0.9	2.5	2.5	2.6	2.6	2.6	2.7	2.7	2.8	2.8	2.9	2.9	3.0						33.8
252	KELSEY G.S. GATE REHABILITATION	3.5				0.6		0.7		0.7		0.7		0.8										3.5
256	KETTLE ANNUNCIATION SYSTEM RENEWAL	1.5			1.0	0.5																		1.5
	THERMAL REHABILITATION																							
38	THERMAL G.S. ASSURANCE	134.1	129.2	4.0	0.9																			4.9
226	BRANDON G.S. UNIT 5 LCENSE RENEWAL	23.3						2.1	0.9	5.8	0.9	1.7	1.0	2.7	1.5	0.9	2.1	0.5	1.2	0.5	0.5	0.5	0.7	23.3
220	BRANDON G.S. SWITCHYARD JETAIRE BREAKER REPLACEMENT	3.6	2.2	1.4																				1.4
	OTHER																							
224	200MW ONTARIO HYDRO SALE - SYNC COND CONVERSION	7.7	4.2	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.5													3.5
227	SITE REMEDIATION OF CONTAMINATED CORPORATE FACILITIES	12.9	0.9	0.8	0.8	0.8	0.8	0.9	0.9	0.9	0.9	0.9	1.0	1.0	1.0	1.0	0.3							12.0
225	OIL CONTAINMENT	15.6	8.2	0.3	0.6	2.3	1.0	1.6	1.6															7.4
228	FIRE PROTECTION PROJECTS	6.7	2.6	0.5	1.1	0.6																		4.1
13	POWER SUPPLY BUILDINGS	35.4	19.1	5.7	2.3	2.8	3.6	1.8																16.2
990	PLANNING STUDY COSTS			16.1	16.5	3.1	2.7	0.9	2.8	2.8	9.7	9.1	18.9	(14.4)	2.8	(15.0)	2.6	2.6	2.8	2.8	2.9	3.0	3.0	75.7
	DOMESTIC ITEMS - POWER SUPPLY			10.0	10.2	10.5	10.7	11.0	11.2	11.5	11.7	12.0	12.2	12.5	12.8	13.1	13.4	13.7	14.0	14.3	14.6	14.9	15.3	249.5
	SUB-TOTAL POWER SUPPLY			79.4	77.1	61.8	54.0	82.3	84.9	72.1	28.1	30.9	35.8	50.4	72.0	159.0	185.6	342.2	522.5	593.9	588.1	454.8	378.5	3,953.2

CAPITAL EXPENDITURE FORECAST REVISIONS (CEF99-1)
(IN MILLIONS OF DOLLARS)
FOR THE YEARS 1999/00 TO 2018/19

		2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	20 year Forecast
POWER SUPPLY																						
	FUTURE ENERGY SUPPLY																					
24	WUSKWATIM GENERATING STATION											(31.0)	(24.8)	(30.4)	(159.9)	(118.2)	(30.2)	182.5	179.9			(32.1)
264	CONAWAPA GENERATING STATION											45.1	49.9	131.1	151.7	246.4	346.2	393.8	390.1	436.4	359.5	2,550.3
	HVDC FACILITIES																					
223	HVDC BIPOLE RELIABILITY ENHANCEMENTS	(4.2)	(4.1)	(2.1)																		(10.4)
88	BIPOLE 1 CONVERTER TRANSFORMERS	(1.6)																				(1.6)
11	BIPOLE 1 MERCURY ARC VALVES STAGE 3			0.0	0.1	0.7	1.0	0.7	0.0													2.5
5	HVDC BIPOLE 2 THYRISTOR POLY PIPE REPLACEMENTS	(0.8)	0.1																			(0.7)
54	CONVERTER TRANSFORMER BUSHING REPLACEMENT	(0.9)	0.7	0.4	0.1																	0.3
203	DORSEY BIPOLE 1 SYNCH CONDENSER BREAKER REPLACEMENT	0.2	(1.0)	(0.2)	(0.4)																	(1.3)
216	BIPOLE 1 DC FILTER CAPACITOR REPLACEMENT	0.1	0.7	1.0	0.3																	2.1
213	S.E.R. REPLACEMENT	0.7																				0.7
214	BIPOLE 1 VALVE HALL WALL BUSHING REPLACEMENT	1.8	(2.0)	0.2																		0.1
249	DORSEY BRINE EFFLUENT DISPOSAL STUDY AND IMPROVEMENT																					
258	BIPOLE 1 &2 ELECTRODE LINE MONITORING			0.2	1.2																	1.4
259	HVDC SWITCHGEAR ARCPROOF/SAFETY UPGRADES (PHASE 1 & 2)		0.4	0.5	0.1																	1.1
260	HVDC AUXILIARY POWER SUPPLY UPGRADES		0.5	0.5	0.4	0.4																1.8
272	DORSEY SYNCHRONOUS CONDENSER REFURBISHMENT		1.1	1.3	1.3	1.3	1.2	1.2														7.3
	HYDRAULIC REHABILITATION																					
3	GREAT FALLS G.S. REHABILITATION	(0.6)	(6.7)	(0.5)	5.1	2.5																(0.1)
52	SEVEN SISTERS G.S. REHABILITATION	0.8																				0.8
32	PINE FALLS G.S. REHABILITATION	(2.3)	(6.2)	(3.5)	6.9	5.0	0.1															0.1
33	McARTHUR G.S. REHABILITATION	0.1																				0.1
1	LAURIE RIVER PLANT 1 AND 2 REHABILITATION	(0.0)	0.1		(0.0)	(0.0)	(0.0)						(0.0)	(0.0)	(0.0)							0.0
48	GRAND RAPIDS G.S. REHABILITATION	(10.9)	8.8	1.3	(4.6)	(3.6)	(2.4)															(11.5)
25	JENPEG G.S. UNIT OVERHAULS (UNITS 1 - 6)	(1.7)	(3.2)	0.6	3.7	0.3	0.3	0.3	0.3	0.3												0.9
22	KETTLE & LONG SPRUCE G.S. STATOR REWEDGING	0.1	0.0																			0.1
82	PRODUCTION NORTH DAM SAFETY UPGRADES	0.8	1.6	2.2	2.2	2.3	1.1															10.2
26	WINNIPEG RIVER CONTROL SYSTEM	0.7	(4.7)	4.0	0.5																	0.6
234	LIMESTONE OUTSTANDING WORK	(2.2)	2.4	0.0	0.0	0.0																0.2
243	WINNIPEG RIVER RIVERBANK PROTECTION PROGRAM	0.4	0.1	0.1	0.2	0.2	0.2	0.2	0.2													1.5
246	KETTLE GS - STATOR REWIND	(0.9)	(1.2)	(1.3)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.3)	(0.3)	(0.3)	1.0	3.0						(1.6)
252	KELSEY G.S. GATE REHABILITATION		(0.6)	0.6	(0.7)	0.7	(0.7)	0.7	(0.7)	0.7	(0.7)	0.8										0.1
256	KETTLE ANNUNCIATION SYSTEM RENEWAL		1.0	0.5																		1.5
	THERMAL REHABILITATION																					
38	THERMAL G.S. ASSURANCE	3.2	0.9																			4.2
226	BRANDON G.S. UNIT 5 LCENSE RENEWAL		(1.1)	(3.6)	(2.5)	0.9	(0.4)	(1.7)	(1.3)	(0.3)	(0.8)	2.7	1.5	0.9	2.1	0.5	1.2	0.5	0.5	0.5	0.7	0.1
220	BRANDON G.S. SWITCHYARD JETAIRE BREAKER REPLACEMENT	(0.6)																				(0.6)
	OTHER																					
224	200MW ONTARIO HYDRO SALE - SYNC COND CONVERSION	(0.7)	(0.1)	(0.1)	(0.1)	0.1	0.4	0.4	0.5													0.6
227	SITE REMEDIATION OF CONTAMINATED CORPORATE FACILITIES	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0							0.4
225	OIL CONTAINMENT	(0.3)	(1.6)	(2.6)	0.1	1.6	1.6															(1.1)
228	FIRE PROTECTION PROJECTS	0.1	0.7	0.6																		1.3
13	POWER SUPPLY BUILDINGS	(0.2)	(1.6)	(1.1)	1.4	1.8																0.3
990	PLANNING STUDY COSTS	0.0	14.5	0.8	0.4	(1.4)	0.5	(0.2)	3.7	3.0	10.7	0.5	0.5	(17.4)	0.1	(0.2)	(0.1)	2.5	0.5	0.3	0.3	19.0
	DOMESTIC ITEMS - POWER SUPPLY	(0.0)	0.0	0.0																		(0.0)
	SUB-TOTAL POWER SUPPLY	**(19.0)**	**(0.1)**	**0.0**	**15.6**	**12.6**	**2.7**	**1.4**	**2.5**	**3.5**	**8.9**	**17.8**	**26.8**	**84.0**	**(5.0)**	**131.6**	**317.1**	**579.2**	**571.1**	**437.2**	**360.5**	**2,548.4**

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

COMPLEX STATUS: [X] Planned [ ] In progress

Complex no. 24

REVISION STATUS: [ ] New complex [X] In service change [X] Concept change [ ] Estimate change only

COMPLEX: WUSKWATIM GENERATING STATION

Proposal

Design and construct Wuskwatim Generating Station on the Burntwood River upstream of Thompson. This will include the complete installation of equipment for 3 generators with a total installed capacity of approximately 210 MW, in accordance with the following schedule:

Unit #1 - 2016 12 31 Unit #2 - 2017 01 31 Unit #3 - 2017 03 31

JUSTIFICATION

[X] Load [ ] Service
[ ] Safety [ ] Efficiency
[X] Reliability [ ] Other

Explanation

Based on the 1999 load forecast, the Power Resource Plan studies show that an additional dependable energy source will be required in 2016/17. According to current available information, Wuskwatim is the preferred choice.

Estimate Level	COMPLEX START (yyyy mm)
L2	2009 04

IN SERVICE DATES AND AMOUNTS					
2016 12	$210841	2017 01	$210841	2017 03	$210841

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend								
Year 99/00								
00/01								
01/02								
02/03								
03/04								
04/05								
05/06								
06/07								
07/08								
08/09								
09/10						30,986	-30,986	-100
10/11						24,806	-24,806	-100
11/12	21,275	1014	1,860		24,149	54,558	-30,409	-56
12/13	6,735	1996	2,922		11,653	171,537	-159,884	-93
13/14	52,386	16884	6,713		75,983	194,170	-118,187	-61
14/15	104,771	36538	17,036		158,345	188,541	-30,196	-16
15/16	108,513	40770	33,172		182,455		182,455	
16/17	97,287	39229	43,422		179,938		179,938	
17/18								
18/19								
Beyond								
TOTAL	390,967	136,431	105,125		632,523	664,598	-32,075	-5

REVISION: In service deferred from 2014/15 to 2016/17. Project capitalized upon receipt of regulatory approvals/Licence.

Reviewed by ORIGINATOR	yyyy mm dd 99 11 02	Reviewed by COORDINATOR	yyyy mm dd
Reviewed by CONSTRUCTOR	yyyy mm dd	Approved by VICE-PRESIDENT	yyyy mm dd 99 11 12

H2856/r Rev 99 03

Complex no. 24

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Advance or deferral impact

Required as a future source of generation; schedule provisional, subject to contiuing review and revision.

Factors affecting timing or viability

Manitoba Load Forecast
Diversity Agreements
Export Power Sales
Demand-side Management (DSM)
System Efficiency Improvements

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Wuskwatim Generating Station		419,445	427,834	390,967	-36,867	-9
TOTAL		419,445	427,834	390,967	-36,867	-9

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
9510	1,124,080	Reflects revised escalation and interest rates.
9610	1,344,618	In service date deferred from 2011 to 2015 and earlier capitalization of costs..
1997 10	723,551	In service date deferred from 2015 to 2016 and re-assessment of plant concept, cost and schedule.
1998 10	664,598	In service advanced from 2016/17 to 2014/15. Project capitalized upon receipt of regulatory approvals/Licence.
1999 10	632,523	In service deferred from 2014/15 to 2016/17. Project capitalized upon receipt of regulatory approvals/Licence. Reduction reflects amortization of study costs.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION
Complex 58	Wuskwatim Transmission

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item

Title	Budget reference number
WUSKWATIM GENERATING STATION	01-27-6001

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Power Planning & Operations	Power Planning & Operations	Construction	61501

DESCRIPTION:
DESIGN AND CONSTRUCT THE WUSKWATIM GENERATING STATION ON THE BURNTWOOD RIVER UPSTREAM OF THOMPSON. THIS WILL INCLUDE THE COMPLETE INSTALLATION OF EQUIPMENT FOR 3 GENERATORS WITH A TOTAL INSTALLED CAPACITY OF APPROXIMATELY 210 MW, IN ACCORDANCE WITH THE FOLLOWING IN SERVICE DATES: UNIT NO. 1 - 2016 12 31 UNIT NO. 2 - 2017 01 31 UNIT NO. 3 - 2017 03 31.

JUSTIFICATION:
BASED ON THE 1999 LOAD FORECAST, THE POWER RESOURCE PLAN STUDIES INDICATES THAT AN ADDITIONAL DEPENDABLE ENERGY SOURCE WILL BE REQUIRED IN 2016/17. ACCORDING TO CURRENT AVAILABLE INFORMATION, WUSKWATIM IS THE PREFERRED CHOICE.

NOTE: ESTIMATE INCLUDES AN UNAMORTIZED BALANCE OF PRELIMINARY PLANNING STUDIES ESTIMATED AT $17.4 MILLION.

99/09/01:
REFLECTS TRANSFER OF UNAMORTIZED PLANNING STUDY COSTS FROM BRN 01-50-1001 AS PER LIZ CARRIERE.

REVISION:
IN-SERVICE DATE DEFERRED FROM 2014/15 TO 2016/17.
PROJECT CAPITALIZED UPON RECEIPT OF REGULATORY APPROVALS/LICENCE.

IN SERVICE DATES		Base estimate
2016 12 31	210 841	199904 L2
2017 01 31	210 841	
2017 03 31	210 842	Work start date 2011 04 01

PREV. AUTHORITY Authorized to date:	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
2009/10	26 628	2 403	1 955			30 986
2010/11	16 383	4 584	3 839			24 806
2011/12	36 132	11 035	7 391			54 558
2012/13	115 617	38 329	17 591			171 537
2013/14	117 455	42 068	34 647			194 170
2014/15	107 230	41 317	39 994			188 541
TOTAL	419 445	139 736	105 417			664 598
REV. AMOUNTS: Authorized to date:						
Over(under)expend:						
Auth 2011/12	21 275	1 014	1 860			24 149
Req.: 2012/13	6 735	1 997	2 922			11 654
2013/14	52 386	16 883	6 713			75 982
2014/15	104 771	36 539	17 036			158 346
2015/16	108 513	40 770	33 172			182 455
2016/17	97 287	39 229	43 422			179 938
TOTAL	390 967	136 432	105 125			632 524

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

1999-09-28 10:54 AM

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 01-27-6001

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1984 12	1 131 577	NEW ITEM. IN-SERVICE DATE ADVANCED TO 1996 FROM 1999.
1985 11	1 100 624	IN-SERVICE DATE DEFERRED TO 1997 FROM 1996. REVISED TO REFLECT NEW ESCALATION AND INTEREST RATES.
1985 12	2 841 214	IN-SERVICE DATE DEFERRED TO 2012 FROM 1997.
1986 12	1 731 024	IN-SERVICE DATE ADVANCED TO 2009.
1987 12	2 088 251	IN-SERVICE DATE DEFERRED FROM 2009 TO 2012.
1988 11	2 256 909	IN-SERVICE DATE DEFERRED FROM 2012 TO 2014.
1989 10	1 999 046	IN-SERVICE DATE ADVANCED FROM 2014 TO 2012. ALSO REPRESENTS A GENERAL ESTIMATE REVIEW & UPDATE
1990 05	1 568 778	ISD ADVANCED FROM 2012 TO 2008 TO MEET ONTARIO HYDRO 1000 MWSALE OBLIGATIONS.
1991 10	1 870 735	IN-SERVICE DATE DEFERRED FROM 2008 TO 2013.
1992 10	1 378 015	IN-SERVICE DATE ADVANCED FROM 2013 TO 2010.
1993 02	1 328 964	IN-SERVICE DATE ADVANCED FROM 2010 TO 2009.
1993 10	1 216 813	IN-SERVICE DATE DEFERRED FROM 2009 TO 2010.
1994 10	1 128 357	IN-SERVICE DATE DEFERRED FROM 2010 TO 2011 BECAUSE OF INCREASED DSM PROJECTIONS.
1995 10	1 124 080	REVISED INTEREST & ESCALATION RATES.
1996 10	1 344 618	IN-SERVICE DATE DEFERRED FROM 2011 TO 2015 AND EARLIER CAPITALIZATION OF COSTS.
1997 10	723 552	IN-SERVICE DATE DEFERRED FROM 2015 TO 2016 AND RE-ASSESSMENT OF PLANT CONCEPT, COST & SCHEDULE.
1998 10	664 598	IN-SERVICE DATEADVANCED FROM 2016/17 TO 2014/15. RECEIPT OF REGULATORY APPROVALS/LICENCE.
1999 10	632 524	IN-SERVICE DATE DEFERRED FROM 2014/15 TO 2016/17. UPON RECEIPT OF REGULATORY APPROVALS/LICENCE.

ASSOCIATED PROJECTS

Budget reference number	Description

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

COMPLEX STATUS: [X] Planned [ ] In progress

Complex no. 264

REVISION STATUS: [X] New complex [ ] In service change [ ] Concept change [ ] Estimate change only

COMPLEX: CONAWAPA GENERATING STATION

Proposal

DESIGN AND CONSTRUCT THE CONAWAPA GENERATING STATION ON THE NELSON RIVER. THIS WILL INCLUDE THE COMPLETE INSTALLATION OF EQUIPMENT FOR 10 GENERATORS WITH A TOTAL INSTALLED CAPACITY OF APPROXIMATELY 1390MW, IN ACCORDANCE WITH THE FOLLOWING IN SERVICE DATES:

UNIT NO. 1	2018 05 31	UNIT NO. 6	2019 06 30
UNIT NO. 2	2018 07 31	UNIT NO. 7	2019 08 31
UNIT NO. 3	2018 10 31	UNIT NO. 8	2019 11 30
UNIT NO. 4	2018 12 31	UNIT NO. 9	2020 02 28
UNIT NO. 5	2019 03 31	UNIT NO. 10	2020 04 30

JUSTIFICATION: [X] Load [ ] Service [ ] Safety [ ] Efficiency [ ] Reliability [ ] Other

Explanation

BASED ON THE 1999 LOAD FORECAST, THE POWER RESOURCE PLAN STUDIES INDICATE THAT AN ADDITIONAL DEPENDABLE ENERGY SOURCE WILL REQUIRED IN 2018/19.

NOTE: THE CER INCLUDES AN UNAMORTIZED BALANCE OF PRELIMINARY PLANNING STUDIES ESTIMATED AT $23.4 MILLION (CURRENT DOLLARS).

Estimate Level	COMPLEX START (yyyy mm)
L2	1999 10

IN SERVICE DATES AND AMOUNTS

2018 05	$269557	2018 07	$269557	2018 10	$269557	2018 12	$269557
2019 03	$269557	2019 06	$269557	2019 08	$269557	2019 11	$269557
2020 02	$269557	2020 04	$269557				

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend								
Year 99/00								
00/01								
01/02								
02/03								
03/04								
04/05								
05/06								
06/07								
07/08								
08/09								
09/10	42,584	382	2,112		45,078		45,078	
10/11	43,605	1762	4,520		49,887		49,887	
11/12	114,402	7002	9,740		131,144		131,144	
12/13	118,399	9760	23,543		151,702		151,702	
13/14	188,869	19658	37,917		246,444		246,444	
14/15	253,540	31987	60,690		346,217		346,217	
15/16	259,715	38616	95,485		393,816		393,816	
16/17	215,193	36940	137,998		390,131		390,131	
17/18	213,702	41692	181,003		436,397		436,397	
18/19	158,008	34603	166,853		359,464		359,464	
Beyond	53,549	13245	78,497		145,291		145,291	
TOTAL	1,661,566	235,647	798,358		2,695,571		2,695,571	

REVISION: ITEM REINTRODUCED AFTER PREVIOUS DEFERRAL.

Reviewed by ORIGINATOR	yyyy mm dd 99 11 02	Reviewed by COORDINATOR	yyyy mm dd
Reviewed by CONSTRUCTOR	yyyy mm dd	Approved by VICE-PRESIDENT	yyyy mm dd 99 11 12

H2856/r Rev 99 03

Complex no. 264

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Advance or deferral impact

Deferral would jeopardize meeting load.

Factors affecting timing or viability

Timing; Regulatory/Licencing Approvals.
Changes in Manitoba load forecast or DSM target.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Conawapa Generating Station				1,661,566	1,661,566	
TOTAL				1,661,566	1,661,566	

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
1999 10	2,695,571	ITEM REINTRODUCED AFTER PREVIOUS DEFERRAL.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION
262	Conawapa Transmission
263	HVDC Bipole 3
265	Riel > Winnipeg AC Transmission
266	Dorsey > Riel 500kV AC T/L

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item 2

Title	Budget reference number
CONAWAPA GENERATING STATION	01-26-8124

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Power Planning & Operations	Power Planning & Operations	Construction	81970

DESCRIPTION:
DESIGN AND CONSTRUCT THE CONAWAPA GENERATING STATION ON THE NELSON RIVER. THIS WILL INCLUDE THE COMPLETE INSTALLATION OF EQUIPMENT FOR 10 GENERATORS WITH A TOTAL INSTALLED CAPACITY OF APPROXIMATELY 1390MW, IN ACCORDANCE WITH THE FOLLOWING IN SERVICE DATES:

UNIT NO. 1	2018 05 31
UNIT NO. 2	2018 07 31
UNIT NO. 3	2018 10 31
UNIT NO. 4	2018 12 31
UNIT NO. 5	2019 03 31
UNIT NO. 6	2019 06 30
UNIT NO. 7	2019 08 31
UNIT NO. 8	2019 11 30
UNIT NO. 9	2020 02 28
UNIT NO. 10	2020 04 30

JUSTIFICATION:
BASED ON THE 1999 LOAD FORECAST, THE POWER RESOURCE PLAN STUDIES INDICATE THAT AN ADDITIONAL DEPENDABLE ENERGY SOURCE WILL REQUIRED IN 2018/19.

NOTE: THE CER INCLUDES AN UNAMORTIZED BALANCE OF PRELIMINARY PLANNING STUDIES ESTIMATED AT $23.4 MILLION (CURRENT DOLLARS).

99/09/01 REFLECTS TRANSFER OF UNAMORTIZED PLANNING STUDY COSTS FROM BRN 01-50-1001 AS PER LIZ CARRIERE.

REVISION:
ITEM REINTRODUCED AFTER PREVIOUS DEFERRAL.

IN SERVICE DATES						Base estimate
2018 05 31	269 557	2019 03 31	269 557	2020 02 28	269 557	199904 L2
2018 07 31	269 557	2019 06 30	269 557	2020 04 30	269 558	
2018 10 31	269 557	2019 08 31	269 557			Work start date
2018 12 31	269 557	2019 11 30	269 557			2007 04 01

	PREV. AUTHORITY Authorized to date:	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
TOTAL							
REV. AMOUNTS: Authorized to date: Over(under)expend:							
Auth Req.:	2009/10	42 584	383	2 112			45 079
	2010/11	43 605	1 761	4 521			49 887
	2011/12	114 402	7 003	9 740			131 145
	2012/13	118 399	9 760	23 543			151 702
	2013/14	188 869	19 658	37 917			246 444
	2014/15	253 540	31 987	60 690			346 217
	2015/16	259 715	38 616	95 485			393 816
	2016/17	215 193	36 939	137 998			390 130
	2017/18	213 702	41 691	181 004			436 397
	2018/19	158 008	34 602	166 853			359 463
	2019/20	44 949	10 939	76 389			132 277
	2020/21	8 600	2 306	2 108			13 014
	TOTAL	1 661 566	235 645	798 360			2 695 571

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

1999-10-14 10:53 AM

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 01-26-8124

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1999 10	2 634 097	ITEM REINTRODUCED AFTER PREVIOUS DEFERRAL.
1999 10	2 695 466	ITEM REINTRODUCED AFTER PREVIOUS DEFERRAL.

ASSOCIATED PROJECTS

Budget reference number	Description

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

1999-10-14 10:53 AM

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

COMPLEX STATUS: ☐ Planned ☒ In progress

Complex no. 223

REVISION STATUS: ☐ New complex ☐ In service change ☐ Concept change ☒ Estimate change only

COMPLEX: HVDC BIPOLE RELIABILITY ENHANCEMENTS

Proposal

Relocate and reterminate service transformer #1 (SST1) and associated equipment within Radisson Stn. Purchase and install spare converter transformers on new pads as follows: Dorsey single phase 1-300kV & 1-450kV, three phase 1-375kV& 1-500kV; Radisson single phase 1-450kV, Henday three phase 1-500kV.Purchase and install two spare air cooled smoothing reactors set rated at 750 MH reactance and 500kV DC on new pad ,one each for Dorsey and Henday.Upgrade cooling system valves and converter transformers by installing additional cooling capacity to achieve rating and provide necessary degree of redundancy on Bipole 2 at Dorsey and Henday.

JUSTIFICATION

☐ Load ☐ Service
☐ Safety ☒ Efficiency
☒ Reliability ☐ Other

Explanation

Relocating SST1 ensures that Bipole 1 is not left in a single contingency bipole loss situation by permitting syncronization of all 3 transformers. Spare transformers and smoothing reactors provide transmission enhancements required due to the addition of Limestone, delay of Bipole 3, increased capacity for export sales, and provide improved system adequacy and reliability. Cooling system upgrades will increase DC summer output capacity by 200 MW. This will increase benefits from summer export sales, enhance maintenance scheduling/operations and DC transient performance.

Estimate Level	COMPLEX START (yyyy mm)
L2-4	1994 10

IN SERVICE DATES AND AMOUNTS

1997 08	$5295	1997 11	$1957	199712	$2858	1998 03	$511
1998 07	$581	1999 03	$52	1999 09	$6819	1999 10	$543
1999 11	$6892	2000 11	$6836				

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	15,504		927	4	16,427	13,266	3,161	24
Year 99/00	10,433	73	413		10,919	15,100	-4,181	-28
00/01	4,695	73	225		4,993	9,073	-4,080	-45
01/02						2,103	-2,103	-100
02/03								
03/04								
04/05								
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	30,632	146	1,565	4	32,339	39,542	-7,203	-18

REVISION: Reflects increases to put transformer in service if required, and decreases due to charging transformers to inventory, and material costs less than forecast.

Reviewed by	yyyy mm dd	Reviewed by	yyyy mm dd
ORIGINATOR	99 11 03	COORDINATOR	
Reviewed by	yyyy mm dd	Approved by	yyyy mm dd
CONSTRUCTOR		VICE-PRESIDENT	99 11 12

H2856/r Rev 99 03

Complex no. 223

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Advance or deferral impact

Loss of revenue when existing transformers out for repairs.

Factors affecting timing or viability

Delivery of transformers.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	%
Radisson Stn SST1 relocation & SST2&3 cable repl	2,292	2,504	2,554	2,385	-169	-7
Dorsey Bipole 1 spare 300kV converter transformer	3,121	975	995	3,049	2,054	206
Dorsey Bipole 1 spare 450kV converter transformer	3,942	634	647	0	-647	-100
Radisson Bipole 1 spare 450kV converter transform	3,408	1,168	1,191	25	-1,166	-98
Dorsey spare converter transformer foundations	10,709	1,161	1,184	210	-974	-82
Henday Bipole 2 spare 500kV converter transf	5,213	5,607	5,719	5,635	-84	-1
Dorsey Bipole 2 spare smoothing reactor	6,899	6,879	7,017	6,586	-431	-6
Henday Bipole 2 spare smoothing reactor	7,101	7,065	7,206	6,270	-936	-13
Dorsey Bipole 2 cooling upgrade	7,527	3,311	3,377	3,398	21	1
Henday Bipole 2 cooling upgrade	7,830	3,378	3,446	3,076	-370	-11
Dorsey Bipole 1 spare 300kV converter transf (SP#3)		2,871	2,928	0	-2,928	-100
Henday Bipole 2 spare 500kV converter transf (SP #2)		734	749	0	-749	-100
TOTAL	58,042	36,287	37,013	30,634	-6,379	-17

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
96 10	61,156	New complex, items transferred from complex # 67.
9710	63,275	Reflects revised costing methodology of the new financial reporting system. Increase is also due to factory problems with Henday transf, & const and switchgear mods at Radisson.
9810	39,542	Reflects 97/98 underexp 2.6M, transf ISD def 10 Mth, spares charged to inventory, cooling removed, shipping damages (Radisson), and add'n of 5kV repl cables for SST2&3.
1999 10	32,339	Reflects increases to put transformer in service if required, and decreases due to charging transformers to inventory, and material costs less than forecast.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION
PSPD 95-7	Radisson Stn service transformer No.1 re-termination.
PSPD 94-2	Enhancement of the Nelson River transmission system.
Minutes	HVDC task force meeting of 95 04 13 (relocation) & 95 06 28 (cooling upgr)

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item 3

Title: RADISSON STATION SST1 RELOCATION & SST2 & SST3 CABLE REPLACE

Budget reference number: 03-00-6119

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
HVDC	HVDC	Construction	60118:61890

DESCRIPTION:
RELOCATE RADISSON STATION SERVICE TRANSFORMER NO. 1 (SST1) AND RE-TERMINATE TRANSFORMER IN A NEW POSITION BETWEEN EXISTING BREAKER 33 AND NEW BREAKER 34 IN BAY 8. FACILITIES WILL INCLUDE 1 - 138 KV CIRCUIT BREAKER AND ALL ASSOCIATED EQUIPMENT.
REMOVE THE EXISTING 5KV CABLES FOR SST2 AND SST3 AND REPLACE THESE WITH NEW CABLES.

JUSTIFICATION:
RELOCATING STATION SERVICE TRANSFORMER SST1 FROM THE NORTHERN AC BUS TO THE COLLECTOR SYSTEM WILL ENSURE THAT HVDC BIPOLE 1 IS NOT LEFT IN A SINGLE CONTINGENCY BIPOLE LOSS SITUATION BY PERMITTING ALL THREE STATION SERVICE TRANSFORMERS TO BE SYNCHRONIZED.
THE 5KV SST2 AND SST3 CABLES ARE 24 YEARS OLD AND FAILURES HAVE OCCURRED ON SST1. REPLACEMENT WILL ENSURE RELIABLILITY OF THE STATION SERVICE TO BIPOLE 1.

REFERENCE:
MINUTES OF HVDC TASK FORCE MEETING OF 1995 04 13. REPORT PSPD 95-7, RADISSON STATION SERVICE TRANSFORMER NO. 1 RE-TERMINATION.

REVISION:
DECREASE IS DUE TO ACTUAL COSTS OF SST1 RELOCATION BEING LOWER THAN ESTIMATED.
CONTINGENCY AMOUNT: $ 25 000.

s BRN contains Deleted, Blocked, or Closed Orders.

IN SERVICE DATES						Base estimate
Prior Total	2 130	1998 08 31	3	1998 12 31	0	199704 L2
1998 05 31	28	1998 09 30	1	1999 01 31	0	
1998 06 30	0	1998 10 31	0	1999 04 30	4	Work start date
1998 07 31	3	1998 11 30	2	1999 10 31	294	1997 04 01

PREV AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:	2 100		74	-4		2 170
1999/00	409	9	4			422
TOTAL	2 509	9	78	-4		2 592
REV. AMOUNTS:						
Authorized to date:	2 100		74	-4		2 170
Over(under)expend:						
Auth Req.: 1999/00	285	2	4			291
TOTAL	2 385	2	78	-4		2 461

Prepared by: yy mm dd COORDINATOR — Approved by: yy mm dd — Approved by: yy mm dd

Estimated by: ORIGINATOR — COORDINATING MANAGER — ORIGINATING MANAGER

1999-08-21 05:21 PM

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 03-00-6119

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1997 10	2 368	INCREASED COST OF 5KV SWITCHGEAR MODIFICATIONS; HIGHER CONSTRUCTION COSTS AND NEW HIGHER SAP ACTIVITY AND OVERHEAD RATES.

ASSOCIATED PROJECTS

Budget reference number	Description
03-00-5901	DORSEY BIPOLE 1 SPARE 300 KV CONVERTER TRANSFORMER
03-00-5902	RADISSON BIPOLE 1 SPARE 450KV CONVERTER TRANSFORMER
03-00-5903	DORSEY SPARE CONVERTER TRANSFORMER FOUNDATIONS
03-00-5904	HENDAY BIPOLE 2 SPARE 500KV CONV. TFR (SPARE # 1)
03-00-5905	DORSEY BIPOLE 2 SPARE SMOOTHING REACTOR (DORSME8)
03-00-5906	HENDAY BIPOLE 2 SPARE SMOOTHING REACTOR (HENDME2)
03-00-5907	DORSEY BIPOLE 2 COOLING UPGRADE (DORSME11)
03-00-5908	HENDAY - BIPOLE 2 COOLING UPGRADE (HENDME4)
03-00-6129	DORSEY BIPOLE 1 SPARE 450KV CONVERTER TRANSFORMER
03-00-8369	DORSEY BIPOLE 1 SPARE 300 KV CONV. TFR (SPARE # 3)
03-00-8370	HENDAY BIPOLE 2 SPARE 500KV CONV. TFR (SPARE # 2)
03-00-8395	HVDC BP1 & 2 Auxiliary Power Supply Upgrades
03-00-8396	Bipole 1 & 2 Electrode Line Monitoring
03-00-8398	Bipole 1 & 2 5/15KV Arcproofing and Brkr Upgrade

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	7					7	7
May	14					14	21
Jun	13	1				14	35
Jul	7					7	42
Aug	161	2				163	205
Sep	28		1			29	234
Oct	28		2			30	264
Nov	27	-1	1			27	291
Dec							291
Jan							291
Feb							291
Mar							291
TOTAL	285	2	4			291	291
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item

4

Title: DORSEY BIPOLE 1 SPARE 300 KV CONVERTER TRANSFORMER

Budget reference number: 03-00-5901

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
C	HVDC	Construction	60105:62231

DESCRIPTION:
PURCHASE AND INSTALL A SPARE SINGLE-PHASE CONVERTER TRANSFORMER ON A NEW FOUNDATION.

JUSTIFICATION:
THE ADDITION OF LIMESTONE, THE DELAY OF BIPOLE 3 AND THE INCREASED CAPACITY FOR EXPORT SALES JUSTIFIES TRANSMISSION ENHANCEMENTS BASED ON THE ECONOMICS OF EXPORT SALES AND INCREASED SYSTEM ADEQUACY AND RELIABILITY.

REFERENCE:
REPORT PSPD 94-2, ENHANCEMENT OF THE NELSON RIVER TRANSMISSION SYSTEM.

REVISION:
ESTIMATE HAS BEEN INCREASED TO REFLECT THE COST OF PLACING THIS TRANSFORMER IN SERVICE, IF REQUIRED.

IN SERVICE DATES						Base estimate
Prior Total	2 847	1998 10 31	-4	1999 02 28	0	199704 L4
1998 07 31	49	1998 11 30	1	1999 03 31	0	
1998 08 31	35	1998 12 31	0	1999 09 30	191	Work start date
1998 09 30	6	1999 01 31	-12	1999 10 31	39	1997 04 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:	2 824		100			2 924
1999/00	-1 844					-1 844
TOTAL	980		100			1 080
REV. AMOUNTS:						
Authorized to date:	2 824		100			2 924
Over(under)expend:						
Auth Req.: 1999/00	225	2	1			228
TOTAL	3 049	2	101			3 152

Prepared by: yy mm dd COORDINATOR — Approved by: yy mm dd Approved by: yy mm dd

Estimated by: ORIGINATOR — COORDINATING MANAGER — ORIGINATING MANAGER

4053

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 03-00-5901

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1994 10	4 969	NEW ITEM.
1995 10	3 453	IN-SERVICE DATE DEFERRED FROM 1996 02 20 TO 1996 10 31. LATEST ESTIMATED TRANSFORMER COST IS CONSIDERABLY HIGHER THAN IN ORIGINAL ESTIMATE. 450KV TRANSFORMER REMOVED FROM THIS ITEM INTO SEPARATE NEW ITEM BRN 9603-00-6129 AND DEFERRED FROM 1996 TO 2000.
1996 10	3 094	LOWER COST OF TRFR.
1997 10	3 322	UPDATED INTEREST AND ESCALATION.
1998 10	1 082	ESTIMATE DECREASED TO REFLECT ACTUAL COSTS. CASH FLOW REVISED DUE TO DELAYED INSTALLATION OF TRANSFORMER DELUGE SYSTEM. CHANGE IN ACCOUNTING TREATMENT - TRANSFORMER IS NOW CHARGED TO SERIALIZED EQUIPMENT INVENTORY.

ASSOCIATED PROJECTS

Budget reference number	Description
03-00-5902	RADISSON BIPOLE 1 SPARE 450KV CONVERTER TRANSFORMER
03-00-5903	DORSEY SPARE CONVERTER TRANSFORMER FOUNDATIONS
03-00-5904	HENDAY BIPOLE 2 SPARE 500KV CONV. TFR (SPARE # 1)
03-00-5905	DORSEY BIPOLE 2 SPARE SMOOTHING REACTOR (DORSME8)
03-00-5906	HENDAY BIPOLE 2 SPARE SMOOTHING REACTOR (HENDME2)
03-00-5907	DORSEY BIPOLE 2 COOLING UPGRADE (DORSME11)
03-00-5908	HENDAY - BIPOLE 2 COOLING UPGRADE (HENDME4)
03-00-6119	RADISSON STATION SST1 RELOCATION & SST2 & SST3 CABLE REPLACE
03-00-6129	DORSEY BIPOLE 1 SPARE 450KV CONVERTER TRANSFORMER
03-00-8369	DORSEY BIPOLE 1 SPARE 300 KV CONV. TFR (SPARE # 3)
03-00-8370	HENDAY BIPOLE 2 SPARE 500KV CONV. TFR (SPARE # 2)
03-00-8395	HVDC BP1 & 2 Auxiliary Power Supply Upgrades
03-00-8396	Bipole 1 & 2 Electrode Line Monitoring
03-00-8398	Bipole 1 & 2 5/15KV Arcproofing and Brkr Upgrade

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	3					3	3
May	3					3	6
Jun	3					3	9
Jul	9					9	18
Aug	103	2				105	123
Sep	103	2				105	228
Oct	1	-2	1				228
Nov							228
Dec							228
Jan							228
Feb							228
Mar							228
TOTAL	225	2	1			228	228
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

1999-08-21 05:20 PM

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item 5

Title			Budget reference number
DORSEY BIPOLE 1 SPARE 450KV CONVERTER TRANSFORMER			03-00-6129
Originating division	Coordinating division	Constructing division	Project Order Group (Range):
HVDC	HVDC	Construction	60119

DESCRIPTION:
PURCHASE AND INSTALL A SINGLE-PHASE CONVERTER TRANSFORMER ON NEW PAD. THE TRANSFORMER RATING IS: 450 KV DC SUITABLE FOR USE IN T11, T13 AND T23 POSITIONS.

JUSTIFICATION:
THE ADDITION OF LIMESTONE, THE DELAY OF BIPOLE 3 AND THE INCREASED CAPACITY FOR EXPORT SALES JUSTIFIES TRANSMISSION ENHANCEMENTS BASED ON THE ECONOMIES OF EXPORT SALES AND INCREASE SYSTEM ADEQUACY AND RELIABILITY. THIS ITEM PROVIDES FOR SPARE BIPOLE 1 CONVERTER TRANSFORMER AT DORSEY.

REFERENCE:
REPORT PSPD 94-2, ENHANCEMENT OF THE NELSON RIVER TRANSMISSION SYSTEM.

REVISION:
CHANGE IN ACCOUNTING TREATMENT - TRANSFORMER CHARGED TO SERIALIZED EQUIPMENT INVENTORY.

IN SERVICE DATES		Base estimate
1999 12 31	0	199704 L3
		Work start date
		1997 04 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date						
1999/00	658	9	40			707
TOTAL	658	9	40			707
REV. AMOUNTS:						
Authorized to date:						
Over(under)expend:						
Auth Req.:						
TOTAL						

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

1999-08-21 05:21 PM

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number: 03-00-6129

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1995 10	4 674	NEW ITEM. (PREVIOUSLY INCLUDED IN BRN 9503-00-5901).
1998 10	721	CASH FLOW REVISED TO REFLECT REVISED PAYMENT SCHEDULE FOR TRANSFORMER. CHANGE IN ACCOUNTING TREATMENT - TRANSFORMER CHARGED TO SERIALIZED EQUIPMENT INVENTORY.

ASSOCIATED PROJECTS

Budget reference number	Description
03-00-5901	DORSEY BIPOLE 1 SPARE 300 KV CONVERTER TRANSFORMER
03-00-5902	RADISSON BIPOLE 1 SPARE 450KV CONVERTER TRANSFORMER
03-00-5903	DORSEY SPARE CONVERTER TRANSFORMER FOUNDATIONS
03-00-5904	HENDAY BIPOLE 2 SPARE 500KV CONV. TFR (SPARE # 1)
03-00-5905	DORSEY BIPOLE 2 SPARE SMOOTHING REACTOR (DORSME8)
03-00-5906	HENDAY BIPOLE 2 SPARE SMOOTHING REACTOR (HENDME2)
03-00-5907	DORSEY BIPOLE 2 COOLING UPGRADE (DORSME11)
03-00-5908	HENDAY - BIPOLE 2 COOLING UPGRADE (HENDME4)
03-00-6119	RADISSON STATION SST1 RELOCATION & SST2 & SST3 CABLE REPLACE
03-00-8369	DORSEY BIPOLE 1 SPARE 300 KV CONV. TFR (SPARE # 3)
03-00-8370	HENDAY BIPOLE 2 SPARE 500KV CONV. TFR (SPARE # 2)
03-00-8395	HVDC BP1 & 2 Auxiliary Power Supply Upgrades
03-00-8396	Bipole 1 & 2 Electrode Line Monitoring
03-00-8398	Bipole 1 & 2 5/15KV Arcproofing and Brkr Upgrade

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item ___ Domestic Item 6

Title
RADISSON BIPOLE 1 SPARE 450KV CONVERTER TRANSFORMER

Budget reference number
03-00-5902

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
HVDC	HVDC	Construction	60111

DESCRIPTION:
PURCHASE AND INSTALL A SPARE SINGLE PHASE CONVERTER TRANSFORMER ON A NEW PAD RATED AT 450 KV DC AND SUITABLE FOR USE IN T11, T13, AND T23 POSITIONS.

JUSTIFICATION:
THE ADDITION OF LIMESTONE, THE DELAY OF BIPOLE 3 AND THE INCREASED CAPACITY FOR EXPORT SALES JUSTIFIES TRANSMISSION ENHANCEMENTS BASED ON THE ECONOMICS OF EXPORT SALES AND INCREASED SYSTEM ADEQUACY AND RELIABILITY. THIS ITEM PROVIDES A SPARE BIPOLE 1 CONVERTER TRANSFORMER AT RADISSON.

REFERENCE:
REPORT PSPD 94-2, ENHANCEMENT OF THE NELSON RIVER TRANSMISSION SYSTEM.

REVISION:
CHANGE IN ACCOUNTING TREATMENT - TRANSFORMER TO BE CHARGED TO SERIALIZED EQUIPMENT INVENTORY. RESIDUAL VALUE REFLECTS THE COST OF THE SPARE PAD.

IN SERVICE DATES

1999 04 30 — 25

Base estimate
199704 L4

Work start date
1997 04 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:	25					25
1999/00	1 383					1 383
TOTAL	1 408					1 408
REV. AMOUNTS:						
Authorized to date:	25					25
Over(under)expend:						
Auth Req.:						
TOTAL	25					25

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR		COORDINATING MANAGER		ORIGINATING MANAGER

1999-08-21 05:20 PM

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 03-00-5902

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1994 10	2 558	NEW ITEM.
1995 10	3 826	IN-SERVICE DATE DEFERRED FROM 1996 04 30 TO 1996 12 31. LATEST ESTIMATED TRANSFORMER COST IS CONSIDERABLY MORE THAN IN ORIGINAL ESTIMATE.
1996 10	3 567	THE ADDITION OF LIMESTONE, THE DELAY OF BIPOLE 3 AND THE INCREASED CAPACITY FOR EXPORT SALES JUSTIFIES TRANSMISSION ENHANCEMENTS BASED ON THE ECONOMICS OF EXPORT SALES AND INCREASED SYSTEM ADEQUACY AND RELIABILITY. THIS ITEM PROVIDES FOR A SPARE BIPOLE 1 CONVERTER TRANSFORMER AT RADISSON. NOTE: PROJECT ID.: RADIME5
1997 10	3 592	UPDATED ESCALATION AND INTEREST.

ASSOCIATED PROJECTS

Budget reference number	Description
03-00-5901	DORSEY BIPOLE 1 SPARE 300 KV CONVERTER TRANSFORMER
03-00-5903	DORSEY SPARE CONVERTER TRANSFORMER FOUNDATIONS
03-00-5904	HENDAY BIPOLE 2 SPARE 500KV CONV. TFR (SPARE # 1)
03-00-5905	DORSEY BIPOLE 2 SPARE SMOOTHING REACTOR (DORSME8)
03-00-5906	HENDAY BIPOLE 2 SPARE SMOOTHING REACTOR (HENDME2)
03-00-5907	DORSEY BIPOLE 2 COOLING UPGRADE (DORSME11)
03-00-5908	HENDAY - BIPOLE 2 COOLING UPGRADE (HENDME4)
03-00-6119	RADISSON STATION SST1 RELOCATION & SST2 & SST3 CABLE REPLACE
03-00-6129	DORSEY BIPOLE 1 SPARE 450KV CONVERTER TRANSFORMER
03-00-8369	DORSEY BIPOLE 1 SPARE 300 KV CONV. TFR (SPARE # 3)
03-00-8370	HENDAY BIPOLE 2 SPARE 500KV CONV. TFR (SPARE # 2)
03-00-8395	HVDC BP1 & 2 Auxiliary Power Supply Upgrades
03-00-8396	Bipole 1 & 2 Electrode Line Monitoring
03-00-8398	Bipole 1 & 2 5/15KV Arcproofing and Brkr Upgrade

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item __ Domestic Item

7

Title
DORSEY SPARE CONVERTER TRANSFORMER FOUNDATIONS

Budget reference number
03-00-5903

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
DC	HVDC	Construction	60107:62230

DESCRIPTION:
DESIGN AND INSTALL FOUNDATIONS FOR 4 SPARE CONVERTER TRANSFORMERS; 300KV, 375KV, 450KV, AND 500KV.

JUSTIFICATION:
THE ADDITION OF LIMESTONE, THE DELAY OF BIPOLE 3 AND THE INCREASED CAPACITY FOR EXPORT SALES JUSTIFIES TRANSMISSION ENHANCEMENTS BASED ON THE ECONOMICS OF EXPORT SALES AND INCREASED SYSTEM ADEQUACY AND RELIABILITY. THIS ITEM PROVIDES FOR SPARE BIPOLE 2 CONVERTER TRANSFORMERS AT DORSEY.

REFERENCE:
REPORT PSPD 94-2, ENHANCEMENT OF THE NELSON RIVER TRANSMISSION SYSTEM.

REVISION:
TO PROVIDE FOUNDATIONS FOR SPARE CONVERTER TRANSFORMERS WHICH HAVE BEEN CHARGED TO SERIALIZED EQUIPMENT INVENTORY.

IN SERVICE DATES

1999 10 31	214
2001 06 30	-0
2001 08 31	-0

Base estimate
199704 L3

Work start date
1997 04 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:						
1999/00	84	1	6			91
2000/01	623	50	35			708
2001/02	467	48	23			538
TOTAL	1 174	99	64			1 337
REV. AMOUNTS:						
Authorized to date:						
Over(under)expend:						
Auth Req.: 1999/00	210	3	1			214
TOTAL	210	3	1			214

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 03-00-5903

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1995 10	12 731	IN-SERVICE DATES DEFERRED FROM 1996 04 30 AND 1996 06 30 TO 2001 06 30 AND 2001 08 31 RESPECTIVELY. TRANSFORMER BUDGET PRICES ARE CONSIDERABLY HIGHER THAN PREVIOUS ESTIMATES.
1996 10	10 839	IN-SERVICE DATES DEFERRED FROM 1996 04 30 AND 1996 06 30 TO 2001 06 30 AND 2001 08 31 RESPECTIVELY. TRANSFORMER BUDGET PRICES SUBMITTED BY THE SUPPLIER ARE CONSIDERABLY HIGHER THAN PREVIOUS ESTIMATES. CASH FLOW REVISED. ESTIMATE BASE DATE CHANGED TO 1996.
1997 10	12 389	CHANGE IN COST IS DUE TO CONVERSION TO SAP.
1998 10	1 372	CASHFLOW REVISED. CHANGE IN ACCOUNTING TREATMENT - TRANSFORMER CHARGED TO SERIALIZED EQUIPMENT INVENTORY.

ASSOCIATED PROJECTS

Budget reference number	Description
03-00-5901	DORSEY BIPOLE 1 SPARE 300 KV CONVERTER TRANSFORMER
03-00-5902	RADISSON BIPOLE 1 SPARE 450KV CONVERTER TRANSFORMER
03-00-5904	HENDAY BIPOLE 2 SPARE 500KV CONV. TFR (SPARE # 1)
03-00-5905	DORSEY BIPOLE 2 SPARE SMOOTHING REACTOR (DORSME8)
03-00-5906	HENDAY BIPOLE 2 SPARE SMOOTHING REACTOR (HENDME2)
03-00-5907	DORSEY BIPOLE 2 COOLING UPGRADE (DORSME11)
03-00-5908	HENDAY - BIPOLE 2 COOLING UPGRADE (HENDME4)
03-00-6119	RADISSON STATION SST1 RELOCATION & SST2 & SST3 CABLE REPLACE
03-00-6129	DORSEY BIPOLE 1 SPARE 450KV CONVERTER TRANSFORMER
03-00-8369	DORSEY BIPOLE 1 SPARE 300 KV CONV. TFR (SPARE # 3)
03-00-8370	HENDAY BIPOLE 2 SPARE 500KV CONV. TFR (SPARE # 2)
03-00-8395	HVDC BP1 & 2 Auxiliary Power Supply Upgrades
03-00-8396	Bipole 1 & 2 Electrode Line Monitoring
03-00-8398	Bipole 1 & 2 5/15KV Arcproofing and Brkr Upgrade

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May	2					2	2
Jun	6					6	8
Jul	2					2	10
Aug	17					17	27
Sep	53	1				54	81
Oct	130	2	1			133	214
Nov							214
Dec							214
Jan							214
Feb							214
Mar							214
TOTAL	210	3	1			214	214
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item 8

Title
HENDAY BIPOLE 2 SPARE 500KV CONV. TFR (SPARE # 1)

Budget reference number
03-00-5904

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
C	HVDC	Construction	60116:61895

SCRIPTION:
URCHASE AND INSTALL A SPARE THREE-PHASE CONVERTER TRANSFORMER ON A NEW PAD RATED AT 500 KV DC AND SUITABLE FOR USE IN T31S, T32S, T41S AND T42S POSITIONS.

JUSTIFICATION:
THE ADDITION OF LIMESTONE, THE DELAY OF BIPOLE 3 AND THE INCREASED CAPACITY FOR EXPORT SALES JUSTIFIES TRANSMISSION ENHANCEMENTS BASED ON THE ECONOMICS OF EXPORT SALES AND INCREASED SYSTEM ADEQUACY AND RELIABILITY. THIS ITEM PROVIDES FOR A SPARE BIPOLE 2 CONVERTER TRANSFORMER AT HENDAY.

REFERENCE:
REPORT PSPD 94-2, ENHANCEMENT OF THE NELSON RIVER TRANSMISSION SYSTEM.

REVISION:
PROJECT COMPLETE.

IN SERVICE DATES						Base estimate
Prior Total	5 338	1998 03 31	93	1998 10 31	-23	199610 L4
1997 12 31	7	1998 07 31	457	1998 11 30	2	Work start date
1998 01 31	1	1998 08 31	3	1999 03 31	13	1997 04 01
1998 02 28	247	1998 09 30	25	1999 04 30	-1	

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date	5 635		527			6 162
1999/00	-30					-30
TOTAL	5 605		527			6 132
REV. AMOUNTS:						
Authorized to date:	5 635		527			6 162
Over(under)expend:						
Auth Req.:						
TOTAL	5 635		527			6 162

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR		COORDINATING MANAGER		ORIGINATING MANAGER

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number: 03-00-5904

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1994 10	4 610	NEW ITEM.
1995 10	5 033	PURCHASE OF UNITS ADVANCED DUE TO CONDITION OF PRESENT OPERATING UNIT. ACTUAL TRANSFORMER COST IS HIGHER THAN ORIGINALLY ESTIMATED.
1997 10	5 734	BASE DATE UPDATED . ISD DELAYED FROM 1996 11 30 TO 1997 08 31.

ASSOCIATED PROJECTS

Budget reference number	Description
03-00-5901	DORSEY BIPOLE 1 SPARE 300 KV CONVERTER TRANSFORMER
03-00-5902	RADISSON BIPOLE 1 SPARE 450KV CONVERTER TRANSFORMER
03-00-5903	DORSEY SPARE CONVERTER TRANSFORMER FOUNDATIONS
03-00-5905	DORSEY BIPOLE 2 SPARE SMOOTHING REACTOR (DORSME8)
03-00-5906	HENDAY BIPOLE 2 SPARE SMOOTHING REACTOR (HENDME2)
03-00-5907	DORSEY BIPOLE 2 COOLING UPGRADE (DORSME11)
03-00-5908	HENDAY - BIPOLE 2 COOLING UPGRADE (HENDME4)
03-00-6119	RADISSON STATION SST1 RELOCATION & SST2 & SST3 CABLE REPLACE
03-00-6129	DORSEY BIPOLE 1 SPARE 450KV CONVERTER TRANSFORMER
03-00-8369	DORSEY BIPOLE 1 SPARE 300 KV CONV. TFR (SPARE # 3)
03-00-8370	HENDAY BIPOLE 2 SPARE 500KV CONV. TFR (SPARE # 2)
03-00-8395	HVDC BP1 & 2 Auxiliary Power Supply Upgrades
03-00-8396	Bipole 1 & 2 Electrode Line Monitoring
03-00-8398	Bipole 1 & 2 5/15KV Arcproofing and Brkr Upgrade

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

9

[X] Major Item [ ] Domestic Item

Title			Budget reference number
DORSEY BIPOLE 2 SPARE SMOOTHING REACTOR (DORSME8)			03-00-5905
Originating division	Coordinating division	Constructing division	Project Order Group (Range):
HVDC	HVDC	Construction	60108

DESCRIPTION:
PURCHASE AND INSTALL A SPARE AIR-COOLED SMOOTHING REACTOR SET RATED AT 750 MH REACTANCE AND 500 KV DC ON NEW PADS. PROVIDE REQUIRED CHANGES TO DC BUS TO ALLOW SPARE REACTOR TO BE CONNECTED TO EITHER POLE OF BIPOLE 2.

JUSTIFICATION:
THE ADDITION OF LIMESTONE, THE DELAY OF BIPOLE 3 AND THE INCREASED CAPACITY FOR EXPORT SALES JUSTIFIES TRANSMISSION ENHANCEMENTS BASED ON THE ECONOMICS OF EXPORT SALES AND INCREASED SYSTEM ADEQUACY AND RELIABILITY. THIS ITEM PROVIDES FOR A SPARE BIPOLE 2 SMOOTHING REACTOR AT DORSEY.

REFERENCE:
REPORT PSPD 94-2, ENHANCEMENT OF THE NELSON RIVER TRANSMISSION SYSTEM.

REVISION:
DECREASE IS DUE TO LOWER THAN ESTIMATED MATERIAL COSTS.
CONTINGENCY AMOUNT: $693,000

IN SERVICE DATES				Base estimate
1999 11 30	6 893			199610 L3
				Work start date 1997 04 01

	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
PREV. AUTHORITY						
Authorized to date:	674		109			783
1999/00	6 233	392	143			6 768
TOTAL	6 907	392	252			7 551
REV. AMOUNTS:						
Authorized to date:	674		109			783
Over(under)expend:						
Auth 1999/00	5 685	42	152			5 879
Req.: 2000/01	227	4				231
TOTAL	6 586	46	261			6 893

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

1999-09-28 10:55 AM

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 03-00-5905

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1994 10	6 845	NEW ITEM.
1995 10	8 512	NEW SMOOTHING REACTORS BUDGET PRICES SUBMITTED BY THE SUPPLIER ARE CONSIDERABLY HIGHER THAN PREVIOUS SUBMISSION. ADDED COST OF REACTOR RATING STUDY BY SYSTEM PLANNING. IN-SERVICE DATE DEFERRED FROM 1997 09 30 TO 1999 09 30.
1996 10	7 610	BUDGETARY ESTIMATE PROVIDED BY THE SUPPLIER FOR THE SMOOTHING REACTOR IS LESS HTAN PREVIOUS. CONSTRUCTION ESTIMATE IS ALSO LESS THAN PREVIOUS, WHICH HAD BEEN ESTIMATED BY ENGINEERING DIVISION.
1997 10	7 573	UPDATED ESCALATION AND INTEREST.

ASSOCIATED PROJECTS

Budget reference number	Description
03-00-5901	DORSEY BIPOLE 1 SPARE 300 KV CONVERTER TRANSFORMER
03-00-5902	RADISSON BIPOLE 1 SPARE 450KV CONVERTER TRANSFORMER
03-00-5903	DORSEY SPARE CONVERTER TRANSFORMER FOUNDATIONS
03-00-5904	HENDAY BIPOLE 2 SPARE 500KV CONV. TFR (SPARE # 1)
03-00-5906	HENDAY BIPOLE 2 SPARE SMOOTHING REACTOR (HENDME2)
03-00-5907	DORSEY BIPOLE 2 COOLING UPGRADE (DORSME11)
03-00-5908	HENDAY - BIPOLE 2 COOLING UPGRADE (HENDME4)
03-00-6119	RADISSON STATION SST1 RELOCATION & SST2 & SST3 CABLE REPLACE
03-00-6129	DORSEY BIPOLE 1 SPARE 450KV CONVERTER TRANSFORMER
03-00-8369	DORSEY BIPOLE 1 SPARE 300 KV CONV. TFR (SPARE # 3)
03-00-8370	HENDAY BIPOLE 2 SPARE 500KV CONV. TFR (SPARE # 2)

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	45	1	5			51	51
May	50		6			56	107
Jun	38	1	6			45	152
Jul	2 802	19	7			2 828	2 980
Aug	319	3	26			348	3 328
Sep	315	2	29			346	3 674
Oct	1 536	17	31			1 584	5 258
Nov	5		42			47	5 305
Dec	5					5	5 310
Jan	5					5	5 315
Feb	5					5	5 320
Mar	560	-1				559	5 879
TOTAL	5 685	42	152			5 879	5 879
2000/01 Apr	76	1				77	77
May	76	1				77	154
Jun	75	2				77	231
Jul							231
Aug							231
Sep							2
Oct							2
Nov							231
Dec							231
Jan							231
Feb							231
Mar							231
TOTAL	227	4				231	231

1999-09-28 10:55 AM

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item 10

Title			Budget reference number
HENDAY BIPOLE 2 SPARE SMOOTHING REACTOR (HENDME2)			03-00-5906
Originating division	Coordinating division	Constructing division	Project Order Group (Range):
MC	HVDC	Construction	60109

DESCRIPTION:
PURCHASE AND INSTALL A SPARE AIR-COOLED SMOOTHING REACTOR SET RATED AT 750 MH REACTANCE AND 500 KV DC ON NEW PADS. PROVIDE REQUIRED CHANGES TO DC BUS TO ALLOW SPARE REACTOR TO BE CONNECTED TO EITHER POLE OF BIPOLE 2. TO REFLECT CARRY OVER OF FUNDS FROM THE 1995/96 FISCAL YEAR

JUSTIFICATION:
THE ADDITION OF LIMESTONE, THE DELAY OF BIPOLE 3 AND THE INCREASED CAPACITY FOR EXPORT SALES JUSTIFIES TRANSMISSION ENHANCEMENTS BASED ON THE ECONOMICS OF EXPORT SALES AND INCREASED SYSTEM ADEQUACY AND RELIABILITY. THIS ITEM PROVIDES FOR A SPARE BIPOLE 2 SMOOTHING REACTOR AT HENDAY.

REFERENCE:
REPORT PSPD 94-2, ENHANCEMENT OF THE NELSON RIVER TRANSMISSION SYSTEM.

REVISION:
DECREASE DUE TO LOWER MATERIAL, FOUNDATION COSTS THAN ESTIMATED.
CONSTRUCTION ESTIMATES AND CONTINGENCY DECREASED.
CONTINGENCY AMOUNT: $565 000.

IN SERVICE DATES		Base estimate
1999 09 30	6 600	199610 L2
		Work start date
		1997 04 01

	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
PREV. AUTHORITY						
Authorized to date	4 150		108			4 258
1999/00	2 922	403	138			3 463
TOTAL	7 072	403	246			7 721
REV. AMOUNTS:						
Authorized to date	4 150		108			4 258
Over(under)expend						
Auth 1999/00	2 120	8	214			2 342
Req.:						
TOTAL	6 270	8	322			6 600

Prepared by: yy mm dd COORDINATOR Approved by: yy mm dd Approved by: yy mm dd
Estimated by: ORIGINATOR COORDINATING MANAGER ORIGINATING MANAGER

1999-08-21 05:20 PM

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 03-00-5906

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1994 10	7 643	NEW ITEM.
1995 10	9 628	NEW SMOOTHING REACTORS BUDGET PRICES SUBMITTED BY THE SUPPLIER ARE CONSIDERABLY HIGHER THAN PREVIOUS SUBMISSION. ADDED COST REACTOR RATING STUDY BY SYSTEM PLANNING. IN-SERVICE DATE DEFERRED FROM 1997 09 30 TO 1999 09 30.
1996 10	8 438	NEW SMOOTHING REACTORS BUDGET PRICES SUBMITTED BY THE SUPPLIER ARE CONSIDERABLY HIGHER THAN PREVIOUS SUBMISSION. ADDED COST OF REACTOR RATING STUDY BY SYSTEM PLANNING. IN-SERVICE DATE DEFERRED FROM 1997 09 30 TO 1999 09 30.
1997 10	7 758	CHANGE IN COST IS DUE TO CONVERSION TO SAP.

ASSOCIATED PROJECTS

Budget reference number	Description
03-00-5901	DORSEY BIPOLE 1 SPARE 300 KV CONVERTER TRANSFORMER
03-00-5902	RADISSON BIPOLE 1 SPARE 450KV CONVERTER TRANSFORMER
03-00-5903	DORSEY SPARE CONVERTER TRANSFORMER FOUNDATIONS
03-00-5904	HENDAY BIPOLE 2 SPARE 500KV CONV. TFR (SPARE # 1)
03-00-5905	DORSEY BIPOLE 2 SPARE SMOOTHING REACTOR (DORSME8)
03-00-5907	DORSEY BIPOLE 2 COOLING UPGRADE (DORSME11)
03-00-5908	HENDAY - BIPOLE 2 COOLING UPGRADE (HENDME4)
03-00-6119	RADISSON STATION SST1 RELOCATION & SST2 & SST3 CABLE REPLACE
03-00-6129	DORSEY BIPOLE 1 SPARE 450KV CONVERTER TRANSFORMER
03-00-8369	DORSEY BIPOLE 1 SPARE 300 KV CONV. TFR (SPARE # 3)
03-00-8370	HENDAY BIPOLE 2 SPARE 500KV CONV. TFR (SPARE # 2)
03-00-8395	HVDC BP1 & 2 Auxiliary Power Supply Upgrades
03-00-8396	Bipole 1 & 2 Electrode Line Monitoring
03-00-8398	Bipole 1 & 2 5/15KV Arcproofing and Brkr Upgrade

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	406		30			436	436
May	256		33			289	725
Jun	265	1	35			301	1 026
Jul	300	2	37			339	1 365
Aug	263	2	39			304	1 669
Sep	34		41			75	1 744
Oct	10					10	1 754
Nov	4					4	1 758
Dec	4					4	1 762
Jan	4					4	1 766
Feb	4					4	1 770
Mar	570	3	-1			572	2 342
TOTAL	2 120	8	214			2 342	2 342
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item

Title			Budget reference number
DORSEY BIPOLE 2 COOLING UPGRADE (DORSME11)			03-00-5907
Originating division	Coordinating division	Constructing division	Project Order Group (Range):
HVDC	HVDC	Planning & Control	60110

DESCRIPTION:
UPGRADE THE COOLING SYSTEM FOR BIPOLE 2 BY MODIFYING THE THYRISTOR VALVE EVAPORATIVE SPRAY WATER COOLERS AND ASSOCIATED CONTROLS TO ALLOW CONTINUOUS OPERATION AT 2000MW UNDER MAXIMUM SUMMER AMBIENT TEMPERATURE CONDITIONS AND MAINTAIN FULL REDUNDANCY OF COOLING SYSTEMS. INSTALL MORE ACCURATE TEMPERATURE MONITORING ON THE CONVERTER TRANSFORMERS.
UPGRADE OF EXISTING WELLS AND/OR ADDITION OF NEW WELLS.

JUSTIFICATION:
HVDC BIPOLE 2 COOLING SYSTEM UPGRADES WILL INCREASE DC SUMMER OUTPUT CAPACITY BY 200 MW. THIS WILL INCREASE BENEFITS FROM SUMMER EXPORT SALES, AND ENHANCE MAINTENANCE SCHEDULING, DAY-TO-DAY OPERATIONS AND DC TRANSIENT PERFORMANCE. THIS ITEM PROVIDES FOR UPGRADE OF FACILITIES AT DORSEY.

REFERENCE:
REPORT PSPD 94-2, ENHANCEMENT OF THE NELSON RIVER TRANSMISSION SYSTEM. MINUTES OF HVDC TASK FORCE MEETING OF 1995 06 28. MEMO FROM L.D. RECKSIEDLER TO I.H. MCKAY DATED 1998 04 07.

REVISION:
UPGRADE OF EXISTING WELLS AND/OR ADDITION OF NEW WELLS ADDED TO THE ESTIMATE.
CASH FLOW REVISED. ISD DEFERRED TWO MONTHS.

CONTINGENCY: $150,000

IN SERVICE DATES				Base estimate
2000 11 30	3 597			199610 L3
				Work start date
				1997 04 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:	69		6			75
1999/00	322	7	20			349
2000/01	2 927	139	62			3 128
TOTAL	3 318	146	88			3 552
REV. AMOUNTS:						
Authorized to date:	69		6			75
Over(under)expend:						
Auth 1999/00	1 048	9	26			1 083
Req.: 2000/01	2 281	34	124			2 439
TOTAL	3 398	43	156			3 597

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

1999-09-28 10:55 AM

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 03-00-5907

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1994 10	5 574	NEW ITEM.
1995 10	7 211	TRANSFORMER COOLER BANKS BUDGET PRICES PROVIDED BY THE SUPPLIER NEARLY DOUBLED OVER THE PREVIOUS SUBMISSION BY THE SUPPLIER. VALVE COOLING REMOVED. IN-SERVICE DATE DEFERRED FROM 1997 09 30 TO 1998 09 30.
1996 10	7 565	TRANSFORMER COOLER BANKS BUDGET PRICES PROVIDED BY THE SUPPLIER ARE CONSIDERABLY LESS THAN LAST YEAR'S SUBMISSION. HOWEVER, THE TOTAL COST IS INCREASED DUE TO THE INACCURATE EQUIPMENT COST DISTRIBUTION BETWEEN HENDAY AND DORSEY AND DEFERMENT OF ISD FROM 1998 09 30 TO 2000 09 30. VALVE COOLING ADDED.
1997 10	7 948	CHANGE IN COST IS DUE TO CONVERSION TO SAP.

ASSOCIATED PROJECTS

Budget reference number	Description
03-00-5901	DORSEY BIPOLE 1 SPARE 300 KV CONVERTER TRANSFORMER
03-00-5902	RADISSON BIPOLE 1 SPARE 450KV CONVERTER TRANSFORMER
03-00-5903	DORSEY SPARE CONVERTER TRANSFORMER FOUNDATIONS
03-00-5904	HENDAY BIPOLE 2 SPARE 500KV CONV. TFR (SPARE # 1)
03-00-5905	DORSEY BIPOLE 2 SPARE SMOOTHING REACTOR (DORSME8)
03-00-5906	HENDAY BIPOLE 2 SPARE SMOOTHING REACTOR (HENDME2)
03-00-5908	HENDAY - BIPOLE 2 COOLING UPGRADE (HENDME4)
03-00-6119	RADISSON STATION SST1 RELOCATION & SST2 & SST3 CABLE REPLACE
03-00-6129	DORSEY BIPOLE 1 SPARE 450KV CONVERTER TRANSFORMER
03-00-8369	DORSEY BIPOLE 1 SPARE 300 KV CONV. TFR (SPARE # 3)
03-00-8370	HENDAY BIPOLE 2 SPARE 500KV CONV. TFR (SPARE # 2)

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	11		1			12	12
May	11		1			12	24
Jun	20		1			21	45
Jul	29		1			30	75
Aug	37		1			38	113
Sep	111	1	1			113	226
Oct	70	1	2			73	299
Nov	17	-1	3			19	318
Dec	17	-1	3			19	337
Jan	230	1	3			234	571
Feb	230	2	5			237	808
Mar	265	6	4			275	1 083
TOTAL	1 048	9	26			1 083	1 083
2000/01 Apr	272	3	8			283	283
May	272	4	10			286	569
Jun	286	4	12			302	871
Jul	415	6	14			435	1 306
Aug	187	3	17			207	1 513
Sep	254	5	19			278	1 7[illegible]
Oct	218	4	21			243	2 0[illegible]
Nov	368	4	23			395	2 42[illegible]
Dec	9	1				10	2 439
Jan							2 439
Feb							2 439
Mar							2 439
TOTAL	2 281	34	124			2 439	2 439

1999-09-28 10:55 AM

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item

12

Title			Budget reference number
HENDAY - BIPOLE 2 COOLING UPGRADE (HENDME4)			03-00-5908
Originating division	Coordinating division	Constructing division	Project Order Group (Range):
HVDC	HVDC	Construction	60115

DESCRIPTION:
UPGRADE THE COOLING SYSTEM FOR BIPOLE 2 BY MODIFYING THE THYRISTOR VALVE EVAPORATIVE SPRAY WATER COOLERS AND ASSOCIATED CONTROLS TO ALLOW CONTINUOUS OPERATION AT 2000MW UNDER MAXIMUM SUMMER AMBIENT TEMPERATURE CONDITIONS AND MAINTAIN FULL REDUNDANCY OF COOLING SYSTEMS. INSTALL MORE ACCURATE TEMPERATURE MONITORING ON THE CONVERTER TRANSFORMERS.

JUSTIFICATION:
HVDC BIPOLE 2 COOLING SYSTEM UPGRADES WILL INCREASE DC SUMMER OUTPUT CAPACITY BY 200 MW. THIS WILL INCREASE BENEFITS FROM SUMMER EXPORT SALES, AND ENHANCE MAINTENANCE SCHEDULING, DAY-TO-DAY OPERATIONS AND DC TRANSIENT PERFORMANCE. THIS ITEM PROVIDES FOR UPGRADE OF FACILITIES AT HENDAY.

REFERENCE:
REPORT PSPD 94-2, ENHANCEMENT OF THE NELSON RIVER TRANSMISSION SYSTEM. MINUTES OF HVDC TASK FORCE MEETING OF 1995 06 28. MEMO FROM L.D. RECKSIEDLER TO I.H. MCKAY DATED 1998 04 07.

REVISION:
CASH FLOW REVISED. ISD DEFERRED TWO MONTHS.

IN SERVICE DATES				Base estimate
2000 11 30	3 239			199610 L2
				Work start date
				1997 04 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:	28		4			32
1999/00	323	8	14			345
2000/01	3 028	146	58			3 232
TOTAL	3 379	154	76			3 609
REV. AMOUNTS:						
Authorized to date:	28		4			32
Over(under)expend:						
Auth 1999/00	861	7	16			884
Req.: 2000/01	2 187	35	101			2 323
TOTAL	3 076	42	121			3 239

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

1999-09-28 10:56 AM

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 03-00-5908

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1994 10	5 728	NEW ITEM.
1995 10	8 479	TRANSFORMER COOLER BANKS BUDGET PRICES PROVIDED BY THE SUPPLIER NEARLY DOUBLED OVER THE PREVIOUS SUBMISSION BY THE SUPPLIER. VALVE COOLING REMOVED. IN-SERVICE DATE DEFERRED FROM 1997 09 30 TO 1998 09 30.
1996 10	8 224	HVDC BIPOLE 2 COOLING SYSTEM UPGRADES WILL INCREASE DC SUMMER OUTPUT CAPACITY BY 200 MW. THIS WILL INCREASE BENEFITS FROM SUMMER EXPORT SALES, AND ENHANCE MAINTENANCE SCHEDULING, DAY-TO-DAY OPERATIONS AND DC TRANSIENT PERFORMANCE. THIS ITEM PROVIDES FOR UPGRADE OF FACILITIES AT HENDAY.
1997 10	8 265	CHANGE IN COST IS DUE TO CONVERSION TO SAP.

ASSOCIATED PROJECTS

Budget reference number	Description
03-00-5901	DORSEY BIPOLE 1 SPARE 300 KV CONVERTER TRANSFORMER
03-00-5902	RADISSON BIPOLE 1 SPARE 450KV CONVERTER TRANSFORMER
03-00-5903	DORSEY SPARE CONVERTER TRANSFORMER FOUNDATIONS
03-00-5904	HENDAY BIPOLE 2 SPARE 500KV CONV. TFR (SPARE # 1)
03-00-5905	DORSEY BIPOLE 2 SPARE SMOOTHING REACTOR (DORSME8)
03-00-5906	HENDAY BIPOLE 2 SPARE SMOOTHING REACTOR (HENDME2)
03-00-5907	DORSEY BIPOLE 2 COOLING UPGRADE (DORSME11)
03-00-6119	RADISSON STATION SST1 RELOCATION & SST2 & SST3 CABLE REPLACE
03-00-6129	DORSEY BIPOLE 1 SPARE 450KV CONVERTER TRANSFORMER
03-00-8369	DORSEY BIPOLE 1 SPARE 300 KV CONV. TFR (SPARE # 3)
03-00-8370	HENDAY BIPOLE 2 SPARE 500KV CONV. TFR (SPARE # 2)

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	14					14	14
May	14					14	28
Jun	14	1				15	43
Jul	19		1			20	63
Aug	19		1			20	83
Sep	46		1			47	130
Oct	19		1			20	150
Nov	15	1	1			17	167
Dec	15	1	1			17	184
Jan	228	1	2			231	415
Feb	229	3	3			235	650
Mar	229		5			234	884
TOTAL	861	7	16			884	884
2000/01 Apr	228	3	6			237	237
May	240	3	8			251	488
Jun	247	4	10			261	749
Jul	283	4	12			299	1 048
Aug	56	1	14			71	1 119
Sep	341	7	14			362	1 48[illegible]
Oct	316	6	17			339	1 82[illegible]
Nov	466	7	19			492	2 312
Dec	10		1			11	2 323
Jan							2 323
Feb							2 323
Mar							2 323
TOTAL	2 187	35	101			2 323	2 323

1999-09-28 10:56 AM

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item 13

Title: DORSEY BIPOLE 1 SPARE 300 KV CONV. TFR (SPARE # 3)

Budget reference number: 03-00-8369

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
HVDC	HVDC	HVDC	61896

DESCRIPTION:
Purchase and install a spare single-phase converter treansformer. The transformer rating is: 300 kV DC suitable for use in T12, T21 and T22 positions.

JUSTIFICATION:
Dorsey T22B phase is gassing. The dissolve gas analysis indicates that there is a defective connection which could fail at any time.

REFERENCE:
HVDC 98-03, Dorsey BP1 Spare 300kV Converter transformer Spare #3 for Dorsey T22B Phase.

REVISION:
CHANGE IN ACCOUNTING TREATMENT - TRANSFORMER TO BE CHARGED TO SERIALIZED EQUIPMENT INVENTORY.

IN SERVICE DATES

Base estimate: 199807 L4

Work start date: 2000 03 01

PREV. AUTHORITY Authorized to date:	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
1999/00	5					5
2000/01	1 471	2	10			1 483
2001/02	1 395	15	155			1 565
TOTAL	2 871	17	165			3 053
REV. AMOUNTS:						
Authorized to date:						
Over(under)expend:						
Auth Req.:						
TOTAL						

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

1999-08-21 05:25 PM

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 03-00-8369

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS

ASSOCIATED PROJECTS

Budget reference number	Description
03-00-5901	DORSEY BIPOLE 1 SPARE 300 KV CONVERTER TRANSFORMER
03-00-5902	RADISSON BIPOLE 1 SPARE 450KV CONVERTER TRANSFORMER
03-00-5903	DORSEY SPARE CONVERTER TRANSFORMER FOUNDATIONS
03-00-5904	HENDAY BIPOLE 2 SPARE 500KV CONV. TFR (SPARE # 1)
03-00-5905	DORSEY BIPOLE 2 SPARE SMOOTHING REACTOR (DORSME8)
03-00-5906	HENDAY BIPOLE 2 SPARE SMOOTHING REACTOR (HENDME2)
03-00-5907	DORSEY BIPOLE 2 COOLING UPGRADE (DORSME11)
03-00-5908	HENDAY - BIPOLE 2 COOLING UPGRADE (HENDME4)
03-00-6119	RADISSON STATION SST1 RELOCATION & SST2 & SST3 CABLE REPLACE
03-00-6129	DORSEY BIPOLE 1 SPARE 450KV CONVERTER TRANSFORMER
03-00-8370	HENDAY BIPOLE 2 SPARE 500KV CONV. TFR (SPARE # 2)
03-00-8395	HVDC BP1 & 2 Auxiliary Power Supply Upgrades
03-00-8396	Bipole 1 & 2 Electrode Line Monitoring
03-00-8398	Bipole 1 & 2 5/15KV Arcproofing and Brkr Upgrade

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item ___ Domestic Item 14

Title: HENDAY BIPOLE 2 SPARE 500KV CONV. TFR (SPARE # 2)

Budget reference number: 03-00-8370

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
[illegible]S	HVDC	Construction	61897

DESCRIPTION:
PURCHASE AND INSTALL A SPARE THREE-PHASE CONVERTER TRANSFORMER RATED AT 500 KV DC AND SUITABLE FOR USE IN T31S, T32S, T41S AND T42S POSITIONS. COST OF TRANSFORMER PUT INTO SERIALIZED EQUIPMENT INVENTORY.

JUSTIFICATION:
HENDAY T315 TRANSFORMER FAILED. THE EXISTING SPARE HAS BEEN PUT IN ITS PLACE. A NEW 500 KV SPARE IS REQUIRED BECAUSE THE EXISTING T315 FAILED UNIT CANNOT BE ECONOMICALLY AND RELIABLY REPAIRED.

REFERENCE:
REPORT HVDC 98-01, ENHANCEMENT OF THE NELSON RIVER TRANSMISSION SYSTEM.

REVISION:
CHANGE IN ACCOUNTING TREATMENT - TRANSFORMER CHARGED TO SERIALIZED EQUIPMENT INVENTORY.

IN SERVICE DATES

Base estimate: 199807 L4

Work start date: 1999 01 01

PREV. AUTHORITY Authorized to date	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
1999/00	266	7	6			279
2000/01	469	20	33			522
TOTAL	735	27	39			801
REV. AMOUNTS:						
Authorized to date:						
Over(under)expend:						
Auth Req.:						
TOTAL						

Prepared by: yy mm dd COORDINATOR Approved by: yy mm dd Approved by:
Estimated by: ORIGINATOR COORDINATING MANAGER ORIGINATING MANAGER

1999-08-21 05:25 PM

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 03-00-8370

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1998 10	809	NEW ITEM.

ASSOCIATED PROJECTS

Budget reference number	Description
03-00-5901	DORSEY BIPOLE 1 SPARE 300 KV CONVERTER TRANSFORMER
03-00-5902	RADISSON BIPOLE 1 SPARE 450KV CONVERTER TRANSFORMER
03-00-5903	DORSEY SPARE CONVERTER TRANSFORMER FOUNDATIONS
03-00-5904	HENDAY BIPOLE 2 SPARE 500KV CONV. TFR (SPARE # 1)
03-00-5905	DORSEY BIPOLE 2 SPARE SMOOTHING REACTOR (DORSME8)
03-00-5906	HENDAY BIPOLE 2 SPARE SMOOTHING REACTOR (HENDME2)
03-00-5907	DORSEY BIPOLE 2 COOLING UPGRADE (DORSME11)
03-00-5908	HENDAY - BIPOLE 2 COOLING UPGRADE (HENDME4)
03-00-6119	RADISSON STATION SST1 RELOCATION & SST2 & SST3 CABLE REPLACE
03-00-6129	DORSEY BIPOLE 1 SPARE 450KV CONVERTER TRANSFORMER
03-00-8369	DORSEY BIPOLE 1 SPARE 300 KV CONV. TFR (SPARE # 3)
03-00-8395	HVDC BP1 & 2 Auxiliary Power Supply Upgrades
03-00-8396	Bipole 1 & 2 Electrode Line Monitoring
03-00-8398	Bipole 1 & 2 5/15KV Arcproofing and Brkr Upgrade

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

COMPLEX STATUS	Complex no.	REVISION STATUS
☐ Planned ☒ In progress	88	☐ New complex ☐ In service change ☒ Concept change ☐ Estimate change only

COMPLEX: BIPOLE 1 - CONVERTER TRANSFORMERS

Proposal

Repairs to Dorsey BP1 T13A & T21A converter transformers, and completion of Radisson windings and winding clampings on one single phase converter transformer.

JUSTIFICATION	Explanation
☐ Load ☐ Service ☐ Safety ☐ Efficiency ☒ Reliability ☐ Other	Arc backs and consequential arc backs from the mercury arc valves are causing the tertiary windings to shift. This movement can cause the insulation to be damaged and result in failures.

Estimate Level	COMPLEX START (yyyy mm)
L2	1994 04

IN SERVICE DATES AND AMOUNTS					
1997 03	$1245	1999 02	$3526	1999 03	$164

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	4,804		131		4,935	5,873	-938	-16
ar 99/00						1,585	-1,585	-100
00/01								
01/02								
02/03								
03/04								
04/05								
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	4,804		131		4,935	7,458	-2,523	-34

REVISION: Reflects actual cost to repair T13A converter transformer, and to change accounting treatment by charging Conv Tfr T21A (spare #2) to inventory.

Reviewed by ORIGINATOR	yyyy mm dd 94 11 01	Reviewed by COORDINATOR	yyyy mm dd
Reviewed by CONSTRUCTOR	yyyy mm dd	Approved by VICE-PRESIDENT	yyyy mm dd 94 11 12

H2856/r Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Complex no. 88

Advance or deferral impact

Tertiary winding shift can cause the insulation to be damaged and result in failures.

Factors affecting timing or viability

Delivery of new spare converter transformer at site (slated for 1994)

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Dorsey BP1 T21A Converter Transformer Repairs	2,437	2,621	2,673	0	-2,673	-100
Dorsey BP1 T13A Converter Transformer Repairs	3,091	3,327	3,394	3,590	196	6
Radisson Stn Converter Transformer Modification				1,215	1,215	
TOTAL	5,528	5,948	6,067	4,805	-1,262	-21

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
9510	4,616	Base date updated. Divisional overhead rate increase applied Last 2 transformer deliveries delayed one year..
9610	1,481	Cancel remaining two transformer modifications based on inspection of first transformer by Pauwels Canada Inc. Revised escalation and interest rates and re-cashflowed.
9710	7,053	Reflects completion of Radisson transformer modification, & addition of items covering repairs to Dorsey BP1 T13A, & T21A converter transformers.
9810	7,458	Scope of work revised to reflect the decision to purchase a new transformer rather than extensive repairs.
1999 10	4,935	Reflects actual cost to repair T13A converter transformer, and to change accounting treatment by charging Conv Tfr T21A (spare #2) to inventory.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item 15

Title			Budget reference number
DORSEY BP1 300kv CONV. TFR FOR T21A (SPARE # 2)			03-00-8294
Originating division	Coordinating division	Constructing division	Project Order Group (Range):
HVDC	HVDC	HVDC	61856

DESCRIPTION:
REPLACE T21-A PHASE CONVERTER TRANSFORMER WITH A NEW TRANSFORMER.

JUSTIFICATION:
IN 1994 THE 230kv AC BUSHING EXPLODED SPREADING DEBRIS AND ALUMINUM FOIL THROUGH THE TRANSFORMER. THE TANK ON THE TRANSFORMER WAS REPLACED IN THE FACTORY. THE CORE AND COILS WERE THOROUGHLY FLUSHED TO CLEAN THEM AND THEY WERE REUSED. RECENTLY THE TRANSFORMER HAS BEEN GASSING AND WE HAVE DETERMINED IT IS COMING FROM THE CORE STEEL. THIS REQUIRES REPLACING BOTH THE CORE AND COILS AS THE COILS STILL HAVE DEBRIS IN THEM. ESTIMATES HAVE DETERMINED THAT THE COST OF A NEW TRANSFORMER IS LESS THAN THAT OF REPAIRING THE EXISTING UNIT (INCLUDING OUTAGE COSTS), THUS IT HAS BEEN DECIDED TO PURCHASE A NEW TRANSFORMER.

REFERENCE:
REPORT HVDC 97-06

REVISION:
CHANGE IN ACCOUNTING TREATMENT - TRANSFORMER CHARGED TO SERIALIZED EQUIPMENT INVENTORY.

IN SERVICE DATES			Base estimate
1999 07 31	0		199805 L3
			Work start date 1997 10 01

PREV. AUTHORITY Authorized to date	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
1999/00	2 652	28	48			2 728
TOTAL	2 652	28	48			2 728
REV. AMOUNTS:						
Authorized to date:						
Over(under)expend:						
Auth Req.:						
TOTAL						

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 03-00-8294

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS

ASSOCIATED PROJECTS

Budget reference number	Description
03-00-1685	RADISSON STATION - CONVERTER TRANSFORMER MODIFICATION
03-00-8302	DORSEY - BIPOLE 1 T13A CONVERTER TRANSFORMER REPAIRS

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item

16

Title
DORSEY - BIPOLE 1 T13A CONVERTER TRANSFORMER REPAIRS

Budget reference number
03-00-8302

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
[illegible]r Deleted	Master Deleted	Master Deleted	61860:61865

DESCRIPTION:
REPLACE THE COILS OF T13 A-PHASE CONVERTER TRANSFORMER AT THE MANUFACTURER'S FACTORY AND SUCCESSFULLY TEST THE COMPLETE UNIT.
RETURN THE UNIT TO SERVICE.

JUSTIFICATION:
THE TRANSFORMER TRIPPED ON FAST GAS. SUBSEQUENT TESTS REVEALED THAT ONE LEG OF THE WINDING WAS COMPLETELY DAMAGED AND WAS OPEN CIRCUITED. THIS REQUIRES REPLACING THE COILS. THE CORE CAN STILL BE USED.

REFERENCE:
REPORT HVDC 97-03

REVISION:
REVISED TO REFLECT ACTUAL COST OF REPAIRS AND PLACING THE UNIT BACK INTO SERVICE.

IN SERVICE DATES		Base estimate
1999 02 28	3 526	199707 L3
1999 03 31	164	Work start date
1999 04 30	0	1997 10 01

	PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date		3 590		100			3 690
1999/00		- 205					- 205
TOTAL		3 385		100			3 485
REV. AMOUNTS:							
Authorized to date:		3 590		100			3 690
Over(under)expend:							
Auth Req.:	1999/00						
TOTAL		3 590		100			3 690

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 03-00-8302

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1997 10	3 216	NEW ITEM.

ASSOCIATED PROJECTS

Budget reference number	Description
03-00-1685	RADISSON STATION - CONVERTER TRANSFORMER MODIFICATION
03-00-8294	DORSEY BP1 300kv CONV. TFR FOR T21A (SPARE # 2)

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

17

[X] Major Item [ ] Domestic Item

Title			Budget reference number
RADISSON STATION - CONVERTER TRANSFORMER MODIFICATION			03-00-1685
Originating division	Coordinating division	Constructing division	Project Order Group (Range):
HVDC	HVDC	HVDC	61826

DESCRIPTION:
REPLACE TERTIARY WINDINGS AND MODIFY THE WINDING CLAMPINGS ON THREE SINGLE PHASE CONVERTER TRANSFORMERS FROM RADISSON STATION.

JUSTIFICATION:
TESTS HAVE INDICATED THAT THE TERTIARY WINDINGS ON THESE TRANSFORMERS ARE SHIFTING. THESE TRANSFORMERS ARE LIABLE TO FAIL IF KEPT IN SERVICE WITHOUT MODIFICATIONS. THESE CONVERTER TRANSFORMERS WERE BUILT BEFORE AXIAL COMPRESSION OF THE WINDINGS BECAME AN INDUSTRY STANDARD. ARC BACKS AND CONSEQUENTIAL ARC BACKS FROM THE MERCURY ARC VALVES ARE CAUSING THE TERTIARY WINDINGS TO SHIFT. THIS MOVEMENT CAN CAUSE THE INSULATION TO BE DAMAGED AND RESULT IN FAILURES.

REVISION:
COMPLETE.

IN SERVICE DATES				Base estimate
1997 03 31	1 246			199610 L2
				Work start date
				1997 08 01

	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
PREV. AUTHORITY Authorized to date:	1 215		31			1 246
TOTAL	1 215		31			1 246
REV. AMOUNTS: Authorized to date:	1 215		31			1 246
Over(under)expend:						
Auth Req.:						
TOTAL	1 215		31			1 246

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

4081

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 03-00-1685

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1991 10	3 785	PROJECT DEFERRED TO 1992/93 START.
1992 10	4 331	PROJECT DEFERRED TO 1994/95 START.
1993 10	4 375	PROJECT START DEFERRED TO OCT/94.
1994 10	4 120	PROJECT START DEFERRED TO APR/95.
1995 10	4 616	REVISED ESTIMATE BASED ON DORSEY AND HENDAY REPAIRS.
1996 10	1 481	CANCELLED REMAINING TWO TRANSFORMER MODIFICATIONS. REVISED ESCALATION AND INTEREST RATES AND RE-CASHFLOWED.
1997 10	1 245	COMPLETE.

ASSOCIATED PROJECTS

Budget reference number	Description
03-00-8294	DORSEY BP1 300kv CONV. TFR FOR T21A (SPARE # 2)
03-00-8302	DORSEY - BIPOLE 1 T13A CONVERTER TRANSFORMER REPAIRS

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

COMPLEX STATUS: [X] Planned [ ] In progress

Complex no. 11

REVISION STATUS: [ ] New complex [ ] In service change [ ] Concept change [X] Estimate change only

COMPLEX: BIPOLE 1 MERCURY ARC VALVES - STAGE 3

Proposal

Replace Bipole 1 HVDC Mercury Arc Valve Groups 21, 22 and 23 with Thyristor Valves at Dorsey and Radisson stations.

JUSTIFICATION

[ ] Load [ ] Service
[ ] Safety [ ] Efficiency
[X] Reliability [ ] Other

Explanation

Continuing deterioration of the Mercury Arc Valves will make change-out of the remaining valve groups necessary. State-of-the-art Thyristor Valves will be used to replace all Mercury Arc Valves in three stages. This complex is the 3rd stage.

Estimate Level	COMPLEX START (yyyy mm)
L2	2001 06

IN SERVICE DATES AND AMOUNTS

2004 09	$54490	2005 03	$54490	2005 09	$42064

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend								
Year 99/00								
00/01								
01/02	870	84	37		991	975	16	2
02/03	3,218	383	230		3,831	3,768	63	2
03/04	36,299	5129	2,078		43,506	42,774	732	2
04/05	48,364	7937	4,194		60,495	59,470	1,025	2
05/06	34,699	6503	366		41,568	40,897	671	2
06/07	539	114			653	643	10	2
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	123,989	20,150	6,905		151,044	148,527	2,517	2

REVISION: Reflects updated escalation and interest.

Reviewed by ORIGINATOR	yyyy mm dd 99 11 03	Reviewed by COORDINATOR	yyyy mm dd		
Reviewed by CONSTRUCTOR	yyyy mm dd	Approved by VICE PRESIDENT	yyyy mm dd 99 11 4083		

H2856/r Rev 99 03

Complex no. 11

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Advance or deferral impact

Deferral would reduce HVDC Bipole 1 availability due to frequent outages of the Mercury Arc Valves. Loss of export revenues would result.

Factors affecting timing or viability

Rate of deterioration of Mercury Arc Valves.
Delays from Valve suppliers.
Opportunities for outages to do valve changeouts.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Dorsey-Bipole 1 Mercury Arc Valve Repl.-Stage 3		57,191	58,335	58,789	454	1
Radisson-Bipole 1 Mercury Arc Valve Repl-Stage 3		63,558	64,829	65,201	372	1
TOTAL		120,749	123,164	123,990	826	1

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
9510	156,451	In-service dates deferred 2 years to 2003 09 30, 2004 03 31 and 2004 09 30.
9610	158,593	In-service dates deferred 1 year to 2004 09 30, 2005 03 31 and 2005 09 30.
9710	152,465	Revised to reflect current escalation and interest rates.
9810	148,527	Reflects updated escalation and interest.
1999 10	151,044	Reflects updated escalation and interest.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION
Complex 44	Bipole 1 Mercury Arc Valves - Stage 1
Complex 37	Bipole 1 Mercury Arc Valves - Stage 2

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item 18

Title			Budget reference number
DORSEY STATION BIPOLE 1 MERCURY ARC VALVE REPL-STAGE 3			03-00-2334
Originating division	Coordinating division	Constructing division	Project Order Group (Range):
HVDC	HVDC	Construction	61849

DESCRIPTION:
DESIGN AND REPLACEMENT OF VALVE GROUPS 21, 22, AND 23 OF THE BIPOLE 1 MERCURY ARC VALVES WITH THYRISTOR VALVES AT DORSEY STATION INCLUDING NEW VALVE GROUP CONTROL AND PROTECTION SYSTEMS WITH EACH VALVE GROUP RATED AT 167 KV, 2000 A, AND 333 MW.

JUSTIFICATION:
BASED ON INVESTIGATIONS AND REPORTS ON VALVE CONDITIONS AND PORCELAIN FAILURES, NEED FOR REPLACEMENT OF REMAINING VALVE GROUPS IS PROJECTED ACCORDING TO THE FOLLOWING SCHEDULE:
VALVE GROUP 21 - 2004 09 30
VALVE GROUP 22 - 2005 03 31
VALVE GROUP 23 - 2005 09 30

REFERENCE:
HVDC TASK FORCE REPORT OF 1988 04 27 TITLED 'MERCURY ARC VALVE GROUP REPLACEMENT'. HVDC TASK FORCE REPORT OF 1988 07 25 TITLED 'ADDENDUM TO MERCURY ARC VALVE GROUP REPLACEMENT REPORT'. MINUTES OF HVDC TASK FORCE MEETING OF 1995 01

REVISION:
UPDATED ESCALATION AND INTEREST.

IN SERVICE DATES		Base estimate
2004 09 30	25 896	199604 L1
2005 03 31	25 896	
2005 09 30	20 140	Work start date
		2001 04 01

PREV AUTHORITY Authorized to date:	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
2001/02	401	45	18			464
2002/03	1 485	201	106			1 792
2003/04	16 743	2 647	956			20 346
2004/05	22 308	4 044	1 938			28 290
2005/06	16 005	3 279	174			19 458
2006/07	249	57				306
TOTAL	57 191	10 273	3 192			70 656
REV. AMOUNTS: Authorized to date: Over(under)expend:						
Auth 2001/02	412	42	18			472
Req. 2002/03	1 526	189	109			1 824
2003/04	17 211	2 516	990			20 717
2004/05	22 932	3 879	1 999			28 810
2005/06	16 452	3 167	179			19 798
2006/07	256	55				311
TOTAL	58 789	9 848	3 295			71 932

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

CAPITAL EXPENDITURE REVISION

Budget reference number 03-00-2334

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1991 10	93 398	NEW ITEM. VALVE GROUPS 21, 22 AND 23 REPLACEMENTS WERE PREVIOUSLY INCLUDED UNDER BRN 9203-00-8558.
1992 10	82 302	DECREASE IN ESCALATION AND INTEREST RATES PARTIALLY OFFSET BY INCREASE IN ENGINEERING.
1993 10	79 149	DECREASE IN ESCALATION AND INTEREST RATES.
1994 10	70 446	COSTS ARE BASED ON STAGES 1 AND 2 ACTUALS. REVISED INTEREST AND ESCALATION RATES.
1995 10	74 186	IN-SERVICE DATES DEFERRED 2 YEARS TO 2003 09 30, 2004 03 31 AND 2004 09 30.
1996 10	75 251	IN-SERVICE DATES DEFERRED 1 YEARS TO 2004 09 30, 2005 03 31 AND 2005 09 30.
1997 10	72 755	UPDATED ESCALATION AND INTEREST.

ASSOCIATED PROJECTS

Budget reference number	Description
03-00-2335	RADISSON STATION BIPOLE 1 MERCURY ARC VALVE REPL - STAGE 3

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item

19

Title
RADISSON STATION BIPOLE 1 MERCURY ARC VALVE REPL - STAGE 3

Budget reference number
03-00-2335

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
HVDC	HVDC	Construction	61850

DESCRIPTION:
DESIGN AND REPLACEMENT OF VALVE GROUPS 21, 22 , AND 23 OF THE BIPOLE 1 MERCURY ARC VALVES WITH THYRISTOR VALVES AT RADISSON STATION INCLUDING NEW VALVE GROUP CONTROL AND PROTECTION SYSTEMS WITH EACH VALVE GROUP RATED AT 167 KV , 2000 A, AND 333 MW.

JUSTIFICATION:
BASED ON INVESTIGATIONS AND REPORTS ON VALVE CONDITIONS AND PORCELAIN FAILURES, NEED FOR REPLACEMENT OF REMAINING VALVE GROUPS IS PROJECTED ACCORDING TO THE FOLLOWING SCHEDULE: VALVE GROUP 21 - 2004 09 30
VALVE GROUP 22 - 2005 03 31
VALVE GROUP 23 - 2005 09 30

REFERENCE:
HVDC TASK FORCE REPORT OF 1988 04 27 TITLED 'MERCURY ARC VALVE GROUP REPLACEMENT'.HVDC TASK FORCE REPORT OF 1988 07 25 TITLED 'ADDENDUM TO MERCURY ARC VALVE GROUP REPLACEMENT REPORT'.

MINUTES OF HVDC TASK FORCE MEETING OF 1995 01 12.

REVISION:
UPDATED ESCALATION AND INTEREST.

IN SERVICE DATES		Base estimate
2004 09 30	28 595	199604 L1
2005 03 31	28 595	
2005 09 30	21 922	Work start date
		2001 03 01

PREV. AUTHORITY Authorized to date:	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
2001/02	446	46	20			512
2002/03	1 650	208	117			1 975
2003/04	18 607	2 767	1 054			22 428
2004/05	24 792	4 256	2 132			31 180
2005/06	17 787	3 470	182			21 439
2006/07	276	61				337
TOTAL	63 558	10 808	3 505			77 871
REV. AMOUNTS: Authorized to date. Over(under)expend:						
Auth 2001/02	457	43	19			519
Req 2002/03	1 692	195	120			2 007
2003/04	19 088	2 612	1 089			22 789
2004/05	25 433	4 059	2 194			31 686
2005/06	18 247	3 335	187			21 769
2006/07	284	58				342
TOTAL	65 201	10 302	3 609			79 112

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

1999-08-21 05:19 PM

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 03-00-2335

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1991 10	105 886	NEW ITEM. VALVE GROUPS 21, 22 AND 23 REPLACEMENTS WERE PREVIOUSLY INCLUDED UNDER BRN 9203-00-8559.
1992 10	92 724	DECREASE IN ESCALATION AND INTEREST RATES PARTIALLY OFFSET BY INCREASE IN ENGINEERING.
1993 10	88 995	DECREASE IN ESCALATION AND INTEREST RATES.
1994 10	78 103	COSTS ARE BASED ON STAGES 1 AND 2 ACTUALS. REVISED INTEREST AND ESCALATION RATES.
1995 10	82 265	IN-SERVICE DATES DEFERRED 2 YEARS TO 2003 09 30, 2004 03 31 & 2004 09 30.
1996 10	83 342	IN-SERVICE DATES DEFERRED 1 YEAR TO 2004 09 30, 2005 03 31, & 2005 09 30.

ASSOCIATED PROJECTS

Budget reference number	Description
03-00-2334	DORSEY STATION BIPOLE 1 MERCURY ARC VALVE REPL-STAGE 3

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

COMPLEX STATUS: ☐ Planned ☒ In progress

Complex no. 5

REVISION STATUS: ☐ New complex ☒ In service change ☐ Concept change ☒ Estimate change only

COMPLEX: HVDC BIPOLE 2 THYRISTOR POLY PIPE REPLACEMENTS

Proposal

Complete replacement of all polyamide piping associated with the thyristor module and header system on valve halls 31, 32, 41 and 42 at Henday and Dorsey converter stations.

Material will be purchased in Aug/Sept 96 and 97. Piping replacement will be installed equally over two years beginning Aug 96.

JUSTIFICATION

☐ Load ☐ Service
☐ Safety ☐ Efficiency
☒ Reliability ☐ Other

Explanation

The polyamide tubing directs cooling water essential for the operation of the valves. This tubing has reached the end of it's useful life and must be replaced before it fails, becomes brittle and breaks, plugging and overheating the thyristor and reactor modules.

Estimate Level	COMPLEX START (yyyy mm)
L4	1995 05

IN SERVICE DATES AND AMOUNTS							
1998 03	$2294	1999 01	$880	1999 06	$476	1999 10	$695
2000 10	$1170						

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	3,091		269		3,360	4,613	-1,253	-27
Year 99/00	1,306	25	29		1,360	2,184	-824	-38
00/01	732	27	35		794	702	92	13
01/02								
02/03								
03/04								
04/05								
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	5,129	52	333		5,514	7,499	-1,985	-26

REVISION: Reflects lower actual cost of polyamide tubing and reduction in installation estimates.

Reviewed by ORIGINATOR	yyyy mm dd 94 11 03	Reviewed by COORDINATOR	yyyy mm dd
Reviewed by CONSTRUCTOR	yyyy mm dd	Approved by VICE-PRESIDENT	yyyy mm dd 94 11 12

H2856/r Rev 99 03

Complex no. 5

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Advance or deferral impact

Loss of bipole 2 capability.

Factors affecting timing or viability

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
DORSEY BP2 POLY PIPE REPLACEMENT	3,687	3,393	3,461	2,417	-1,044	-30
HENDAY BP2 POLY PIPE REPLACEMENT	4,384	3,738	3,813	2,712	-1,101	-29
TOTAL	8,071	7,131	7,274	5,129	-2,145	-29

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
9510	8,140	Increased overhead rates, higher estimate level (includes quoted prices). Advanced work schedule.
9610	8,169	Revised estimate based on current replacement schedule, escalation and interest rates and recashflowed.
9710	8,722	Reflects revised costing methodology of the new financial reporting system. Increased costs are also due to in-service date deferrals (approx 2 yr) for each remaining installation.
9810	7,499	Revised to reflect 97/98 underexpenditure of 0.9M and lower projected cost of polyamide tubing installation.
1999 10	5,514	Reflects lower actual cost of polyamide tubing and reduction in installation estimates.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item 20

Title: DORSEY - BP II THYRISTOR MODULES POLYAMIDE TUBING REPL.

Budget reference number: 03-00-4804

Originating division	Coordinating division	Constructing division	Project Order Group (Range)
HVDC	HVDC	HVDC	61829

DESCRIPTION:
THE POLYAMIDE TUBING IS USED FOR THE COOLING WATER OF THE THYRISTOR VALVES.

JUSTIFICATION:
THE POLYAMIDE TUBING HAS REACHED THE END OF ITS USEFULL LIFE BASED ON THE RECOMMENDATION OF THE DESIGNER/SUPPLIER, AND MUST BE REPLACED BEFORE FAILURES OCCUR IN SERVICE.

REVISION:
ESTIMATE DECREASED TO REFLECT LOWER ACTUAL COST OF POLYAMIDE TUBING AND REDUCTION IN INSTALLATION ESTIMATES.

IN SERVICE DATES

1998 03 31	1 113
1999 01 31	536
1999 06 30	476
2000 10 31	475

Base estimate: 199707 L4

Work start date: 1997 04 01

PREV AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date	1 595		145			1740
1999/00	1 580	27	24			1631
2000/01	198	8	15			221
TOTAL	3 373	35	184			3592
REV. AMOUNTS						
Authorized to date:	1 595		145			1740
Over(under)expend:						
Auth 1999/00	612	6	10			628
Req. 2000/01	210	5	17			232
TOTAL	2 417	11	172			2600

Prepared by: yy mm dd COORDINATOR — Approved by: yy mm dd Approved by: yy mm dd

Estimated by: ORIGINATOR — COORDINATING MANAGER — ORIGINATING MANAGER

CAPITAL EXPENDITURE REVISION

Budget reference number 03-00-4804

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1994 10	2 457	NEW ITEM.
1995 10	4 049	INCREASED DIVISIONAL OVERHEAD RATES. PRICES BASED ON SUPPLIER QUOTE. SCHEDULE ADVANCED.
1997 10	3 925	BASE DATE UPDATED. ISD'S DEFERRED APPROXIMATELY 2 YEARS FOR EACH REMAINING INSTALLATION.
1999 10	2 578	ESTIMATE DECREASED TO REFLECT LOWER ACTUAL COST OF POLYAMIDE TUBING AND REDUCTION IN INSTALLATION ESTIMATES.

ASSOCIATED PROJECTS

Budget reference number	Description
03-00-5827	HENDAY-BP II THYRISTOR MODULES POLYAMIDE TUBING REPL.

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	115	1	1			117	117
May	115	2	1			118	235
Jun	115	2	2			119	354
Jul	30					30	384
Aug	30					30	414
Sep	30					30	444
Oct	30					30	474
Nov	30		1			31	505
Dec	29	1	1			31	536
Jan	29	1	1			31	567
Feb	29	1	1			31	598
Mar	30	-2	2			30	628
TOTAL	612	6	10			628	628
2000/01 Apr	30		2			32	32
May	30	1	2			33	65
Jun	30	1	2			33	98
Jul	30	1	2			33	131
Aug	30		3			33	164
Sep	30	1	3			34	198
Oct	30	1	3			34	232
Nov							232
Dec							232
Jan							232
Feb							232
Mar							232
TOTAL	210	5	17			232	232

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — 21 Domestic Item

Title
HENDAY-BP II THYRISTOR MODULES POLYAMIDE TUBING REPL.

Budget reference number
03-00-5827

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
HVDC	HVDC	HVDC	61827

DESCRIPTION:
COMPLETE REPLACEMENT OF ALL PLASTIC PIPING ASSOCIATED WITH THE THYRISTOR MODULE AND HEADER SYSTEM IN VALVE HALLS 31, 32, 41, AND 42. MATERIAL WILL BE PURCHASED IN TWO BATCHES. THE FIRST SHIPMENT IS SCHEDULED FOR JAN/FEB, 1996 AND THE SECOND IS SCHEDULED FOR JAN/FEB, 1998. PIPING REPLACEMENT WILL BE INSTALLED EQUALLY OVER THE YEARS OF MARCH 1996 TO MARCH 1997 FOR THE FIRST BATCH AND MARCH 1998 TO MARCH 1999 FOR THE SECOND BATCH.

JUSTIFICATION:
THE POLYAMIDE TUBING IS USED TO DIRECT THE COOLING WATER REQUIRED BY THE THYRISTOR VALVES. THEY WILL NOT OPERATE WITHOUT THEM. THE POLYAMIDE TUBING HAS REACHED THE END OF ITS USEFUL LIFE BASED ON THE RECOMMENDATION OF THE DESIGNER/SUPPLIER, AND MUST BE REPLACED BEFORE FAILURES OCCUR IN SERVICE.

REVISION:
ESTIMATE DECREASED TO REFLECT LOWER ACTUAL COST OF POLYAMIDE TUBING AND REDUCTION IN INSTALLATION ESTIMATES.

IN SERVICE DATES

1998 03 31	1 181
1999 01 31	344
1999 10 31	695
2000 10 31	693

Base estimate
199707 L3

Work start date
1997 04 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date	1 496		123			1 619
1999/00	1 769	33	4			1 806
2000/01	450	19	12			481
TOTAL	3 715	52	139			3 906
REV. AMOUNTS:						
Authorized to date:	1 496		123			1 619
Over(under)expend:						
Auth 1999/00	694	18	20			732
Req.: 2000/01	522	21	19			562
TOTAL	2 712	39	162			2 913

Prepared by — yy mm dd — COORDINATOR
Approved by — yy mm dd — COORDINATING MANAGER
Approved by — yy mm dd — ORIGINATING MANAGER
Estimated by — ORIGINATOR

1999-08-21 05:20 PM

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 03-00-5827

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1994 10	2 433	NEW ITEM.
1995 10	4 091	INCREASED DIVISIONAL OVERHEAD RATES. PRICES BASED ON SUPPLIER QUOTE. SCHEDULE ADVANCED.
1996 10	4 605	REVISED ESTIMATE, ESCALATION AND INTEREST RATES, AND RECASHFLOWED.
1997 10	4 716	INCREASE IN COST IS DUE TO NEW HIGHER SAP ACTIVITY AND OVERHEAD RATES. ISD'S DEFERRED APPROXIMATELY 2 YEARS FOR EACH REMAINING INSTALLATION.

ASSOCIATED PROJECTS

Budget reference number	Description
03-00-4804	DORSEY - BP II THYRISTOR MODULES POLYAMIDE TUBING REPL.

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	117	2	1			120	120
May	117	3	1			121	241
Jun	117	3	2			122	363
Jul	38	1	3			42	405
Aug	38	2	3			43	448
Sep	38	1	4			43	491
Oct	38	1	4			43	534
Nov	38	1				39	573
Dec	38	1				39	612
Jan	38	1				39	651
Feb	38	2				40	691
Mar	39		2			41	732
TOTAL	694	18	20			732	732
2000/01 Apr	80	3	1			84	84
May	79	3	2			84	168
Jun	73	3	2			78	246
Jul	73	2	3			78	324
Aug	72	4	3			79	4[illegible]
Sep	72	3	4			79	[illegible]
Oct	73	3	4			80	[illegible]
Nov							562
Dec							562
Jan							562
Feb							562
Mar							562
TOTAL	522	21	19			562	562

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

COMPLEX STATUS: ☐ Planned ☒ In progress

Complex no. 54

REVISION STATUS: ☐ New complex ☐ In service change ☐ Concept change ☒ Estimate change only

COMPLEX: CONVERTER TRANSFORMER BUSHING REPLACEMENT

Proposal

Replace converter transformer bushings with NGK bushings, and purchase spares as follows: at Dorsey replace six 230kv AC, and six 25kv tertiary bushings; and at Radisson/Henday replace five 138kv, two 150kv, four 230kv, and three 15kv tertiary bushings, and purchase two 300kv and two 450kv spares.

JUSTIFICATION

☒ Load ☐ Service
☐ Safety ☐ Efficiency
☒ Reliability ☐ Other

Explanation

The bushing replacement program was undertaken due to failure of a 230kv bushing in Dorsey T21 A-phase converter transformer which resulted in costly repairs to the transformer, and loss of revenue due to the outage. Also during repair of Dorsey T31S converter transformer in Pauwel's Canada plant two out of two 230kv bushings being tested failed at far below the full test voltage. The manufacturers expected service life is 25 years. These bushings have all been in service more than 17 years. Replacement cost is justified when compared to transformer damage due to an in service failure.

Estimate Level	COMPLEX START (yyyy mm)
L3	1994 11

IN SERVICE DATES AND AMOUNTS

1995 03 31	$134	1996 03	$946	1996 05	$575	1997 03	$403
1997 10	$357	1998 04	$275	1998 06	$123	1999 01	$1359
1999 02	($342)	1999 04	$199	1999 12	$236	2000 on	$2170

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	3,776		264		4,040	4,079	-39	-1
Year 99/00	327	2	22		351	1,215	-864	-71
00/01	1,286	31	23		1,340	676	664	98
01/02	545	24	11		580	218	362	166
02/03	120	7	1		128		128	
03/04								
04/05								
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	6,054	64	321		6,439	6,188	251	4

REVISION: Revised to reflect a seven month ISD and forecast deferral at Dorsey.

Reviewed by ORIGINATOR	yyyy mm dd 94 11 03	Reviewed by COORDINATOR	yyyy mm dd		
Reviewed by CONSTRUCTOR	yyyy mm dd	Approved by VICE-PRESIDENT	yyyy mm dd 94 11 12		

H2856/r Rev 99 03

Complex no. 54

CAPITAL EXPENDITURE FORECAST COMPLEX
(IN THOUSANDS OF DOLLARS)

Advance or deferral impact

Deferral will increase the number of bushing failures, and occurances of damage to converter transformers, outages, and associated revenue loss.

Factors affecting timing or viability

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE	
					Amount	%
Dorsey AC converter transformer bushing repl	2,911	3,269	3,334	3,428	94	3
Radisson/Henday converter transformer bushing rep	3,376	2,596	2,648	2,626	-22	-1
TOTAL	6,287	5,865	5,982	6,054	72	1

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
95 10	6,114	New Complex transferred from domestic.
96 10	6,591	Revised to add regasketing of T41 & T31 transformers at Henday, in service date at Dorsey, and update cashflows, escalation & interest.
9710	5,852	Reflects revised costing methodology of the new financial reporting system, reduction for favourable install costs at Rad/Hen, & increase due to work deferral 3-6 mo. at Dorsey.
9810	6,188	Reflects 97/98 underexpenditure .5M and increases to include the purchase of additional spare bushings for Henday converter and Dorsey DC transformers.
1999 10	6,439	Revised to reflect a seven month ISD and forecast deferral at Dorsey.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item _ Domestic Item

Title
DORSEY CONVERTER TRANSFORMER BUSHING REPLACEMENT/SPARES

Budget reference number
03-00-6126

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
C	HVDC	HVDC	61830

DESCRIPTION:
THE AC 230KV BUSHINGS IN CONVERTER TRANSFORMERS (T22, T23, T31S, T31D, T41S AND T41D) AND THE 25KV TERTIARY BUSHINGS IN CONVERTER TRANSFORMERS (T11, T12, T13, T21, T22, AND T23) ARE BEING REPLACED WITH NGK BUSHINGS. THE PURCHASE OF ONE SPARE 125kv DC, ONE SPARE 250kv DC, ONE SPARE 300kv DC, ONE SPARE 375kv DC, ONE SPARE 450kv DC, AND ONE SPARE 500kv DC TRANSFORMER BUSHING, AND THE WORK TO TEST THE BUSHINGS AND BUILD BUSHING STANDS.

JUSTIFICATION:
THE DECISION TO GO INTO A BUSHING REPLACEMENT PROGRAM WAS MADE DUE TO A FAILURE OF A 230KV BUSHING IN DORSEY T21 A-PHASE CONVERTER TRANSFORMER WHICH RESULTED IN THE VERY COSTLY REPAIRS TO THE TRANSFORMER AND LOSS OF REVENUE DUE TO THE OUTAGE. ALSO DURING THE REPAIR OF DORSEY T31S CONVERTER TRANSFORMER IN PAUWEL'S CANADA PLANT TWO OUT OF TWO 230KV BUSHINGS BEING TESTED FAILED AT FAR BELOW THE FULL TEST VOLTAGE. THE MANUFACTURER OF THESE BUSHINGS STATES THAT THE EXPECTED SERVICE LIFE OF THESE BUSHINGS IS 25 YEARS. SERVICE LIFE MEANS THAT A FAILURE RATE OF 50 PERCENT CAN BE EXPECTED WITHIN 25 YEARS. THESE BUSHINGS HAVE ALL BEEN IN SERVICE FOR MORE THAN SEVENTEEN YEARS. THE COST OF REPLACING ALL OF THESE BUSHINGS IS JUSTIFIED WHEN COMPARED TO THE REPAIR AND OUTAGE COSTS RESULTING FROM CONVERTER TRANSFORMERS BEING DAMAGED DUE TO AN IN SERVICE BUSHING FAILURE. BECAUSE THE SERVICE LIFE IS 25 YEARS AND WE ARE STARTING TO EXPERIENCE FAILURES WE ARE ANTICIPATING THAT THE FAILURE RATE WILL INCREASE DRAMATICALLY IN THE NEXT FEW YEARS IF THE BUSHINGS ARE NOT REPLACED. THE PURCHASE OF SPARE DC TRANSFORMER BUSHINGS WILL ENSURE THAT WE HAVE REPLACEMENTS IN THE EVENT THAT THEY ARE REQUIRED.

REVISION:
ISD DEFERRED 7 MONTHS.
UPDATED INTEREST AND ESCALATION.

IN SERVICE DATES

1996 03 31	850	2000 04 30	236	2002 04 30	235
1999 01 31	1 348	2000 10 31	472		
1999 02 28	- 343	2001 04 30	236		
1999 12 31	236	2001 10 31	472		

Base estimate
199610 L4

Work start date
1997 04 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date	1 832		218			2 050
1999/00	786	17	20			823
2000/01	391	16	16			423
2001/02	201	14	3			218
TOTAL	3 210	47	257			3 514
REV. AMOUNTS:						
Authorized to date:	1 832		218			2 050
Over(under)expend:						
Auth 1999/00	110	1	20			131
Req 2000/01	821	21	11			853
2001/02	545	24	11			580
2002/03	120	7	1			128
TOTAL	3 428	53	261			3 742

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

1999-08-21 05:21 PM

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number: 03-00-6126

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1995 10	3 199	PROJECT TRANSFERRED FROM DOMESTIC BUDGET BRN:9603-00-5953.
1996 10	3 101	REVISED CASHFLOWS AND ESCALATION AND INTEREST.
1997 10	3 220	BASE DATE UPDATED . REVISED INSERVICE DATES.

ASSOCIATED PROJECTS

Budget reference number	Description
03-00-6127	RADISSON/HENDAY CONV. TRANSFORMER BUSHING REPLACEMENT/SPARES

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	53		1			54	54
May	57		2			59	113
Jun			2			2	115
Jul			2			2	117
Aug			2			2	119
Sep			2			2	121
Oct			2			2	123
Nov			2			2	125
Dec			2			2	127
Jan			1			1	128
Feb	1		1			2	130
Mar	-1	1	1			1	131
TOTAL	110	1	20			131	131
2000/01 Apr	78	1	1			80	80
May	71	1				72	152
Jun							152
Jul							152
Aug	61	1				62	214
Sep	390	11				401	6
Oct	106	3	3			112	7
Nov	114	3	1			118	845
Dec			2			2	847
Jan			2			2	849
Feb	1		2			3	852
Mar		1				1	853
TOTAL	821	21	11			853	853

1999-08-21 05:21 PM

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item

23

Title: RADISSON/HENDAY CONV. TRANSFORMER BUSHING REPLACEMENT/SPARES

Budget reference number: 03-00-6127

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
[illegible]C	HVDC	HVDC	61803:61894

DESCRIPTION:
THE 138KV BUSHINGS IN CONVERTER TRANSFORMERS (T11, T12, T13, T21 AND T22), THE 150KV BUSHINGS IN CONVERTER TRANSFORMERS(T11 AND T21), THE 230KV BUSHINGS IN CONVERTER TRANSFORMERS(T31S, T31D, T41S, T41D) AND THE 15KV TERTIARY BUSHINGS IN CONVERTER TRANSFORMERS(T12, T21 AND T22) ARE BEING REPLACED WITH NGK BUSHINGS. AS WELL ONE SPARE 125KV BUSHING FOR CONVERTER TRANSFORMERS (T31D OR T41D), ONE 250KV SPARE BUSHING FOR CONVERTER TRANSFORMERS (T31S OR T41S), ONE SPARE 300KV BUSHING FOR CONVERTER TRANSFORMERS (T12 OR T22), ONE SPARE 375KV BUSHING FOR CONVERTER TRANSFORMERS (T32D OR T42D), ONE SPARE 450KV BUSHING FOR CONVERTER TRANSFORMERS (T13 OR T23), AND ONE SPARE 500KV BUSHING FOR CONVERTER TRANSFORMERS (T32S OR T42S) ARE BEING PURCHASED. TO REFLECT CARRY OVER OF FUNDS FROM THE 1995/96 FISCAL YEAR.

JUSTIFICATION:
THE DECISION TO GO INTO A BUSHING REPLACEMENT PROGRAM WAS MADE DUE TO A FAILURE OF A 230KV BUSHING IN DORSEY T21 A-PHASE CONVERTER TRANSFORMER WHICH RESULTED IN THE VERY COSTLY REPAIRS TO THE TRANSFORMER AND LOSS OF REVENUE DUE TO THE OUTAGE. ALSO DURING THE REPAIR OF DORSEY Y31S CONVERTER TRANSFORMER IN PAUWELS'S CANADA PLANT TWO OUT OF TWO 230KV BUSHINGS BEING TESTED FAILED AT FAR BELOW THE FULL TEST VOLTAGE. THE MANUFACTURER OF THESE BUSHINGS STATES THAT THE EXPECTED SERVICE LIFE OF THESE BUSHINGS IS 25 YEARS. THESE BUSHINGS HAVE ALL BEEN IN SERVICE FOR MORE THAN 17 YEARS. THE COST OF REPLACING THESE BUSHINGS IS JUSTIFIED WHEN COMPARED TO THE REPAIR AND OUTAGE COSTS RESULTING FROM THE CONVERTER TRANSFORMERS BEING DAMAGED DUE TO AN IN SERVICE FAILURE. BECAUSE THE SERVICE LIFE IS 25 YEARS AND WE ARE STARTING TO EXPERIENCE FAILURES, WE ARE ANTICIPATING THAT THE FAILURE RATE WILL INCREASE DRAMATICALLY IN THE NEXT FEW YEARS IF THE BUSHINGS ARE NOT REPLACED.

REFERENCE:
MEMOS FROM L.D. RECKSIEDLER TO I.H. MCKAY DATED 1998 04 30 AND 1998 05 20..

REVISION:
UPDATED ESCALATION AND INTEREST.

IN SERVICE DATES						Base estimate
Prior Total	1 566	1998 07 31	2	1999 02 28	1	199610 L3
1998 04 30	273	1998 11 30	6	1999 03 31	13	
1998 05 31	62	1998 12 31	2	1999 04 30	186	Work start date
1998 06 30	62	1999 01 31	2	2000 09 30	520	1997 04 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date	1 944		46			1 990
1999/00	418	12				430
2000/01	237	11	5			253
TOTAL	2 599	23	51			2 673
REV. AMOUNTS:						
Authorized to date	1 944		46			1 990
Over(under)expend:						
Auth 1999/00	217	1	1			219
Req 2000/01	465	10	11			486
TOTAL	2 626	11	58			2 695

Prepared by: yy mm dd COORDINATOR — Approved by: yy mm dd Approved by: yy mm dd

Estimated by: ORIGINATOR — COORDINATING MANAGER — ORIGINATING MANAGER

1999-08-21 05:21 PM

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number: 03-00-6127

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1995 10	2 915	PROJECT TRANSFERRED FROM DOMESTIC BRN: 9503-00-5942 AND BRN: 9603-00-6989
1996 10	3 490	ADDITION OF MONIES FROM RADISSON TRANSFORMER MOD, 41004; AND REGASKETTING OF T41 & T31 TRANSFORMERS AT HENDAY. REVISED ESCALATION AND INTEREST RATES AND RECASHFLOWED.
1997 10	2 567	BASE DATE UPDATED . REVISED INSERVICE DATES.

ASSOCIATED PROJECTS

Budget reference number	Description
03-00-6126	DORSEY CONVERTER TRANSFORMER BUSHING REPLACEMENT/SPARES

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	186					186	186
May							186
Jun							186
Jul							186
Aug	17	1				18	204
Sep	1					1	205
Oct	2					2	207
Nov	2					2	209
Dec	2					2	211
Jan	2					2	213
Feb	2					2	215
Mar	3		1			4	219
TOTAL	217	1	1			219	219
2000/01 Apr	1					1	1
May	1					1	2
Jun	434	10				444	446
Jul	11		3			14	460
Aug	13	1	3			17	477
Sep	5	-1	5			9	4[illegible]
Oct							4[illegible]
Nov							486
Dec							486
Jan							486
Feb							486
Mar							486
TOTAL	465	10	11			486	486

1999-08-21 05:21 PM

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

COMPLEX STATUS: [X] Planned [ ] In progress

Complex no. 203

REVISION STATUS: [ ] New complex [X] In service change [ ] Concept change [ ] Estimate change only

COMPLEX: DORSEY BIPOLE 1 SYNCH CONDENSER BREAKER REPL

Proposal
Design & replacement of six 17kV breakers and associated equipment for English Electric and ASEA synchronous condensers at Dorsey stn with new 120,000A breakers. To be replaced 2 per year over 3 years.

JUSTIFICATION: [X] Load [ ] Service [X] Safety [ ] Efficiency [X] Reliability [ ] Other

Explanation
The existing 17kV breakers have become under rated due to system changes. New breakers with increased rating are required to eliminate potential breaker damage and other adverse system and safety implications.

Estimate Level	COMPLEX START (yyyy mm)
L2	1996 11

IN SERVICE DATES AND AMOUNTS							
1999 06	$1120	2000 04	$1149	2001 06	$1169	2001 07	$1171
2002 06	$1192	2002 07	$1194				

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	583		5		588	171	417	244
Year 99/00	1,473	20	23		1,516	1,287	229	18
00/01	334	9	8		351	1,311	-960	-73
01/02	2,235	91	18		2,344	2,499	-155	-6
02/03	2,056	122	18		2,196	2,588	-392	-15
03/04								
04/05								
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	6,681	242	72		6,995	7,856	-861	-11

REVISION: Reflects ISD'S advanced 3 months due to SCC requirements.

Reviewed by ORIGINATOR	yyyy mm dd	Reviewed by COORDINATOR	yyyy mm dd 99 11 12
Reviewed by CONSTRUCTOR	yyyy mm dd	Approved by VICE-PRESIDENT	yyyy mm dd 99 11 1[illegible]201

H2856/r Rev 99 03

Complex no. 203

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Advance or deferral impact

Deferral will maintain reliance on six underrated breakers , the potential for breaker damage, and adverse system and safety implications.

Factors affecting timing or viability

Requirement to not have all breakers down at one time.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Dorsey bipole 1 synch condenser breaker repl	6,681	7,215	7,359	6,681	-678	-9
TOTAL	6,681	7,215	7,359	6,681	-678	-9

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
96 10	7,818	NEW COMPLEX
9710	7,858	In service date deferred 14 mo., and estimate base changed to 1997
9810	7,856	ISD'S DEFERRED 14 MONTHS.
1999 10	6,995	Reflects ISD'S advanced 3 months due to SCC requirements.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION
SPED rpt 96-2	Dorsey Stn 17kV synchronous condenser breaker replacement.

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item 24

Title
DORSEY BIPOLE 1 SYNCH CONDENSER BREAKER REPLACEMENT

Budget reference number
03-00-6185

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
HVDC	HVDC	Construction	61000:62222

DESCRIPTION:
DESIGN AND REPLACEMENT OF SIX 17KV BREAKERS AND ASSOCIATED EQUIPMENT FOR ENGLISH ELECTRIC AND ASEA SYNCHRONOUS CONDENSERS AT DORSEY STATION WITH NEW 120,000 A BREAKERS. THE BREAKERS ARE TO BE REPLACED 2 PER YEAR STARTING 1997 05.

JUSTIFICATION:
THE EXISTING 17KV BREAKERS HAVE BECOME UNDER RATED DUE TO SYSTEM CHANGES. NEW BREAKERS WITH INCREASED RATING ARE REQUIRED TO ELIMINATE POTENTIAL BREAKER DAMAGE AND OTHER ADVERSE SYSTEM AND SAFETY IMPLICATIONS.

REFERENCE:
SPED REPORT 96-02, DORSEY STATION 17KV SYNCHRONOUS CONDENSER BREAKER REPLACEMENT.

REVISION:
ISDS' ADVANCED 3 MONTHS DUE TO SCC REQUIREMENTS. ESTIMATE BASE DATE CHANGED TO 1999.
CONTINGENCY AMOUNT: $270,000

IN SERVICE DATES

1999 06 30	1 120	2002 06 30	1 192
2000 04 30	1 149	2002 07 31	1 194
2001 06 30	1 169		
2001 07 31	1 171		

Base estimate
199707 L2

Work start date
1997 04 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date	583		5			588
1999/00	804	50	16			870
2000/01	1 222	74	15			1 311
2001/02	2 296	191	12			2 499
2002/03	2 316	246	26			2 588
TOTAL	7 221	561	74			7 856
REV. AMOUNTS:						
Authorized to date:	583		5			588
Over(under)expend:						
Auth 1999/00	1 473	20	23			1 516
Req.: 2000/01	334	9	8			351
2001/02	2 235	91	18			2 344
2002/03	2 056	122	18			2 196
TOTAL	6 681	242	72			6 995

Prepared by — yy mm dd — COORDINATOR
Approved by — yy mm dd — COORDINATING MANAGER
Approved by — yy mm dd — ORIGINATING MANAGER
Estimated by — ORIGINATOR

4103

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 03-00-6185

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1996 10	7 817	NEW ITEM
1997 10	7 850	ISD'S DEFERRED 14 MONTHS. ESTIMATE BASE CHANGED TO 1997.

ASSOCIATED PROJECTS

Budget reference number	Description
03-00-8376	DORSEY SYNCH. CONDENSER REFURBISHMENT

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	183	1	4			188	188
May	182	2	5			189	377
Jun	132	1	7			140	517
Jul	15	1				16	533
Aug							533
Sep							533
Oct							533
Nov							533
Dec	16	1				17	550
Jan	64	1				65	615
Feb	782	13	1			796	1 411
Mar	99		6			105	1 516
TOTAL	1 473	20	23			1 516	1 516
2000/01 Apr	120	2	7			129	129
May	18					18	147
Jun	18					18	165
Jul							165
Aug							16
Sep							1
Oct							16
Nov							165
Dec	14	1				15	180
Jan	29	1				30	210
Feb	55	2				57	267
Mar	80	3	1			84	351
TOTAL	334	9	8			351	351

1999-08-21 05:22 PM

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

COMPLEX STATUS: ☐ Planned ☒ In progress

Complex no. 216

REVISION STATUS: ☐ New complex ☐ In service change ☒ Concept change ☐ Estimate change only

COMPLEX: BIPOLE 1 & 2 DC FILTER CAPACITOR REPLACEMENT

Proposal

Replace all bipole 1 & 2 DC PCB filled capacitors at Dorsey , Radisson and Henday Stns, with non-PCB replacement capacitors.

JUSTIFICATION: ☐ Load ☐ Service ☒ Safety ☐ Efficiency ☒ Reliability ☐ Other

Explanation

Existing filter capacitors are PCB filled. New capacitors contain a more flamable oil and mixing them could result in a fire if toxic compounds from the PCB's are released. There is no sensitive protection to protect them against failure, and they will be 25 years old and approaching the end of their usable life.

Estimate Level	COMPLEX START (yyyy mm)
L2	1998 04

IN SERVICE DATES AND AMOUNTS

1999 10	$590	2000 04	$710	2000 09	$338	2000 10	$290
2001 04	$848	2001 10	$1726	2002 04	$172	2002 10	$281

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	231		5		236	264	-28	-11
ar 99/00	755	9	16		780	689	91	13
00/01	1,594	39	21		1,654	956	698	73
01/02	1,863	73	28		1,964	1,007	957	95
02/03	302	17	3		322		322	
03/04								
04/05								
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	4,745	138	73		4,956	2,916	2,040	70

EVISION: Scope change to include replacement of BP2 DC PCB filled capacitors at Dorsey and Henday Converter Stations.

Reviewed by ORIGINATOR	yyyy mm dd 99 11 03	Reviewed by COORDINATOR	yyyy mm dd		
Reviewed by CONSTRUCTOR	yyyy mm dd	Approved by VICE-PRESIDENT	yyyy mm dd 99 11 12		

H2856/r Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Complex no. 216

Advance or deferral impact

Factors affecting timing or viability

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE	
					Amount	%
Bipole 1 & 2 DC filter capacitor replacement	4,745	2,806	2,862	4,745	1,883	66
TOTAL	4,745	2,806	2,862	4,745	1,883	66

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
96 10	2,817	NEW COMPLEX
9710	2,791	Revised escalation and interest rates.
9810	2,916	Revised to reflect the start date is advanced 1 year, and updated escalation and interest.
1999 10	4,956	Scope change to include replacement of BP2 DC PCB filled capacitors at Dorsey and Henday Converter Stations.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item 25

Title			Budget reference number
Bipole 1 & 2 DC Filter Capacitor Replacements			03-00-7223
Originating division	Coordinating division	Constructing division	Project Order Group (Range):
HVDC	HVDC	HVDC	61851:62239

DESCRIPTION:
The replacement of all BP1 and 2 DC PCB filled high power capacitors at the Dorsey, Radisson and Henday Converter Stations, with non-PCB replacement capacitors.

JUSTIFICATION:
We have experienced numerous PCB filled capacitor failures at HVDC Converter Stations. This results in requests for outages via SCC to allow for repairs. The catastrophic failure of a capacitor can in a DC Filter Bank of BP2 would result in a pole outage. Manitoba Hydro is committed to being PCB free as outlined in Corporate policy statement CP486B. The capacitors will be 25 years old and are approaching the end of their usable life

REFERENCE:
Report HVDC 99-03 HVDC System Capacitor Replacement

REVISION:
Scope of Work expanded to include for the replacement of BP2 DC PCB filled capacitors at Dorsey and Henday Converter Stations.

CONTINGENCY $ 427,700.00

IN SERVICE DATES				Base estimate
1999 10 31	590	2001 04 30	785	199704 L2
2000 04 30	679	2001 10 31	1 695	Work start date
2000 09 30	460	2002 04 30	172	1998 04 01
2000 10 31	290	2002 10 31	280	

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:	231		5			236
1999/00	703	18	-4			717
2000/01	934	46	-24			956
2001/02	940	58	10			1 008
TOTAL	2 808	122	-13			2 917
REV. AMOUNTS:						
Authorized to date:	231		5			236
Over(under)expend:						
Auth 1999/00	755	9	16			780
Req.: 2000/01	1 594	39	18			1 651
2001/02	1 863	73	26			1 962
2002/03	302	17	3			322
TOTAL	4 745	138	68			4 951

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

1999-09-28 10:58 AM

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number: 03-00-7223

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1996 10	2 817	NEW ITEM.
1997 10	2 790	UPDATED ESCALATION AND INTEREST.

ASSOCIATED PROJECTS

Budget reference number	Description

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	1		2			3	3
May	2		2			4	7
Jun			2			2	9
Jul			2			2	11
Aug	8	-1	2			9	20
Sep	214	2	2			218	238
Oct	177	1	3			181	419
Nov							419
Dec							419
Jan							419
Feb	23	1				24	443
Mar	330	6	1			337	780
TOTAL	755	9	16			780	780
2000/01 Apr	351	5	3			359	359
May			1			1	360
Jun			1			1	361
Jul	11		1			12	373
Aug	298	7	1			306	679
Sep	328	7	3			338	1 [illegible]
Oct	167	4	2			173	1
Nov			1			1	1 19[illegible]
Dec			1			1	1 192
Jan			1			1	1 193
Feb	11	1	1			13	1 206
Mar	428	15	2			445	1 651
TOTAL	1 594	39	18			1 651	1 651

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

COMPLEX STATUS	Complex no.	REVISION STATUS
☒ Planned ☐ In progress	213	☐ New complex ☒ In service change ☐ Concept change ☒ Estimate change only

COMPLEX: S.E.R. REPLACEMENT

Proposal

Design, purchase and install new sequence of events recorders at Dorsey & Radisson to replace the existing ones.

JUSTIFICATION

☐ Load ☐ Service
☐ Safety ☒ Efficiency
☒ Reliability ☐ Other

Explanation

The SER provides station operators with a central alarm annunciation to aid in the operation of the station and provide plant engineers with the means to analyse system disturbances. The existing SER has reached the end of its useful life and must be replaced. In addition the manufacturers no longer support this equipment and spare parts are unavailable.

Estimate Level	COMPLEX START (yyyy mm)
L2	1996 11

IN SERVICE DATES AND AMOUNTS

1998 12	$921	1999 01	$9	1999 02	$6	1999 03	$27
1999 08	$254	1999 11	$820				

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	1,255		84		1,339	1,926	-587	-30
Year 99/00	663	5	31		699		699	
00/01								
01/02								
02/03								
03/04								
04/05								
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	1,918	5	115		2,038	1,926	112	6

REVISION: Reflects 8 month ISD deferral.

Reviewed by ORIGINATOR	yyyy mm dd 94 11 03	Reviewed by COORDINATOR	yyyy mm dd		
Reviewed by CONSTRUCTOR	yyyy mm dd	Approved by VICE-PRESIDENT	yyyy mm dd 94 11 12		

H2856/r Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Complex no. 213

Advance or deferral impact

Factors affecting timing or viability

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Dorsey bipole 1 S.E.R. replacement	764	812	828	764	-64	-8
Radisson bipole 1 S.E.R. replacement	1,027	1,034	1,055	1,154	99	9
TOTAL	1,791	1,846	1,883	1,918	35	2

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
96 10	1,718	NEW COMPLEX
9710	1,892	Reflects revised costing methodology of the new financial reporting system, 6 mo advancement of Radisson, & 1 yr deferral of Dorsey S.E.R. replacement.
9810	1,926	Revised to reflect 97/98 underexpenditure .7M and 5 and 6 month ISD deferrals.
1999 10	2,038	Reflects 8 month ISD deferral.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item __ Domestic Item 26

Title			Budget reference number
DORSEY BP1 S.E.R. REPLACEMENT			03-00-7217
Originating division	Coordinating division	Constructing division	Project Order Group (Range):
[illegible]C	HVDC	Construction	61001

DESCRIPTION:
DESIGN, PURCHASE AND INSTALL A NEW SEQUENCE OF EVENTS RECORDER TO REPLACE THE EXISTING ONE.

JUSTIFICATION:
THE SER PROVIDES THE STATION OPERATORS WITH A CENTRAL ALARM ANNUNCIATION TO AID IN THE OPERATION OF THE STATION AND PROVIDE THE PLANT ENGINEERS WITH THE MEANS TO ANALYZE SYSTEM DISTURBANCES. THE EXISTING SER HAS REACHED THE END OF ITS USEFUL LIFE AND MUST BE REPLACED. IN ADDITION, THE MANUFACTURERS NO LONGER SUPPORT THE EXISTING EQUIPMENT AND SPARE PARTS ARE UNAVAILABLE.

REFERENCE:
PRODUCTION SOUTH REPORT: PS 96-09

REVISION:
CASH FLOW REVISED.
CONTINGENCY AMOUNT IS $42,000

IN SERVICE DATES		Base estimate
1999 11 30	820	199706 L2
		Work start date
		1997 04 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:	349		26			375
1999/00	477					477
TOTAL	826		26			852
REV. AMOUNTS:						
Authorized to date:	349		26			375
Over(under)expend.						
Auth Req.: 1999/00	415	4	26			445
TOTAL	764	4	52			820

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 03-00-7217

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1996 10	741	NEW ITEM.
1997 10	843	BASE DATE UPDATED, RECASHFLOWED WITH REVISED ACTIVITY AND OVERHEAD RATES. ISD DEFERRED FROM 1997 09 30 TO 1998 09 30.

ASSOCIATED PROJECTS

Budget reference number	Description
03-00-7218	RADISSON S.E.R. REPLACEMENT

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	21		3			24	24
May	21		3			24	48
Jun	21		3			24	72
Jul	21		3			24	96
Aug	21		3			24	120
Sep	21	1	3			25	145
Oct	48		4			52	197
Nov	43		4			47	244
Dec	48	1				49	293
Jan	51	1				52	345
Feb	82	1				83	428
Mar	17					17	445
TOTAL	415	4	26			445	445
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item

27

Title
RADISSON S.E.R. REPLACEMENT

Budget reference number
03-00-7218

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
HVDC	HVDC	Construction	61002

DESCRIPTION:
DESIGN, PURCHASE AND INSTALL A NEW SEQUENCE OF EVENTS RECORDER TO REPLACE THE EXISTING ONE.

JUSTIFICATION:
THE SER PROVIDES THE STATION OPERATORS WITH A CENTRAL ALARM ANNUNCIATION TO AID IN THE OPERATION OF THE STATION AND PROVIDE THE PLANT ENGINEERS WITH THE MEANS TO ANALYZE SYSTEM DISTURBANCES. THE EXISTING SER HAS REACHED THE END OF ITS USEFUL LIFE AND MUST BE REPLACED. IN ADDITION THE MANUFACTURERS NO LONGER SUPPORT THE EXISTING EQUIPMENT AND SPARE PARTS ARE UNAVAILABLE.

REFERENCE:
PRODUCTION SOUTH REPORT: PS 96-09.

REVISION:
CASH FLOW REVISED.

IN SERVICE DATES

1998 12 31	921	1999 08 31	255
1999 01 31	9		
1999 02 28	6		
1999 03 31	27		

Base estimate
199706 L2

Work start date
1997 04 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date	906		58			964
1999/00	110					110
TOTAL	1 016		58			1 074
REV. AMOUNTS:						
Authorized to date:	906		58			964
Over(under)expend:						
Auth 1999/00	248	1	5			254
Req.:						
TOTAL	1 154	1	63			1 218

Prepared by — yy mm dd — COORDINATOR
Estimated by — ORIGINATOR
Approved by — yy mm dd — COORDINATING MANAGER
Approved by — ORIGINATING MANAGER — yy mm dd

1999-08-21 05:23 PM

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 03-00-7218

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1996 10	977	NEW ITEM.
1997 10	1 030	BASE DATE UPDATED, RECASHFLOWED WITH REVISED ACTIVITY AND OVERHEAD RATES. ISD ADVANCED FROM 1998 09 30 TO 1998 03 31.

ASSOCIATED PROJECTS

Budget reference number	Description
03-00-7217	DORSEY BP1 S.E.R. REPLACEMENT

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	81					81	81
May	80		1			81	162
Jun	80	1	1			82	244
Jul	3		2			5	249
Aug	4		1			5	254
Sep							254
Oct							254
Nov							254
Dec							254
Jan							254
Feb							254
Mar							254
TOTAL	248	1	5			254	254
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

COMPLEX STATUS: [X] Planned [ ] In progress

Complex no. 214

REVISION STATUS: [ ] New complex [X] In service change [ ] Concept change [ ] Estimate change only

COMPLEX: BIPOLE 1 VALVE HALL WALL BUSHING REPLACEMENT

Proposal
Replacement of existing valve hall oil filled wall bushings with composite dry type bushings.

JUSTIFICATION
[ ] Load [ ] Service
[X] Safety [X] Efficiency
[X] Reliability [ ] Other

Explanation
Replacement of these wall bushings is needed because of their age, maintenance concerns and the excessive cost of fire protection that would have to be installed if the oil filled bushings were retained.

Estimate Level	COMPLEX START (yyyy mm)
L2	1996 11

IN SERVICE DATES AND AMOUNTS					
1999 04	$3021	2000 04	$3021	2001 04	$3021

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	1,937		61		1,998	1,810	188	10
Year 99/00	4,634	47	175		4,856	3,061	1,795	59
00/01	1,791	64	110		1,965	3,924	-1,959	-50
01/02	215	9	19		243		243	
02/03								
03/04								
04/05								
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	8,577	120	365		9,062	8,795	267	3

REVISION: Increased to reflect receipt of material earlier than previously forecast.

Reviewed by	yyyy mm dd	Reviewed by	yyyy mm dd
ORIGINATOR	99 11 03	COORDINATOR	
Reviewed by	yyyy mm dd	Approved by	yyyy mm dd
CONSTRUCTOR		VICE-PRESIDENT	99 11 12

H2856/r Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Complex no. 214

Advance or deferral impact

Factors affecting timing or viability

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Dorsey bipole 1 valve hall wall bushings repl	3,768	3,790	3,866	3,975	109	3
Radisson bipole 1 valve hall wall bushings repl	4,282	4,361	4,448	4,601	153	3
TOTAL	8,050	8,151	8,314	8,576	262	3

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
96 10	8,574	NEW COMPLEX
9710	8,802	Reflects revised costing methodology of the new financial reporting system
9810	8,795	Reflects 97/98 underexpenditure 1.7M and revised ISD's and cost flows.
1999 10	9,062	Increased to reflect receipt of material earlier than previously forecast.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION
PS-96.07	

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item 28

Title
DORSEY BIPOLE 1 VALVE HALL WALL BUSHINGS REPLACEMENT

Budget reference number
03-00-7219

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
DC	HVDC	Construction	61003

DESCRIPTION:
REPLACEMENT OF EXISTING VALVE HALL OIL FILLED WALL BUSHINGS WITH COMPOSITE DRY TYPE BUSHINGS.

JUSTIFICATION:
THE REPLACEMENT OF THESE WALL BUSHINGS IS NEEDED BECAUSE OF THE AGE OF THE ORIGINAL WALL BUSHINGS, MAINTENANCE CONCERNS AND THE EXCESSIVE COST OF FIRE PROTECTION THAT WOULD HAVE TO BE INSTALLED IF THE OIL FILLED BUSHINGS WERE RETAINED.

REFERENCE:
PRODUCTION SOUTH REPORT PS-96.07

REVISION:
CASH FLOW REVISED.
INCREASE DUE TO ACTIVITY RATE CHANGES.
CONTINGENCY AMOUNT $56,000

IN SERVICE DATES

1999 04 30	1 404
2000 04 30	1 404
2001 04 30	1 403

Base estimate
199610 L2

Work start date
1997 04 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:	1 048		28			1 076
1999/00	1 100	83	11			1 194
2000/01	1 658	137	25			1 820
TOTAL	3 806	220	64			4 090
REV. AMOUNTS:						
Authorized to date:	1 048		28			1 076
Over(under)expend:						
Auth 1999/00	2 070	21	90			2 181
Req: 2000/01	771	28	56			855
2001/02	86	4	9			99
TOTAL	3 975	53	183			4 211

Prepared by: yy mm dd COORDINATOR
Approved by: yy mm dd Approved by: yy mm dd
Estimated by: ORIGINATOR
COORDINATING MANAGER
ORIGINATING MANAGER

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number: 03-00-7219

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1998 10	4 114	NEW ITEM CONTINGENCY AMOUNT: $56,000

ASSOCIATED PROJECTS

Budget reference number	Description
03-00-7220	RADISSON BIPOLE 1 VALVE HALL WALL BUSHINGS REPLACEMENT

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	1 302	7	7			1 316	1 316
May	1		7			8	1 324
Jun	1		7			8	1 332
Jul	2		7			9	1 341
Aug	27		7			34	1 375
Sep	34	1	7			42	1 417
Oct	34		8			42	1 459
Nov	1		8			9	1 468
Dec	1		8			9	1 477
Jan	1		8			9	1 486
Feb	1		8			9	1 495
Mar	665	13	8			686	2 181
TOTAL	2 070	21	90			2 181	2 181
2000/01 Apr	27	1	13			41	41
May	1	1	3			5	46
Jun	1		4			5	51
Jul	2		4			6	57
Aug	1		4			5	
Sep	34	1	4			39	
Oct	34	1	4			39	140
Nov	1	1	4			6	146
Dec	1	1	4			6	152
Jan	1	1	4			6	158
Feb	1	1	4			6	164
Mar	667	20	4			691	855
TOTAL	771	28	56			855	855

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — 29 — Domestic Item

Title
RADISSON BIPOLE 1 VALVE HALL WALL BUSHINGS REPLACEMENT

Budget reference number
03-00-7220

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
HVDC	HVDC	Construction	61004

DESCRIPTION:
REPLACEMENT OF EXISTING VALVE HALL OIL FILLED WALL BUSHINGS WITH COMPOSITE DRY TYPE BUSHINGS.

JUSTIFICATION:
THE REPLACEMENT OF THESE WALL BUSHINGS IS NEEDED BECAUSE OF THE AGE OF THE ORIGINAL WALL BUSHINGS, MAINTENANCE CONCERNS AND THE EXCESSIVE COST OF FIRE PROTECTION THAT WOULD HAVE TO BE INSTALLED IF THE OIL FILLED BUSHINGS WERE RETAINED.

REFERENCE:
PRODUCTION SOUTH REPORT PS-96.07

REVISION:
CASH FLOW REVISED.
INCREASE DUE TO ACTIVITY RATE CHANGES.
CONTINGENCY AMOUNT: $70,000

IN SERVICE DATES

1999 04 30	1 617
2000 04 30	1 617
2001 04 30	1 617

Base estimate
199610 L2

Work start date
1997 04 01

	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
PREV. AUTHORITY						
Authorized to date	888		33			921
1999/00	1 571	92	17			1 680
2000/01	1 919	157	28			2 104
TOTAL	4 378	249	78			4 705
REV. AMOUNTS:						
Authorized to date:	888		33			921
Over(under)expend:						
Auth 1999/00	2 564	26	85			2 675
Req.: 2000/01	1 020	37	54			1 111
2001/02	129	5	10			144
TOTAL	4 601	68	182			4 851

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

1999-08-21 05:23 PM

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number: 03-00-7220

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1998 10	4 114	NEW ITEM CONTINGENCY AMOUNT: $70,000

ASSOCIATED PROJECTS

Budget reference number	Description
03-00-7219	DORSEY BIPOLE 1 VALVE HALL WALL BUSHINGS REPLACEMENT

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	1 601	9	6			1 616	1 616
May	1		6			7	1 623
Jun	1		6			7	1 630
Jul	1		7			8	1 638
Aug	1		7			8	1 646
Sep	64	1	7			72	1 718
Oct	62	1	7			70	1 788
Nov	1		8			9	1 797
Dec	1		8			9	1 806
Jan	1		8			9	1 815
Feb	1		8			9	1 824
Mar	829	15	7			851	2 675
TOTAL	2 564	26	85			2 675	2 675
2000/01 Apr	57	1	14			72	72
May	1		3			4	76
Jun	1		3			4	80
Jul	1	1	3			5	85
Aug	1		3			4	[illegible]
Sep	65	2	3			70	[illegible]
Oct	63	1	4			68	[illegible]
Nov	1		4			5	232
Dec	1		4			5	237
Jan	1		4			5	242
Feb	1		4			5	247
Mar	827	32	5			864	1 111
TOTAL	1 020	37	54			1 111	1 111

1999-08-21 05:23 PM

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

COMPLEX STATUS: [X] Planned [ ] In progress

Complex no. 249

REVISION STATUS: [ ] New complex [X] In service change [ ] Concept change [X] Estimate change only

COMPLEX: DORSEY BRINE EFFLUENT IMPROVEMENT

Proposal

Design supply and drilling of a pilot well to determine feasibility of the deep well injection method. After satisfactory evaluation of the pilot well test results , design, supply, install and commission it with associated tanks, pumps and pipe works to transfer the salt brine effluent from the water softeners of the two bipoles. (It is assumed that Government Approval is not needed for this work.) Design and install cathodic protection for the wells.

JUSTIFICATION

[ ] Load [ ] Service
[ ] Safety [ ] Efficiency
[ ] Reliability [X] Other

Explanation

The existing deep well is not functioning properly. It was originally installed in 1984. In 1986 it lost its ability to accomodate the flow of effluent. Presently some effluent is being dumped to the station drainage ditches. It is now essential that a new well be drilled incorporating the latest design.

Estimate Level	COMPLEX START (yyyy mm)
L2	1998 08

IN SERVICE DATES AND AMOUNTS

1998 10	$762	1998 11	$26	1999 01	$6

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	776		18		794	792	2	0
Year 99/00								
00/01								
01/02								
02/03								
03/04								
04/05								
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	776		18		794	792	2	0

REVISION: Revised to reflect actual costs to completion.

Reviewed by ORIGINATOR	yyyy mm dd 99 11 03	Reviewed by COORDINATOR	yyyy mm dd		
Reviewed by CONSTRUCTOR	yyyy mm dd	Approved by VICE-PRESIDENT	yyyy mm dd 99 11 12		

H2856/r Rev 99 03

Complex no. 249

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Advance or deferral impact

Inability to properly dispose of brine effluent.

Factors affecting timing or viability

Complete failure of existing deep well.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE	
					Amount	%
Dorsey Brine Effluent Disposal Well Replacement	776	779	795	776	-19	-2
TOTAL	776	779	795	776	-19	-2

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
9710	2,403	New complex.
9810	792	Revised to reflect in servce date advanced 1 year, and reduced cost of well drilling contract.
1999 10	794	Revised to reflect actual costs to completion.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item 30

Title
DORSEY BRINE EFFLUENT DISPOSAL WELL REPLACEMENT

Budget reference number
03-00-8300

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
HVDC	HVDC	HVDC	61861

DESCRIPTION:
DESIGN, SUPPLY AND DRILLING OF A PILOT WELL TO DETERMINE FEASIBILITY OF THE DEEP WELL INJECTION METHOD. AFTER SATISFACTORY EVALUATION OF THE PILOT WELL TEST RESULTS, DESIGN, SUPPLY, INSTALL AND COMMISSION THE DEEP WELL WITH ASSOCIATED TANKS, PUMPS AND PIPE WORKS TO TRANSFER THE SALT BRINE EFFLUENT FROM THE WATER SOFTENERS OF THE TWO BIPOLES TO THE DEEP WELL. IT IS ASSUMED THAT GOVERNMENT APPROVAL IS NOT NEEDED FOR THIS WORK. DESIGN AND INSTALL CATHODIC PROTECTION FOR THE WELLS.

JUSTIFICATION:
THE EXISTING DEEP WELL IS NOT FUNCTIONING PROPERLY. IT WAS ORIGINALLY INSTALLED IN 1984. IN 1996 THE WELL LOST ITS ABILITY TO ACCOMMODATE THE FLOW OF EFFLUENT. THE WELL WAS CLEANED AND ACID FLUSHED BUT STILL CANNOT HANDLE THE NORMAL FLOW. PRESENTLY SOME EFFLUENT IS BEING DUMPED TO THE STATION DRAINAGE DITCHES. IT IS NOW ESSENTIAL THAT A NEW WELL BE DRILLED INCORPORATING THE LATEST DESIGN.

REVISION:
ESTIMATE REVISED TO REFLECT ACTUAL COST.
PROJECT COMPLETE.

IN SERVICE DATES				Base estimate
1998 10 31	762	1999 02 28	-0	199707 L2
1998 11 30	26	1999 03 31	0	
1998 12 31	5	1999 04 30	-0	Work start date
1999 01 31	1			1998 04 01

	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
PREV. AUTHORITY						
Authorized to date:	776		18			794
1999/00	-3					-3
TOTAL	773		18			791
REV. AMOUNTS:						
Authorized to date:	776		18			794
Over(under)expend:						
Auth Req.:						
TOTAL	776		18			794

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

1999-08-21 05:25 PM

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 03-00-8300

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1997 10	2 403	NEW ITEM.

ASSOCIATED PROJECTS

Budget reference number	Description

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

COMPLEX STATUS: [X] Planned [ ] In progress

Complex no. 258

REVISION STATUS: [X] New complex [ ] In service change [ ] Concept change [ ] Estimate change only

COMPLEX: BIPOLE 1 & 2 ELECTRODE LINE MONITORING

Proposal
Install a Siemens pulse-echo electrode line fault detection system on Dorsey Bipole 1 and 2, Radisson Bipole 1 and Henday Bipole 2 Electrode lines.

JUSTIFICATION: [ ] Load [ ] Service [X] Safety [X] Efficiency [X] Reliability [ ] Other

Explanation
There is a need for detection of open circuit, faulted, or partially down electrode line conductors based on public safety concerns, possible damage to equipment, and the security of Bipole 1 and 2.

Estimate Level	COMPLEX START yyyy mm
L2	2001 04

IN SERVICE DATES AND AMOUNTS				
2002 10	$1352			

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend								
Year 99/00								
00/01								
01/02	161	8	6		175		175	
02/03	1,086	64	27		1,177		1,177	
03/04								
04/05								
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	1,247	72	33		1,352		1,352	

REVISION: New Complex

Reviewed by ORIGINATOR	yyyy mm dd 99 11 03	Reviewed by COORDINATOR	yyyy mm dd
Reviewed by CONSTRUCTOR	yyyy mm dd	Approved by VICE-PRESIDENT	yyyy mm dd 99 11 4125

H2856/r Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Complex no. 258

Advance or deferral impact

Factors affecting timing or viability

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Bipole 1 & 2 Electrode Line Monitoring				1,247	1,247	
TOTAL				1,247	1,247	

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
1999 10	1,352	New Complex

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION
E.C. # 789.01	CPJ for BP 1 & 2 Electrode Line Monitoring.

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — 31 Domestic Item

Title
Bipole 1 & 2 Electrode Line Monitoring

Budget reference number
03-00-8396

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
HVDC	HVDC	HVDC	62224:62226

DESCRIPTION:
Installation of a Siemens pulse-echo electrode line fault detection system on Dorsey Bipole 1 and 2, Radisson Bipole 1 and Henday Bipole 2 Electrode Lines.

JUSTIFICATION:
There is a need for detection of open circuit, faulted, or partially down electrode line conductors based on public safety concerns, possible damage to equipment, and the security of Bipole 1 and 2.

REFERENCE:
Report SPD 98/8 entitled 'Bipole 1 and 2 Electrode Line Monitoring'

REVISION:
New item.

IN SERVICE DATES		Base estimate
2002 10 31	1 352	199901 L2
		Work start date 2001 04 01

PREV. AUTHORITY Authorized to date:	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
TOTAL						
REV. AMOUNTS:						
Authorized to date:						
Over(under)expend.						
Auth 2001/02	161	8	6			175
Req 2002/03	1 086	64	27			1 177
TOTAL	1 247	72	33			1 352

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR		COORDINATING MANAGER		ORIGINATING MANAGER

1999-08-21 05:25 PM

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 03-00-8396

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS

ASSOCIATED PROJECTS

Budget reference number	Description
03-00-5901	DORSEY BIPOLE 1 SPARE 300 KV CONVERTER TRANSFORMER
03-00-5902	RADISSON BIPOLE 1 SPARE 450KV CONVERTER TRANSFORMER
03-00-5903	DORSEY SPARE CONVERTER TRANSFORMER FOUNDATIONS
03-00-5904	HENDAY BIPOLE 2 SPARE 500KV CONV. TFR (SPARE # 1)
03-00-5905	DORSEY BIPOLE 2 SPARE SMOOTHING REACTOR (DORSME8)
03-00-5906	HENDAY BIPOLE 2 SPARE SMOOTHING REACTOR (HENDME2)
03-00-5907	DORSEY BIPOLE 2 COOLING UPGRADE (DORSME11)
03-00-5908	HENDAY - BIPOLE 2 COOLING UPGRADE (HENDME4)
03-00-6119	RADISSON STATION SST1 RELOCATION & SST2 & SST3 CABLE REPLACE
03-00-6129	DORSEY BIPOLE 1 SPARE 450KV CONVERTER TRANSFORMER
03-00-8369	DORSEY BIPOLE 1 SPARE 300 KV CONV. TFR (SPARE # 3)
03-00-8370	HENDAY BIPOLE 2 SPARE 500KV CONV. TFR (SPARE # 2)
03-00-8395	HVDC BP1 & 2 Auxiliary Power Supply Upgrades
03-00-8398	Bipole 1 & 2 5/15KV Arcproofing and Brkr Upgrade

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

COMPLEX STATUS: [X] Planned [ ] In progress

Complex no. 259

REVISION STATUS: [X] New complex [ ] In service change [ ] Concept change [ ] Estimate change only

COMPLEX: HVDC SWITCHGEAR ARCPROOF/SAFETY UPGRADES (PH 1 & 2)

Proposal

Arcproof the 5kV switchgear at Dorsey and Radisson Converter stations and the 15kV switchgear at Henday Converter station.

JUSTIFICATION: [ ] Load [ ] Service [X] Safety [ ] Efficiency [ ] Reliability [ ] Other

Explanation

The existing metal clad switchgear have no means of containing fire or smoke within individual cubicle cells or the switchgear itself in the event of a breaker failure. Explosion, smoke, fire and gas emissions pose a health hazard to staff if working in the vicinity should a failure occur.

Estimate Level	COMPLEX START (yyyy mm)
L2	2000 02

IN SERVICE DATES AND AMOUNTS					
2001 05	$741	2002 05	$317		

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend								
Year 99/00								
00/01	407	10	13		430		430	
01/02	493	19	12		524		524	
02/03	95	5	3		103		103	
03/04								
04/05								
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	995	34	28		1,057		1,057	

REVISION: New Complex

Reviewed by ORIGINATOR	yyyy mm dd 99 11 03	Reviewed by COORDINATOR	yyyy mm dd
Reviewed by CONSTRUCTOR	yyyy mm dd	Approved by VICE PRESIDENT	yyyy mm dd 99 11 12

H2856/r Rev 99 03

Complex no. 259

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Advance or deferral impact

Risk of injury.

Factors affecting timing or viability

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE	
					Amount	%
Bipole 1 & 2 5/15kv Arcproofing				995	995	
TOTAL				995	995	

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
1999 10	1,057	New Complex

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item

32

Title			Budget reference number
Bipole 1 & 2 5/15KV Arcproofing			03-00-8398
Originating division	Coordinating division	Constructing division	Project Order Group (Range):
HVDC	HVDC	HVDC	61819:62264

DESCRIPTION:
Arcproof the 5kV switchgear at Dorsey and Radisson Converter Stns. and the 15kV switchgear at Henday Converter Stn.

JUSTIFICATION:
The existing metal clad switchgear have no means of containing fire or smoke within individual cubicle cells or the switchgear itself in the event of a breaker failure. Explosion, smoke, fire and gas emissions pose a health hazard to staff if working in the vicinity should a failure occur.

REFERENCE:
Report HVDC 99-04 titled HVDC System Switchgear Upgrades.

REVISION:
New Item

IN SERVICE DATES				Base estimate
2001 05 31	741			199902 L2
2002 05 31	317			Work start date
				2000 02 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:						
TOTAL						
REV. AMOUNTS:						
Authorized to date:						
Over(under)expend:						
Auth 2000/01	407	11	13			431
Req.: 2001/02	493	19	12			524
2002/03	95	5	3			103
TOTAL	995	35	28			1 058

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

1999-09-28 10:58 AM

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 03-00-8398

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS

ASSOCIATED PROJECTS

Budget reference number	Description

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May	18					18	18
Jun	3	1				4	22
Jul	3	1				4	26
Aug	3	1				4	30
Sep	60	1				61	[illegible]
Oct	103	2	1			106	[illegible]
Nov	103	3	1			107	36
Dec	93	3	2			98	402
Jan	3		3			6	408
Feb	3		3			6	414
Mar	15	-1	3			17	431
TOTAL	407	11	13			431	4132

1999-09-28 10:58 AM

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

COMPLEX STATUS: [X] Planned [ ] In progress

Complex no. 260

REVISION STATUS: [X] New complex [ ] In service change [ ] Concept change [ ] Estimate change only

COMPLEX: HVDC AUXILIARY POWER SUPPLY UPGRADES

Proposal

The review and upgrading of eight battery banks and four power centres at Dorsey, Radisson, and Henday Converter stations. Replacement of +/- 25VDC & 60VDC battery chargers and the 129VDC/60VDC inverters in Bipole 2 at Dorsey & Henday.

JUSTIFICATION

[X] Load [ ] Service
[ ] Safety [X] Efficiency
[X] Reliability [ ] Other

Explanation

Upgrading of the HVDC System Auxiliary Power Supplies is necessary to obtain maintenance outages for them without additional system costs and to maintain reliability of the HVDC System. This will allow Manitoba Hydro to maintain/increase firm energy sales and keep spinning reserve requirements to a minimum.

Estimate Level	COMPLEX START (yyyy mm)
L2	1999 05

IN SERVICE DATES AND AMOUNTS							
2000 11	$535	2001 11	$468	2002 11	$436	2003 11	$351

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend								
Year 99/00								
00/01	519	12	4		535		535	
01/02	446	19	3		468		468	
02/03	407	26	3		436		436	
03/04	322	26	3		351		351	
04/05								
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	1,694	83	13		1,790		1,790	

REVISION: New Complex

Reviewed by	yyyy mm dd	Reviewed by	yyyy mm dd
ORIGINATOR	99 11 03	COORDINATOR	
Reviewed by	yyyy mm dd	Approved by	yyyy mm dd
CONSTRUCTOR		VICE-PRESIDENT	99 11 12

H2856/r Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Complex no. 260

Advance or deferral impact

Factors affecting timing or viability

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
HVDC BP 1 & 2 Auxiliary Power Supply Upgrades				1,694	1,694	
TOTAL				1,694	1,694	

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
1999 10	1,790	New Complex

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item 33

Title			Budget reference number
HVDC BP1 & 2 Auxiliary Power Supply Upgrades			03-00-8395
Originating division	Coordinating division	Constructing division	Project Order Group (Range):
HVDC	HVDC	HVDC	62249:62260

DESCRIPTION:
The review and upgrading of eight battery banks and four power centres at Dorsey, Radisson and Henday Converter Stations.

JUSTIFICATION:
Upgrading of the HVDC System Auxiliary Power Supplies is necessary to obtain maintenance outages for them without additional system costs and to maintain reliability of the HVDC System. This will allow Manitoba Hydro to maintain/increase firm energy sales and keep spinning reserve requirements to a minimum.

REFERENCE:
HVDC Report HVDC 99-01 entitled HVDC Auxiliary Power Supply Upgrades

REVISION:
New Item

Contingency 147,300

IN SERVICE DATES		Base estimate
2000 11 30	535	199902 L2
2001 11 30	468	
2002 11 30	436	Work start date
2003 11 30	351	1999 05 01

PREV AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:						
TOTAL						
REV. AMOUNTS:						
Authorized to date:						
Over(under)expend:						
Auth 2000/01	519	12	4			535
Req. 2001/02	446	19	3			468
2002/03	407	26	3			436
2003/04	322	26	3			351
TOTAL	1 694	83	13			1 790

Prepared by: yy mm dd COORDINATOR — Approved by: yy mm dd — Approved by: yy mm dd

Estimated by: ORIGINATOR — COORDINATING MANAGER — ORIGINATING MANAGER

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 03-00-8395

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS

ASSOCIATED PROJECTS

Budget reference number	Description
03-00-5901	DORSEY BIPOLE 1 SPARE 300 KV CONVERTER TRANSFORMER
03-00-5902	RADISSON BIPOLE 1 SPARE 450KV CONVERTER TRANSFORMER
03-00-5903	DORSEY SPARE CONVERTER TRANSFORMER FOUNDATIONS
03-00-5904	HENDAY BIPOLE 2 SPARE 500KV CONV. TFR (SPARE # 1)
03-00-5905	DORSEY BIPOLE 2 SPARE SMOOTHING REACTOR (DORSME8)
03-00-5906	HENDAY BIPOLE 2 SPARE SMOOTHING REACTOR (HENDME2)
03-00-5907	DORSEY BIPOLE 2 COOLING UPGRADE (DORSME11)
03-00-5908	HENDAY - BIPOLE 2 COOLING UPGRADE (HENDME4)
03-00-6119	RADISSON STATION SST1 RELOCATION & SST2 & SST3 CABLE REPLACE
03-00-6129	DORSEY BIPOLE 1 SPARE 450KV CONVERTER TRANSFORMER
03-00-8369	DORSEY BIPOLE 1 SPARE 300 KV CONV. TFR (SPARE # 3)
03-00-8370	HENDAY BIPOLE 2 SPARE 500KV CONV. TFR (SPARE # 2)
03-00-8396	Bipole 1 & 2 Electrode Line Monitoring
03-00-8398	Bipole 1 & 2 5/15KV Arcproofing and Brkr Upgrade

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May	18	1				19	19
Jun	13					13	32
Jul	13					13	45
Aug	17	1				18	[illegible]
Sep	26	1				27	
Oct	204	5	1			210	3[illegible]
Nov	166	5	2			173	473
Dec	62	-1	1			62	535
Jan							535
Feb							535
Mar							535
TOTAL	519	12	4			535	535

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

COMPLEX STATUS: [X] Planned [ ] In progress

Complex no. 272

REVISION STATUS: [X] New complex [ ] In service change [ ] Concept change [ ] Estimate change only

COMPLEX: DORSEY SYNCHRONOUS CONDENSER REFURBISHMENT

Proposal

Major inspection and overhaul of synchronous condensers SC7Y, SC8Y, SC9Y, SC21Y, SC22Y, and SC23Y. Replacement of coolers to restore original thermal performance on SC21Y, SC22Y, and SC23Y.

JUSTIFICATION: [ ] Load [ ] Service [ ] Safety [ ] Efficiency [X] Reliability [ ] Other

Explanation

Synchronous condensers are required for proper operation of the HVDC system, voltage regulation of the southern AC system and to provide reactive power for power export to the USA. A major inspection and overhaul of each machine is necessary to prevent catastrophic failure, involving the rotors and rotor bolts as indicated by the failures of SC12Y in 1987 and SC11Y in 1988. The cost of repairing a failure when conbined with our inability to export power will well exceed the cost of major inspection and overhaul.

Estimate Level	COMPLEX START (yyyy mm)
L2	2000 04

IN SERVICE DATES AND AMOUNTS							
2000 10	$1066	2001 10	$1274	2002 10	$1298	2003 10	$1325
2004 10	$1154	2005 10	$1177				

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend								
Year 99/00								
00/01	1,006	31	29		1,066		1,066	
01/02	1,179	59	36		1,274		1,274	
02/03	1,179	82	37		1,298		1,298	
03/04	1,179	109	37		1,325		1,325	
04/05	1,007	115	32		1,154		1,154	
05/06	1,007	137	33		1,177		1,177	
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	6,557	533	204		7,294		7,294	

REVISION: New complex.

Reviewed by ORIGINATOR	yyyy mm dd	Reviewed by COORDINATOR	yyyy mm dd 99 11 12
Reviewed by CONSTRUCTOR	yyyy mm dd	Approved by VICE-PRESIDENT	yyyy mm dd 99 11 12

H2856/r Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Complex no. 272

Advance or deferral impact

Deferral will maintain the potential for a failure that disrupts export sales.

Factors affecting timing or viability

Export sales.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Dorsey synchronous condenser refurbishment				6,557	6,557	
TOTAL				6,557	6,557	

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
1999 10	7,294	New complex.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION
HVDC 99-02	Dorsey Stn synchronous condenser major refurbishment

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item

34

Title			Budget reference number
DORSEY SYNCH. CONDENSER REFURBISHMENT			03-00-8376
Originating division	Coordinating division	Constructing division	Project Order Group (Range):
HVDC	HVDC	Construction	62200:62205

DESCRIPTION:
the major inspection and overhaul of synchronous condensers SC7Y, SC8Y, SC9Y, SC21Y, SC22Y, and SC23Y. The replacement of coolers to restore original thermal performance on SC21Y, SC22Y and SC23Y.

JUSTIFICATION:
The synchronous condensers are required for the proper operation of the HVDC system voltage regulation of the southern AC system and to provide reactive power for export of power to the USA. A major inspection and overhaul of each machine is necessary to prevent catastrophic failure, involving the rotors and rotor bolts as indicated by the failures of SC12Y in 1987 and SC11Y in 1988. The cost of repairing a failure when combined with our inability to export power will well exceed the cost of major inspection and overhaul.

REFERENCE:
Report HVDC 99-02, Dorsey Station Synchronous Condenser Major Refurbishment.

REVISION:
New Item
Contingency $264,000

IN SERVICE DATES				Base estimate
2000 10 31	1 066	2004 10 31	1 154	199810 L2
2001 10 31	1 274	2005 10 31	1 177	Work start date
2002 10 31	1 298			2000 04 01
2003 10 31	1 325			

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:						
TOTAL						
REV. AMOUNTS:						
Authorized to date:						
Over(under)expend:						
Auth 2000/01	1 006	31	29			1 066
Req.: 2001/02	1 179	59	36			1 274
2002/03	1 179	82	37			1 298
2003/04	1 179	109	37			1 325
2004/05	1 007	115	32			1 154
2005/06	1 007	137	33			1 177
TOTAL	6 557	533	204			7 294

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

1999-09-30 08:50 AM

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number: 03-00-8376

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS

ASSOCIATED PROJECTS

Budget reference number	Description
03-00-6185	DORSEY BIPOLE 1 SYNCH CONDENSER BREAKER REPLACEMENT

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr	54	2				56	56
May	312	10				322	378
Jun	316	9	3			328	706
Jul	269	9	5			283	989
Aug	4		7			11	1 000
Sep	4		7			11	1 01
Oct	47	1	7			55	1 0
Nov							1 06
Dec							1 066
Jan							1 066
Feb							1 066
Mar							1 066
TOTAL	1 006	31	29			1 066	1 06

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

COMPLEX STATUS: ☐ Planned ☒ In progress

Complex no. 3

REVISION STATUS: ☐ New complex ☒ In service change ☐ Concept change ☒ Estimate change only

COMPLEX: GREAT FALLS G.S.REHABILITATION

Proposal

Replace existing gates, roller paths and hoists (installed between 1920 - 1928) with new fixed-roller,vertical lift gates, stainless steel roller paths and wire rope type hoists. Anchor the intake piers to bedrock, to stabilize the intake. Replace main water passage components (bottom ring, discharge ring and draft tube liner) ,install new propeller type runner, rewind generator, provide new transformer and modernize to present standards.

JUSTIFICATION

☐ Load ☐ Service
☒ Safety ☒ Efficiency
☒ Reliability ☐ Other

Explanation

The existing a) intake gates and hoists cannot be expected to provide reliable emergency closure functions as they have the potential to malfunction during an emergency. b) draft tube liner is failing in spite of expensive repairs and is in urgent need of replacement. The potential to utilize the outage to replace the seventy year old runner with a larger, more efficient unit has been reviewed and approved by the re-runnering committee. While the generator was rewound forty years ago, many of the electrical components are original equipment from the 1920's.

Estimate Level	COMPLEX START (yyyy mm)
L1	1998 08

IN SERVICE DATES AND AMOUNTS

2001 03	$393	2001 11	$7212	2002 03	$6011	2003 03	$7301
2004 03	$2621						

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	128		3		131	208	-77	-37
Year 99/00	267	2	19		288	847	-559	-66
00/01	2,513	46	137		2,696	9,366	-6,670	-71
01/02	9,792	346	457		10,595	11,055	-460	-4
02/03	6,748	374	295		7,417	2,342	5,075	217
03/04	2,206	169	107		2,482		2,482	
04/05								
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	21,654	937	1,018		23,609	23,818	-209	-1

REVISION: Reflects revised work schedules, and deferred in service dates.

Reviewed by ORIGINATOR	yyyy mm dd	Reviewed by COORDINATOR	yyyy mm dd
Reviewed by CONSTRUCTOR	yyyy mm dd	Approved by VICE-PRESIDENT	yyyy mm dd 2011 04 12

H2856/r Rev 99 03

Complex no. 3

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Advance or deferral impact

Lost opportunity to coordinate two required repair jobs on unit #3 with only one shut down.
Danger of experiencing an intake gate malfunction during an emergency.

Factors affecting timing or viability

Urgency of requirement to replace intake gate and hoist.
Failing condition of the draft tube liner and age of electrical components.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Great Falls G.S. Unit #3 Draft Tube Liner & Rerunner		6,474	6,603	6,700	97	1
Great Falls G.S. Intake Gates		14,931	15,230	14,953	-277	-2
TOTAL		21,405	21,833	21,653	-180	-1

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
9710	23,583	New complex.
9810	23,818	Replacement of existing intake gates deferred one year, and unit #3 overhaul recostflowed.
1999 10	23,609	Reflects revised work schedules, and deferred in service dates.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item

35

Title			Budget reference number
GREAT FALLS G.S. - UNIT # 3 OVERHAUL & DRAFT TUBE LINER REPL			01-01-8057
Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Generation - South	Generation - South	Generation - South	61318

DESCRIPTION:
REPLACE MAIN WATER PASSAGE COMPONENTS (BOTTOM RING, DISCHARGE RING AND DRAFT TUBE LINER), INSTALL NEW PROPELLOR TYPE RUNNER, REWIND GENERATOR, PROVIDE NEW TRANSFORMER AND MODERNIZE TO PRESENT STANDARDS.

JUSTIFICATION:
THIS WORK IS DRIVEN BY A FAILING DRAFT TUBE LINER WHICH IN SPITE OF EXTENSIVE REPAIRS IS IN URGENT NEED OF REPLACEMENT. THE POTENTIAL TO UTILIZE THE OUTAGE TO REPLACE THE SEVENTY YEAR OLD RUNNER WITH A LARGER, MORE EFFICIENT UNIT HAS BEEN REVIEWED AND APPROVED BY THE RE-RUNNERING COMMITTEE. WHILE THE GENERATOR WAS REWOUND FOURTY YEARS AGO, MANY OF THE ELECTRICAL COMPONENTS ARE ORIGINAL EQUIPMENT FROM THE 1920'S.

REVISION:
MAINTAIN SCHEDULE AND CASH FLOW AS SHOWN. ESTIMATES TO BE REFINED DURING 1999/00.

This BRN contains Deleted, Blocked, or Closed Orders.

IN SERVICE DATES				Base estimate
2001 11 30	7 212			199704 L1
				Work start date 1998 08 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:	12					12
1999/00	118	3	9			130
2000/01	1 972	140	97			2 209
2001/02	4 229	390	176			4 795
2002/03	147	16				163
TOTAL	6 478	549	282			7 309
REV. AMOUNTS:						
Authorized to date:	12					12
Over(under)expend:						
Auth 1999/00	155		5			160
Req.: 2000/01	2 087	39	98			2 224
2001/02	4 333	155	210			4 698
2002/03	113	5				118
TOTAL	6 700	199	313			7 212

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 01-01-8057

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1997 10	7 382	NEW ITEM

ASSOCIATED PROJECTS

Budget reference number	Description
01-01-8069	GREAT FALLS G.S. INTAKE GATES

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun	5	1				6	6
Jul	5	1				6	12
Aug	5	1				6	18
Sep	18					18	36
Oct	18					18	54
Nov	18					18	72
Dec	18		1			19	91
Jan	18		1			19	110
Feb	24		1			25	135
Mar	26	-3	2			25	160
TOTAL	155		5			160	160
2000/01 Apr	164	2	1			167	167
May	173	2	2			177	344
Jun	164	2	4			170	514
Jul	173	2	5			180	694
Aug	173	3	6			182	876
Sep	173	3	7			183	
Oct	173	3	9			185	
Nov	173	3	10			186	1 450
Dec	173	4	11			188	1 618
Jan	188	3	13			204	1 822
Feb	181	5	14			200	2 022
Mar	179	7	16			202	2 224
TOTAL	2 087	39	98			2 224	2 224

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item

36

Title			Budget reference number
GREAT FALLS G.S. INTAKE GATES			01-01-8069
Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Generation - South	Generation - South	Generation - South	61358

DESCRIPTION:
REPLACEMENT OF EXISTING GATES, ROLLER PATHS AND HOISTS (INSTALLED BETWEEN 1920 AND 1928) WITH NEW FIXED-ROLLER, VERTICAL LIFT TYPE GATES, STAINLESS STEEL ROLLERPATHS AND WIRE ROPE TYPE HOISTS. ANCHORING OF THE INTAKE PIERS TO BEDROCK, TO STABILIZE THE INTAKE.

JUSTIFICATION:
THE EXISTING INTAKE GATES AND HOISTS CANNOT BE EXPECTED TO PROVIDE RELIABLE EMERGENCY CLOSURE FUNCTIONS AS THEY HAVE THE POTENTIAL TO MALFUNCTION DURING AN EMERGENCY.

REVISION:
PROJECT REFLECTS REVISED WORK SCHEDULE.

This BRN contains Deleted, Blocked, or Closed Orders.

IN SERVICE DATES				Base estimate
2001 03 31	393			199704 L1
2002 03 31	6 011			Work start date
2003 03 31	7 371			1998 10 01
2004 03 31	2 620			

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:	115		2			117
1999/00	719	35	41			795
2000/01	6 642	471	44			7 157
2001/02	5 594	517	149			6 260
2002/03	1 865	200	115			2 180
TOTAL	14 935	1 223	351			16 509
REV. AMOUNTS:						
Authorized to date:	115		2			117
Over(under)expend:						
Auth 1999/00	112	1	15			128
Req.: 2000/01	426	7	39			472
2001/02	5 458	191	247			5 896
2002/03	6 635	369	295			7 299
2003/04	2 207	169	107			2 483
TOTAL	14 953	737	705			16 395

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

1999-09-28 10:59 AM

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 01-01-8069

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1997 10	16 200	NEW ITEM.

ASSOCIATED PROJECTS

Budget reference number	Description
01-01-8057	GREAT FALLS G.S. - UNIT # 3 OVERHAUL & DRAFT TUBE LINER REPL

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr			1			1	1
May			1			1	2
Jun			1			1	3
Jul	19		1			20	23
Aug	19		1			20	43
Sep	19		1			20	63
Oct	19		1			20	83
Nov	19		1			20	103
Dec	19	-1	2			20	123
Jan			2			2	125
Feb			2			2	127
Mar	-2	2	1			1	128
TOTAL	112	1	15			128	128
2000/01 Apr	31		2			33	33
May	31	1	2			34	67
Jun	31	1	2			34	101
Jul	40	1	2			43	144
Aug	40		3			43	187
Sep	40		3			43	
Oct	40	1	3			44	
Nov	40		4			44	
Dec	40		4			44	362
Jan	31	1	4			36	398
Feb	31	1	5			37	435
Mar	31	1	5			37	472
TOTAL	426	7	39			472	472

1999-09-28 10:59 AM

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

COMPLEX STATUS	Complex no.	REVISION STATUS
☐ Planned ☒ In progress	52	☐ New complex ☐ In service change ☐ Concept change ☒ Estimate change only

COMPLEX: SEVEN SISTERS G.S. REHABILITATION

Proposal

Replace Unit # 1, 2 & 3 turbine runners together with rehabilitation of the generator field poles and rewinding of the stators. Conduct turbine model tests. Modify the draft tube on Unit 1 by adding a Moody Spreading Cone, and partially fill in the draft tube elbow with concrete. Perform restoration work on the generator rotor poles, rewind exciters and install new transformer sprinkler systems. Rehabilitation, replacement of and addition to various electrical and mechanical equipment and systems such as; station lighting, 110kv line protection, bus disconnects, station grounding, oil interceptor, spillway hoist housing upgrade, powerhouse ventilation, generator cable replacement, powerhouse and tailrace cranes, standby generator and EPS, control room air conditioning, generator terminal equipment, governor system, compressed air system, line & bus potential transformers, and spillway gate limit switches.

JUSTIFICATION	Explanation
☐ Load ☒ Service ☒ Safety ☒ Efficiency ☒ Reliability ☐ Other	New runners would produce rated power under lower head at greater efficiency levels. A redesigned draft tube would allow increased output. The original asphalt type stator windings should be replaced by modern epoxy materials before serious coil failures occur without warning. Assessment of the electrical and mechanical systems has identified concerns in terms of obsolete equipment, safety, fire risk and adaptability to present day operating conditions and standards. Upgrading is necessary to ensure reliable safe and economical operation.

Estimate Level	COMPLEX START (yyyy mm)
L3-5	1986 04

IN SERVICE DATES AND AMOUNTS							
1997 03	$8870	1997 07	$144	1997 10	$71	1997 11	$357
1997 12	$50	1998 02	$280	1998 08	$90	1998 10	$68
1998 12	$67	1999 03	$67	1999 06	$9369	1999 08	$48

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	16,945		1,049		17,994	35,630	-17,636	-49
ar 99/00	1,311	2	175		1,488	709	779	110
00/01								
01/02								
02/03								
03/04								
04/05								
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	18,256	2	1,224		19,482	36,339	-16,857	-46

VISION: Reflects costs to reassemble and commission unit 4, and clean up concrete rehab and spillway spud hoist deficiencies. Three completed & closed turbine runner items have been removed.

Reviewed by ORIGINATOR	yyyy mm dd	Reviewed by COORDINATOR	yyyy mm dd
Reviewed by CONSTRUCTOR	yyyy mm dd	Approved by VICE PRESIDENT	yyyy mm dd 99 11 12

H2856/r Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Complex no. 52

Advance or deferral impact

Component failures
Loss of capability/ derate
Inefficiency
Accelerated wear creating additional rehab cost

Factors affecting timing or viability

Drought conditions (may postpone or accelerate activities)
Forebay/ tailrace levels
Unit maintenance schedules

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Seven Sisters G.S. Electrical/Mechanical Systems	6,241	4,034	4,115	4,048	-67	-2
Seven Sisters G.S. Unit #4 Rehabilitation	6,205	6,623	6,755	8,788	2,033	30
Seven Sisters G.S. Major Concrete Rehab	2,132	3,178	3,242	3,025	-217	-7
Seven Sisters G.S. Cranes & Spillway Anchors	2,261	2,288	2,334	2,396	62	3
TOTAL	16,839	16,123	16,446	18,257	1,811	11

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
9510	36,738	Runner #3 ISD delayed. Revised to add widen tailrace deck, ramp, extend spillway deck and tailrace crane. Unit control metering & relaying and AVR repl transf'd to Cx26
9610	36,169	Reflects actual costs on completed work orders, correction to unit #4 rehab escalation calculation, and cash flow adjustments.
9710	36,760	Increased to provide funding for outstanding items, and extended to include repairs to spillway deck.
9810	36,339	Reflects 97/98 underexpenditure 2.3M and cash flows revised to reflect current work schedules, and outstanding deficiency requirements.
1999 10	19,482	Reflects costs to reassemble and commission unit 4, and clean up concrete rehab and spillway spud hoist deficiencies. Three completed & closed turbine runner items have been removed.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item

37

Title
SEVEN SISTERS G.S. ELECTRICAL/MECHANICAL SYSTEMS

Budget reference number
01-02-6017

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Generation - South	Generation - South	Generation - South	70174

DESCRIPTION:
REHABILITATION, REPLACEMENT OF, AND ADDITION TO VARIOUS ITEMS OF ELECTRICAL AND MECHANICAL EQUIPMENT AND SYSTEMS. ITEMS INCLUDED ARE:

49312	GENERATOR AVR REPLACEMENT (UNITS 4-6)	$ 821	TRANSFERRED (POG 60082)
49338	UPGRADING OF STANDBY GENERATOR & E.P.S	144	COMPLETE
49346	SPILLWAY HOIST HOUSING UPGRADE	387	COMPLETE
49353	UNIT CONTROL METERING & RELAYING	1,877	TRANSFERRED (POG 60083)
49361	110 KV LINE PROTECTION	617	(POG 70174)
49379	GENERATOR TERMINAL EQUIPMENT	117	COMPLETE
49387	110 KV LINE & BUS DISCONNECT	555	COMPLETE
49395	110 KV LINE & BUS POTENTIAL TRANSFORMER	56	COMPLETE
49403	STATION GROUNDING	451	COMPLETE
49411	STATION LIGHTING	709	COMPLETE
49429	SPILLWAY GATE LIMIT SWITCHES	34	COMPLETE
49437	POWERHOUSE AND TAILRACE CRANES	145	COMPLETE
49445	POWERHOUSE VENTILATION	225	COMPLETE
49452	GOVERNOR SYSTEM	80	COMPLETE
49460	COMPRESSED AIR SYSTEM	60	COMPLETE
49478	OIL SEPARATION SYSTEM	691	COMPLETE
49486	CONTROL ROOM AIR CONDITIONING	99	COMPLETE
49494	GENERATOR 2 11 KV POWER CABLE REPLACEMENT	227	COMPLETE

JUSTIFICATION:
ENGINEERING ASSESSMENT OF THE ELECTRICAL AND MECHANICAL EQUIPMENT AND SYSTEMS AT SEVEN SISTERS HAS IDENTIFIED VARIOUS AREAS OF CONCERN IN TERMS OF OBSOLETE EQUIPMENT, SAFETY, FIRE RISK AND ADAPTABILITY TO PRESENT DAY OPERATING CONDITIONS AND STANDARDS. UPGRADING WORK IS NECESSARY TO ENSURE CONTINUED RELIABLE SAFE AND ECONOMIC OPERATION OF THE GENERATING STATION.

REFERENCE:
E&C DIVISION REPORT NO. 85-E-1, JULY 25, 1985- S.S.G.S. PLANT EVALUATION REPORT STAGE III.

REVISION:
REFLECTS COSTS TO COMPLETION. PROJECT CLOSED OUT.

IN SERVICE DATES

						Base estimate
Prior Total	4 367	1998 07 31	1	1999 01 31	1	199704 L3
1998 04 30	5	1998 09 30	10	1999 02 28	9	
1998 05 31	5	1998 10 31	-4	1999 03 31	3	Work start date
1998 06 30	1	1998 11 30	1	1999 04 30	-1	1986 04 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date	4 048		350			4 398
1999/00	-15					-15
TOTAL	4 033		350			4 383
REV. AMOUNTS						
Authorized to date	4 048		350			4 398
Over(under)expend						
Auth Req.:						
TOTAL	4 048		350			4 398

Prepared by — yy mm dd — COORDINATOR
Approved by — yy mm dd — COORDINATING MANAGER
Approved by — yy mm dd — ORIGINATING MANAGER
Estimated by — ORIGINATOR

4149

CAPITAL EXPENDITURE REVISION

Budget reference number 01-02-6017

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1985 12	11 255	NEW ITEM.
1986 12	10 598	BASE DATE AND ESTIMATE REMAIN UNCHANGED. REVISED INTEREST AND ESCALATION RATES.
1987 11	11 905	BASE DATE REVISED FROM 1985 TO 1986.
1988 11	10 303	BASE DATE REVISED FROM 1986 TO 1988. REFLECTS REVISED INTEREST AND ESCALATION RATES. 110KV CIRCUIT BREAKER PORTION DELETED.
1989 10	6 590	THIS DECREASE IS PARTIALLY OFFSET BY INCREASES IN INSTALLATION COST ON OTHER WORK ITEMS. GENERATORS 1, 2, AND 3 STATOR WINDINGS DELETED FROM C.E.R. AND SET UP UNDER SEPARATE C.E.R.'S.
1990 10	6 384	DECREASE REFLECTS WORK COMPLETED AND REDUCTION OF CONTIGENCY
1991 10	7 074	INCREASE IN ESTIMATE DUE TO ADDITION OF THE FOLLOWING WORK: 1) POWERHOUSE AND TAILRACE CRANES, WHICH HAD BEEN DELETED FROM PREVIOUSCER. 2) UPGRADING OF STANDBY GENERATOR AND EMERGENCY POWER SUPPLY, RE: MEMO FROM M.J. MINOR TO K.R. OUELETTE 91 04 26. 3) SPILLWAY HOIST HOUSING UPGRADE, RE: MEMO FROM R.B. GIBSON TO L.J. HOLDEN 91 07 31.
1992 10	6 862	IN-SERVICE DATES REVISED TO ACCOMMODATE ENGINEERING WORKLOADS.
1993 10	6 969	IN SERVICE DATES REVISED TO ACCOMMODATE REVIEW TO SCOPE OF WORK FOR UNIT CONTROLS, METERING AND RELAYING AND RELATED ELECTRICAL SYSTEMS.
1994 10	7 393	INCREASE IS DUE TO REVISION TO THE OIL SEPARATION SYSTEM REQUIREMENTS IN ACCORDANCE WITH DESIGN REPORT 93-M12 AND REVIEW BY THE OIL CONTAINMENT WORKING GROUP.
1995 10	4 815	WO. 49478 - CONSTRUCTION SCHEDULE REVISED TO MATCH GENERATOROUTAGE SCHEDULE. WO. 49312 AND 49353 - TRANSFERRED TO BRN 9601-02-6960,NEW COMPLEX IS SET UP TO COMBINE ALL UNIT CENTRAL FUNCTION.
1996 10	4 597	ADJUSTED TO REFLECT COMPLETION OF WO# 49478
1997 10	4 628	ADJUSTED TO REFLECT COMPLETION OF WO # 49478.

ASSOCIATED PROJECTS

Budget reference number	Description
01-02-0028	SEVEN SISTERS G.S. TURBINE RUNNER #1
01-02-0029	SEVEN SISTERS G.S. - TURBINE RUNNER #2
01-02-0030	SEVEN SISTERS G.S. - TURBINE RUNNER #3
01-02-5924	SEVEN SISTERS G.S. - UNIT #4 REHABILITATION
01-02-5925	SEVEN SISTERS G.S. - MAJOR CONCRETE REHABILITATION
01-02-5926	SEVEN SISTERS G.S. - CRANES AND SPILLWAY ANCHORS

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item

38

Title
SEVEN SISTERS G.S. - UNIT #4 REHABILITATION

Budget reference number
01-02-5924

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Generation - South	Generation - South	Generation - South	60084

DESCRIPTION:
REPLACEMENT OF THE TURBINE RUNNER; REWINDING OF THE GENERATOR STATOR AND FIELD POLES, PLUS OTHER UPGRADES; AND THE REPLACEMENT OF THE STEP UP TRANSFORMER ON UNIT #4 AT SEVEN SISTERS GENERATING STATION.

JUSTIFICATION:
INSTALLATION OF A NEW RUNNER OF MODERN DESIGN ON UNIT 4 WILL RESULT IN INCREASED REVENUE ACCRUING FROM IMPROVEMENTS IN POWER OUTPUT AND EFFICIENCY OF THE UNIT. UNIT #4 GENERATOR WINDING IS IN DETERIORATED CONDITION. IT MUST BE REWOUND AT AN EARLY DATE TO AVOID AN IN SERVICE FAILURE WITH COSTLY CONSEQUENCES. REPLACEMENT OF THE STEP UP TRANSFORMER IS ECONOMICAL DUE TO REDUCTION IN LOSSES FOR THE NEW TRANSFORMER DESIGNS SIMILAR TO UNITS #1-#3.

REFERENCE:
REPORT NO. PS94-03 SEVEN SISTERS GENERATING STATION UNIT #4 GENERATOR TRANSFORMER REPLACEMENT.

REVISION:
CASH FLOW REVISED BASED ON CURRENT SCHEDULE. WORK SCHEDULED FOR 1999/00 IS TO COMPLETELY REASSEMBLE AND COMMISSION THE UNIT.

CONTINGENCY AMOUNT: $100 000.

BRN contains Deleted, Blocked, or Closed Orders.

IN SERVICE DATES

1999 06 30 | 9 364

Base estimate
199610 L3

Work start date
1994 09 01

PREV. AUTHORITY Authorized to date.	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
1999/00	7 531		399			7 930
	- 923					- 923
TOTAL	6 608		399			7 007
REV. AMOUNTS						
Authorized to date:	7 531		399			7 930
Over(under)expend:						
Auth Req. 1999/00	1 257	2	175			1 434
TOTAL	8 788	2	574			9 364

Prepared by: yy mm dd COORDINATOR — Approved by: yy mm dd COORDINATING MANAGER

Estimated by: ORIGINATOR — Approved by: yy mm dd ORIGINATING MANAGER

4151

CAPITAL EXPENDITURE REVISION

Budget reference number 01-02-5924

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1994 10	7 120	NEW ITEM.
1995 10	7 263	REVISED INTEREST AND ESCALATION RATES.
1996 10	7 088	REVISED INTEREST RATES. CORRECTED TO CALCULATED ESCALATION.
1997 10	7 099	REVISED INTEREST AND ESCALATION RATES..

ASSOCIATED PROJECTS

Budget reference number	Description
01-02-0028	SEVEN SISTERS G.S. TURBINE RUNNER #1
01-02-0029	SEVEN SISTERS G.S. - TURBINE RUNNER #2
01-02-0030	SEVEN SISTERS G.S. - TURBINE RUNNER #3
01-02-5925	SEVEN SISTERS G.S. - MAJOR CONCRETE REHABILITATION
01-02-5926	SEVEN SISTERS G.S. - CRANES AND SPILLWAY ANCHORS
01-02-6017	SEVEN SISTERS G.S. ELECTRICAL/MECHANICAL SYSTEMS

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	399	1	55			455	455
May	394	1	58			453	908
Jun	396		62			458	1 366
Jul	55					55	1 421
Aug	6					6	1 427
Sep	4					4	1 431
Oct	2					2	1 433
Nov	1					1	1 434
Dec							1 434
Jan							1 434
Feb							1 434
Mar							1 434
TOTAL	1 257	2	175			1 434	1 434
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item

39

Title
SEVEN SISTERS G.S. - MAJOR CONCRETE REHABILITATION

Budget reference number
01-02-5925

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Generation - South	Generation - South	Generation - South	60150

DESCRIPTION:
REHABILITATION OF INTAKE HEADBLOCKS 4 AND 5 WHICH SERVES AS A BARRIER TO PREVENT ICE FROM ENCROACHING INTO THE STOPLOG & GATE CHECKS AND, AS WELL, PROVIDES THE UPSTREAM ACCESSACROSS THE POWERHOUSE AND THE SUPPORTING STRUCTURE FOR THE UPSTREAM WALL. IT IS PARTICULARLY VULNERABLE TO FREEZE-THAW DETERIORATION AS WELL AS STRESSES RESULTING FROM THE SEVERE CLIMATIC CONDITIONS.

REHABILITATION OF THE TAILRACE PIERS AND DECK. THE TAILRACE CONSISTS OF A 9' WIDE DECK, A CRANE BEAM SUPPORTING THE RAILS FOR THE DRAFT TUBE STOP LOG CRANE AND THE PIERS. THE PIERS SEPARATE THE UNITS AND, AS WELL, SUPPORT THE CRANE BEAM AND THE DECK AND CONTAIN THE GAINS FOR THE STOP LOGS.

JUSTIFICATION:
THE LATEST CONDITION SURVEY REPORT INDICATES CONTINUING DETERIORATION OF INTAKE HEADBLOCKS 4 AND 5, TO THE POINT WHERE IT IS RECOMMENDED THAT THEY BE REHABILITATED.

AS A RESULT OF THE CONDITION OF THE CONCRETE AS DETERMINED BY THE LATEST CONCRETE INVESTIGATION, AS WELL AS A STUDY OF THE STRUCTURAL ADEQUACY OF THE PIERS AND DECK, THE RECOMMENDATION IS TO REMOVE THE EXISTING GUNITE AND DETERIORATED CONCRETE BELOW IT FROM THE UNDERSIDE OF THE DECK TO ELEVATION 840'; TO REPLACE THE DECK OVER THE FULL LENGTH WITH A WIDER, HIGHER CAPACITY DECK AND TO RESURFACE THE DOWNSTREAM WALL WITH A CEMENTITIOUS REPAIR MATERIAL.

REVISION:
SCOPE OF WORK IN 1999/00 IS COMPLETION OF MISCELLANEOUS CLEAN UP WORK.

CONTINGENCY AMOUNT: $5 000.

s BRN contains Deleted, Blocked, or Closed Orders.

IN SERVICE DATES						Base estimate
Prior Total	3 079	1998 09 30	8	1999 01 31	1	199704 L3
1998 06 30	9	1998 10 31	31	1999 02 28	1	
1998 07 31	3	1998 11 30	1	1999 03 31	3	Work start date
1998 08 31	20	1998 12 31	29	1999 08 31	48	1994 11 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date	2 992		208			3 200
1999/00	189					189
TOTAL	3 181		208			3 389
REV. AMOUNTS:						
Authorized to date:	2 992		208			3 200
Over(under)expend:						
Auth Req. 1999/00	33					33
TOTAL	3 025		208			3 233

Prepared by — yy mm dd — COORDINATOR
Approved by — yy mm dd — COORDINATING MANAGER
Approved by — yy mm dd — ORIGINATING MANAGER
Estimated by — ORIGINATOR

4153

1999-08-21 05:14 PM

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 01-02-5925

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1994 10	2 207	NEW ITEM.
1995 10	3 214	CHANGE IN SCOPE OF THE WORK, INCLUDING WIDENING OF THE TAILRACE DECK, ADDITION OF AN ACCESS RAMP FROM THE TAILRACE DECK TO THE INTERPOSING DYKE AND AN EXTENSION TO THE SPILLWAY DECK.
1996 10	3 154	COSTS ADJUSTED TO REFLECT 1995/96 ACTUALS.
1997 10	3 409	CASHFLOW EXTENDED TO INCLUDE REPAIRS TO SPILLWAY DECK.

ASSOCIATED PROJECTS

Budget reference number	Description
01-02-0028	SEVEN SISTERS G.S. TURBINE RUNNER #1
01-02-0029	SEVEN SISTERS G.S. - TURBINE RUNNER #2
01-02-0030	SEVEN SISTERS G.S. - TURBINE RUNNER #3
01-02-5924	SEVEN SISTERS G.S. - UNIT #4 REHABILITATION
01-02-5926	SEVEN SISTERS G.S. - CRANES AND SPILLWAY ANCHORS
01-02-6017	SEVEN SISTERS G.S. ELECTRICAL/MECHANICAL SYSTEMS

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May	4					4	4
Jun	9	1				10	14
Jul	8					8	22
Aug	12	-1				11	33
Sep							33
Oct							33
Nov							33
Dec							33
Jan							33
Feb							33
Mar							33
TOTAL	33					33	33
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

1999-08-21 05:14 PM

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item

40

Title
SEVEN SISTERS G.S. - CRANES AND SPILLWAY ANCHORS

Budget reference number
01-02-5926

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Generation - South	Generation - South	Generation - South	60091

DESCRIPTION:
TO PERFORM THE NECESSARY ENGINEERING DESIGN AND REMEDIAL CONSTRUCTION TO UPGRADE SEVEN SISTERS GENERATING STATION TO PRESENT DAY DAM SAFETY STANDARDS AND TO ALLOW THEM TO CONTINUE TO OPERATE IN A SAFE AND RELIABLE MANNER.

WORK DESCRIPTION TO INCLUDE THE FOLLOWING:

(1) ANCHOR REINFORCEMENT FOR THE NORTH SPILLWAY PIERS AND ROLLWAYS, THE CENTRE SLUICEWAY PIER AND THE SOUTH NON-OVERFLOW DAM (COMPLETED);

(2) PURCHASE OF NEW OR OVERHAUL EXISTING SPUD HOISTS TO IMPROVE RELIABILITY AND STOPLOG REMOVAL RATES;

(3) PINAWA CONTROL DAM UPGRADING.

JUSTIFICATION:
IT IS RECOMMENDED THAT THE ABOVE WORK BE UNDERTAKEN TO UPGRADE SEVEN SISTERS STRUCTURES TO PRESENT DAY DAM SAFETY STANDARDS AND TO ALLOW THEM TO CONTINUE TO OPERATE IN A SAFE AND RELIABLE MANNER.

REFERENCE:
DAM SAFETY PROGRAM SEVEN SISTERS GENERATING STATION DEFICIENCY INVESTIGATIONS SUMMARY REPORT # 93DSP-S06 DATED 93 11 03.

REVISION:
SCOPE OF WORK IN 1999/00 TO COVER OUTSTANDING DEFICIENCIES ON SPILLWAY SPUD HOIST.

IN SERVICE DATES						Base estimate
Prior Total	2 363	1998 09 30	18	1999 01 31	15	199704 L3
1998 06 30	6	1998 10 31	5	1999 02 28	11	
1998 07 31	0	1998 11 30	5	1999 03 31	23	Work start date
1998 08 31	5	1998 12 31	31	1999 04 30	6	1994 02 01

PREV AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date	2 375		92			2 467
1999/00	-86					-86
TOTAL	2 289		92			2 381
REV AMOUNTS:						
Authorized to date:	2 375		92			2 467
Over(under)expend:						
Auth Req.: 1999/00	21					21
TOTAL	2 396		92			2 488

Prepared by — yy mm dd — COORDINATOR
Approved by — yy mm dd — COORDINATING MANAGER
Approved by — yy mm dd — ORIGINATING MANAGER
Estimated by — ORIGINATOR

1999-08-21 05:15 PM

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 01-02-5926

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1994 10	2 018	NEW ITEM. TRANSFERRED FROM DOMESTIC PLAN (RE: B.R.N. 9401-02-4918).
1995 10	2 386	COSTS FOR SPUD HOIST RE-ESTIMATED TO REFLECT RECENT QUOTATIONS AND TAILRACE GANTRY CRANE TRANSFERRED FROM WO 41046.
1996 10	2 336	COSTS ADJUSTED TO REFLECT 1995/96 ACTUALS.
1997 10	2 352	COSTS ADJUSTED TO REFLECT 1996/97 ACTUALS.

ASSOCIATED PROJECTS

Budget reference number	Description
01-02-0028	SEVEN SISTERS G.S. TURBINE RUNNER #1
01-02-0029	SEVEN SISTERS G.S. - TURBINE RUNNER #2
01-02-0030	SEVEN SISTERS G.S. - TURBINE RUNNER #3
01-02-5924	SEVEN SISTERS G.S. - UNIT #4 REHABILITATION
01-02-5925	SEVEN SISTERS G.S. - MAJOR CONCRETE REHABILITATION
01-02-6017	SEVEN SISTERS G.S. ELECTRICAL/MECHANICAL SYSTEMS

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	21					21	21
May							21
Jun							21
Jul							21
Aug							21
Sep							21
Oct							21
Nov							21
Dec							21
Jan							21
Feb							21
Mar							21
TOTAL	21					21	21
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

COMPLEX STATUS: ☐ Planned ☒ In progress

Complex no. 32

REVISION STATUS: ☐ New complex ☒ In service change ☐ Concept change ☐ Estimate change only

COMPLEX: PINE FALLS G.S. REHABILITATION

Proposal

Rehabilitation, replacement of and addition to various electrical and mechanical equipment and systems such as; spillway mechanical components, station service upgrade, station lighting, 11kv cable replacement, spillway electrical distribution, water system, air system, transformer lightning arrestors and station drawings. Replace Unit #1and #2 turbine runners with more efficient new design runners, rebuild existing servomotors for increased wicket gate opening allowing more discharge, and rewind the generator stators utilizing modern insulating materials.

JUSTIFICATION

☐ Load ☒ Service
☒ Safety ☒ Efficiency
☒ Reliability ☐ Other

Explanation

Assessment of the electrical and mechanical systems has identified concerns in terms of obsolete equipment, safety, fire risk and adaptability to present day operating conditions and standards. Upgrading is necessary to ensure reliable safe and economical operation.Pine Falls consistantly spills more water than the other Winnipeg River plants. Additional generation can be obtained (approximately 17%) with increased discharge capability. Tests have confirmed that the 2 stator windings are in danger of failure at any time.

Estimate Level	COMPLEX START (yyyy mm)
L3-5	1988 12

IN SERVICE DATES AND AMOUNTS							
1997 03 31	$2700	2002 03	$25	2002 11	$8163	2003 11	$7234

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	2,672		160		2,832	2,928	-96	-3
Year 99/00	795	5	36		836	3,158	-2,322	-74
00/01	655	14	113		782	6,934	-6,152	-89
01/02	1,259	46	198		1,503	4,955	-3,452	-70
02/03	6,446	289	355		7,090	163	6,927	NA
03/04	4,543	214	209		4,966		4,966	
04/05	110	6			116		116	
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	16,480	574	1,071		18,125	18,138	-13	-0

REVISION: Revised to include funding for review of MFG's,prep design & spec's assistance during dis/ assembly & commissioning of unit, as built drawing prep, and deferral of Stn service upgrade.

Reviewed by ORIGINATOR	yyyy mm dd	Reviewed by COORDINATOR	yyyy mm dd
Reviewed by CONSTRUCTOR	yyyy mm dd	Approved by VICE-PRESIDENT	yyyy mm dd 99 11 12

H2856/r Rev 99 03

Complex no. 32

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Advance or deferral impact

Component failures
Loss of capability/ derate
Inefficiency
Accelerated wear creating additional rehab cost

Factors affecting timing or viability

Drought conditions (may postpone or accelerate activities)
Forebay/ tailrace levels
Unit maintenance schedules

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Pine Falls G.S. Electrical/Mechanical Systems	3,535	3,387	3,455	3,312	-143	-4
Pine Falls G.S. Units #1 &2 Gen Rewind & Rerunner		13,003	13,263	13,169	-94	-1
TOTAL	3,535	16,390	16,718	16,481	-237	-1

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
9510	8,918	250 VDC distribution upgrade transferred to WPG R CNTRL SYS - SEVEN SISTERS, and units 5 & 6 rehab completed.
9610	8,837	Revised interest rates. Costs revised to reflect 95/96 actual costs.
9710	17,936	Reflects revised costing implemented with the new financial reporting system, and addition of a new item for units 1 & 2 generator rewind & rerunner at Pine Falls.
9810	18,138	Units # 1 and 2 rerunnering/rewind deferred one year.
1999 10	18,125	Revised to include funding for review of MFG's,prep design & spec's assistance during dis/ assembly & commissioning of unit, as built drawing prep, and deferral of Stn service upgrade

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item

41

Title	Budget reference number
PINE FALLS G.S. ELECTRICAL/MECHANICAL SYSTEMS	01-03-8024

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Generation - South	Generation - South	Generation - South	61932

DESCRIPTION:
REHABILITATION, REPLACEMENT OF AND ADDITION TO VARIOUS ITEMS OF ELECTRICAL AND MECHANICAL EQUIPMENT AND SYSTEMS.

ITEMS INCLUDED ARE:

49502	TRANSFORMER LIGHTNING ARRESTORS	$ 149	COMPLETE
49510	STATION SERVICE UPGRADE	821	(POG 61932)
49528	250 VDC DISTRIBUTION	360	TRANSFERRED (POG 60081)
49536	STATION LIGHTING UPGRADE	553	COMPLETE
49544	SPILLWAY ELECTRICAL DISTRIBUTION	345	COMPLETE
49551	STATION ELECTRICAL DRAWINGS		(TRANSFERRED TO POG 61932)
49569	11 KV CABLE REPLACEMENT	313	COMPLETE
49585	SPILLWAY MECHANICAL	985	COMPLETE
49601	AIR SYSTEM	144	COMPLETE
49619	WATER SYSTEM	162	COMPLETE

JUSTIFICATION:
ENGINEERING ASSESSMENT OF THE ELECTRICAL AND MECHANICAL EQUIPMENT AND SYSTEMS AT PINE FALLS G.S. HAD IDENTIFIED VARIOUS AREAS OF CONCERN IN TERMS OF OBSOLETE EQUIPMENT,SAFETY, FIRE RISK AND ADAPTABILITY TO PRESENT DAY OPERATING CONDITIONS AND STANDARDS. UPGRADING WORK IS NECESSARY TO ENSURE CONTINUED RELIABLE, SAFE AND ECONOMICAL OPERATION OF THE GENERATING STATION.

REFERENCE:
E&C DIVISION REPORT NO. 87-E1 - PINE FALLS GENERATING STATION PLANT EVALUATION REPORT - STAGE III.

REVISION:
STATION SERVICE UPGRADE RESCHEDULED 2002/03.

This BRN contains Deleted, Blocked, or Closed Orders.

IN SERVICE DATES				Base estimate
1997 03 31	2 700			199704 L3
2002 03 31	25			Work start date
2002 11 30	762			1988 12 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:	2 552		151			2 703
1999/00	834	35	35			904
TOTAL	3 386	35	186			3 607
REV. AMOUNTS:						
Authorized to date:	2 552		151			2 703
Over(under)expend:						
Auth 2001/02	24	2				26
Req.: 2002/03	736	6	16			758
TOTAL	3 312	8	167			3 487

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

1999-09-28 11:02 AM

CAPITAL EXPENDITURE REVISION

Budget reference number 01-03-8024

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1988 11	2 653	NEW ITEM.
1989 10	3 675	INCREASE IN ESTIMATES FOR STATION SERVICE, DC DISTRIBUTION AND STATION LIGHTING BASED ON SIMILAR WORK PERFORMED AT GREAT FALLS AND SEVEN SISTERS GENERATING STATIONS.
1990 10	4 251	INCREASE RELATES TO ADDITION OF SPILLWAY GEN. BUILDING, ACCESS STAIRS, AND HOIST HOUSING INSULATION. STN. SERVICE, LIGHTING AND DC DISTRIBUTION WORK DEFERRED.
1991 10	4 045	REFLECTS FAVOURABLE CONTRACT COSTS FOR SPILLWAY ELECTRICAL, MECHANICAL, WATER SYSTEM UPGRADE PLUS DECREASED FIELD INSPECTION COSTS AND REDUCED CONTINGENCY.
1992 10	3 868	REFLECTS FAVOURABLE PURCHASE FOR 11KV GENERATOR CABLES. IN-SERVICE DATES REVISED TO ACCOMMODATE ENGINEERING WORKLOAD.
1993 10	3 949	IN-SERVICE DATES ADJUSTED TO ACCOMMODATE ENGINEERING WORKLOAD. STATION LIGHTING UPGRADE IS NOW SCHEDULED TO BE INSTALLED BY T&S CONSTRUCTION.
1994 10	3 977	IN-SERVICE DATE FOR STATION LIGHTING REVISED TO 1994 10 31 FROM 1993 12 31.
1995 10	3 624	WORK ORDER 49528 TRANSFERRED TO BRN 9601-02-6960. COSTS REVISED TO REFLECT ACTUALS.
1996 10	3 544	REVISED INTEREST RATES. COSTS REVISED TO REFLECT 95/96 ACTUAL COSTS.
1997 10	3 618	REVISED TO REFLECT NEW ACTIVITY AND OVERHEAD RATES.
		75,000.

ASSOCIATED PROJECTS

Budget reference number	Description
01-03-8058	PINE FALLS G.S. - UNITS # 1 & 2 OVERHAULS

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item __ Domestic Item

42

Title
PINE FALLS G.S. - UNITS # 1 & 2 OVERHAULS

Budget reference number
01-03-8058

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Generation - South	Generation - South	Generation - South	61320:61322

DESCRIPTION:
REWIND GENERATOR, INSTALL NEW PROPELLER TYPE TURBINE, PROVIDE NEW TRANSFORMER, MACHINE MAIN WATER PASSAGE COMPONENTS AND MODERNIZE TO PRESENT STANDARDS FOR BOTH UNIT # 1 AND # 2.

JUSTIFICATION:
BOTH UNITS HAVE BEEN IDENTIFIED AS HAVING GENERATORS IN URGENT NEED OF REPLACEMENT DUE TO THEIR DETERIORATING CONDITION. THE REPLACEMENT OF THE RUNNER DURING THE SAME OUTAGE HAS BEEN REVIEWED AND APPROVED BY THE RE-RUNNERING COMMITTEE.

REVISION:
REVISION TO REFLECT WORK INVOLVING THE REVIEW OF MANUFACTURERS, PREPARATION OF DESIGN AND MISCELLANEOUS TECHNICAL SPECIFICATIONS, THE PROVISION OF ASSISTANCE DURING THE DISASSEMBLY AND ASSEMBLY OF THE UNIT, ASSISTANCE DURING COMMISSIONING, AND THE PREPARATION OF AS-BUILT DRAWINGS.

IN SERVICE DATES

2002 11 30 7 404
2003 11 30 7 235

Base estimate
199704 L1

Work start date
1998 03 01

	PREV AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
	Authorized to date	120		9			129
	1999/00	2 144	107	99			2 350
	2000/01	6 219	441	274			6 934
	2001/02	4 376	403	176			4 955
	2002/03	147	16				163
	TOTAL	13 006	967	558			14 531
	REV. AMOUNTS:						
	Authorized to date	120		9			129
	Over(under)expend.						
Auth	1999/00	795	4	36			835
Req.	2000/01	655	14	113			782
	2001/02	1 235	45	197			1 477
	2002/03	5 711	283	339			6 333
	2003/04	4 543	214	210			4 967
	2004/05	110	6				116
	TOTAL	13 169	566	904			14 639

Prepared by yy mm dd COORDINATOR
Approved by yy mm dd Approved by yy mm dd
Estimated by ORIGINATOR COORDINATING MANAGER ORIGINATING MANAGER

1999-08-21 05:15 PM

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 01-03-8058

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1997 10	14 317	New item.

ASSOCIATED PROJECTS

Budget reference number	Description
01-03-8024	PINE FALLS G.S. ELECTRICAL/MECHANICAL SYSTEMS

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	4		1			5	5
May	12		1			13	18
Jun	67		1			68	86
Jul	75		1			76	162
Aug	75		2			77	239
Sep	75	-1	3			77	316
Oct	75		3			78	394
Nov	75		4			79	473
Dec	75		4			79	552
Jan	88	1	5			94	646
Feb	88	1	5			94	740
Mar	86	3	6			95	835
TOTAL	795	4	36			835	835
2000/01 Apr	68	1	7			76	76
May	57	1	7			65	141
Jun	57	1	8			66	207
Jul	54	2	8			64	271
Aug	54	1	9			64	335
Sep	54	2	9			65	
Oct	57	1	10			68	
Nov	57	2	10			69	537
Dec	57	1	11			69	606
Jan	46	1	11			58	664
Feb	46	2	11			59	723
Mar	48	-1	12			59	782
TOTAL	655	14	113			782	782

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

COMPLEX STATUS: ☐ Planned ☒ In progress

Complex no. 33

REVISION STATUS: ☐ New complex ☐ In service change ☐ Concept change ☒ Estimate change only

COMPLEX: MCARTHUR G.S. REHABILITATION

Proposal

Rehabilitation, replacement of and addition to various electrical and mechanical equipment and systems such as ; spillway mechanical components, station service upgrade, station lighting, spillway electrical distribution, water system, transformer upgrade, powerhouse gantry crane, governor system, spillway gate and guide rehab., and station drawings.

JUSTIFICATION

☐ Load ☒ Service
☒ Safety ☒ Efficiency
☒ Reliability ☐ Other

Explanation

Assessment of the electrical and mechanical systems has identified concerns in terms of obsolete equipment, safety, fire risk and adaptability to present day operating conditions and standards. Upgrading is necessary to ensure reliable safe and economical operation.

Estimate Level	COMPLEX START (yyyy mm)
L4	1989 04

IN SERVICE DATES AND AMOUNTS

1997 03	$8071	1998 02	$1897	1998 09	$144	1999 10	$1747

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	10,536		522		11,058	11,052	6	0
Year 99/00	736	1	64		801	741	60	8
00/01								
01/02								
02/03								
03/04								
04/05								
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	11,272	1	586		11,859	11,793	66	1

REVISION: Revised to reflect funding requirements to completion.

Reviewed by ORIGINATOR	yyyy mm dd	Reviewed by COORDINATOR	yyyy mm dd
Reviewed by CONSTRUCTOR	yyyy mm dd	Approved by VICE-PRESIDENT	yyyy mm dd 99 11 4/03

H2856/r Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Complex no. 33

Advance or deferral impact

If allowed to deteriorate further, operation of the gates will be impaired.

Factors affecting timing or viability

An orderly schedule of gate roller path and roller replacement is planned over the next 5 years.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
McArthur G.S. Electrical/Mechanical Systems	5,008	11,199	11,423	11,272	-151	-1
TOTAL	5,008	11,199	11,423	11,272	-151	-1

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
9510	11,864	Stn annunciator upgr and 250 VDC distn upgr transferred to Complex 26, and spillway gate and guide rehab revised to cost and work remaining.
9610	12,180	Correction of interest and overhead calculations.
9710	11,764	Revised to reflect actual costs to date.
9810	11,793	Revised to adjust cost flows.
1999 10	11,859	Revised to reflect funding requirements to completion.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item 43

Title
MCARTHUR G.S. ELECTRICAL / MECHANICAL SYSTEMS

Budget reference number
01-04-8005

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Generation - South	Generation - South	Generation - South	61955

DESCRIPTION:
REHABILITATION, REPLACEMENT OF AND ADDITION TO VARIOUS ITEMS OF ELECTRICAL AND MECHANICAL EQUIPMENT AND SYSTEMS.

ITEMS INCLUDED ARE:

47852	TRANSFORMER UPGRADE	$129 (COMPLETE)
47860	STATION SERVICE	508 (COMPLETE)
47878	STATION ANNUNCIATOR UPGRADE	238 (TRANSFERRED TO POG 60075) WPG R CONTROL - McA BRN 01 04 6962
47886	250 VDC DIST'N UPGRADE	376 (TRANSFERRED TO POG 60076) WPG R CONTROL - McA. BRN 01 04 6962
47894	STATION LIGHTING UPGRADE	460 (COMPLETE)
47928	UPDATE STN ELECTRICAL DRAWINGS	(INCLUDED IN POG 61955)
47936	POWERHOUSE GANTRY CRANE	99 (COMPLETE)
47944	WATER SYSTEM UPGRADE	84 (COMPLETE)
47951	GOVERNOR SYSTEM UPGRADE	3 (COMPLETE)
47969	SPILLWAY UPGRADE-ELEC/MECH	1604 (COMPLETE)
47977	SPILLWAY GATE & GUIDE REHAB.	9251 (INCL. IN POG 61955)

JUSTIFICATION:
ENGINEERING ASSESSMENT OF THE ELECTRICAL AND MECHANICAL EQUIPMENT AND SYSTEMS AT MCARTHUR FALLS G.S. HAS IDENTIFIED VARIOUS AREAS OF CONCERN IN TERMS OF OBSOLETE EQUIPMENT, SAFETY, FIRE RISK AND ADAPTABILITY TO PRESENT DAY OPERATING CONDITIONS AND STANDARDS. UPGRADING WORK IS NECESSARY TO ENSURE CONTINUED RELIABLE, SAFE AND ECONOMICAL OPERATION OF THE GENERATING STATION.

REFERENCE:
E&C DIVISION REPORT NO. 87-E2 - MCARTHUR FALLS GENERATING STATION PLANT EVALUATION REPORT - STAGE III.

REVISION:
REMAINING WORK SCHEDULED FOR 1999/00 INCLUDES REHABILITATION OF SPILLWAY GATES 7 & 8, AXLES AND ROLLERS AND MISC. OUTSTANDING DEFICIENCIES.

This BRN contains Deleted, Blocked, or Closed Orders.

IN SERVICE DATES

1997 03 31	8 071
1998 02 28	1 897
1998 09 30	144
1999 10 31	1 747

Base estimate
199610 L4

Work start date
1989 09 01

	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
PREV. AUTHORITY						
Authorized to date	10 536		522			11 058
1999/00	686	31	18			735
TOTAL	11 222	31	540			11 793
REV. AMOUNTS						
Authorized to date:	10 536		522			11 058
Over(under)expend.						
Auth Req.: 1999/00	736	1	64			801
TOTAL	11 272	1	586			11 859

Prepared by — yy mm dd — COORDINATOR
Approved by — yy mm dd — COORDINATING MANAGER
Approved by — yy mm dd — ORIGINATING MANAGER
Estimated by — ORIGINATOR

1999-08-21 05:15 PM

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 01-04-8005

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1988 11	2 935	NEW ITEM.
1989 10	5 164	INCREASE DUE TO ADDITION OF SPILLWAY MECHANICAL UPGRADE WHICH WAS NOT INCLUDED IN PREVIOUS CER. ESTIMATE INCREASED FOR 250 DC AND STATION LIGHTING BASED ON ACTUAL COST OF SIMILAR WORK AT GREAT FALLSAND SEVEN SISTERS. START DATE DEFERRED FROM 88/12/01 TO 89/04/01.
1990 10	4 055	ESTIMATE REFLECTS A MORE DETAILED AND RESCHEDULED REHABILITATION PLAN.
1991 10	3 955	REFLECTS FAVOURABLE CONTRACT COST ON WATER SYSTEM UPGRADE PLUS REDUCED INSTALLATION COST ESTIMATE FOR STATION LIGHTING BASED ON CURRENT MARKET PRICES.
1992 10	7 610	ADDED NEW ITEM, SPILLWAY GATE AND GUIDE REHABILITATION, AS PER R.B. GIBSON'S MEMORANDUM TO L.J. HOLDEN DATED 1992 02 11. IN-SERVICE DATES REVISED TO ACCOMMODATE ENGINEERING WORKLOADS.
1993 10	8 419	INCREASE TO WO# 47977 (SPILLWAY GATE & GUIDE REHABILITATION)DUE TO ADJUSTMENT OF CONTRACT ESTIMATE FOR GATE REHABILITATION WORK. IN-SERVICE DATES OF POWERHOUSE WORK ORDERS REVISED TO ACCOMMODATE ENGINEERING WORKLOADS.
1994 10	7 990	REDUCTION DUE TO A LOWER ESTIMATE FOR STATION SERVICE UPGRADE AND IN-SERVICE DATE ADVANCED SEVEN MONTHS.
1995 10	11 863	WORK ORDERS 47878, 47886 TRANSFERRED TO BRN 9601-04-6962, AND 47977 REVISED TO REFLECT COSTS TO DATE AND WORK REMAINING, PROBABLE CHANGE IN SCOPE OF WORK.
1996 10	12 180	CORRECTION OF INTEREST AND OVERHEAD CALCULATIONS.
1997 10	11 764	ESTIMATE REWORKED BASED ON ACTUAL COSTS TO DATE.

ASSOCIATED PROJECTS

Budget reference number	Description

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	31	-1	7			37	37
May	162		7			169	206
Jun	162		8			170	376
Jul	160		9			169	545
Aug	123	1	10			134	679
Sep	78	1	11			90	769
Oct	10		12			22	791
Nov	10					10	801
Dec							801
Jan							801
Feb							801
Mar							801
TOTAL	736	1	64			801	801
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

1999-08-31 05:15 PM

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

COMPLEX STATUS: ☐ Planned ☒ In progress

Complex no. 1

REVISION STATUS: ☐ New complex ☒ In service change ☐ Concept change ☒ Estimate change only

COMPLEX: LAURIE RIVER PLANT # 1 AND # 2 - REHABILITATION

Proposal

Rehabilitation, replacement of and addition to various civil works, electrical and mechanical equipment and systems such as ; concrete and structures, supervisory control system, vehicle storage building, bailey bridge, road, airstrip, electrical/ mechanical systems upgrade and 2.3kv breakers.

JUSTIFICATION

☐ Load ☒ Service ☒ Safety ☐ Efficiency ☒ Reliability ☐ Other

Explanation

Assessment of the civil, electrical and mechanical systems has identified concerns in terms of deterioration, obsolete equipment, safety, fire risk and adaptability to present day operating conditions and standards. Upgrading is necessary to ensure reliable safe and economical operation.

Estimate Level	COMPLEX START (yyyy mm)
L2	1991 05

IN SERVICE DATES AND AMOUNTS

up to 1997 12	$7093	1999 02	$1986	1999 12	$178	2000 12	$2724
2003 03	$117	2004 03	$511	2005 03	$524	2011 03	$1256
2012 03	$875	2013 03	$872				

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	8,394		858	1	9,251	9,261	-10	-0
Year 99/00	465	4	28		497	544	-47	-9
00/01	2,114	35	86		2,235	2,149	86	4
01/02								
02/03	99	10	9		118	118	0	0
03/04	424	50	38		512	515	-3	-1
04/05	424	60	39		523	526	-3	-1
05/06								
06/07								
07/08								
08/09								
09/10								
10/11	879	250	103		1,232	1,236	-4	-0
11/12	613	190	73		876	878	-2	-0
12/13	613	206	75		894	897	-3	-0
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	14,025	805	1,309	1	16,138	16,124	14	0

REVISION: Revised to reflect a deferral and estimate increase for bridge abutment, automation, and remote control work.

Reviewed by ORIGINATOR	yyyy mm dd 99 11 07	Reviewed by COORDINATOR	yyyy mm dd
Reviewed by CONSTRUCTOR	yyyy mm dd	Approved by VICE-PRESIDENT	yyyy mm dd 99 11 12

H2856/r Rev 99 03

Complex no. 1

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Advance or deferral impact

Component failures
Loss of capability/ derate
Inefficiency
Accelerated wear creating additional rehab cost

Factors affecting timing or viability

Drought conditions (may postpone or accelerate activities)
Forebay/ tailrace levels
Unit maintenance schedules

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Laurie River Plant #1 and Plant #2 - Phase1	10,119	10,523	10,733	10,973	240	2
Laurie River Plant #1 and Plant #2 - Phase2		947	966	947	-19	-2
Laurie River Plant #1 and Plant #2 - Phase3		2,105	2,147	2,105	-42	-2
TOTAL	10,119	13,575	13,846	14,025	179	1

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
9510	16,257	.Elec/Mech & RTU work deferred to 1996. Scope revised to add Civil & Elect/Mech items.
9610	16,106	In service dates deferred: Bailey Bridge to 1997, Automation & Supervisory Control to 1998. Revised interest rates.
9710	16,158	In service date deferred for automation and supervisory control in phase 1,and revised escalation and interest rates.
9810	16,124	Revised to reflect increased cash flows required to complete bridge work in 98/99 and advance engineering for automation & remote control, which is deferred 1 year.
9910	16,138	Revised to reflect a deferral and estimate increase for bridge abutment, automation, and remote control work.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item

Title
LAURIE RIVER PLANT #1 AND PLANT #2 - PHASE I

Budget reference number
01-10-9006

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Generation - North	Generation - South	Generation - South	60065:60155

DESCRIPTION:
REHABILITATION, UPGRADING OR REPLACEMENT OF, AND ADDITION TO VARIOUS ITEMS OF ELECTRICAL AND MECHANICAL SYSTEMS AND EQUIPMENT. ITEMS IDENTIFIED IN THE LAURIE RIVER ECONOMICVIABILITY STUDY ARE:
A) CONCRETE AND STRUCTURES; (COMPLETE) W/O#48082 & 48090
B) AUTOMATION AND REMOTE CONTROL; P.O.G.#60066
C) VEHICLE STORAGE BUILDING; (COMPLETE) W/O#46102
D) BAILEY BRIDGE; P.O.G.#60067
E) ROAD AND AIRSTRIP; (COMPLETE) W/O# 48066 & 48058
F) ELECTRICAL/MECHANICAL SYSTEMS UPGRADE & 2.3 KV BREAKERS. P.O.G.#'s 60065,60068,60069 & 60070. (COMPLETE)

SEPARATE BUDGET ITEMS WILL BE RAISED TO COVER PHASE II AND PHASE III.

JUSTIFICATION:
IT IS ECONOMICALLY VIABLE TO MAINTAIN AND REHABILITATE THE FACILITIES TO PRODUCE ELECTRICITY IN A SAFE, RELIABLE AND EFFICIENT MANNER. THE AGE AND CONDITION OF THE PLANT IS SUCH THAT REHABILITATION WORK IS REQUIRED

REFERENCE:
EASTERN REGION LAURIE RIVER ECONOMIC VIABILITY STUDY.

REVISION:
BRIDGE ABUTMENT WORK DEFERRED TO 99/00, AUTOMATION AND REMOTE CONTROL WORK DEFERRED TO 2000/01 AND ESTIMATED COST FOR AUTOMATION AND REMOTE CONTROL HAS INCREASED.

CONTINGENCY AMOUNT: $496,000

IN SERVICE DATES						Base estimate
Prior Total	7 092	1998 09 30	4	1999 03 31	1	199610 L3
1998 03 31	2	1998 11 30	15	1999 10 31	0	
1998 04 30	0	1999 01 31	0	1999 12 31	177	Work start date
1998 08 31	1	1999 02 28	1 966	2000 12 31	2 727	1998 04 01

PREV. AUTHORITY	GROSS	ESCALATION	INT CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date	8 394		858	-1		9 251
1999/00	347	17	191			555
2000/01	1 796	124	229			2 149
TOTAL	10 537	141	1 278	-1		11 955
REV. AMOUNTS:						
Authorized to date:	8 394		858	-1		9 251
Over(under)expend:						
Auth 1999/00	465	5	28			498
Req 2000/01	2 114	35	86			2 235
TOTAL	10 973	40	972	-1		11 984

Prepared by — yy mm dd — COORDINATOR
Approved by — yy mm dd — COORDINATING MANAGER
Approved by — yy mm dd — ORIGINATING MANAGER
Estimated by — ORIGINATOR

1999-08-21 05:16 PM

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 01-10-9006

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1990 10	11 159	NEW ITEM
1991 10	12 528	ESTIMATES WERE INCREASED FOR ROAD WORK NOW AT LEVEL THREE, TO INCLUDE A WORKSHOP WITH THE STORAGE BUILDING, TO INCLUDE WIRING INTERFACE COSTS AND FIELD EXPENSES TO SUPERVISORY CONTROL SYSTEM, AND TOINCREASE THE MAGNITUDE OF CONCRETE REPAIRS AT LAURIE RIVER #1 AND BRING FORWARD MAJOR CONCRETE WORK FROM PHASES II & III. PROJECT MANAGEMENT AND FIELD INSPECTION COSTS WERE ADDED TO ALL WORK ORDERS (NOT IN ORIGINAL REPORT).
1992 10	10 878	BASE ESTIMATE DECREASED DUE TO CANCELLATION OF ROAD UPGRADING WORK.
1993 10	11 623	LAURIE RIVER G.S. NO. 1: ADDED POST TENSIONAL ANCHORS AT GRAVITY STRUCTURES AND SLUICEWAY PIERS AND DELAYED OTHER ITEMS ONE YEAR RE: IOM H.J. CLOUSTON TO L.P. JONASSEN DATED 93 02 19. REVISED CONCRETE AND STRUCTURES SCOPE OF WORK TO INCLUDE NEW SPILLWAY DECK AND THRUST BLOCK AT CENTRE GRAVITY STRUCTURE.
1994 10	11 705	SCOPE OF CONCRETE & STRUCTURES WORK WAS REVISED FOR LAURIE RIVER NO.1 TO INCLUDE REPL. OF THE POWERHOUSE EXTERIOR DOORS & THE ACCESS LADDER FR THE EAST GRAVITY STRUCTURE, TO PROVIDE A TAILRACE ACCESS PLATFORM & TO UPGRADE THE EXTERIOR LIGHTING TO HPS. AT LAURIE RIVER NO.2 THIS REVISION INCLUDES REPL. OF THE MAIN POWERHOUSE DOOR AND REPL OF THE INTAKE HEADGATES.
1995 05	11 705	SELECTIVE REVISION TO DEFER ELECT/MECH AND RTU WORK TO 1996.
1995 10	11 917	ELECTRICAL/MECHANICAL AND RTU WORK DEFERRED TO 1996. SCOPE OF WORK REVISED TO INCLUDE ADDITIONAL CIVIL ITEMS IN ACCORDANCE WITH I.O.M. H.J. CLOUSTON TO R.O. LAMBERT DATED 95 02 09 AND TO INCLUDE ADDITIONAL ELECTRICAL/MECHANICAL ITEMS IN ACCORDANCE WITH I.O.M. H.J. CLOUSTON TO R.O. LAMBERT DATED 95 06 06. 06.
1996 10	11 767	
1997 10	11 991	INSERVICE DATE FOR AUTOMATION AND SUPERVISORY CONTROL DEFERRED TO 1999.

ASSOCIATED PROJECTS

Budget reference number	Description
01-10-2110	LAURIE RIVER PLANT #1 AND PLANT #2 - PHASE II
01-10-2111	LAURIE RIVER PLANT #1 AND PLANT #2 - PHASE III

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	17	1	1			19	19
May	16	1	1			18	37
Jun	16	1	1			18	55
Jul	77		2			79	134
Aug	83		2			85	219
Sep	82	1	3			86	305
Oct	1	1	3			5	310
Nov			3			3	313
Dec			3			3	316
Jan	88	1	2			91	407
Feb	29		3			32	439
Mar	56	-1	4			59	498
TOTAL	465	5	28			498	498
2000/01 Apr	63	1	3			67	67
May	93	1	4			98	165
Jun	79	1	5			85	250
Jul	447	10	5			462	712
Aug	443	10	8			461	1 173
Sep	379	9	12			400	
Oct	111	2	15			128	
Nov	499	1	15			515	2 216
Dec			19			19	2 235
Jan							2 235
Feb							2 235
Mar							2 235
TOTAL	2 114	35	86			2 235	2 235

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item

45

Title
LAURIE RIVER PLANT #1 AND PLANT #2 - PHASE II

Budget reference number
01-10-2110

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
eration - North	Generation - South	Generation - South	61311

SCRIPTION:
EHABILITATION OF CONCRETE STRUCTURES AS IDENTIFIED IN THE LAURIE RIVER ECONOMIC VIABILITY STUDY.

JUSTIFICATION:
IT IS ECONOMICALLY VIABLE TO MAINTAIN AND REHABILITATE THE FACILITIES TO PRODUCE ELECTRICITY IN A SAFE, RELIABLE AND EFFICIENT MANNER. THE AGE AND CONDITION OF THE PLANT IS SUCH THAT REHABILITATION WORK IS REQUIRED.

REFERENCE:
EASTERN REGION LAURIE RIVER ECONOMIC VIABILITY STUDY.

REVISION:
CONTINGENCY AMOUNT: $284,000

IN SERVICE DATES

2003 03 31	117
2004 03 31	511
2005 03 31	524

Base estimate
199704 L2

Work start date
2003 02 01

PREV AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date						
2002/03	99	10	9			118
2003/04	424	53	38			515
2004/05	424	63	39			526
TOTAL	947	126	86			1 159
REV. AMOUNTS:						
Authorized to date:						
Over(under)expend:						
Auth 2002/03	99	9	9			117
Req 2003/04	424	50	38			512
2004/05	424	60	39			523
TOTAL	947	119	86			1 152

Prepared by yy mm dd COORDINATOR Approved by yy mm dd Approved by yy mm dd

Estimated by ORIGINATOR COORDINATING MANAGER ORIGINATING MANAGER

4171

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 01-10-2110

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1991 10	1 592	NEW ITEM.
1992 10	1 374	REVISED TO REFLECT CURRENT ESCALATION AND INTEREST RATES.
1993 10	1 267	REVISED TO REFLECT CURRENT ESCALATION AND INTEREST RATES.
1994 10	1 185	UPDATED INTEREST AND ESCALATION RATES.
1995 10	1 182	UPDATED INTEREST AND ESCALATION RATES.
1997 10	1 162	REVISED INTEREST RATES.

ASSOCIATED PROJECTS

Budget reference number	Description
01-10-2111	LAURIE RIVER PLANT #1 AND PLANT #2 - PHASE III
01-10-9006	LAURIE RIVER PLANT #1 AND PLANT #2 - PHASE I

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item

46

Title
LAURIE RIVER PLANT #1 AND PLANT #2 - PHASE III

Budget reference number
01-10-2111

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Generation - North	Generation - South	Generation - South	61312

DESCRIPTION:
REHABILITATION OF ROAD AND CONCRETE STRUCTURES AS IDENTIFIED IN THE LAURIE RIVER ECONOMIC VIABILITY STUDY.

JUSTIFICATION:
IT IS ECONOMICALLY VIABLE TO MAINTAIN AND REHABILITATE THE FACILITIES TO PRODUCE ELECTRICITY IN A SAFE, RELIABLE AND EFFICIENT MANNER. THE AGE AND CONDITION OF THE PLANT IS SUCH THAT REHABILITATION WORK IS REQUIRED

REFERENCE:
EASTERN REGION LAURIE RIVER ECONOMIC VIABILITY STUDY.

REVISION:
CONTINGENCY AMOUNT $632,000

IN SERVICE DATES

2011 03 31	1 256
2012 03 31	875
2013 03 31	872

Base estimate
199704 L2

Work start date
2011 03 01

PREV. AUTHORITY Authorized to date	GROSS	ESCALATION	INT. CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
2010/11	879	258	99			1 236
2011/12	613	196	69			878
2012/13	613	212	72			897
TOTAL	2 105	666	240			3 011
REV. AMOUNTS Authorized to date						
Over(under)expend:						
Auth 2010/11	879	250	103			1 232
Req 2011/12	613	190	73			876
2012/13	613	207	75			895
TOTAL	2 105	647	251			3 003

Prepared by: yy mm dd COORDINATOR
Approved by: yy mm dd COORDINATING MANAGER
Approved by: yy mm dd ORIGINATING MANAGER
Estimated by: ORIGINATOR

4173

1999-08-21 05:15 PM

CAPITAL EXPENDITURE REVISION

Budget reference number 01-10-2111

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1997 10	3 006	REVISED INTEREST RATES.

ASSOCIATED PROJECTS

Budget reference number	Description
01-10-2110	LAURIE RIVER PLANT #1 AND PLANT #2 - PHASE II
01-10-9006	LAURIE RIVER PLANT #1 AND PLANT #2 - PHASE I

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

COMPLEX STATUS: ☐ Planned ☒ In progress

Complex no. 48

REVISION STATUS: ☐ New complex ☒ In service change ☐ Concept change ☒ Estimate change only

COMPLEX: GRAND RAPIDS G.S. REHABILITATION

Proposal

Disassemble Unit 1 and assess damage. Replace outer, intermediate and inner head covers, turbine guide bearings, servomotors, operating ring and links. Repair various other components and reassemble the unit utilizing the repaired existing runner for an in-service date of 1994 05 12.

Replace Kaplan turbine runners on Units 1,2 and 3 and modify servomotors, head covers, operating ring and governor pressure system on Unit 4. Rewind generators on Units 1, 2 and 3. Modify the stator frame support and add 13.8 kv ciruit breakers on all four generators. Upgrade the controls, annunciation and protection, to provide synchronous condencer capability.

JUSTIFICATION

☐ Load ☐ Service
☒ Safety ☒ Efficiency
☒ Reliability ☐ Other

Explanation

To repair the Unit 1 damage which occurred as a result of the head cover failure and return the unit to service prior to the 1993/94 winter peak.

Excessive wear of the turbine units requires complete repair or replacement with new more powerful and efficient runners on Units 1, 2 and 3. Unit 4 will be upgraded by wicket gate opening enlargement. Breakers will improve system reliability. DC zoning rearrangement will enhance security.

Estimate Level	COMPLEX START (yyyy mm)
L3	1990 06

IN SERVICE DATES AND AMOUNTS

1997 03	$35035	1997 06	$17098	1997 12	$942	1998 02	$7034
1998 09	$603	1998 11	$3324	1999 03	$1083	1999 10	$3507
2000 03	$86	2001 03	$112	2001 04	$25385	2002 03	$6541

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	66,107		9,620	30	75,697	76,128	-431	-1
Year 99/00	4,398	26	980		5,404	16,297	-10,893	-67
00/01	12,168	185	1,491		13,844	5,020	8,824	176
01/02	5,247	171	356		5,774	4,509	1,265	28
02/03						4,636	-4,636	-100
03/04						3,594	-3,594	-100
04/05						2,417	-2,417	-100
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	87,920	382	12,447	30	100,719	112,601	-11,882	-11

REVISION: Reflects add'n of repl of wicket gate bushings & shaft rod seal-u 4, repair internal problems -u 1,des mods & def -gen brkrs, reschedule units 2 & 3,& transfer of Dam Safety prog.to Cx82

Reviewed by ORIGINATOR	yyyy mm dd 99 11 08	Reviewed by COORDINATOR	yyyy mm dd
Reviewed by CONSTRUCTOR	yyyy mm dd	Approved by VICE-PRESIDENT	yyyy mm dd

H2856/r Rev 99 03

Complex no. 48

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Advance or deferral impact

Grand Rapids GS was designed and built to provide various uses such as automatic generation control (AGC), spinning reserves, a... as a daily peaking plant. Unit 1 and 2 are for peak loading, and Unit 3 and 4 are on AGC.

Factors affecting timing or viability

Schedule of equipment delivery and installation.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Grand Rapids Unit 1 Overhaul	9,048	15,811	16,127	16,058	-69	-0
Grand Rapids Unit 2 Overhaul	8,397	18,515	18,885	17,966	-919	-5
Grand Rapids Unit 3 Overhaul	8,486	19,685	20,079	18,957	-1,122	-6
Grand Rapids Unit 4 Overhaul	6,527	9,797	9,993	13,103	3,110	31
Grand Rapids Unit 1 Repairs	5,194	11,636	11,869	11,565	-304	-3
Grand Rapids Gen Brkrs & Sync Cond Conv	5,398	9,134	9,317	10,269	952	10
TOTAL	43,050	84,578	86,270	87,918	1,648	2

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
9510	70,749	Overhaul of units 1-3 def'd to Nov 95, tendered prices, deficiency requirements, install'n of accumulator tanks, and anticipated insurance claim legal fees were added.
9610	72,200	Adjusted to reflect actual expenditures, to complete deficiencies, and to include increased generator components repair in units 2 & 3.
9710	98,489	Reflects deficiency requirements, actual costs, anticipated insurance claim legal fees (unit 1 repairs) , addition of repairing spare turbine bearing, and new dam safety deficiency program
9810	112,601	Reflects 97/98 underexpenditure 1.3M, work deferral, deficiency compl'n req, reest for unit 2 , runner repairs - unit 3, reliab and perform mods, and int correction to dam safety prog.
1999 10	100,719	Reflects add'n of repl of wicket gate bushings & shaft rod seal-u 4, repair internal problems -u 1,des mods & def -gen brkrs, reschedule units 2 & 3,& transfer of Dam Safety prog.to Cx...

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item

47

Title			Budget reference number
GRAND RAPIDS G.S. UNIT #1 OVERHAUL			01-08-3011
Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Generation - South	Generation - South	Generation - South	60092:61315

DESCRIPTION:
REPLACE THE KAPLAN RUNNER, REWIND GENERATOR AND MODIFY THE STATOR FRAME SUPPORT. ADD A 13.8 KV GENERATOR CIRCUIT BREAKER.

JUSTIFICATION:
EXCESSIVE WEAR TO THE RUNNER BLADE TRUNNIONS AND LEAKING OIL SEALS REQUIRE A REPLACEMENT OF THE RUNNER. THE NEW RUNNER WILL BE MORE EFFICIENT THAN THE EXISTING ONE. THE GENERATOR WILL BE REWOUND AND RADIAL EXPANSION KEYS INSTALLED ON THE STATOR SOLE PLATES TO ACCEPT THE INCREASED POWER OUTPUT. NEW 13.8 KV BREAKERS WILL BE INSTALLED TO IMPROVE SYSTEM RELIABILITY. THE POWER TRANSFORMER WILL BE MODIFIED TO ACCEPT THE INCREASED OUTPUT. OTHER WORK WILL BE PERFORMED TO MODERNIZE THE UNIT.

REVISION:
ALLOWANCE TO COMPLETE DEFICIENCIES IDENTIFIED IN COMMISSIONING AND MODIFICATIONS TO RUNNER AND WICKET GATES. COST INCREASE DUE TO RESOLUTION OF MAJOR PROBLEMS WITHIN THE UNIT.

IN SERVICE DATES						Base estimate
Prior Total	13 716	1998 11 30	3 275	1999 03 31	610	199704 L3
1998 08 31	111	1998 12 31	103	1999 06 30	8	Work start date
1998 09 30	23	1999 01 31	50	2001 03 31	112	1992 12 01
1998 10 31	15	1999 02 28	57	2002 03 31	113	

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:	15 836		2 124	-9		17 951
1999/00	6					6
TOTAL	15 842		2 124	-9		17 957
REV. AMOUNTS:						
Authorized to date:	15 836		2 124	-9		17 951
Over(under)expend:						
Auth 1999/00	56	1				57
Req.: 2000/01	83	4				87
2001/02	83	6				89
TOTAL	16 058	11	2 124	-9		18 184

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

1999-09-28 11:02 AM

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 01-08-3011

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1992 10	9 966	NEW ITEM. (PREVIOUSLY INCLUDED UNDER B.R.N. --01-08-1068). ESTIMATE INCREASE DUE TO STATOR REWINDING SUPPLY AND INSTALLATION AND THE ADDITION OF A 13.8 KV CIRCUIT BREAKER. MAJOR SCHEDULE CHANGES WERE IMPOSED BY THE UNIT 1 HEADCOVER FAILURE IN MARCH 1992 AND THE UNIT 3 STATOR DAMAGE IN MAY 1992. IN GENERAL THE WORK HAS BEEN ADVANCED TO COPE WITH THESE FORCED OUTAGES.
1993 10	10 727	IN-SERVICE DATE DEFERRED ONE MONTH. COSTS OF TURBINE RUNNERREVISED TO REFLECT ACTUAL CONTRACT COSTS.
1994 10	11 378	IN-SERVICE DATE DEFERRED FROM 1994 09 30 TO 1995 07 31. SYNCHRONOUS CONDENSER CONVERSION AND GENERATOR BREAKERS TRANSFERRED TO BRN 01-08-5931).
1995 10	12 708	IN-SERVICE DATE DEFERRED FROM 95 07 31 TO 95 11 29 RESULTINGIN INCREASED INTEREST AND INDIRECT CHARGES. ADDITIONAL INCREASES REFLECT ACTUAL TENDERED PRICES.
1996 10	13 054	ALLOWANCE TO COMPLETE DEFICIENCIES IDENTIFIED IN COMMISSIONING.
1997 10	14 815	ALLOWANCE TO COMPLETE DEFICIENCIES IDENTIFIED IN COMMISSIONING AND DEFICIENCIES BROUGHT TO LIGHT IN 1997.

ASSOCIATED PROJECTS

Budget reference number	Description
01-08-1068	GRAND RAPIDS UNIT #4 OVERHAUL
01-08-3009	GRAND RAPIDS G.S. UNIT 1 REPAIRS
01-08-3012	GRAND RAPIDS G.S. UNIT #2 OVERHAUL
01-08-3013	GRAND RAPIDS G.S. UNIT#3 OVERHAUL
01-08-5931	GRAND RAPIDS G.S. GEN. BRKRS. & SYNC. COND. CONVERSION
01-08-7041	Generation South Dam Safety Deficiency Program

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	12					12	12
May	4					4	16
Jun	4					4	20
Jul	4					4	24
Aug	4					4	28
Sep	4					4	32
Oct	4					4	36
Nov	4					4	40
Dec	4					4	44
Jan	3					3	47
Feb	3					3	50
Mar	6	1				7	57
TOTAL	56	1				57	57
2000/01 Apr	7					7	7
May	7					7	14
Jun	7					7	21
Jul	7					7	28
Aug	7					7	35
Sep	7					7	
Oct	7					7	
Nov	7					7	
Dec	7					7	63
Jan	7					7	70
Feb	7					7	77
Mar	6	4				10	87
TOTAL	83	4				87	87

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item

48

Title	Budget reference number
GRAND RAPIDS G.S. UNIT #2 OVERHAUL	01-08-3012

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Generation - South	Generation - South	Generation - South	60059

DESCRIPTION:
REPLACE THE KAPLAN RUNNER. REWIND GENERATOR AND MODIFY THE STATOR FRAME SUPPORT. ADD 13.8KV GENERATOR CIRCUIT BREAKER.

JUSTIFICATION:
EXCESSIVE WEAR TO THE RUNNER BLADE TRUNNIONS AND LEAKING OIL SEALS REQUIRE A REPLACEMENT OF THE RUNNER. THE NEW RUNNER WILL BE MORE EFFICIENT THAN THE EXISTING ONE. THE GENERATOR WILL BE REWOUND AND RADIAL EXPANSION KEYS INSTALLED ON THE STATOR SOLE PLATES TO ACCEPT THE INCREASED POWER OUTPUT. NEW 13.8KV BREAKERS WILL BE INSTALLED TO IMPROVE SYSTEM RELIABILITY. THE POWER TRANSFORMER WILL BE MODIFIED TO ACCEPT THE INCREASED OUTPUT. OTHER WORK WILL BE PERFORMED TO MODERNIZE THE UNIT.

REVISION:
ESTIMATE REWORKED TO REFLECT COSTS INCURRED FOR SIMILAR WORK ON UNIT # 3. OVERHAUL START DATE DEFERRED TO FEB/2000.

CONTINGENCY AMOUNT: $535 000.

This BRN contains Deleted, Blocked, or Closed Orders.

IN SERVICE DATES				Base estimate
2001 04 30	22 564			199610 L3
				Work start date 1992 10 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:	6 133		2 353			8 486
1999/00	12 373	491	1 120			13 984
TOTAL	18 506	491	3 473			22 470
REV. AMOUNTS:						
Authorized to date:	6 133		2 353			8 486
Over(under)expend:						
Auth 1999/00	260	3	740			1 003
Req.: 2000/01	9 943	140	1 189			11 272
2001/02	1 630	29	144			1 803
TOTAL	17 966	172	4 426			22 564

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

1999-09-28 11:03 AM

CAPITAL EXPENDITURE REVISION

Budget reference number 01-08-3012

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1992 10	9 874	NEW ITEM. (PREVIOUSLY INCLUDED UNDER B.R.N. –01-08-1068). ESTIMATE INCREASE DUE TO STATOR REWINDING SUPPLY AND INSTALLATION AND THE ADDITION OF A 13.8 KV CIRCUIT BREAKER. MAJOR SCHEDULE CHANGES WERE IMPOSED BY THE UNIT 1 HEADCOVER FAILURE IN MARCH 1992 AND THE UNIT 3 STATOR DAMAGE IN MAY 1992. IN GENERAL THE WORK HAS BEEN ADVANCED TO COPE WITH THESE FORCED OUTAGES.
1993 10	8 951	IN-SERVICE DATE ADVANCED 1 MONTH. COSTS REVISED TO REFLECT ACTUALS TO DATE AND COMMITTED COSTS FOR TURBINE RUNNERS.
1994 10	13 044	ESTIMATED COSTS AND SCHEDULE INCREASED TO REFLECT EXPERIENCEFROM SIMILAR WORK ON UNIT 4. SYNCHRONOUS CONDENSER CONVERSION AND GENERATOR BREAKERS TRANSFERRED TO BRN (01-08-5931). IN-SERVICE DATE DEFERRED FROM 1995 09 30 TO 1997 02 28.
1995 10	14 220	IN-SERVICE DATE DEFERRED FROM 97 02 28 TO 97 11 19 RESULTINGIN INCREASED INTEREST AND INDIRECT CHARGES. ANTICIPATED DURATION OF THE WORK INCREASED BY 6 WEEKS BASED ON PREVIOUS EXPERIENCE FOR SIMILAR WORK.
1996 10	14 469	ESTIMATES ADJUSTED TO REFLECT EXPERIENCES ON UNIT # 3 OVERHAUL.
1997 10	18 270	ESTIMATE REWORKED TO REFLECT ACTUAL COSTS FOR SIMILAR WORK ON UNIT # 3.

ASSOCIATED PROJECTS

Budget reference number	Description
01-08-1068	GRAND RAPIDS UNIT #4 OVERHAUL
01-08-3009	GRAND RAPIDS G.S. UNIT 1 REPAIRS
01-08-3011	GRAND RAPIDS G.S. UNIT #1 OVERHAUL
01-08-3013	GRAND RAPIDS G.S. UNIT#3 OVERHAUL
01-08-5931	GRAND RAPIDS G.S. GEN. BRKRS. & SYNC. COND. CONVERSION
01-08-7041	Generation South Dam Safety Deficiency Program

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	1		59			60	60
May	1	1	59			61	121
Jun	1		60			61	182
Jul	1	1	60			62	244
Aug	1		61			62	306
Sep	9		61			70	376
Oct	11	-1	62			72	448
Nov	24	1	62			87	535
Dec	24		63			87	622
Jan	24	1	63			88	710
Feb	57		64			121	831
Mar	106		66			172	1 003
TOTAL	260	3	740			1 003	1 003
2000/01 Apr	335	3	67			405	405
May	447	5	70			522	927
Jun	460	6	73			539	1 466
Jul	599	7	77			683	2 149
Aug	724	9	82			815	2 964
Sep	1 267	15	88			1 370	4 [illegible]
Oct	1 434	17	98			1 549	
Nov	1 362	19	108			1 489	
Dec	1 325	20	119			1 464	8 836
Jan	848	16	129			993	9 829
Feb	579	12	136			727	10 556
Mar	563	11	142			716	11 272
TOTAL	9 943	140	1 189			11 272	11 272

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item

49

Title			Budget reference number
GRAND RAPIDS G.S. UNIT#3 OVERHAUL			01-08-3013
Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Generation - South	Generation - South	Generation - South	61385:61966

DESCRIPTION:
REPLACE THE KAPLAN RUNNER. REWIND GENERATOR AND MODIFY THE STATOR FRAME SUPPORT. ADD A 13.8KV GENERATOR CIRCUIT BREAKER.

JUSTIFICATION:
EXCESSIVE WEAR TO THE RUNNER BLADE TRUNNIONS AND LEAKING OIL SEALS REQUIRE A REPLACEMENT OF THE RUNNER. THE NEW RUNER WILL BE MORE EFFICIENT THAN THE EXISTING ONE. THE GENERATOR WILL BE REWOUND AND RADIAL EXPANSION KEYS INSTALLED ON THE STATOR SOLE PLATES TO ACCEPT THE INCREASED POWER OUTPUT. A NEW 13.8KV BREAKER WILL BE INSTALLED TO IMPROVE SYSTEM RELIABILITY. THE POWER TRANSFORMER WILL BE MODIFIED TO ACCEPT THE INCREASED OUTPUT. OTHERWORK WILL BE PERFORMED TO MODERNIZE THE UNIT.

REVISION:
ESTIMATE REVISED TO REFLECT ORDER OF REPAIR TO DO UNIT 3 IN 1999/00 AHEAD OF UNIT 2 WHICH IS NOW PUSHED BACK TO 2000/01.

This BRN contains Deleted, Blocked, or Closed Orders.

IN SERVICE DATES						Base estimate
Prior Total	17 712	1998 08 31	3	1999 01 31	69	199704 L3
1998 05 31	9	1998 09 30	2	1999 02 28	21	
1998 06 30	5	1998 10 31	20	1999 03 31	157	Work start date
1998 07 31	-4	1998 12 31	34	1999 10 31	3 498	1992 11 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:	15 750		2 494	-21		18 223
1999/00	467	2	29			498
2000/01	3 468	1	218			3 687
TOTAL	19 685	3	2 741	-21		22 408
REV. AMOUNTS:						
Authorized to date:	15 750		2 494	-21		18 223
Over(under)expend:						
Auth Req.: 1999/00	3 207	19	56			3 282
TOTAL	18 957	19	2 550	-21		21 505

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

1999-09-28 11:03 AM

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 01-08-3013

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1992 10	9 495	NEW ITEM. (PREVIOUSLY INCLUDED UNDER B.R.N. --01-08-1068). ESTIMATE INCREASE DUE TO STATOR REWINDING SUPPLY AND INSTALLATION AND THE ADDITION OF A 13.8 KV CIRCUIT BREAKER. MAJOR SCHEDULE CHANGES WERE IMPOSED BY THE UNIT 1 HEADCOVER FAILURE IN MARCH 1992 AND THE UNIT 3 STATOR DAMAGE IN MAY 1992. IN GENERAL THE WORK HAS BEEN ADVANCED TO COPE WITH THESE FORCED OUTAGES.
1993 10	9 459	IN-SERVICE DATE ADVANCED FROM 1995 11 01 TO 1995 03 25. INSTRUMENTATION AND ROTORMOUNTED SCANNER FOR VIBRATION DETECTION AND AIRGAP MONITERING ADDED PER MEMO FROM R. GIBSON.
1994 10	13 225	ESTIMATED COSTS AND SCHESCHEDULE INCREASED TO REFLECT EXPERIENCE FROM SIMILAR WORK ON UNIT 4. SYNCHRONOUS CONDENSER CONVERSION AND GENERATOR BREAKERS TRANSFERRED TO BRN (01-08-5931). IN-SERVICE DATE DEFERRED FROM 1995 03 25 TO 1996 04 30.
1995 10	14 596	IN-SERVICE DATE DEFERRED FROM 96 04 30 TO 96 11 16 RESULTINGIN INCREASED INTEREST AND INDIRECT CHARGES. ANTICIPATED DURATION OF THEWORK INCREASED BY 6 WEEKS BASED ON PREVIOUS EXPERIENCE FOR SIMILAR WORK.
1996 10	14 856	ADJUSTED TO REFLECT ACTUAL EXPENDITUES TO DATE INCLUDING INCREASED GENERATOR COMPONENTS REPAIR.
1997 10	17 421	ADJUSTED TO REFLECT ACTUAL EXPENDITUES TO DATE INCLUDING INCREASED TURBINE AND GENERATOR COMPONENTS REPAIR.

ASSOCIATED PROJECTS

Budget reference number	Description
01-08-1068	GRAND RAPIDS UNIT #4 OVERHAUL
01-08-3009	GRAND RAPIDS G.S. UNIT 1 REPAIRS
01-08-3011	GRAND RAPIDS G.S. UNIT #1 OVERHAUL
01-08-3012	GRAND RAPIDS G.S. UNIT #2 OVERHAUL
01-08-5931	GRAND RAPIDS G.S. GEN. BRKRS. & SYNC. COND. CONVERSION
01-08-7041	Generation South Dam Safety Deficiency Program

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	182	1	1			184	184
May	396		3			399	583
Jun	395	2	5			402	985
Jul	395	2	8			405	1 390
Aug	181	1	11			193	1 583
Sep	654	4	12			670	2 253
Oct	620	4	17			641	2 894
Nov	341	4				345	3 239
Dec	13					13	3 252
Jan	13					13	3 265
Feb	9					9	3 274
Mar	8	1	-1			8	3 282
TOTAL	3 207	19	56			3 282	3 282
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item

50

Title			Budget reference number
GRAND RAPIDS UNIT #4 OVERHAUL			01-08-1068
Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Generation - South	Generation - South	Generation - South	60088

DESCRIPTION:
OVERHAUL AND UPGRADE THE KAPLAN TURBINE. MODIFY THE STATOR FRAME SUPPORT. ADD A 13.8 KV GENERATOR CIRCUIT BREAKER, AND CONVERSION TO SYNCHRONOUS CONDENSER OPERATION.

JUSTIFICATION:
A MAJOR OVERHAUL OF THE TURBINE IS REQUIRED TO EXTEND THE LIFE OF THE RUNNER AND REDUCE OIL LEAKS. MAJOR STRUCTURAL REPAIRS TO THE HEADCOVERS ARE ALSO REQUIRED. THE GOVERNOR PRESSURE SYSTEM, SERVOMOTORS AND OPERATING RING WILL BE ENLARGED TO PERMIT ADDITIONAL OPENING OF THE WICKET GATES TO GENERATE MORE POWER. RADIAL EXPANSION KEYS WILL BE INSTALLED ON THE STATOR SOLE PLATES TO ACCEPT THE INCREASED POWER OUTPUT. A NEW 13.8 KV BREAKER WILL BE INSTALLED TO IMPROVE SYSTEM RELIABILITY. THE POWER TRANSFORMER WILL BE MODIFIED TO ACCEPT THE INCREASED OUTPUT. OTHER WORK WILL BE PERFORMED TO MODERNIZE THE UNIT.

REVISION:
ESTIMATE REVISED TO REFLECT THE POSSIBLE WICKET GATE BUSHINGS REPLACEMENT AND SHAFT ROD SEAL: TO BE CONFIRMED BY ENGINEERING INSPECTION/REVIEW.

IN SERVICE DATES						Base estimate
Prior Total	10 132	1998 05 31	1	1999 01 31	7	199704 L3
1997 11 30	9	1998 07 31	11	1999 02 28	5	
1998 01 31	0	1998 11 30	0	1999 03 31	3	Work start date
1998 02 28	1	1998 12 31	6	2002 03 31	3 608	1990 12 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:	9 628		547			10 175
1999/00	-33					-33
2000/01	202	14				216
TOTAL	9 797	14	547			10 358

REV. AMOUNTS:						
Authorized to date:	9 628		547			10 175
Over(under)expend:						
Auth 1999/00	67					67
Req.: 2000/01	735	20				755
2001/02	2 673	113				2 786
TOTAL	13 103	133	547			13 783

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 01-08-1068

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1990 10	8 435	NEW ITEM.
1991 10	34 167	REHABILITATION PROGRAM REVISED FROM ONE OF MAJOR REPAIR ON 3RUNNERS AND POSSIBLY REPLACING 1 RUNNER, TO A PROGRAM OF MAJOR REPAIR ON1 RUNNER AND REPLACING 3 RUNNERS.
1992 10	6 767	ITEM PREVIOUSLY INCLUDED GRAND RAPIDS G.S. RUNNER REHAB. UNITS 1,2,3 AND 4, NOW ONLY INCLUDES ESTIMATE FOR UNIT 4. INCREASE DUE TO: OVERHAUL WORK TRANSFERRED FROM MTCE W.O. 53777 (COSTS INCREASED DUE TO EXTENSIVE REMEDIAL WORK REVEALED AFTER DISASSEMBLY); THE ADDITIONOF A 13.8 KV CIRCUIT BREAKER AND INCREASE IN SERVOMOTOR WORK.
1993 10	9 995	PROBLEMS ENCOUNTERED IN INSTALLING AND COMMISSIONING THE UNIT RESULTED IN THE MAJOR COST OVERRUNS.
1994 10	9 537	ESTIMATED COSTS FOR SYNCHRONOUS CONDENSER CONVERSION AND GENERATOR BREAKERS TRANSFERRED TO BRN 01-08-5931.
1995 10	10 045	BUDGET REVISED TO REFLECT ACTUAL TO-DATE COSTS AND INCREASED WORK TO COMPLETE DEFICIENCIES AND INSTALL ACCUMULATOR TANKS.
1996 10	10 231	ALLOWANCE TO COMPLETE DEFICIENCIES IDENTIFIED IN COMMISSIONING REPORT.
1997 10	10 354	ALLOWANCE TO COMPLETE DEFICIENCIES IDENTIFIED IN COMMISSIONING REPORT.

ASSOCIATED PROJECTS

Budget reference number	Description
01-08-3009	GRAND RAPIDS G.S. UNIT 1 REPAIRS
01-08-3011	GRAND RAPIDS G.S. UNIT #1 OVERHAUL
01-08-3012	GRAND RAPIDS G.S. UNIT #2 OVERHAUL
01-08-3013	GRAND RAPIDS G.S. UNIT#3 OVERHAUL
01-08-5931	GRAND RAPIDS G.S. GEN. BRKRS. & SYNC. COND. CONVERSION
01-08-7041	Generation South Dam Safety Deficiency Program

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	4					4	4
May	1					1	5
Jun	1					1	6
Jul	1					1	7
Aug	1					1	8
Sep	1					1	9
Oct	1					1	10
Nov	1					1	11
Dec	10					10	21
Jan	14					14	35
Feb	14					14	49
Mar	18					18	67
TOTAL	67					67	67
2000/01 Apr	12					12	12
May	10					10	22
Jun	10					10	32
Jul	10					10	42
Aug	13					13	55
Sep	13					13	
Oct	113	2				115	
Nov	113	3				116	[illegible]
Dec	113	3				116	415
Jan	110	3				113	528
Feb	110	3				113	641
Mar	108	6				114	755
TOTAL	735	20				755	755

1999-09-28 11:03 AM

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item

51

Title			Budget reference number
GRAND RAPIDS G.S. UNIT 1 REPAIRS			01-08-3009
Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Generation - South	Generation - South	Generation - South	60089

DESCRIPTION:
DISASSEMBLE UNIT AND ASSESS DAMAGE.

REPLACE OUTER, INTERMEDIATE AND INNER HEAD COVERS, TURBINE GUIDE BEARINGS, SERVOMOTORS,OPERATING RING AND LINKS

REPAIR VARIOUS OTHER COMPONENTS.

REASSEMBLE UNIT UTILIZING THE REPAIRED EXISTING RUNNER FOR AN IN-SERVICE DATE OF 1994 05 12.

NOTE: GENERATOR REWINDING AND INSTALLATION OF RADIAL STATOR KEYS WILL ALSO BE DONE AT THIS TIME (INCLUDED UNDER B.R.N. 9101 08-1068).

JUSTIFICATION:
TO REPAIR THE UNIT 1 DAMAGE WHICH OCCURRED AS A RESULT OF THE HEAD COVER FAILURE AND RETURN THE UNIT TO SERVICE.

NOTE: A NEW RUNNER IS SCHEDULED FOR INSTALLATION IN THE SUMMER OF 1994 (INCLUDED UNDER B.R.N. 9101-08-1068).

REVISION:
ESTIMATE REVISED TO COVER OUTSTANDING LEGAL ISSUES ASSOCIATED WITH INSURANCE CLAIM.

IN SERVICE DATES						Base estimate
Prior Total	11 975	1998 05 31	0	1998 11 30	15	199704 L3
1998 02 28	5	1998 06 30	7	1998 12 31	0	
1998 03 31	0	1998 07 31	3	1999 01 31	-38	Work start date
1998 04 30	2	1998 09 30	12	2000 03 31	87	1992 05 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:	11 480		502			11 982
1999/00	155					155
TOTAL	11 635		502			12 137
REV. AMOUNTS:						
Authorized to date:	11 480		502			11 982
Over(under)expend:						
Auth 1999/00 Req.:	85	1				86
TOTAL	11 565	1	502			12 068

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 01-08-3009

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1992 10	5 481	NEW ITEM.
1993 10	8 370	ISD DEFERRED ONE MONTH. EXTENT OF REPAIRS TO TURBINE AND GENERATOR PARTS WAS UNDERESTIMATED.
1994 10	11 696	INCREASE REFLECTS ACTUAL COSTS.
1995 10	11 880	WORK ESSENTIALLY COMPLETE. BUDGET REVISED TO REFLECT ACTUALCOSTS AND TO ALLOW FOR LEGAL FEES ASSOCIATED WITH THE INSURANCE CLAIM.
1996 10	11 888	REFLECTS ACTUAL COSTS TO COMPLETION OF WORK AND ALLOWANCE FOR ANTICIPATED LEGAL FEES ASSOCIATED WITH INSURANCE CLAIM.
1997 10	12 142	REFLECTS ACTUAL COSTS TO COMPLETION OF WORK AND ALLOWANCE FOR ANTICIPATED LEGAL FEES ASSOCIATED WITH INSURANCE CLAIM, AND COSTS OF REPAIRING SPARE TURBINE BEARING.

ASSOCIATED PROJECTS

Budget reference number	Description
01-08-1068	GRAND RAPIDS UNIT #4 OVERHAUL
01-08-3011	GRAND RAPIDS G.S. UNIT #1 OVERHAUL
01-08-3012	GRAND RAPIDS G.S. UNIT #2 OVERHAUL
01-08-3013	GRAND RAPIDS G.S. UNIT#3 OVERHAUL
01-08-5931	GRAND RAPIDS G.S. GEN. BRKRS. & SYNC. COND. CONVERSION
01-08-7041	Generation South Dam Safety Deficiency Program

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	7					7	7
May	7					7	14
Jun	7					7	21
Jul	7					7	28
Aug	7					7	35
Sep	7					7	42
Oct	7					7	49
Nov	7					7	56
Dec	7					7	63
Jan	7					7	70
Feb	7					7	77
Mar	8	1				9	86
TOTAL	85	1				86	86
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

1999-09-28 11:04 AM

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item

52

Title			Budget reference number
GRAND RAPIDS G.S. GEN. BRKRS. & SYNC. COND. CONVERSION			01-08-5931
Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Generation - South	Generation - South	Generation - South	60061

DESCRIPTION:
DESIGN, ADMINISTRATION, PURCHASE, AND INSTALLATION OF THE 13.8KV GENERATOR CIRCUIT BREAKERS, TAILWATER DEPRESSION SYSTEM COMPRISING OF AIR COMPRESSORS, RECEIVERS AND PIPING, SYNCHRONOUS CONDENSER CONVERSION AND ASSOCIATED CONTROLS, ANNUNCIATION AND PROTECTION.

JUSTIFICATION:
INSTALLATION OF THE 13.8KV BREAKERS IS REQUIRED TO IMPROVE SYSTEM RELIABILITY. REPORT GP91-11 IDENTIFIED THE SUBSTANTIAL ECONOMIC BENEFITS TO PROVIDING SYNCHRONOUS CONDENSER CAPABILITY FOR THE GRAND RAPIDS UNITS. UPGRADING THE CONTROLS, ANNUNCIATION, AND PROTECTION WILL BE PERFORMED TO MODERNIZE THE UNITS.

REVISION:
ESTIMATE REVISED TO REFLECT THE EXTENDED SCHEDULE, DESIGN MODIFICATIONS, AND DEFICIENCIES. WORK WILL BE COORDINATED WITH FUTURE MAJOR OVERHAULS ON UNITS 2 AND 4.

IN SERVICE DATES				Base estimate
1998 02 28	6 973			199704 L3
2001 04 30	2 820			
2002 03 31	2 821			Work start date
				1994 02 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:	7 279		1 599			8 878
1999/00	1 889	57	174			2 120
TOTAL	9 168	57	1 773			10 998
REV. AMOUNTS:						
Authorized to date:	7 279		1 599			8 878
Over(under)expend:						
Auth 1999/00	723	2	184			909
Req.: 2000/01	1 406	22	302			1 730
2001/02	861	24	212			1 097
TOTAL	10 269	48	2 297			12 614

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

1999-09-28 11:04 AM

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 01-08-5931

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1994 10	6 109	NEW ITEM. (ACTUALS TO DATE TRANSFERRED FROM MAJOR ITEM BRN 9301-08-3011).
1995 10	7 300	INCREASE MAINLY DUE TO RE-ESTIMATED COST OF THE PLC AND ASSOCIATED ENGINEERING AND INSTALLATION COSTS.
1996 10	7 703	ADJUSTED TO REFLECT ACTUAL EXPENDITURES FOR DESIGN. REVISED INTEREST AND OVERHEAD CALCULATIONS.
1997 10	10 457	ESTIMATE REWORKED BASED ON ACTUAL COSTS OF UNIT # 3 AND CORE SYSTEM.

ASSOCIATED PROJECTS

Budget reference number	Description
01-08-1068	GRAND RAPIDS UNIT #4 OVERHAUL
01-08-3009	GRAND RAPIDS G.S. UNIT 1 REPAIRS
01-08-3011	GRAND RAPIDS G.S. UNIT #1 OVERHAUL
01-08-3012	GRAND RAPIDS G.S. UNIT #2 OVERHAUL
01-08-3013	GRAND RAPIDS G.S. UNIT#3 OVERHAUL
01-08-7041	Generation South Dam Safety Deficiency Program

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	34		13			47	47
May	14	-1	14			27	74
Jun	13		14			27	101
Jul	14		14			28	129
Aug	25		14			39	168
Sep	28		14			42	210
Oct	106		15			121	331
Nov	95		16			111	442
Dec	95	1	16			112	554
Jan	94		17			111	665
Feb	101		18			119	784
Mar	104	2	19			125	909
TOTAL	723	2	184			909	909
2000/01 Apr	107		20			127	127
May	104	1	21			126	253
Jun	104	1	22			127	380
Jul	101	1	23			125	505
Aug	120	2	23			145	650
Sep	115	2	24			141	[illegible]
Oct	135	3	25			163	
Nov	121	2	27			150	
Dec	121	2	28			151	1 255
Jan	121	2	29			152	1 407
Feb	128	2	30			160	1 567
Mar	129	4	30			163	1 730
TOTAL	1 406	22	302			1 730	1 730

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

COMPLEX STATUS: ☐ Planned ☒ In progress

Complex no. 25

REVISION STATUS: ☐ New complex ☒ In service change ☐ Concept change ☒ Estimate change only

COMPLEX: JENPEG G.S. UNIT OVERHAULS

Proposal

Major overhaul of units 1-6 to inspect, repair, modify and replace components of the turbine/generator.

Areas of concern; journal bearings, thrust bearings, turbine seals, servo-motors, wicket gate seals and bushings, waterhead and oil head, stator and rotor, auxiliary systems.

JUSTIFICATION: ☐ Load ☒ Service ☐ Safety ☐ Efficiency ☒ Reliability ☐ Other

Explanation

A complete overhaul is required to ensure reliable operation of the units when maximum power requirements on the system are essential.

Estimate Level	COMPLEX START (yyyy mm)
L1	1995 04

IN SERVICE DATES AND AMOUNTS

1998 07	$5060	1998 09	$75	1999 02	$1166	1999 03	($44)
1999 04	$59	2000 03	$3275	2002 01	$3611	2003 01	$3685
2004 01	$3909	2006 01	$4038	2008 01	$4173		

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	6,249		495		6,744	7,260	-516	-7
Year 99/00	2,012	47	155	-3	2,217	3,935	-1,718	-44
00/01	713	26	1		740	3,973	-3,233	-81
01/02	3,584	29	120		3,733	3,172	561	18
02/03	3,573	30	129		3,732		3,732	
03/04	3,469	32	133		3,634	3,285	349	11
04/05	281	1	4		286		286	
05/06	3,580	32	139		3,751	3,421	330	10
06/07	292	1	5		298		298	
07/08	3,694	34	147		3,875	3,561	314	9
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	27,447	232	1,328	-3	29,010	28,607	403	1

REVISION: Reflects continuing unit 6 costs to completion, re-estimate of remaining units based on experience with unit 6 and schedule revision.

Reviewed by J.J. Monster (ORIGINATOR)	yyyy mm dd 99 11 08	Reviewed by (COORDINATOR)	yyyy mm dd
Reviewed by (CONSTRUCTOR)	yyyy mm dd	Approved by (VICE-PRESIDENT)	yyyy mm dd 99 11 4289

H2856/r Rev 99 03

Complex no. 25

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Advance or deferral impact

Factors affecting timing or viability

Maintenance schedule.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE	
					Amount	%
JENPEG GS UNIT 1-6 OVERHAUL	11,992	15,501	16,011	27,449	11,438	71
TOTAL	11,992	15,501	16,011	27,449	11,438	71

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
9510	12,427	Increased costs due to higher overhead rates.
9610	13,494	Scope of work changed for unit 6 to schedule the overhaul during 96/97 and 97/98 so it is available by Nov/96 for winter generation.
9710	16,679	Reflects actual costs to date , cost of trailers for additional staff accommodations, and deferral of start of next unit by one year.
9810	28,607	Reflects unit 6 costs to completion, re-estimate of remaining units based on experience with unit 6 and schedule revision to overhaul one unit every two years.
1999 10	29,010	Reflects continuing unit 6 costs to completion, re-estimate of remaining units based on experience with unit 6 and schedule revision.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item

53

Title			Budget reference number
JENPEG GS - UNIT OVERHAULS (UNITS 1-6)			01-23-4905
Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Generation - South	Generation - South	Generation - South	61345:61965

DESCRIPTION:
FOR THE MAJOR OVERHAUL OF UNITS 1-6 TO INSPECT, REPAIR, MODIFY AND REPLACE COMPONENTS OF THE BULB TURBINE/GENERATOR.

JUSTIFICATION:
A COMPLETE OVERHAUL IS REQUIRED TO ENSURE RELIABLE OPERATION OF THE UNIT WHEN MAXIMUM POWER REQUIREMENTS ON THE SYSTEM ARE ESSENTIAL. AREAS OF CONCERN ARE: JOURNAL BEARINGS, THRUST BEARINGS, TURBINE SEAL, SERVO-MOTORS, WICKET GATE SEALS AND BUSHINGS, WATER HEAD AND OIL HEAD, STATOR AND ROTOR, AUXILIARY SYSTEMS.

REVISION:
SCOPE OF WORK DURING 1999/00 WILL INCLUDE COMPLETION OF OUTSTANDING WORK ON UNIT 6; INSPECTION OF UNITS 1 TO 5 AND GENERATOR COOLING TUBE CLEANING ON UNITS 3 AND 4. SCOPE OF WORK DURING 2000/01 INCLUDES GENERATOR COOLING TUBE CLEANING ON UNITS 1 AND 2 AND ENGINEERING PREPARATION FOR UNIT 1 OVERHAUL (SCHEDULED FOR 2001/02). BALANCE OF UNITS TO BE OVERHAULED AS PER PROPOSED SCHEDULED IN CPJ DATED 1999/03/31.

This BRN contains Deleted, Blocked, or Closed Orders.

IN SERVICE DATES						Base estimate
Prior Total	5 141	1999 03 31	-44	2003 01 31	3 685	199804 L1
1998 12 31	0	1999 04 30	59	2004 01 31	3 909	
1999 01 31	6	2000 03 31	3 275	2006 01 31	4 038	Work start date
1999 02 28	1 154	2002 01 31	3 611	2008 01 31	4 172	1997 04 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:	6 249		495			6 744
1999/00	4 192	107	152			4 451
2000/01	3 638	182	153			3 973
2001/02	2 849	202	121			3 172
2003/04	2 837	324	124			3 285
2005/06	2 837	452	132			3 421
2007/08	2 837	585	139			3 561
TOTAL	25 439	1 852	1 316			28 607
REV. AMOUNTS:						
Authorized to date:	6 249		495			6 744
Over(under)expend:						
Auth 1999/00	2 012	46	156	3		2 217
Req.: 2000/01	713	26	1			740
2001/02	3 584	29	120			3 733
2002/03	3 573	29	129			3 731
2003/04	3 469	32	133			3 634
2004/05	282	1	4			287
2005/06	3 580	32	139			3 751
2006/07	293		5			298
2007/08	3 694	33	147			3 874
TOTAL	27 449	228	1 329	3		29 009

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

1999-09-28 11:05 AM

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number: 01-23-4905

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1994 10	10 593	NEW ITEM.
1995 05	10 593	SELECTIVE REVISION DEFERRING PROGRAM BY ONE YEAR.
1995 10	12 427	INCREASED COSTS DUE TO HIGHER OVERHEAD RATE.
1996 10	13 494	WORK ON UNIT 6 TO BE SCHEDULED TO ENABLE GENERATION DURING THE WINTER OF 1996/97.
1997 10	16 679	SCOPE OF WORK FOR UNIT 6 REFLECTS THE OVERHAUL DURING 96/97 AND 97/98. INCREASED ESTIMATE REFLECTS THE ACTUAL LABOUR AND MATERIALS TO COMPLETE THE GENERATOR OVERHAUL ON UNIT 6 AS WELL AS ADDITIONAL LABOUR AND EXPENSES FOR STAFF HIRED TO WORK ON THIS PROJECT. REVISED ESTIMATE ALSO INCLUDES ACCOMODATIONS AND MEALS NOT PREVIOUSLY CHARGED BY STATION STAFF. ALSO INCLUDES PURCHASE OF TRAILERS @$135,000 FOR ADDITIONAL STAFF ACCOMODATIONS DURING PROJECT. SCHEDULED REVISED TO DEFER START OF NEXT UNIT BY ONE YEAR TO ALLOW TIME TO ANALYZE THE RESULTS OF THE OVERHAUL ON UNIT 6 AND DEVELOP SCOPE OF WORK FOR REMAINING UNITS.

ASSOCIATED PROJECTS

Budget reference number	Description

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	312	6	3		3	324	324
May	351	7	6			364	688
Jun	353	9	8			370	1 058
Jul	196	5	11			212	1 270
Aug	198	5	12			215	1 485
Sep	153	3	14			170	1 655
Oct	186	5	15			206	1 861
Nov	140	4	16			160	2 021
Dec	51	1	17			69	2 090
Jan	26		18			44	2 134
Feb	36	1	18			55	2 189
Mar	10		18			28	2 217
TOTAL	2 012	46	156		3	2 217	2 217
2000/01 Apr	200	7				207	207
May	9					9	216
Jun	84	4				88	304
Jul	84	4				88	392
Aug	14	1				15	407
Sep	9					9	
Oct	84	4				88	
Nov	94	4				98	
Dec	25	1				26	628
Jan	37					37	665
Feb	37	1				38	703
Mar	36		1			37	740
TOTAL	713	26	1			740	740

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

COMPLEX STATUS: ☐ Planned ☒ In progress

Complex no. 22

REVISION STATUS: ☐ New complex ☐ In service change ☐ Concept change ☒ Estimate change only

COMPLEX: KETTLE & LONG SPRUCE GS STATOR REWEDGING

Proposal

Kettle GS - Rewedge stators on unit 5 (93/94) unit 4 (95/96) unit 3 & 11 (96/97) units 7, 8, 10, and 12 to follow at the rate of one per year. Sequence determined by insulation tests.

Long Spruce GS - Rewedge stators on unit 3 (92/93), unit 5 and 1 (93/94) unit 6 (94/95) and unit 9 (95/96). Units 7, 8 and 10 are scheduled one per year over the next four years, based on insulation tests.

JUSTIFICATION

☐ Load ☐ Service ☐ Safety ☐ Efficiency ☒ Reliability ☐ Other

Explanation

The stator wedges on several units are becoming loose. The insulation readings are deteriorating rapidly, thus indicating looseness of wedges and stator coils in their respective slots. Looseness can cause a coil failure due to ground fault and result in an extended generator outage.

Estimate Level	COMPLEX START (yyyy mm)
L3	1992 04

IN SERVICE DATES AND AMOUNTS

1997 03	$3881	1997 04	$92	1998 03	$47	1998 04	$437
1998 05	$70	1998 06	$397	1999 01	$81	1999 02	$454
1999 03	$34	1999 04	$611	1999 09	$443	2000 04	$526

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	5,763		39		5,802	5,706	96	2
Year 99/00	937	18	4		959	869	90	10
00/01	300	9	2		311	307	4	1
01/02								
02/03								
03/04								
04/05								
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	7,000	27	45		7,072	6,882	190	3

REVISION: Revised to correct 98/99 document transfer caused overstatement,and apply cost experience to date, to the forecast.

Reviewed by ORIGINATOR	yyyy mm dd 99 11 07	Reviewed by COORDINATOR	yyyy mm dd
Reviewed by CONSTRUCTOR	yyyy mm dd	Approved by VICE-PRESIDENT	yyyy mm dd 99 12

H2856/r Rev 99 03

Complex no. 22

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Advance or deferral impact

Deteriorated insulation levels could result in extended unit outages.

Factors affecting timing or viability

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
LONG SPRUCE REWDGING	2,989	2,795	2,851	3,118	267	9
KETTLE STATOR REWEDGING	3,795	4,003	4,083	3,884	-199	-5
TOTAL	6,784	6,798	6,934	7,002	68	1

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
9510	7,123	Revised escalation and interest rates.
9610	7,003	Long Spruce deferred and Kettle advanced one year, per insulation testing. Revised escalation and interest rates.
9710	6,654	Reflects advancement of Kettle unit 10 by 1 year to 96/97, a one year deferral of a unit at Long Spruce to 98/99, and updated base dates.
9810	6,882	Revised to adjust Kettle Stator Rewedging 97/98 actuals, and to update base dates.
1999 10	7,072	Revised to correct 98/99 document transfer caused overstatement,and apply cost experience to date, to the forecast.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item

54

Title: LONG SPRUCE STATOR REWEDGING

Budget reference number: 01-21-5941

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Generation - North	Generation - North	Generation - North	61623:61662

DESCRIPTION:
REWEDGE STATORS ON UNIT 3 (92/93), UNIT 5 AND UNIT 1 (93/94), UNIT 6 (94/95), UNIT 9 (95/96). UNITS 7, 8 & 10 ARE SCHEDULED TO BE COMPLETED BEGINNING 1998/99. SEQUENCING OF UNITS WILL BE DETERMINED BASED ON INSULATION TESTING RESULTS.

JUSTIFICATION:
THE STATOR WEDGES ON SEVERAL UNITS ARE BECOMING LOOSE. THE INSULATION READINGS (PDA READINGS) ARE DETERIORATING RAPIDLY, THUS INDICATING LOOSENESS OF WEDGES AND STATOR COILS IN THEIR RESPECTIVE SLOTS. THIS LOOSENESS OF WEDGES CAN CAUSE A STATOR COIL FAILURE (DUE TO GROUND FAULT) WHICH CAN RESULT IN AN EXTENDED GENERATOR OUTAGE.

REFERENCE:
DOMESTIC BRN 9301-21-3018.

REVISION:
ACTUAL COSTS HIGHER THAN ESTIMATED DUE TO INCREASED ACTIVITIES OVER THE PLAN FOR UNITS 7 AND 10. ESTIMATE FOR UNIT 8 INCREASED TO REFLECT THE CHARGES ON THE PREVIOUS TWO UNITS.

IN SERVICE DATES						Base estimate
Prior Total	2 144	1998 10 31	-0	1999 02 28	454	199706 L3
1998 07 31	5	1998 11 30	0	1999 03 31	34	
1998 08 31	0	1998 12 31	-0	1999 04 30	0	Work start date
1998 09 30	4	1999 01 31	64	1999 09 30	443	1998 06 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date	2 679		26			2 705
1999/00	110	9	1			120
TOTAL	2 789	9	27			2 825
REV. AMOUNTS:						
Authorized to date.	2 679		26			2 705
Over(under)expend:						
Auth 1999/00 Req.:	439	2	2			443
TOTAL	3 118	2	28			3 148

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

1999-08-21 05:16 PM

CAPITAL EXPENDITURE REVISION

Budget reference number 01-21-5941

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1994 10	3 097	NEW ITEM.
1995 10	3 065	BASE DATE UPDATED AND RE-CASHFLOWED.
1996 10	3 065	REVISED ESCALATION AND INTEREST RATES AND RE-CASHFLOWED.
1997 10	2 806	BASE DATE UPDATED AND RE-CASHFLOWED DEFERRING THE UNIT SCHEDULED IN 1997/98 TO 1998/99.

ASSOCIATED PROJECTS

Budget reference number	Description
01-20-5942	KETTLE STATOR REWEDGING

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug	220	1				221	221
Sep	219	1	2			222	443
Oct							443
Nov							443
Dec							443
Jan							443
Feb							443
Mar							443
TOTAL	439	2	2			443	443
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item 55

Title
KETTLE STATOR REWEDGING

Budget reference number
01-20-5942

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Generation - North	Generation - North	Generation - North	61624:61668

DESCRIPTION:
REWEDGE STATORS ON UNIT 5 (93/94), UNIT 4 (95/96), UNIT 3 (96/97), UNIT 11 (96/97), UNIT 10 (96/97). UNITS 7, 8, AND 12 ARE SCHEDULED TO BE COMPLETED ONE PER YEAR FOR THE NEXT THREE YEARS. SEQUENCING OF UNITS WILL BE DETERMINED BASED ON INSULATION TESTING RESULTS.

JUSTIFICATION:
THE STATOR WEDGES ON SEVERAL UNITS ARE BECOMING LOOSE. THE INSULATION READINGS (PDA READINGS) ARE DETERIORATING RAPIDLY, THUS INDICATING LOOSENESS OF WEDGES AND STATOR COILS IN THEIR RESPECTIVE SLOTS. THIS LOOSENESS OF WEDGES CAN CAUSE A STATOR COIL FAILURE (DUE TO GROUND FAULT) WHICH CAN RESULT IN AN EXTENDED GENERATOR OUTAGE.

REFERENCE:
DOMESTIC BRN 9501-20-3019.

REVISION:
THERE WAS AN ERROR MADE IN THE TRANSFER FROM THE WORK DATABASE TO THE PRODUCTION DATABASE FOR THE AMOUNT OF $241K. LAST YEAR'S ESTIMATE SHOULD HAVE BEEN $3815K NOT $4056K. THEREFORE NO CHANGE IN ESTIMATE FOR REMAINING UNITS.

IN SERVICE DATES						Base estimate
Prior Total	2 258	1998 06 30	2	1999 01 31	0	199706 L3
1998 03 31	13	1998 09 30	6	1999 03 31	0	
1998 04 30	437	1998 10 31	1	1999 04 30	611	Work start date
1998 05 31	70	1998 11 30	1	2000 04 30	525	1997 04 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date	3 085		13			3 098
1999/00	637	15	2			654
2000/01	295	9	2			306
TOTAL	4 017	24	17			4 058
REV. AMOUNTS:						
Authorized to date:	3 085		13			3 098
Over(under)expend:						
Auth 1999/00	499	15	2			516
Req 2000/01	300	8	2			310
TOTAL	3 884	23	17			3 924

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

CAPITAL EXPENDITURE REVISION

Budget reference number 01-20-5942

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1994 10	4 175	NEW ITEM.
1995 10	4 058	BASE DATE UPDATED AND RE-CASHFLOWED.
1996 10	3 938	REVISED ESCALATION AND INTEREST RATES AND RE-CASHFLOWED.
1997 10	3 771	BASE DATE UPDATED AND RECASHFLOWED. UNIT 10 ADVANCED TO 1996/97 FROM 1997/98.
1998 10	4 056	BASE DATE UPDATED AND RECASHFLOWED. REFLECTS ACTUAL COSTS TO 1997/98.

ASSOCIATED PROJECTS

Budget reference number	Description
01-21-5941	LONG SPRUCE STATOR REWEDGING

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	227	7	2			236	236
May	65					65	301
Jun							301
Jul							301
Aug							301
Sep							301
Oct							301
Nov							301
Dec							301
Jan							301
Feb	20					20	321
Mar	187	8				195	516
TOTAL	499	15	2			516	516
2000/01 Apr	235	8	2			245	245
May	65					65	310
Jun							310
Jul							310
Aug							310
Sep							31
Oct							3
Nov							310
Dec							310
Jan							310
Feb							310
Mar							310
TOTAL	300	8	2			310	310

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

COMPLEX STATUS: ☐ Planned ☒ In progress

Complex no. 82

REVISION STATUS: ☐ New complex ☒ In service change ☒ Concept change ☐ Estimate change only

COMPLEX	PRODUCTION NORTH DAM SAFETY UPGRADES

Proposal

Perform necessary engineering design and remedial construction, to upgrade Northern generating stations to present day dam safety standards, to allow them to continue safe and reliable operation.
Work description to include the following:
(1) Kettle Generating Station - upgrade main and saddle dams for freeboard
(2) Kelsey Generating Station - armour plating at spillway rollways, erection of heated hoist housing, insulating of spillway gates, upgrading of dykes, upgrading of spillway feeders and electrical systems at the spillway and upgrading of the station service transformers due to increased loading.

JUSTIFICATION

☐ Load ☐ Service
☒ Safety ☐ Efficiency
☒ Reliability ☐ Other

Explanation

Manitoba Hydro has underway a formal dam safety program covering all its plants. Ulilizing present day standards, various deficiencies have been reported in the Production North generating stations. Work is therefore required to correct the deficiencies to all the plants, to operate in a safe and reliable manner.

Estimate Level	COMPLEX START (yyyy mm)
L2	1995 11

IN SERVICE DATES AND AMOUNTS

1997 03	$351	1997 07	$356	1997 12	$1995	1998 04	($114)
1998 10	$60	1998 11	$88	1999 03	$39	1999 10	$2542
2000 03	$628	2001 03	$1135	2002 03	$2216	2003 on	$5540

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	3,168		116		3,284	3,719	-435	-12
Year 99/00	2,009	24	59		2,092	1,283	809	63
00/01	1,606	38	42		1,686	105	1,581	NA
01/02	2,000	88	79		2,167		2,167	
02/03	2,000	130	78		2,208		2,208	
03/04	2,000	172	80		2,252		2,252	
04/05	1,000	108	41		1,149		1,149	
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	13,783	560	495		14,838	5,107	9,731	191

REVISION Scope change to include items for both Generations North and South , and revised to reflect deferral of the Kettle, Long Spruce, and Kelsey stand pipes.

Reviewed by ORIGINATOR	yyyy mm dd 99 11 07	Reviewed by COORDINATOR	yyyy mm dd		
Reviewed by CONSTRUCTOR	yyyy mm dd	Approved by VICE-PRESIDENT	yyyy mm dd 99 11		

H2856/r Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Complex no. 82

Advance or deferral impact

Loss of capability / derate
Safety liability

Factors affecting timing or viability

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Generation North dam safety upgrades	4,315	4,867	4,964	5,134	170	3
Generation South dam safety deficiency program		14,000	14,280	8,649	-5,631	-39
TOTAL	4,315	18,867	19,244	13,783	-5,461	-28

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
95 10	3,839	New Complex to cover the cost of correcting Dam Safety Program deficiencies.
96 10	3,800	Reflects change from level 1 to level 3 estimate.
9710	4,413	Scope increased to include dyke monitoring instrumentation at Kettle, Long Spruce, Laurie River, and Notigiand dyke repairs at Long Spruce.
9810	5,107	Scope revised to includebathemetric surveys; spillway hoist housing fire prot imp's; & to defer Kelsey stn service work; instrument install'n at various sites & stability studies at Kettle.
1999 10	14,838	Scope change to include items for both Generations North and South , and revised to reflect deferral of the Kettle, Long Spruce, and Kelsey stand pipes.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item

56

Title			Budget reference number
GENERATION NORTH DAM SAFETY UPGRADES			01-70-6971
Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Generation - North	Generation - South	Generation - South	60093:93352

DESCRIPTION:
TO PERFORM THE NECESSARY ENGINEERING DESIGN AND REMEDIAL CONSTRUCTION TO UPGRADE THE NORTHERN GENERATING STATIONS TO PRESENT DAY DAM SAFETY STANDARDS AND TO ALLOW THEM TO CONTINUE TO OPERATE IN A SAFE AND RELIABLE MANNER. WORK DESCRIPTION TO INCLUDE THE FOLLOWING: (1) KETTLE GENERATING STATION - UPGRADE MAIN AND SADDLE DAMS FOR FREEBOARD (2) KELSEY GENERATING STATION - ARMOUR PLATING AT SPILLWAY ROLLWAYS, ERECTION OF HEATED HOIST HOUSING, INSULATING OF SPILLWAY GATES, UPGRADING OF DYKES, UPGRADING OF SPILLWAY FEEDERS AND ELECTRICAL SYSTEMS AT THE SPILLWAY AND UPGRADING OF THE STATION SERVICE TRANSFORMERS DUE TO INCREASED LOADING.

JUSTIFICATION:
MANITOBA HYDRO HAS UNDERWAY A FORMAL DAM SAFETY PROGRAM COVERING ALL ITS PLANTS. UTILIZING PRESENT DAY SAFETY STANDARDS, VARIOUS DEFICIENCIES HAVE BEEN REPORTED IN THE GENERATION-NORTH GENERATING STATIONS. WORK IS THEREFORE REQUIRED TO CORRECT THE DEFICIENCIES TO ALL THE PLANTS TO OPERATE IN A SAFE AND RELIABLE MANNER.

REFERENCE:
KELSEY GENERATING STATION DAM SAFETY PROGRAM DEFICIENCY INVESTIGATIONS SUMMARY REPORT REPORT NO. DSP 95-S11 DATED 95 06 20 KETTLE GENERATING STATION DAM SAFETY PROGRAM DEFICIENCY INVESTIGATIONS SUMMARY REPORT NO. DSP 95-S09 DATED 95 06 20

MECHANICAL DEPT. REPORT PP&O 98/03 DATED 1998/02/27 (ISD ADVANCED TO 1999 TO CORRESPOND WITH THE CURRENT PROJECT I.E. LIMESTONE FP&P)

REVISION:
REVISED THE SCOPE OF WORK TO INCLUDE BATHEMETRIC SURVEYS; REFERENCE: I.O.M.- R.J. WITTEBOLLE TO W.D. BURBANK DATED 1998 03 20, AND TO INCLUDE SPILLWAY HOIST HOUSING FIRE PROTECTION IMPROVEMENTS; REFERENCE: PRELIMINARY REPORT P.P.& O.- 98/03. DEFERRED KELSEY G.S. STATION SERVICE WORK TO 1999/2000 DUE TO THE UNAVAILABILITY OF UNIT OUTAGES. DEFERRED INSTRUMENTATION INSTALLATION AT VARIOUS SITES AND STABILITY STUDIES AT KETTLE G.S. TO 1999/2000.

CONTINGENCY AMOUNT: $190 701

REVISION 1: TO DEFER KETTLE, LONGSPRUCE, AND KELSEY STAND PIPES--REFERENCE J. VAN DENBUSSCHE MEMO TO SPENCE OF 99/04/15.

This BRN contains Deleted, Blocked, or Closed Orders.

IN SERVICE DATES						Base estimate
Prior Total	2 596	1998 09 30	2	1999 01 31	9	199804 L3
1998 06 30	12	1998 10 31	24	1999 02 28	10	Work start date
1998 07 31	7	1998 11 30	88	1999 03 31	16	1997 04 01
1998 08 31	7	1998 12 31	5	1999 10 31	2 543	

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:	3 168		116			3 284
1999/00	1 625	34	59			1 718
2000/01	101	4				105
TOTAL	4 894	38	175			5 107
REV. AMOUNTS:						
Authorized to date:	3 168		116			3 284
Over(under)expend:						
Auth 1999/00	1 534	20	40			1 594
Req.: 2000/01	432	9				441
TOTAL	5 134	29	156			5 319

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

1999-09-28 11:05 AM

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 01-70-6971

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1997 10	4 413	REVISED THE SCOPE OF WORK TO INCLUDE DYKE MONITORING INSTRUMENTATION AT KETTLE, LONG SPRUCE, LAURIE RIVER AND NOTIGI AND DYKE REPAIRS AT LONG SPRUCE PER I.O.M. FROM G.A. MAHER TO W.D. BURBANK DATED 1997 07 28. CONTINGENCY AMOUNT: $582 000.

ASSOCIATED PROJECTS

Budget reference number	Description

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	43		4			47	47
May	43	1	4			48	95
Jun	71	1	4			76	171
Jul	137	1	5			143	314
Aug	303	4	6			313	627
Sep	286	5	8			299	926
Oct	225	3	10			238	1 164
Nov	225	1				226	1 390
Dec	89	1				90	1 480
Jan	37	1				38	1 518
Feb	37	1				38	1 556
Mar	38	1	-1			38	1 594
TOTAL	1 534	20	40			1 594	1 594
2000/01 Apr	38	1				39	39
May	38	1				39	78
Jun	38	1				39	117
Jul	38	1				39	156
Aug	94	1				95	251
Sep	120	2				122	373
Oct	51	2				53	426
Nov	15					15	441
Dec							441
Jan							441
Feb							441
Mar							441
TOTAL	432	9				441	444

999-09-28 11:05 AM

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item

57

Title	Budget reference number
Generation South Dam Safety Deficiency Program	01-08-7041

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Generation - South	Generation - South	Generation - South	61359:61416

DESCRIPTION:
The scope of work consists of all required capital works identified in the Dam Safety Certification process or indicated through observation and discussion with staff.

JUSTIFICATION:
All the work is required to demonstrate due diligence with respect to dam safety at the various sites within.

REFERENCE:
Power Supply Generation South. Each item has a detailed capital project justification prepared.

REVISION:
Program revised from dealing exclusively with Grand Rapids to be all encompassing for all Generation South facilities.

IN SERVICE DATES				Base estimate
2000 03 31	628	2004 03 31	2 216	199903 L1
2001 03 31	1 135	2005 03 31	1 108	Work start date
2002 03 31	2 216			2004 03 01
2003 03 31	2 216			

PREV. AUTHORITY Authorized to date:	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
2000/01	1 000	63	54			1 117
2001/02	4 000	337	172			4 509
2002/03	4 000	424	212			4 636
2003/04	3 000	384	210			3 594
2004/05	2 000	301	116			2 417
TOTAL	14 000	1 509	764			16 273
REV. AMOUNTS: Authorized to date: Over(under)expend:						
Auth 1999/00	475	4	19			498
Req.: 2000/01	1 174	29	42			1 245
2001/02	2 000	88	79			2 167
2002/03	2 000	130	78			2 208
2003/04	2 000	172	80			2 252
2004/05	1 000	108	41			1 149
TOTAL	8 649	531	339			9 519

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

1999-09-28 11:05 AM

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 01-08-7041

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1997 10	15 029	New item.

ASSOCIATED PROJECTS

Budget reference number	Description
01-08-1068	GRAND RAPIDS UNIT #4 OVERHAUL
01-08-3009	GRAND RAPIDS G.S. UNIT 1 REPAIRS
01-08-3011	GRAND RAPIDS G.S. UNIT #1 OVERHAUL
01-08-3012	GRAND RAPIDS G.S. UNIT #2 OVERHAUL
01-08-3013	GRAND RAPIDS G.S. UNIT#3 OVERHAUL
01-08-5931	GRAND RAPIDS G.S. GEN. BRKRS. & SYNC. COND. CONVERSION

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	40					40	40
May	40					40	80
Jun	40	-1	1			40	120
Jul	40		1			41	161
Aug	40		1			41	202
Sep	40		1			41	243
Oct	40		2			42	285
Nov	40		2			42	327
Dec	40		2			42	369
Jan	40		3			43	412
Feb	40		3			43	455
Mar	35	5	3			43	498
TOTAL	475	4	19			498	498
2000/01 Apr	98	1				99	99
May	98	1	1			100	199
Jun	98	2	1			101	300
Jul	98	2	2			102	402
Aug	98	2	3			103	505
Sep	98	2	3			103	608
Oct	98	2	4			104	71
Nov	98	3	4			105	817
Dec	98	3	5			106	923
Jan	98	3	6			107	1 030
Feb	98	3	6			107	1 137
Mar	96	5	7			108	1 245
TOTAL	1 174	29	42			1 245	1 245

999-09-28 11:05 AM

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

COMPLEX STATUS: ☐ Planned ☒ In progress

Complex no. 26

REVISION STATUS: ☐ New complex ☒ In service change ☐ Concept change ☒ Estimate change only

COMPLEX: WINNIPEG RIVER CONTROL SYSTEM

Proposal

Upgrading or replacement of, and additions to, various items of electrical and mechanical systems and equipment.

Items included are:

Great Falls GS - DC distribution, and unit control, metering and relaying.
Seven Sisters GS - U#4-U#6 AVR replacement, and unit control, metering and relaying.
Pine Falls GS - 250 VDC distribution, and station control.
Mcarthur Falls GS - station annunciator upgrade, 250 VDC distribution, and station control.

JUSTIFICATION

☐ Load ☒ Service
☒ Safety ☒ Efficiency
☒ Reliability ☐ Other

Explanation

Previous engineering assessment of the electrical and mechanical systems in these stations have identified various areas of concern in terms of obsolete equipment, safety, fire risk and adaptability to present day operating conditions and standards and the requirement for upgrading work.
Production south have identified the need for an integrated system for control of all the Winnipeg River stations, therefor this complex has been created to co-ordinate the design and installation of the various systems and System Control Centre's requirement for data acquisition.

Estimate Level	COMPLEX START (yyyy mm)
L3	1987 05

IN SERVICE DATES AND AMOUNTS

1997 03	$1543	1999 12	$1611	2001 03	$1561	2002 03	$3230
2002 06	$5564						

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	1,602		810		2,412	3,081	-669	-22
Year 99/00	2,436	20	141		2,597	1,900	697	37
00/01	1,779	26	228		2,033	6,691	-4,658	-70
01/02	4,969	177	432		5,578	1,529	4,049	265
02/03	760	25	102		887	405	482	119
03/04								
04/05								
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	11,546	248	1,713		13,507	13,606	-99	-1

REVISION: Revised to allign cash flow requirements with progress of work, and to defer Pine and McArthur Falls items by one year.

Reviewed by ORIGINATOR	yyyy mm dd 99 11 08	Reviewed by COORDINATOR	yyyy mm dd
Reviewed by CONSTRUCTOR	yyyy mm dd	Approved by VICE-PRESIDENT	yyyy mm dd 99 11 12

H2856/r Rev 99 03

Complex no. 26

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Advance or deferral impact

Factors affecting timing or viability

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
WINNIPEG RIVER CONTROL SYSTEM COMPLEX:						
- Great Falls GS	5,547	5,158	5,261	5,691	430	8
- Seven Sisters GS	2,481	3,082	3,144	2,937	-207	-7
- Pine Falls GS		1,372	1,399	1,390	-9	-1
- Mcarthur Falls GS		1,519	1,549	1,528	-21	-1
TOTAL	8,028	11,131	11,353	11,546	193	2

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
95 10	12,516	New Complex to co-ordinate the design & installation of an integrated system for control of all the Winnipeg River Stations.
96 10	12,515	Cashflow modified to reflect schedule for defined items - scope and schedule for balance to be established.
9710	12,900	Reflects revised costing methodology with the new financial reporting system.
9810	13,606	Scope of Seven Sisters AVR replacement expanded to include units 1 - 3 and the house unit.
1999 10	13,507	Revised to allign cash flow requirements with progress of work, and to defer Pine and McArthur Falls items by one year.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item ___ Domestic Item

58

Title
WINNIPEG RIVER CONTROL SYSTEM COMPLEX - GREAT FALLS G.S.

Budget reference number
01-01-6959

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Generation - South	Generation - South	Generation - South	60058:60060

DESCRIPTION:
UPGRADING OR REPLACEMENT OF, AND ADDITIONS TO, VARIOUS ITEMS OF ELECTRICAL AND MECHANICAL SYSTEMS AND EQUIPMENT.

ITEMS INCLUDED ARE:
POG 60058 (WO 47001) - DC DISTRIBUTION
POG 60060 (WO 47019) - UNIT CONTROL, METERING AND RELAYING

JUSTIFICATION:
PREVIOUS ENGINEERING ASSESSMENT OF THE ELECTRICAL AND MECHANICAL SYSTEM IN THE GREAT FALLS GENERATING STATION IDENTIFIED VARIOUS AREAS OF CONCERN IN TERMS OF OBSOLETE EQUIPMENT, SAFETY, FIRE RISK AND ADAPTABILITY TO PRESENT DAY OPERATING CONDITIONS AND STANDARDS AND THE REQUIREMENT FOR UPGRADING WORK TO ENSURE THE CONTINUED RELIABLE, SAFE AND ECONOMIC OPERATION OF THE PLANT.

REFERENCE:
E&C DIVISION REPORT NO.E2, JUNE 1984, GREAT FALLS GENERATING STATION PLANT EVALUATION REPORT STAGE III (INCLUDING ADDENDUM 1) PRODUCTION DIVISION - SOUTH HAVE IDENTIFIED THE NEED FOR AN INTEGRATED SYSTEM FOR CONTROL OF ALL THE WINNIPEG RIVER STATIONS, THEREFORE THE WINNIPEG RIVER CONTROL SYSTEM COMPLEX HAS BEEN CREATED TO CO-ORDINATE THE DESIGN AND INSTALLATION OF THE VARIOUS SYSTEMS AND SYSTEM CONTROL CENTRE'S REQUIREMENT FOR DATA ACQUISITION.

REVISION:
CASHFLOW REVISED TO REFLECT WORK PROCEEDING IN 1999/00 TO UPGRADE MONITORING AND CONTROL SYSTEMS AS PER SCOPING REP[ORT.

This BRN contains Deleted, Blocked, or Closed Orders.

IN SERVICE DATES

1997 03 31	1 543
2002 06 30	5 564

Base estimate
199610 L2

Work start date
1987 05 01

PREV AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date	969		711			1 680
1999/00	757	34	35			826
2000/01	2 092	138	219			2 449
2001/02	1 082	100	347			1 529
2002/03	270	29	106			405
TOTAL	5 170	301	1 418			6 889
REV. AMOUNTS						
Authorized to date:	969		711			1 680
Over(under)expend						
Auth 1999/00	1 247	13	51			1 311
Req 2000/01	985	18	161			1 164
2001/02	1 730	34	301			2 065
2002/03	760	25	102			887
TOTAL	5 691	90	1 326			7 107

Prepared by: yy mm dd COORDINATOR — Approved by: yy mm dd COORDINATING MANAGER

Estimated by: ORIGINATOR — Approved by: yy mm dd ORIGINATING MANAGER

4207

1999-08-21 05:14 PM

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 01-01-6959

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1995 10	6 692	NEW ITEM: WORK ORDERS TRANSFERRED FROM B.R.N. 8701-01-6017.IN-SERVICE DATE CHANGED TO 1997 12 31 AND 1998 03 31.
1996 10	6 773	CASHFLOW MODIFIED TO REFLECT SCHEDULE FOR DEFINED ITEMS - SCOPE AND SCHEDULE FOR BALANCE TO BE ESTABLISHED.
1997 10	6 914	REVISED TO REFLECT NEW ACTIVITY AND OVERHEAD RATES.

ASSOCIATED PROJECTS

Budget reference number	Description
01-02-6960	WINNIPEG RIVER CONTROL SYSTEM COMPLEX - SEVEN SISTERS G.S.
01-03-6961	WINNIPEG RIVER CONTROL SYSTEM COMPLEX - PINE FALLS G.S.
01-04-6962	WINNIPEG RIVER CONTROL SYSTEM COMPLEX - MCARTHUR FALLS G.S.

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	46		1			47	47
May	46		1			47	94
Jun	46		2			48	142
Jul	46		2			48	190
Aug	127	1	2			130	320
Sep	127	1	3			131	451
Oct	127	1	4			132	583
Nov	157	3	5			165	748
Dec	126	2	6			134	882
Jan	132	3	7			142	1 024
Feb	132	3	8			143	1 167
Mar	135	-1	10			144	1 311
TOTAL	1 247	13	51			1 311	1 311
2000/01 Apr	124	2	10			136	136
May	27	2	11			40	176
Jun	27	2	11			40	216
Jul	27	1	12			40	256
Aug	85	1	12			98	354
Sep	85	1	13			99	451
Oct	85	2	13			100	553
Nov	85	2	14			101	654
Dec	85	1	15			101	755
Jan	85	1	16			102	857
Feb	85	2	16			103	960
Mar	185	1	18			204	1 164
TOTAL	985	18	161			1 164	1 164

999-08-21 05:14 PM

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item ___ Domestic Item 59

Title: WINNIPEG RIVER CONTROL SYSTEM COMPLEX - SEVEN SISTERS G.S.

Budget reference number: 01-02-6960

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Generation - South	Generation - South	Generation - South	60082:60083

DESCRIPTION:
UPGRADING OR REPLACEMENT OF, AND ADDITIONS TO, VARIOUS ITEMS OF ELECTRICAL AND MECHANICAL SYSTEMS AND EQUIPMENT

ITEMS INCLUDED ARE:

POG 60082 (WO 49312) - U#4-U#6 GENERATOR AVR REPLACEMENT
POG 60083 (WO 49353) - UNIT CONTROL, METERING AND RELAYING

JUSTIFICATION:
PREVIOUS ENGINEERING ASSESSMENT OF THE ELECTRICAL AND MECHANICAL SYSTEM IN THE SEVEN SISTERS GENERATING STATION IDENTIFIES VARIOUS AREAS OF CONCERN IN TERMS OF OBSOLETE EQUIPMENT, SAFETY, FIRE RISK AND ADAPTABILITY TO PRESENT DAY OPERATING CONDITIONS AND STANDARDS AND THE REQUIREMENT FOR UPGRADING WORK TO ENSURE THE CONTINUED RELIABLE, SAFE AND ECONOMIC OPERATION OF THE PLANT.

REFERENCE:
E&C DIVISION REPORT NO.85-E-1, JULY 25, 1985, SEVEN SISTERS GENERATING STATION PLANT EVALUATION REPORT STAGE III PRODUCTION DIVISION - SOUTH HAVE IDENTIFIED THE NEED FOR AN INTEGRATED SYSTEM FOR CONTROL OF ALL THE WINNIPEG RIVER STATIONS, THEREFORE, THE WINNIPEG RIVER CONTROL SYSTEM COMPLEX HAS BEEN CREATED TO CO-ORDINATE THE DESIGN AND INSTALLATION OF THE VARIOUS SYSTEMS AND SYSTEM CONTROL CENTRE'S REQEUIREMENT FOR DATA ACQUISITION.

REVISION:
CASHFLOW REVISED TO REFLECT WORK PROCEEDING IN 1999/00 TO UPGRADE MONITORING AND CONTROL SYSTEMS AS PER SCOPING REPORT.

This BRN contains Deleted, Blocked, or Closed Orders.

IN SERVICE DATES

1999 12 31	1 611
2001 03 31	1 560

Base estimate: 199610 L2

Work start date: 1987 07 01

PREV AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date	581		76			657
1999/00	1 294	25	104			1 423
2000/01	1 232	88	85			1 405
TOTAL	3 107	113	265			3 485
REV AMOUNTS:						
Authorized to date:	581		76			657
Over(under)expend:						
Auth 1999/00	1 146	6	82			1 234
Req 2000/01	726	5	54			785
2001/02	484	11				495
TOTAL	2 937	22	212			3 171

Prepared by: ____ yy mm dd COORDINATOR Approved by: ____ yy mm dd ORIGINATOR

Estimated by: ____ COORDINATING MANAGER Approved by: ____ ORIGINATING MANAGER

4209

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 01-02-6960

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1995 10	2 681	NEW ITEM: WORK ORDERS TRANSFERRED FROM B.R.N. 8701-02-6017.IN-SERVICE DATE CHANGED TO 1998 03 31.
1996 10	2 681	CASHFLOW MODIFIED TO REFLECT SCHEDULE FOR DEFINED ITEMS - SCOPE AND SCHEDULE FOR BALANCE TO BE ESTABLISHED.
1997 10	2 719	REVISED TO REFLECT NEW ACTIVITY AND OVERHEAD RATES.
1999 10	3 331	SCOPE OF AVR REPLACEMENT EXPANDED TO INCLUDE UNITS 1 - 3 AND HOUSE UNIT AS APPROVED BY R. GIBSON.

ASSOCIATED PROJECTS

Budget reference number	Description
01-01-6959	WINNIPEG RIVER CONTROL SYSTEM COMPLEX - GREAT FALLS G.S.
01-03-6961	WINNIPEG RIVER CONTROL SYSTEM COMPLEX - PINE FALLS G.S.
01-04-6962	WINNIPEG RIVER CONTROL SYSTEM COMPLEX - MCARTHUR FALLS G.S.

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	130		5			135	135
May	135		6			141	276
Jun	135	1	6			142	418
Jul	134	2	7			143	561
Aug	134	2	8			144	705
Sep	123	2	9			134	839
Oct	123	2	10			135	974
Nov	119	2	11			132	1 106
Dec	103		12			115	1 221
Jan	3		2			5	1 226
Feb	3		2			5	1 231
Mar	4	-5	4			3	1 234
TOTAL	1 146	6	82			1 234	1 234
2000/01 Apr	60		2			62	62
May	60	1	2			63	125
Jun	60	1	3			64	189
Jul	60	1	3			64	253
Aug	60	1	4			65	318
Sep	60	1	4			65	383
Oct	60	1	5			66	449
Nov	60	1	5			66	515
Dec	60	1	6			67	582
Jan	60	1	6			67	649
Feb	60	1	7			68	717
Mar	66	-5	7			68	785
TOTAL	726	5	54			785	785

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item ___ Domestic Item 60

Title
WINNIPEG RIVER CONTROL SYSTEM COMPLEX - PINE FALLS G.S.

Budget reference number
01-03-6961

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Generation - South	Generation - South	Generation - South	60081:60087

DESCRIPTION:
UPGRADING OR REPLACEMENT OF, AND ADDITIONS TO, VARIOUS ITEMS OF ELECTRICAL AND MECHANCIAL SYSTEMS AND EQUIPMENT.

ITEMS INCLUDED ARE:
POG 60081 - (WO 49528) - 250 VDC DISTRIBUTION
POG 60087 - (WO 49577) - STATION CONTROL
NOTE: WORK ORDER 49528 WAS PREVIOUSLY INCLUDED IN BRN 8901-03-8024.

JUSTIFICATION:
PREVIOUS ENGINEERING ASSESSMENT OF THE ELECTRICAL AND MECHANICAL SYSTEM IN THE PINE FALLS GENERATING STATION IDENTIFIED VARIOUS AREAS OF CONCERN IN TERMS OF OBSOLETE EQUIPMENT, SAFETY, FIRE RISK AND ADAPTABILITY TO PRESENT DAY OPERATING CONDITIONS AND STANDARDS AND THE REQUIREMENT FOR UPGRADING WORK TO ENSURE THE CONTINUED RELLIABLE, SAFE AND ECONOMIC OPERATION OF THE PLANT.

REFERENCE:
E&C DIVISION REPORT NO.87-E1, PINE FALLS GENERATING STATION PLANT EVALUATION REPORT STAGE III PRODUCTION DIVISION - SOUTH HAVE IDENTIFIED THE NEED FOR AN INTEGRATED SYSTEM FOR CONTROL OF ALL THE WINNIPEG RIVER STATIONS, THEREFORE, THE WINNIPEG RIVER CONTROL SYSTEM COMPLEX HAS BEEN CREATED TO CO-ORDINATE THE DESIGN AND INSTALLATION OF THE VARIOUS SYSTEMS AND SYSTEM CONTROL CENTRE'S REQUIREMENT FOR DATA ACQUISITION.

REVISION:
CASHFLOW - SCHEDULE FOR PROJECT REVISED TO 2001/02.

IN SERVICE DATES		Base estimate
2002 03 31	1 548	199610 L2
		Work start date
		1995 01 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date	39		16			55
1999/00	138	4	14			156
2000/01	1 197	81	51			1 329
TOTAL	1 374	85	81			1 540
REV. AMOUNTS						
Authorized to date	39		16			55
Over(under)expend:						
Auth 1999/00	26		6			32
Req 2000/01	30	1	9			40
2001/02	1 295	62	64			1 421
TOTAL	1 390	63	95			1 548

Prepared by: yy mm dd COORDINATOR Approved by: yy mm dd Approved by: yy mm dd
Estimated by: ORIGINATOR COORDINATING MANAGER ORIGINATING MANAGER

1999-08-21 05:15 PM

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 01-03-6961

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1995 10	1 492	NEW ITEM - WORK ORDER 49528 TRANSFERRED FROM B.R.N. 8901-03-8024.
1996 10	1 492	CASHFLOW MODIFIED TO REFLECT SCHEDULE FOR DEFINED ITEMS - SCOPE AND SCHEDULE FOR BALANCE TO BE ESTABLISHED.
1997 10	1 554	REVISED TO REFLECT NEW ACTIVITY AND OVERHEAD RATES.

ASSOCIATED PROJECTS

Budget reference number	Description
01-01-6959	WINNIPEG RIVER CONTROL SYSTEM COMPLEX - GREAT FALLS G.S.
01-02-6960	WINNIPEG RIVER CONTROL SYSTEM COMPLEX - SEVEN SISTERS G.S.
01-04-6962	WINNIPEG RIVER CONTROL SYSTEM COMPLEX - MCARTHUR FALLS G.S.

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun	3					3	3
Jul	3					3	6
Aug	3					3	9
Sep	3					3	12
Oct	3					3	15
Nov	3	-1	1			3	18
Dec	3	-1	1			3	21
Jan	3	-1	1			3	24
Feb	3	-1	1			3	27
Mar	-1	4	2			5	32
TOTAL	26		6			32	32
2000/01 Apr	1	-1	1			1	1
May	1	-1	1			1	2
Jun	3		1			4	6
Jul	3		1			4	10
Aug	3		1			4	14
Sep	3		1			4	18
Oct	3		1			4	22
Nov	3		1			4	26
Dec	3		1			4	30
Jan	3		1			4	34
Feb	3		1			4	38
Mar	1	3	-2			2	40
TOTAL	30	1	9			40	40

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item 61

Title
WINNIPEG RIVER CONTROL SYSTEM COMPLEX - MCARTHUR FALLS G.S.

Budget reference number
01-04-6962

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Generation - South	Generation - South	Generation - South	60075:60085

DESCRIPTION:
UPGRADING OR REPLACEMENT OF, AND ADDITIONS TO, VARIOUS ITEMS OF ELECTRICAL AND MECHANICAL SYSTEMS AND EQUIPMENT.

ITEMS INCLUDED ARE:

POG 60075 - (WO 47878) - STATION ANNUNICATOR UPGRADE
POG 60076 - (WO 47886) - 250 VDC DISTRIBUTION
POG 60085 - (WO 47910) - STATION CONTROL

NOTE: WORK ORDERS 47878 AND 47886 WERE PREVIOUSLY INCLUDED IN BRN 9001-04-8005.

JUSTIFICATION:
PREVIOUS ENGINEERING ASSESSMENT OF THE ELECTRICAL AND MECHANICAL SYSTEM IN THE MCARTHUR FALLS GENERATING STATION IDENTIFIED VARIOUS AREAS OF CONCERN IN TERMS OF OBSOLETE EQUIPMENT, SAFETY, FIRE RISK AND ADAPTABILITY TO PRESENT DAY OPERATING CONDITIONS AND STANDARDS AND THE REQUIREMENT FOR UPGRADING WORK TO ENSURE THE CONTINUED RELIABLE, SAFE AND ECONOMIC OPERATION OF THE PLANT.

REFERENCE:
E&C DIVISION REPORT NO.87-E2, MCARTHUR FALLS GENERATING STATION PLANT EVALUATION REPORT STAGE III PRODUCTION DIVISION - SOUTH HAVE IDENTIFIED THE NEED FOR AN INTEGRATED SYSTEM FOR CONTROL OF ALL THE WINNIPEG RIVER STATIONS, THEREFORE, THE WINNIPEG RIVER CONTROL SYSTEM COMPLEX HAS BEEN CREATED TO CO-ORDINATE THE DESIGN AND INSTALLATION OF THE VARIOUS SYSTEMS AND SYSTEM CONTROL CENTRE'S REQUIREMENT FOR DATA ACQUISITION.

REVISION:
CASH FLOW - SCHEDULE FOR PROJECT REVISED TO 2001/02.

This BRN contains Deleted, Blocked, or Closed Orders.

IN SERVICE DATES		Base estimate
2002 03 31	1 679	199610 L2
		Work start date
		1990 09 01

PREV AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date	14		6			20
1999/00	147	5	10			162
2000/01	1 360	93	54			1 507
TOTAL	1 521	98	70			1 689
REV. AMOUNTS						
Authorized to date	14		6			20
Over(under)expend:						
Auth 1999/00	17	1	2			20
Req 2000/01	37	1	5			43
2001/02	1 460	69	67			1 596
TOTAL	1 528	71	80			1 679

Prepared by yy mm dd COORDINATOR — Approved by yy mm dd — Approved by yy mm dd

Estimated by ORIGINATOR — COORDINATING MANAGER — ORIGINATING MANAGER

1999-08-21 05:15 PM

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 01-04-6962

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1995 10	1 651	NEW ITEM - WORK ORDERS 47878 & 47886 TRANSFERRED FROM B.R.N.9001-04-8005.
1996 10	1 651	CASHFLOW MODIFIED TO REFLECT SCHEDULE FOR DEFINED ITEMS - SCOPE AND SCHEDULE FOR BALANCE TO BE ESTABLISHED.
1997 10	1 712	REVISED TO REFLECT NEW ACTIVITY AND OVERHEAD RATES.

ASSOCIATED PROJECTS

Budget reference number	Description
01-01-6959	WINNIPEG RIVER CONTROL SYSTEM COMPLEX - GREAT FALLS G.S.
01-02-6960	WINNIPEG RIVER CONTROL SYSTEM COMPLEX - SEVEN SISTERS G.S.
01-03-6961	WINNIPEG RIVER CONTROL SYSTEM COMPLEX - PINE FALLS G.S.

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun	2					2	2
Jul	2					2	4
Aug	2					2	6
Sep	2					2	8
Oct	2					2	10
Nov	2					2	12
Dec	2					2	14
Jan	2					2	16
Feb	2					2	18
Mar	-1	1	2			2	20
TOTAL	17	1	2			20	20
2000/01 Apr	2	1				3	3
May	2	1				3	6
Jun	3	1				4	10
Jul	3	1				4	14
Aug	3	1				4	18
Sep	3	1				4	22
Oct	3	1				4	26
Nov	3	1				4	30
Dec	3	1				4	34
Jan	3		1			4	38
Feb	3		1			4	42
Mar	6	-8	3			1	43
TOTAL	37	1	5			43	43

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

COMPLEX STATUS: ☐ Planned ☒ In progress

Complex no. 234

REVISION STATUS: ☐ New complex ☒ In service change ☐ Concept change ☒ Estimate change only

COMPLEX	LIMESTONE OUTSTANDING WORK

Proposal

To complete outstanding work including final disposition of buildings, and final site cleanup.

To perform modifications to thrust bearings, air admissions, cooling systems, governors and install a rotor mounted scanner.

To design and construct a channel improvement in the Nelson River at Sundance Rapids, to reduce ice staging in the tailrace.

JUSTIFICATION

☒ Load ☐ Service
☐ Safety ☐ Efficiency
☒ Reliability ☐ Other

Explanation

To provide funding for the completion of outstanding work at Limestone G.S., and modifications to a number of the original systems. The modifications are designed to reduce failures, and eliminate revenue reducing operating restrictions. Ice staging of the tailwater is causing a loss of up to 1.5 meters of energy head, and associated generation capacity, throughout the winter.

Estimate Level	COMPLEX START (yyyy mm)
L3	1996 04

IN SERVICE DATES AND AMOUNTS							
1997 03	$5893	1997 09	$1660	1997 12	$861	1998 07	$1704
1999 02	$654	1999 03	($378)	1999 06	$343	1999 09	$488
1999 12	$1059	2000 06	$672	2000 11	$2749	2001 on	$2009

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	11,641		304	445	11,500	11,497	3	0
Year 99/00	1,614	7	65		1,686	3,900	-2,214	-57
00/01	2,568	146	58		2,772	337	2,435	723
01/02	603	32	1		636	634	2	0
02/03	603	42	2		647	645	2	0
03/04	591	51	1		643	642	1	0
04/05								
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	17,620	278	431	445	17,884	17,655	229	1

REVISION: Revised to allign cash flows with optimum outage schedules, and to defer channel improvements one year.

Reviewed by ORIGINATOR	yyyy mm dd 99 11 10	Reviewed by COORDINATOR	yyyy mm dd		
Reviewed by CONSTRUCTOR	yyyy mm dd	Approved by VICE-PRESIDENT	yyyy mm dd 99 11 18		

H2856/r Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Complex no. 234

Advance or deferral impact

Plant is almost completed and is producing power.

Factors affecting timing or viability

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Limestone G.S. Area Cleanup	7,951	7,859	8,016	7,645	-371	-5
Limestone G.S. Modifications	6,966	7,507	7,657	7,875	218	3
Limestone G.S. Channel Improvements		2,088	2,130	2,100	-30	-1
TOTAL	14,917	17,454	17,803	17,620	-183	-1

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
96 10	7,609	Addition of Gillam-Limestone road resurfacing, environmental monitoring, thrust bearing repairs, air cooling/data sys and governor mods and the cleanup deferral to 97/98
9710	17,759	Scope revised to include additional modifications to original equipment to correct identified deficiencies and include a new item covering channel improvements.
9810	17,655	Reflects 97/98 underexpenditure 0.8M, deferral of building site cleanup, channel improve's, mods + revised for outage schedules and to reflect anticipated costs to completion.
1999 10	17,884	Revised to allign cash flows with optimum outage schedules, and to defer channel improvements one year.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION
Complex 43	Limestone System Requirements
Complex 14	Limestone Generating Station

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item __ Domestic Item

62

Title: LIMESTONE AREA CLEANUP

Budget reference number: 01-25-7044

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Generation - North	Generation - South	Generation - South	60146:61604

DESCRIPTION:
PREVIOUS EXPENDITURES COVERED GILLAM-LIMESTONE ROAD RESURFACING COSTS, THRUST BEARING REPAIRS , AQUATIC ENVIRONMENTAL MONITORING (POG 61604), AND SOME WORK INVOLVING DISPOSITION OF BUILDINGS AND ENVIRONMENTAL MONITORING. REMAINING DOLLARS ARE FOR FINAL DISPOSITION OF BUILDINGS AND FINAL SITE CLEAN UP.

JUSTIFICATION:
THIS ITEM IS NEEDED TO COMPLETE THE OUTSTANDING WORK FROM B.R.N.01-25-5001, AND FROM DOMESTIC ITEM 9701-25-6966.

REVISION:
DISPOSITION OF RECREATION CENTRE OUTSTANDING PLUS FINAL SITE CLEANUP SCHEDULED FOR 1999/00.

CONTINGENCY AMOUNT: $100 000

IN SERVICE DATES						Base estimate
Prior Total	6 793	1998 10 31	-1	1999 02 28	3	199704 L3
1998 07 31	170	1998 11 30	-28	1999 03 31	- 392	
1998 08 31	76	1998 12 31	-50	1999 04 30	0	Work start date
1998 09 30	48	1999 01 31	-3	1999 12 31	1 060	1997 04 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:	6 686		30	- 445		6 271
1999/00	1 088	44				1 132
TOTAL	7 774	44	30	- 445		7 403
REV. AMOUNTS:						
Authorized to date:	6 686		30	- 445		6 271
Over(under)expend:						
Auth 1999/00 Req.:	959	1				960
TOTAL	7 645	1	30	- 445		7 231

Prepared by	yy mm dd	Approved by	yy mm dd	Approved by	yy mm dd
	COORDINATOR				
Estimated by	ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

1999-08-21 05:16 PM

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 01-25-7044

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1996 10	3 483	NEW ITEM
1997 10	7 843	INCLUDES COSTS ASSOCIATED WITH AQUATIC ENVIRONMENTAL MONITORING PREVIOUSLY A DOMESTIC ITEM). THE AQUATIC ENV. MONITORING WILL BE TRANSFERRED TO OPERATING IN SEPT 97. ALSO REVISED TO REFLECT NEW ACTIVITY AND O/H RATES.

ASSOCIATED PROJECTS

Budget reference number	Description
01-25-7045	LIMESTONE G.S. MODIFICATIONS
01-25-8068	Limestone GS - Channel Improvements

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	31					31	31
May	170					170	201
Jun	170					170	371
Jul	170					170	541
Aug	170					170	711
Sep	143					143	854
Oct	4					4	858
Nov	100					100	958
Dec	1		1			2	960
Jan							960
Feb							960
Mar							960
TOTAL	959		1			960	960
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

1999-08-21 05:16 PM

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — 63 Domestic Item

Title: LIMESTONE G.S. MODIFICATIONS

Budget reference number: 01-25-7045

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Generation - North	Generation - North	Generation - North	61637:61722

DESCRIPTION:
Modifications to original equipment to correct identified deficiencies, including :
-Replacement of generator thrust bearings and high pressure oil lift systems
-Addition of oil filtration systems on generator thrust bearings
-Upgraded unit monitoring and data acquisition systems
-Additional turbine air admission valves and piping
-Increased generator cooling
-Modified governor settings
-Installation of a rotor mounted scanner on one generator

JUSTIFICATION:
Improvements to the generator thrust bearings and unit monitoring systems will decrease the frequency of thrust bearing failures and associated revenue losses. Improvements to the turbine air admission and generator cooling systems will allow operating restrictions to be removed, thereby increasing revenue from the generators.

REFERENCE:
Memorandum H.J. Clouston to A.M. Snyder, Limestone Generating Station - Financing to Correct Known Operational Concerns, dated 1996 08 08; Power Engineering Report No. 1210-03-02, Hydroelectric Turbine Generator Assessment for Limestone Generating Station, Issue 2 - March,1997; MED Report No. GN97-04, Limestone G.S. Data Acquisition Enhancements Required for Thrust Bearing; Report No. GN97-12, Limestone G.S. Cooling Modifications and Installation of a Rotor Mounted Scanner; Report No. GN97-17, Recommendations and Options for Limestone Thrust Bearing; Report No. GN97-22 Limestone Data Acquisition Enhancements; and Report No. GN98-04 Method to Correct Repeated Genius Block Failures.

REVISION:
Estimate revised for outage schedules and to reflect costs to completion.

IN SERVICE DATES						Base estimate
Prior Total	4 392	2000 05 31	329	2001 05 31	289	199706 L3
1999 04 30	-0	2000 06 30	343	2001 09 30	84	
1999 06 30	343	2000 09 30	476	2001 11 30	265	Work start date
1999 09 30	488	2001 03 31	84	And On	1 288	1997 04 01

PREV AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date	4 955		274			5 229
1999/00	471	25	50			546
2000/01	314	16	7			337
2001/02	599	34	1			634
2002/03	599	44	2			645
2003/04	587	54	1			642
TOTAL	7 525	173	335			8 033
REV. AMOUNTS:						
Authorized to date:	4 955		274			5 229
Over(under)expend:						
Auth 1999/00	655	5	65			725
Req. 2000/01	468	11	21			500
2001/02	603	32	1			636
2002/03	603	42	2			647
2003/04	591	52	1			644
TOTAL	7 875	142	364			8 381

Prepared by: yy mm dd — COORDINATOR — Approved by: yy mm dd — Approved by: yy mm dd

Estimated by: ORIGINATOR — COORDINATING MANAGER — ORIGINATING MANAGER

1999-08-21 05:16 PM

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 01-25-7045

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1996 10	4 126	NEW ITEM.
1997 10	7 458	BASE DATE UPDATED AND PROJECT RE-ESTIMATED BASED ON ACTUALS.
1998 10	7 741	ESTIMATE REVISED FOR OUTAGE SCHEDULES AND TO REFLECT COSTS TO COMPLETION.

ASSOCIATED PROJECTS

Budget reference number	Description
01-25-7044	LIMESTONE AREA CLEANUP
01-25-8068	Limestone GS - Channel Improvements

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	71		6			77	77
May	131	1	6			138	215
Jun	104	1	7			112	327
Jul	3		6			9	336
Aug	99		6			105	441
Sep	190	2	7			199	640
Oct			4			4	644
Nov			5			5	649
Dec			5			5	654
Jan			5			5	659
Feb	30	1	5			36	695
Mar	27		3			30	725
TOTAL	655	5	65			725	725
2000/01 Apr	27	1	5			33	33
May	117	3	5			125	158
Jun	73	1	4			78	236
Jul			2			2	238
Aug	73	1	2			76	314
Sep	88	2	3			93	407
Oct	10					10	4[illegible]
Nov							4[illegible]
Dec							417
Jan							417
Feb							417
Mar	80	3				83	500
TOTAL	468	11	21			500	500

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item 64

Title			Budget reference number
Limestone GS - Channel Improvements			01-25-8068
Originating division: Generation - North	Coordinating division: Power Planning & Operations	Constructing division: Generation - South	Project Order Group (Range): 61509

DESCRIPTION:
Design and construct a channel improvement in the Nelson River at Sundance Rapids, such that the amount of winter ice staging at the tailrace of Limestone Generating Station is reduced.

JUSTIFICATION:
Unexpected staging of the winter tailwater level at Limestone Generating Station has occured since 1991 because of an ice buildup or constriction which forms just downstream at Sundance Rapids in the Nelson River. This phenomenon causes a loss of energy head of up to 1.5 meters at the Limestone plant for an extended period of time in the winter. The estimated loss of energy associated with this head loss is in excess of $1,000,000 per annum.

REFERENCE:
Memo from R.R. Raban to K.R.F. Adams dated 1997 07 10.

REVISION:
Deferred pending final design recommendation.

IN SERVICE DATES				Base estimate
2000 11 30	2 273			199903 L1
				Work start date 2000 04 01

PREV AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date: 1999/00	2 088	104	29			2 221
TOTAL	2 088	104	29			2 221
REV. AMOUNTS: Authorized to date: Over(under)expend: Auth Req.: 2000/01	2 100	136	37			2 273
TOTAL	2 100	136	37			2 273

Prepared by yy mm dd COORDINATOR — Approved by yy mm dd Approved by yy mm dd
Estimated by ORIGINATOR — COORDINATING MANAGER — ORIGINATING MANAGER

1999-08-21 05:16 PM

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 01-25-8068

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1997 10	2 177	New item.
1998 10	2 221	Deferred to 1999/2000
1999 10	2 276	Deferred to 2000/2001

ASSOCIATED PROJECTS

Budget reference number	Description
01-25-7044	LIMESTONE AREA CLEANUP
01-25-7045	LIMESTONE G.S. MODIFICATIONS

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr	171	10				181	181
May	171	11	1			183	364
Jun	171	10	3			184	548
Jul	179	10	4			193	741
Aug	179	11	5			195	936
Sep	179	11	7			197	1 13[illegible]
Oct	179	11	8			198	1 3[illegible]
Nov	179	12	9			200	1 5[illegible]
Dec	179	12				191	1 722
Jan	171	12				183	1 905
Feb	171	13				184	2 089
Mar	171	13				184	2 273
TOTAL	2 100	136	37			2 273	2 273

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

COMPLEX STATUS	Complex no.	REVISION STATUS
☐ Planned ☒ In progress	243	☐ New complex ☐ In service change ☒ Concept change ☐ Estimate change only

COMPLEX	WINNIPEG RIVER RIVERBANK PROTECTION PROGRAM

Proposal

Placement of rock protection and construction of slope stabilization to reduce erosion of riverbank along the Winnipeg River. The work includes inspection, design, mapping, land acquisition and remedial construction at Pine Falls and McArthur Falls.

JUSTIFICATION

☐ Load ☐ Service ☐ Safety ☐ Efficiency ☐ Reliability ☒ Other

Explanation

Provision of riverbank protection and stabilization work along the Winnipeg River and tributaries between Seven Sisters forebay and Manitou Rapids from erosion partially due to hydraulic operations.

Estimate Level	COMPLEX START
	yyyy mm

IN SERVICE DATES AND AMOUNTS							
1998 03	$585	1999 04	$420	2000 03	$1856	2001 03	$729
2002 03	$742	2003 03	$757	2004 03	$771	2005 03	$787
2006 03	$802	2007 03	$818				

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	1,948		72	14	2,006	1,802	204	11
Year 99/00	714	6	120		840	460	380	83
00/01	684	17	28		729	580	149	26
01/02	684	30	28		742	592	150	25
02/03	684	44	29		757	604	153	25
03/04	684	58	30		772	616	156	25
04/05	684	72	30		786	628	158	25
05/06	684	87	31		802	641	161	25
06/07	684	102	32		818	654	164	25
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	7,450	416	400	14	8,252	6,577	1,675	25

REVISION Reflects reduced land acquisition costs, refinement of scope and resource allocation and removal of the McArthur programto be completed under 01-03-8055.

Reviewed by	yyyy mm dd	Reviewed by	yyyy mm dd
ORIGINATOR	99 11 08	COORDINATOR	
Reviewed by	yyyy mm dd	Approved by	yyyy mm dd
CONSTRUCTOR		VICE-PRESIDENT	99 11 22

H2856/r Rev 99 03

Complex no. 243

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Advance or deferral impact

Degree of erosion along the Winnipeg River riverbank.

Factors affecting timing or viability

Season of the year.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Winnipeg R Riverbank Protection Program - Pine Falls	3,193	3,191	3,255	6,865	3,610	111
Winnipeg R Riverbank Protection Program - McArthur	2,630	2,671	2,724	585	-2,139	-79
TOTAL	5,823	5,862	5,979	7,450	1,471	25

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
9710	7,933	New complex.
9810	6,577	Revised to reflect an annual reduction in land acquisition costs and a refinement of the scope and resource allocation to this program.
1999 10	8,252	Reflects reduced land acquisition costs, refinement of scope and resource allocation and removal of the McArthur programto be completed under 01-03-8055.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item

65

Title			Budget reference number
Winnipeg River Riverbank Protection Program - Pine Falls			01-03-8055
Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Generation - South	Generation - South	Generation - South	61316

DESCRIPTION:
Placement of rock protection and construction of slope stabilization to reduce erosion of riverbank along the Winnipeg River. The work includes inspection, design, mapping, land acquisition and remedial construction at Pine Falls.

JUSTIFICATION:
Continuation of the provision of riverbank protection and stabilization work along the Winnipeg River and tributaries between Seven Sisters forebay and Manitou Rapids from erosion partially due to hydraulic operations.

REFERENCE:
Memo W.L. Pawlikewich to H.J. Clouston dated 1997 06 12; Report - 'Winnipeg River Riverbanks Historical Experience and Technical Assessment'

REVISION:
Annual reduction in land acquisition costs, and a refinement of the scope of work and resource allocation for the earlier years of this program. Projection of requirements for 2000/01 and beyond are speculative.

IN SERVICE DATES						Base estimate
1998 03 31	389	2003 03 31	757	2007 03 31	818	199707 L2
2000 03 31	1 856	2004 03 31	771			
2001 03 31	729	2005 03 31	787			Work start date
2002 03 31	742	2006 03 31	802			1997 06 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:	1 363		45		-14	1 394
1999/00	- 205	7	11			- 187
2000/01	291	15	12			318
2001/02	291	22	12			325
2002/03	291	28	12			331
2003/04	291	34	13			338
2004/05	291	40	13			344
2005/06	291	47	14			352
2006/07	291	54	14			359
TOTAL	3 195	247	146		-14	3 574
REV. AMOUNTS:						
Authorized to date:	1 363		45		-14	1 394
Over(under)expend:						
Auth 1999/00	714	6	117			837
Req.: 2000/01	684	17	28			729
2001/02	684	30	28			742
2002/03	684	44	29			757
2003/04	684	57	30			771
2004/05	684	73	30			787
2005/06	684	87	31			802
2006/07	684	102	32			818
TOTAL	6 865	416	370		-14	7 637

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

1999-09-28 11:06 AM

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 01-03-8055

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1997 10	4 141	New item.

ASSOCIATED PROJECTS

Budget reference number	Description
01-04-8056	Winnipeg River Riverbank Protection Program - McArthur Falls

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	60		7			67	67
May	60	-1	8			67	134
Jun	60		8			68	202
Jul	60		8			68	270
Aug	60		9			69	339
Sep	60		9			69	408
Oct	59	1	10			70	478
Nov	59	2	10			71	549
Dec	59	1	11			71	620
Jan	59	2	11			72	692
Feb	59	1	12			72	764
Mar	59		14			73	837
TOTAL	714	6	117			837	837
2000/01 Apr	57	1				58	58
May	57	2				59	117
Jun	57	1	1			59	176
Jul	57	2	1			60	236
Aug	57	1	2			60	296
Sep	57	1	2			60	356
Oct	57	1	3			61	417
Nov	57	1	3			61	478
Dec	57	2	3			62	540
Jan	57	1	4			62	602
Feb	57	2	4			63	665
Mar	57	2	5			64	729
TOTAL	684	17	28			729	729

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

66

[X] Major Item [ ] Domestic Item

Title	Budget reference number
Winnipeg River Riverbank Protection Program - McArthur Falls	01-04-8056

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Generation - South	Generation - South	Generation - South	61317

DESCRIPTION:
Placement of rock protection and construction of slope stabilization to reduce erosion of riverbank along the Winnipeg River. The work includes inspection, design, mapping, land acquisition and remedial construction at McArthur Falls.

JUSTIFICATION:
Continuation of the provision of riverbank protection and stabilization work along the Winnipeg River and tributaries between Seven Sisters forebay and Manitou Rapids from erosion partially due to hydraulic operations.

REFERENCE:
Memo W.L. Pawlikewich to H.J. Clouston dated 1997 06 12; Report - 'Winnipeg River Riverbanks Historical Experience and Technical Assessment'

REVISION:
Cancel BRN. Future years forecast dollars have been transferred to BRN 01-03-8055.

IN SERVICE DATES		Base estimate
1998 03 31	196	199707 L2
1999 04 30	420	Work start date 1997 06 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:	585		28			613
1999/00	429	6	7			442
2000/01	239	13	10			262
2001/02	239	18	10			267
2002/03	239	24	10			273
2003/04	239	29	10			278
2004/05	239	34	11			284
2005/06	239	39	11			289
2006/07	239	45	11			295
TOTAL	2 687	208	108			3 003
REV. AMOUNTS:						
Authorized to date:	585		28			613
Over(under)expend:						
Auth Req.: 1999/00			3			3
TOTAL	585		31			616

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

1999-09-28 11:06 AM

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 01-04-8056

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1997 10	3 790	New item.

ASSOCIATED PROJECTS

Budget reference number	Description
01-03-8055	Winnipeg River RIverbank Protection Program - Pine Falls

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr			3			3	3
May							3
Jun							3
Jul							3
Aug							3
Sep							3
Oct							3
Nov							3
Dec							3
Jan							3
Feb							3
Mar							3
TOTAL			3			3	3
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

COMPLEX STATUS: [X] Planned [ ] In progress

Complex no. 246

REVISION STATUS: [ ] New complex [X] In service change [ ] Concept change [ ] Estimate change only

COMPLEX: KETTLE G.S. STATOR REWIND

Proposal
Rewind generator stators on units 1 - 12.

JUSTIFICATION: [ ] Load [ ] Service [ ] Safety [ ] Efficiency [X] Reliability [ ] Other

Explanation
The stator windings at Kettle are a polyester bonded mica which is prone to internal degredation as a result of thermal and electrical stresses. There has been a much higher failure rate for stator coils at Kettle than in any of our other generators installed since 1960. Analysis of the internal conditions of the insulation system is ongoing. Rewedging units at Kettle is an opportunity to repair isolated cases of severe slot discharge, necessary to avoid deterioration. Replacing stators as well is under investigation to include a single turn roebel bar winding with class 'f' insulation.

Estimate Level	COMPLEX START (yyyy mm)
L2	1998 04

IN SERVICE DATES AND AMOUNTS

2002 10	$2814	2003 10	$2814	2004 10	$2814	2005 10	$2814
2006 10	$2814	2007 10	$2814	2008 10	$2814	2009 10	$2814
2010 10	$2814	2011 10	$2814	2012 10	$2814	2013 10	$2814

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend						196	-196	-100
Year 99/00						924	-924	-100
00/01	184	6	2		192	1,356	-1,164	-86
01/02	832	37	50		919	2,170	-1,251	-58
02/03	2,244	135	135		2,514	2,703	-189	-7
03/04	2,244	183	112		2,539	2,733	-194	-7
04/05	2,244	232	91		2,567	2,769	-202	-7
05/06	2,244	281	72		2,597	2,808	-211	-8
06/07	2,244	332	57		2,633	2,852	-219	-8
07/08	2,243	383	44		2,670	2,900	-230	-8
08/09	2,244	436	34		2,714	2,955	-241	-8
09/10	2,243	489	30		2,762	3,015	-253	-8
10/11	2,244	544	29		2,817	3,083	-266	-9
11/12	2,243	599	34		2,876	3,158	-282	-9
12/13	2,244	656	45		2,945	1,915	1,030	54
13/14	2,243	714	60		3,017		3,017	
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	27,940	5,027	795		33,762	35,537	-1,775	-5

REVISION: Reflects one year deferral.

Reviewed by ORIGINATOR	yyyy mm dd 99 11 07	Reviewed by COORDINATOR	yyyy mm dd		
Reviewed by CONSTRUCTOR	yyyy mm dd	Approved by VICE-PRESIDENT	yyyy mm dd 99 11 4229		

H2856/r Rev 99 03

Complex no. 246

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Advance or deferral impact

Increased down time due to separation of these jobs from rewedging jobs.
Continue to experience a much higher failure rate for stator coils at Kettle.

Factors affecting timing or viability

Coordination of stator rewinding with rewedging units at Kettle.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Kettle G.S. Generator Stator rewind - units 1 - 12		27,940	28,499	27,944	-555	-2
TOTAL		27,940	28,499	27,944	-555	-2

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
9710	35,581	New complex.
9810	35,537	Revised to reflect the start date deferral from 1997 to 1998
1999 10	33,762	Reflects one year deferral.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION
Complex 22	Kettle & Long Spruce G.S. Stator Rewedging.

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item

67

Title
KETTLE G. S.- GENERATOR STATOR REWIND - UNITS 1-12

Budget reference number
01-20-7046

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Generation - North	Generation - South	Generation - South	60165

SCRIPTION:
wind generator stators on Units 1 - 12.

JUSTIFICATION:
The stator windings at Kettle are a polyster bonded mica which is prone to internal degradation as a result of thermal and electrical stresses. There has been a much higher failure rate for stator coils at Kettle than in any of our other generators installed since 1960. Analysis of the internal conditions of the insulation system is ongoing. Rewedging units at Kettle is an opportunity to repair isolated cases of severe slot discharge. This measure is necessary to avoid deterioration. Year 2002 is the target for the first rewind.

Replacing the stator as well as the winding is under investigation. This will confirm the installation of a single turn roebel bar winding with class 'f' insulation instead of the existing multi-turn coil winding.

REVISION:
Work start date changed from 1997 08 to 2000 04. This item should be studied in conjunction with plans to rerunner these units.

IN SERVICE DATES

2002 10 31	2 814	2006 10 31	2 814	2010 10 31	2 814
2003 10 31	2 814	2007 10 31	2 814	2011 10 31	2 814
2004 10 31	2 814	2008 10 31	2 814	2012 10 31	2 814
2005 10 31	2 814	2009 10 31	2 814	2013 10 31	2 809

Base estimate
199610 L2

Work start date
1998 04 01

PREV. AUTHORITY Authorized to date	GROSS ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
1999/00	1 015 52	52			1 119
2000/01	1 119 96	141			1 356
2001/02	1 797 193	181			2 171
2002/03	2 270 291	142			2 703
2003/04	2 270 342	121			2 733
2004/05	2 270 394	105			2 769
2005/06	2 270 447	91			2 808
2006/07	2 270 501	80			2 851
2007/08	2 270 557	73			2 900
2008/09	2 270 614	71			2 955
2009/10&on	8 134 2 680	357			11 171
TOTAL	27 955 6 167	1 414			35 536
REV. AMOUNTS Authorized to date Over(under)expend.					
Auth Req. 2000/01	184 6	2			192
2001/02	832 37	50			919
2002/03	2 244 135	135			2 514
2003/04	2 244 183	112			2 539
2004/05	2 244 231	91			2 566
2005/06	2 244 281	72			2 597
2006/07	2 244 331	57			2 632
2007/08	2 244 382	44			2 670
2008/09	2 244 436	34			2 714
2009/10	2 244 489	30			2 763
2010/11	2 244 544	29			2 817
2011/12&on	6 732 1 969	139			8 840
TOTAL	27 944 5 024	795			33 763

Prepared by: yy mm dd COORDINATOR — Approved by: yy mm dd — Approved by: yy mm dd

Estimated by: ORIGINATOR — COORDINATING MANAGER — ORIGINATING MANAGER

4231

1999-08-21 05:16 PM

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 01-20-7046

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1997 10	35 582	New item.

ASSOCIATED PROJECTS

Budget reference number	Description

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan	153	5				158	[illegible]
Feb	15	1	1			17	[illegible]
Mar	16		1			17	[illegible]
TOTAL	184	6	2			192	[illegible]

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

COMPLEX STATUS: [X] Planned [ ] In progress

Complex no. 252

REVISION STATUS: [X] New complex [ ] In service change [ ] Concept change [ ] Estimate change only

COMPLEX: KELSEY GS GATE REHABILITATION

Proposal

Replacement of rollers, installation of cathodic protection, touch up painting, seal replacement, and replacement of the hoist cables if required for units 1-5.

JUSTIFICATION: [X] Load [ ] Service [X] Safety [ ] Efficiency [X] Reliability [ ] Other

Explanation

The unit 2 gate inspection in 1997 established that the above mentioned work is required to ensure that the intake gates function as designed. If they do not function as designed, there is the possibility of a run away unit.

Estimate Level	COMPLEX START (yyyy mm)
L2	2000 07

IN SERVICE DATES AND AMOUNTS							
2001 09	$646	2003 09	$673	2005 09	$700	2007 09	$728
2009 09	$758						

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend								
Year 99/00								
00/01								
01/02	603	39	4		646		646	
02/03								
03/04	603	65	5		673		673	
04/05								
05/06	603	92	5		700		700	
06/07								
07/08	603	120	5		728		728	
08/09								
09/10	603	149	6		758		758	
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	3,015	465	25		3,505		3,505	

REVISION: Reflects one year deferral.

Reviewed by (ORIGINATOR)	yyyy mm dd	Reviewed by (COORDINATOR)	yyyy mm dd
	99 11 07		
Reviewed by (CONSTRUCTOR)	yyyy mm dd	Approved by (VICE-PRESIDENT)	yyyy mm dd
			99 11 12

H2856/r Rev 99 03

Complex no. 252

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Advance or deferral impact

Possibility of a run away unit.

Factors affecting timing or viability

Must be completed prior to freeze up.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE	
					Amount	%
Kelsey Gate Rehabilitation.		3,010	3,070	3,015	-55	-2
TOTAL		3,010	3,070	3,015	-55	-2

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
1998 06	3,447	NEW ITEM
1999 10	3,505	Reflects one year deferral.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item

68

Title
KELSEY GATE REHABILITATION

Budget reference number
01-07-8084

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Generation - North	Generation - North	Generation - North	61693:61697

DESCRIPTION:
KELSEY GENERATING STATION, UNITS ONE TO FIVE, INTAKE GATE REHABILITATION. THE WORK WILL INCLUDE THE REPLACEMENT OF ROLLERS, INSTALLATION OF CATHODIC PROTECTION, TOUCH UP PAINTING, SEAL REPLACEMENT AND REPLACEMENT OF THE HOIST CABLES IF REQUIRED.

JUSTIFICATION:
THE UNIT 2 GATE INSPECTION IN 1997 ESTABLISHED THAT THE ABOVE MENTIONED WORK IS REQUIRED TO ENSURE THAT THE INTAKE GATES FUNCTION AS DESIGNED. IF THE INTAKE GATES DO NOT FUNCTION AS DESIGNED, THERE IS THE POSSIBILITY OF A RUN AWAY UNIT.

REFERENCE:
KELSEY GENERATING STATION, UNIT TWO, INTAKE GATE INSPECTION AND CATHODIC INSTALLATION, 1997 REPORT NO: GN98-01, FILE NO: 000111-76300, DATE: 98 03 06.

REVISION:
DELAYED ONE YEAR TO FACILITATE THE REHABILITATION WORK TO BE COMPLETED ON UNITS 6 & 7.

IN SERVICE DATES				Base estimate
2001 09 30	646	2009 09 30	758	199803 L2
2003 09 30	673			
2005 09 30	700			Work start date
2007 09 30	728			2001 07 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:						
2000/01	602	30	4			636
2002/03	602	55	4			661
2004/05	602	81	5			688
2006/07	602	109	5			716
2008/09	602	138	5			745
TOTAL	3 010	413	23			3 446
REV. AMOUNTS:						
Authorized to date:						
Over(under)expend.						
Auth 2001/02	603	39	4			646
Req. 2003/04	603	65	5			673
2005/06	603	92	5			700
2007/08	603	120	5			728
2009/10	603	149	6			758
TOTAL	3 015	465	25			3 505

Prepared by (yy mm dd)	Approved by (yy mm dd)	Approved by (yy mm dd)
Estimated by		
ORIGINATOR / COORDINATOR	COORDINATING MANAGER	ORIGINATING MANAGER

1999-08-21 05:15 PM

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 01-07-8084

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1998 10	3 476	NEW ITEM.
1999 03	3 526	Delayed one year to facilitate the rehabilitation work to be completed on units 6 & 7.

ASSOCIATED PROJECTS

Budget reference number	Description

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

COMPLEX STATUS: [X] Planned [ ] In progress

Complex no. 256

REVISION STATUS: [X] New complex [ ] In service change [ ] Concept change [ ] Estimate change only

COMPLEX: KETTLE CENTRAL ANNUNCIATION SYSTEM UPGRADES

Proposal

A new system consisting of GE Fanuc PLCs and a Windows NT based human-machine interface (HMI) should be installed to replace the existing Central Annunciation System (CAS) at Kettle GS.

JUSTIFICATION

[X] Load [ ] Service
[ ] Safety [ ] Efficiency
[X] Reliability [ ] Other

Explanation

A condition assessment of the existing Central Annunciation System (CAS) has revealed that,due to deterioration, lack of spare parts and manufacturer support, the system is at the end of its life. Replacement of the CAS with a new system similar to systems installed at other generating stations has the best net present value of possible options.

Estimate Level	COMPLEX START (yyyy mm)
3	1999 10

IN SERVICE DATES AND AMOUNTS				
2001 09	$1499			

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend								
Year 99/00								
00/01	933	28	22		983		983	
01/02	447	20	49		516		516	
02/03								
03/04								
04/05								
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	1,380	48	71		1,499		1,499	

REVISION: New complex.

Reviewed by ORIGINATOR	yyyy mm dd 99 11 07	Reviewed by COORDINATOR	yyyy mm dd		
Reviewed by CONSTRUCTOR	yyyy mm dd	Approved by VICE-PRESIDENT	yyyy mm dd 99 11 17		

4237

H2856/r Rev 99 03

Complex no. 256

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Advance or deferral impact

Continued deterioration, and increased difficulty in obtaining replacement parts.

Factors affecting timing or viability

Schedule of equipment delivery.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE	
					Amount	%
Kettle GS CAS System Upgrades				1,380	1,380	
TOTAL				1,380	1,380	

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
1999 10	1,499	New complex.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION
GN98-11	KETTLE GS CENTRAL ANNUNCIATION SYST COND ASSESSMENT & RENEWAL

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item

69

Title			Budget reference number
KETTLE G.S. - CAS SYSTEM UPGRADES			01-20-8107
Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Generation - North	Generation - North	Generation - North	61720

DESCRIPTION:
A new system consisting of GE Fanuc PLCs and a Windows NT based human-machine interface (HMI) should be installed to replace the existing Central Annunication System (CAS) at Kettle G.S.

JUSTIFICATION:
A condition assessment of the existing Central Annunciation System (CAS) has revealed that, due to deterioration, lack of spare parts and manufacturer support, the system is at the end of it's life. Over a 20 year life cycle, replacement of the CAS with a new system similar to systems installed at other generating stations has the best net present value of possible options.

REFERENCE:
KETTLE G.S. CENTRAL ANNUNCIATION SYSTEM CONDITION ASSESSMENT AND RENEWAL, report GN98-11, dated 1999 02 08.

REVISION:
New item.

IN SERVICE DATES			Base estimate
2001 09 30	1 499		199901 L3
			Work start date 2000 04 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:						
TOTAL						
REV. AMOUNTS:						
Authorized to date:						
Over(under)expend:						
Auth 2000/01	933	28	22			983
Req.: 2001/02	447	20	49			516
TOTAL	1 380	48	71			1 499

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number: 01-20-8107

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1999 03	1 451	New item.

ASSOCIATED PROJECTS

Budget reference number	Description

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr	11					11	11
May	11	1				12	23
Jun	11	1				12	35
Jul	11	1				12	47
Aug	11	1				12	59
Sep	11	1				12	71
Oct	11	1				12	83
Nov	305	8	1			314	397
Dec	305	9	3			317	714
Jan	68	3	5			76	790
Feb	84	3	6			93	883
Mar	94	-1	7			100	983
TOTAL	933	28	22			983	983

99-10-08 08:19 AM

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

COMPLEX STATUS: ☐ Planned ☒ In progress

Complex no. 38

REVISION STATUS: ☐ New complex ☒ In service change ☒ Concept change ☐ Estimate change only

COMPLEX: THERMAL G.S. ASSURANCE

Proposal

Refurbish the thermal generating units at Brandon and Selkirk Generating Stations as follows;

Brandon - Refurbish Units 1-5. Install electrostatic precipitators and a cooling tower for Unit 5, meet environmental licence requirements, upgrade coal handling facilities, and perform unit 5 mechanical upgrades (1998/99).

Selkirk - Refurbish Units 1 and 2, install ash lagoon and effluent management systems, and modify coal handling facilities.

JUSTIFICATION

☐ Load ☐ Service
☐ Safety ☐ Efficiency
☒ Reliability ☐ Other

Explanation

Based on WP London's report, Brandon and Selkirk Generating Stations require refurbishment of equipment, installation of environmental protection equipment, and modification of the fuel handling system in order to assure; service life to planned retirement, operation under more stringent environmental standards and a continuing supply of fuel.

Estimate Level	COMPLEX START (yyyy mm)
L3	1990 03

IN SERVICE DATES AND AMOUNTS

1992 07 31	$3737	1992 11 30	$7106	1993 11 30	$6741	1994 11 30	$31630
1995 05 31	$4338	1996 02 29	$52156	1996 03 31	$1409	1996 12	$12767
1998 01	$3993	1999 03	$1501	1999 12	$2808	2000 06	$5921

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	117,432		11,787		129,219	129,847	-628	-0
Year 99/00	3,529	14	417		3,960	722	3,238	448
00/01	801	16	112		929		929	
01/02								
02/03								
03/04								
04/05								
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	121,762	30	12,316		134,108	130,569	3,539	3

REVISION: Reflects deferrals pending unit outage clearance,and addition of: retubing Bdn unit 5 condencer & Selkirk unit 1 & 2 lube oil cooler & fish impingement mitigation work.

Reviewed by ORIGINATOR	yyyy mm dd 99 11 08	Reviewed by COORDINATOR	yyyy mm dd
Reviewed by CONSTRUCTOR	yyyy mm dd	Approved by VICE-PRESIDENT	yyyy mm dd 99 11 12

H2856/r Rev 99 03

Complex no. 38

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Advance or deferral impact

The thermal plants are an integral part of the Manitoba System and should remain operational.

Factors affecting timing or viability

Environmental constraints/ standards.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Brandon G.S. Units 1-5 Life Assurance Phase III	49,861	78,176	79,740	79,760	20	0
Selkirk G.S. Units 1&2 Life Assurance Phase III	36,399	40,575	41,387	42,002	615	1
TOTAL	86,260	118,751	121,127	121,762	635	1

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
9510	129,882	Reflects costs to date, scope change to include Bdn 1-4 unit layup mods,Selk boiler front equip, and miscellaneous upgrades offset by reduced contingency.
9610	130,875	Incr's: Bdn - #5 gen overhaul, RTU for control room, hazardous mat storage, & site drainage. Selk - rail repairs, boiler camera. Decr's: both locomotive refurb, & more.
9710	129,364	Reflects potential scope increases at Brandon, asbestos removal,and paving, at Selkirk,main boiler sheet metal cladding,, increase in coal dust contract costs, and additional fire upgrades.
9810	130,569	Reflects 97/98 underexpend 1.8M, higher costs for asbestos abatem't -Bdn , dust mitigat'n-Selkirk, add'n of unit 5 study + drain rehab-Bdn,+ comm, heating, fire upgrades-Selkirk.
1999 10	134,108	Reflects deferrals pending unit outage clearance,and addition of: retubing Bdn unit 5 condencer & Selkirk unit 1 & 2 lube oil cooler & fish impingement mitigation work.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item __ Domestic Item 70

Title
BRANDON G.S. - UNITS 1-5 LIFE ASSURANCE PHASE III (BRGSLA)

Budget reference number
01-16-8023

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Generation - South	Generation - South	Generation - South	60057

DESCRIPTION:
REFURBISH UNITS 1 TO 5, INSTALL ELECTROSTATIC PRECIPITATOR FOR UNIT 5, INSTALL A COOLING TOWER FOR UNIT 5, MEET THE ENVIRONMENTAL LICENSE REQUIREMENTS, UPGRADE COAL HANDLING FACILITIES, PERFORM UNIT 5 MECHANICAL UPGRADES (1998/99).

JUSTIFICATION:
BASED ON GENERATION PLANNING'S REPORT GP91-7 AND CONSULTANT'S W.P. LONDON'S PRELIMINARY REPORT, UNITS 1-5 AT BRANDON AND ASSOCIATED FACILITIES REQUIRE REFURBISHMENT OF EQUIPMENT,INSTALLATION OF ENVIRONMENTAL PROTECTION EQUIPMENT AND MODIFICATION OF THE FUEL TRANSPORTATION SYSTEM IN ORDER TO ASSURE: A) SERVICE LIFE, IMPROVED CAPACITY, AND UNIT5 TWO-SHIFTING CAPABILITIES UNTIL THE PLANNED RETIREMENT DATES. B) OPERATION UNDER MORE STRINGENT ENVIRONMENTAL STANDARDS. C) CONTINUING RELIABLE SUPPLY OF FUEL.

REVISION:
UNIT 5 BLOWDOWN TANK DRAINS REHABILITATION WORK DEFERRED TO 99/00 DUE TO UNAVAILABILITY OF UNIT OUTAGE DUE TO LOW SYSTEM WATER FLOWS. SCOPE OF WORK INCREASED TO INCLUDE RETUBING OF THE UNIT 5 CONDENSER SCHEDULED FOR 1999/00 WITH AN IN -SERVICE OF JUNE/2000.

CONTINGENCY: $88 000.

IN SERVICE DATES

1992 11 30	5 630	1996 12 31	8 914
1993 11 30	3 613	1998 01 31	2 590
1994 11 30	9 433	2000 06 30	5 922
1996 02 28	52 156		

Base estimate
199704 L3

Work start date
1990 09 01

	PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
	Authorized to date	77 729		8 018			85 747
	1999/00	418	2				420
	TOTAL	78 147	2	8 018			86 167
	REV. AMOUNTS:						
	Authorized to date:	77 729		8 018			85 747
	Over(under)expend:						
Auth	1999/00	1 230	12	340			1 582
Req.	2000/01	801	16	112			929
	TOTAL	79 760	28	8 470			88 258

Prepared by yy mm dd COORDINATOR Approved by yy mm dd Approved by yy mm dd

Estimated by ORIGINATOR COORDINATING MANAGER ORIGINATING MANAGER

1999-08-21 05:16 PM

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 01-16-8023

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1990 05	55 758	COAL CARS DELETED, 3RD SH LAGOON DEFERRED 7 YEARS.
1990 10	60 789	REFLECTS INCORPORATION OF CURRENT CONSULTANT REPORTS.
1991 10	87 638	INC COAL HDG,INSTR&CONTR,COOL T2R,ES PRCIP,ENG,OH,CONT.
1992 10	82 726	INC SCOPE TURB WLDG&OVHL,U5 S/B REHAB,U1-4MISC INST,U5 DCIS,COAL HDG&CTRL, SITE INST&RR,COOLING TWR&ESP. DECR TO U1-4 STBLWR MODS& DCIS,COAL TRANS& RAILCAR UNLDG, DUST CTRL & UNDEFINED WORK.
1993 06	82 726	FLOWS ADJUSTED FOR DELAY OF ENVIRO LIC&REV'D OUTAGE WNDOWS.
1993 10	85 934	INC SCOP FOR COAL HNDG& 5 DCIS; WP'S ADD FOR U5 GNRTR, ASB DUST CLNUP&BLKT PROT'N; ENV MON REQ;U5 COOL TWR; MISC INST'N&STN COMM; PROJ ADMIN. DEC: DEL'N OF U5 TURB CASING BOLT REPL,U5 HP/LP C/O PIPING, MISC COAL HDNG. ITEMS, LOCO&SCRPR REPL; LO'R CONT; LO'R COSTS ON U1-4 LUBE/SEAL OIL SYS O/H&LO'R EST FOR U5 ESP & STAT SPILL PREV & MITIG.
1994 10	91 524	A) U5 DCIS SCOPE INC FOR INV,RMVL&REPL, OF PCB-IMPGND CABLE(B) PROB AMALG'N OF CTRL RMS&CANC'LN PREM'S OF '94 UNIT OUTAGE ADDED (C) EST FOR U5 COOLING TWR INCR TO COVER DESIGN REQ'T ADDITIOANS (D) INDIRECT O/H, PROJ MGMT & FIELD (E) VARIOUS GNRTR, COAL HDNLG, A/C& ROOF REPAIR WP'S ADDED (F) HI'R ACTUAL COSTS FOR U5 S/B REHAB, BRNR CTRL SYS&TURB SUPV INSTRMTN(G) IN C INDIR EST FOR CONSULTANT'S PRJ MGMT (H) INC U5 AIR HTR,SUP&INSTLN. DEC U5 PONY MTR;PULV&FAN REH,ACSTC;ESP.
1995 10	90 428	COSTS > EST'D: U. 5 GOV'R VAL BOD, 2-SHT OPR, SOOTBLRS&BLR, COAL HDLG SITE INFRA & RR,OIL SPL MIT, ELEC SER UP, PRJ MGMT, FD SUP&CONCNSLT. L'R CSTS:CTRL RM AMAL&INSTR, H2O COND COOL TWR&ELEC PREC FOR U5. SCOP INC: MOTH OF U1-4;REPL OF STAT SLT WEDG & STAT END WIN BLD SUP,FLY ASH UTIL, HAZ MAT STOR. HEAT&SHT CIR&COOR; P FLD ASS/COMM;U5 CAM; U5 ELVUP; ASB REM&FAST TSF OPER. CONT LOW.UP; ASB REM&FAST TSF OPER. CONT LOW.
1996 10	88 378	SCOPE INCREASES: U5 GENERATOR OVERHAUL, RTU FOR AMALGAMATED CONTROL ROOM, HAZ. MTL STORAGE, AND SITE GRADING & DRAINAGE. SCOPE DECREASES: ENV. MONITORING & LOCOMOTIVE REFURB. COSTS HIGHER FOR: TWO-SHIFTING, BURNER/AIRHEATER MODS, DCIS, BURNER CONTROL, COOLING TOWER, COMMISSIONING, COAL HANDLING & ELECTRICAL SERVICE UPGRADES. COSTS LOWER FOR: TSI AND ESP. CONTINGENCY INCLUDES ITEMS IN IOM FROM NGR TO RBG OF 960402. ASH LAGOON MOVED TO ITEM 01-16-7008.

ASSOCIATED PROJECTS

Budget reference number	Description
01-16-8051	SELKIRK G.S.-UNITS 1 & 2 LIFE ASSURANCE PHASE III (SEGSLA)

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	5	-1	24			28	28
May	113		24			137	165
Jun	211		25			236	401
Jul	212		27			239	640
Aug	78		28			106	746
Sep	69		29			98	844
Oct	22		30			52	896
Nov	16		30			46	942
Dec	19	1	30			50	992
Jan			31			31	1 023
Feb	237	4	31			272	1 295
Mar	248	8	31			287	1 582
TOTAL	1 230	12	340			1 582	1 582
2000/01 Apr	250	6	35			291	291
May	250	6	37			293	584
Jun	250	6	39			295	879
Jul	51	-2	1			50	929
Aug							929
Sep							
Oct							
Nov							929
Dec							929
Jan							929
Feb							929
Mar							929
TOTAL	801	16	112			929	929

1999-08-21 05:16 PM

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item __ Domestic Item

71

Title			Budget reference number
SELKIRK G.S.-UNITS 1 & 2 LIFE ASSURANCE PHASE III (SEGSLA)			01-16-8051
Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Generation - South	Generation - South	Generation - South	60152

DESCRIPTION:
REFURBISH UNITS 1 AND 2, UPGRADE COAL HANDLING FACILITIES, AND UPGRADE FACILITY TO MEET ENVIRONMENTAL LICENSE REQUIREMENTS.

JUSTIFICATION:
BASED ON GENERATION PLANNING'S REPORT GP91-7 AND CONSULTANT'S W.P. LONDON REPORT, UNITS 1 AND 2 AT SELKIRK G.S. AND ASSOCIATED FACILITIES REQUIRE REFURBISHMENT OF EQUIPMENT, INSTALLATION OF ENVIRONMENTAL PROTECTION EQUIPMENT AND MODIFICATION OF THE FUEL TRANSPORTATION SYSTEM IN ORDER TO ASSURE: A) SERVICE LIFE AND IMPROVED CAPACITY UNTIL THE PLANNED RETIREMENT DATES. B) OPERATION UNDER MORE STRINGENT ENVIRONMENTAL STANDARDS. C) CONTINUING RELIABLE SUPPLY OF FUEL.

REVISION:
DEFERRED CASH FLOWS FOR LIGHTING, COMMUNICATIONS, AND FIRE PROTECTION SYSTEM UPGRADES IN THE CONVEYER AREAS DUE TO THE UNAVAILABILITY OF STATION OUTAGES DUE TO LOW SYSTEM WATER FLOWS. INCREASE IN SCOPE OF WORK TO INCLUDE FISH IMPINGEMENT MITIGATION WORK AND UNIT 1 & 2 LUBRICATING OIL COOLER RETURBING

CONTINGENCY: $299 200

IN SERVICE DATES						Base estimate
1992 07 31	3 737	1995 05 31	4 338	1999 03 31	1 501	199704 L3
1992 11 30	1 477	1996 03 31	1 409	1999 12 31	2 808	
1993 11 30	3 128	1996 12 31	3 853			Work start date
1994 11 30	22 196	1998 01 31	1 403			1990 03 01

	PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
	Authorized to date	39 703		3 769			43 472
	1999/00	911	19				930
	TOTAL	40 614	19	3 769			44 402
	REV. AMOUNTS.						
	Authorized to date:	39 703		3 769			43 472
	Over(under)expend:						
Auth Req.:	1999/00	2 299	3	76			2 378
	TOTAL	42 002	3	3 845			45 850

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 01-16-8051

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1988 12	33 117	NEW ITEM.
1989 10	44 038	START ADVANCED. 80 MORE GONDOLAS, REPAIR OF UNITS 1&2.
1990 05	43 127	COAL CARS DELETED, EST DEFERRED 4 YEARS.
1990 10	47 238	REFLECTS INCORPORATION OF CURRENT CONSULTANT REPORTS.
1991 10	62 061	ADD'L INST'N&CTRL WORK, BRNR&S/B MODS, BOILER,ENG,OH,&MISC.
1992 10	32 856	RMVL OF E.P.'S&SCOPE RD'NS FOR BOILER REHAB,DCIS,BRNR CTRL, MISC INST'N,COAL TRANS&DUST CTRL. OFFSET BY IN'CS TO S/B MODS&C/H CTRL.
1993 06	32 856	DELAY IN RCPT OF ENVIRO LIC.&REVISED OUTAGE WINDOWS.
1993 10	32 856	SCOPE INCR FOR COAL HNDLNG&BOILER CTRL MODS; ADD'L ENVIRO MON PRGS REQ'D FOR LIC; WP'S ADDED FOR FUEL OIL SYS BRNR LT OFF, ABSTOS DUST CLNUP, STN ELE REHAB&BLCKOUT PROT;IMPL OF REC'S IN HDGEN STOR&PLEN HTRS STUD;INCR FOR BOILER H20 COND SYS UPGRD; INCR PROJ ADMIN COSTS FROMINC DURAT. OFFSET BY LO'R COSTS FOR SOOTBLOWER MODS&DECR SCOPES FOR FURNACE MODS, PULV COAL FEEDER DRIVE & BOILER TUBE REPLACEMENT WP'S.
1994 10	38 668	INCREASE DUE TO COAL HNDLING, PUMP STDY, ROOF REPAIRS ADDED;INDRCT INCRS; VARIOUS SCOPE INCRS.; HGHER PRICE-COAL HNDLING&TURB INSTR.OFFSET BY VARIOUS DECREASES INCLUDING CONTINGENCY.
1995 10	39 454	COSTS FOR UPGRDS WERE HIGHER THAN EST. ON FOLLOWING: BOILER,SOOTBLOWERS, WATER COND., COAL HNDLNG, OIL SPILL MIT., BLACKOUT PROTECT,& CNTRL ROOM. THESE OFFSET BY LOWER COSTS OF FOLLWOING: FD/ID FANS, TURBSUPERVISORY, DUST CONT., COAL HNDLG.CONTROL & LOCOMOTIVE. SCOPE INCREASETO INCLUDE O.T.; BOILER FRT EQUIP UPGRD.; RAIL SPUR; HAZARD MAT. STORAGE& FUGITIVE COAL DUST STUDIES; BLR CAMERA REPLCMT; DUCT CNTRL FOR RAD. STACKER & PORT. CONVEYOR. ADDITIONALASBESTOS REMVL, & LAB EXT./COAL SMPLING/ STORAGE BLDG. CONTINGY REDUCED TO REFLECT FEWER UNKNOWNS & NEARCOMPL. OF WORK.
1996 10	42 497	SCOPES INCREASES: RAIL SPUR REPAIRS AND BOILER CAMERA SYSTEM. SCOPE DECREASES: COAL HANDLING SPARE PARTS AND LOCOMOTIVE REFURBISHMENT. COSTS HIGHER FOR: COMMISSIONING, BURNER FRONT EQUIPMENT UPGRADE, OUTSTANDING COAL HANDLING UPGRADES AND PROJ. MANAGEMENT. CONTINGENCY AMOUNT INCLUDED FOR ESTIMATED ITEMS IDENTIFIED IN IOM FROM NGR TO RBG OF 96 04 02. FINAL ISD DEFERRED ONE YEAR TO 97 03 31.

ASSOCIATED PROJECTS

Budget reference number	Description
01-16-8023	BRANDON G.S. - UNITS 1-5 LIFE ASSURANCE PHASE III (BRGSLA)

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	36		3			39	39
May	44		3			47	86
Jun	442		4			446	532
Jul	207		7			214	746
Aug	301	1	8			310	1 056
Sep	120	1	10			131	1 187
Oct	368		11			379	1 566
Nov	316		14			330	1 896
Dec	457	1	16			474	2 370
Jan	3					3	2 373
Feb	3					3	2 376
Mar	2					2	2 378
TOTAL	2 299	3	76			2 378	2 378
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

1999-08-21 05:16 PM

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

COMPLEX STATUS: [X] Planned [ ] In progress

Complex no. 226

REVISION STATUS: [ ] New complex [ ] In service change [ ] Concept change [X] Estimate change only

COMPLEX: BRANDON G.S. LICENCE RENEWAL

Proposal

Refurbish unit #5, extending the useful life of the plant to 2019. Life extension requires: procurement of a new environmental licence for the period 2006 - 2019, replacement of last two rows of L.P. turbine blading, retube condenser, upgrade electrical services, install nitrous oxides control & continuous emission monitoring. Build new ash lagoon.

JUSTIFICATION: [X] Load [ ] Service [ ] Safety [ ] Efficiency [X] Reliability [ ] Other

Explanation

The 1998 power resource plan report recommends Brandon #5 life extension as an option to meet future load requirements and increase system reliability.

Estimate Level	COMPLEX START (yyyy mm)
L2	2000 04

IN SERVICE DATES AND AMOUNTS

2006 04	$8892	2007 03	$784	2008 03	$1696	2009 03	$1009
2010 03	$2699	2011 03	$1469	2012 03	$864	2013 03	$2071
2014 03	$455	2015 03	$1205	2016 03	$473	2017 on	$1657

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend								
Year 99/00								
00/01						1,089	-1,089	-100
01/02						3,606	-3,606	-100
02/03						2,500	-2,500	-100
03/04	1,909	5	152		2,066	1,136	930	82
04/05	586	63	210		859	1,254	-395	-31
05/06	4,747	610	479		5,836	7,516	-1,680	-22
06/07	716	108	92		916	2,173	-1,257	-58
07/08	1,387	242	67		1,696	2,011	-315	-16
08/09	809	160	40		1,009	1,843	-834	-45
09/10	2,116	469	114		2,699		2,699	
10/11	1,128	278	63		1,469		1,469	
11/12	650	176	38		864		864	
12/13	1,526	453	92		2,071		2,071	
13/14	329	106	20		455		455	
14/15	856	298	50		1,204		1,204	
15/16	329	124	20		473		473	
16/17	329	133	21		483		483	
17/18	329	142	22		493		493	
18/19	445	205	30		680		680	
Beyond								
TOTAL	18,191	3,572	1,510		23,273	23,128	145	1

REVISION: Reflects a two year start deferral.

Reviewed by ORIGINATOR	yyyy mm dd 99 11 02	Reviewed by COORDINATOR	yyyy mm dd
Reviewed by CONSTRUCTOR	yyyy mm dd	Approved by VICE-PRESIDENT	yyyy mm dd 99 11 12

H2856/r Rev 99 03

Complex no. 226

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Advance or deferral impact

Increased imports to meet load requirements.

Factors affecting timing or viability

Local load demands.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Brandon GS Licence Renewal		16,990	17,330	18,191	861	5
TOTAL		16,990	17,330	18,191	861	5

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
96 10	26,992	NEW COMPLEX
9710	23,289	Revised to remove estimate for ash lagoon work transferred from Life Assurance item, and already included.
9810	23,128	Estimate remains valid.
1999 10	23,273	Reflects a two year start deferral.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item

72

Title			Budget reference number
BRANDON G.S. LICENCE RENEWAL			01-16-7008
Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Power Planning & Operations	Power Planning & Operations	Generation - South	61506:81980

DESCRIPTION:
REFURBISH UNIT #5, EXTENDING THE USEFUL LIFE OF THE PLANT TO 2019. LIFE EXTENSION REQUIRES: PROCUREMENT OF A NEW ENVIRONMENTAL LICENCE FOR THE PERIOD BETWEEN 2006 AND 2019, REPLACEMENT OF LAST TWO ROWS OF L.P. TURBINE BLADING, RETUBE CONDENSER, UPGRADE ELETRICAL SERVICES, INSTALL NITROUS OXIDES CONTROL AND CONTINUOUS EMISSION MONITORING. BUILD NEW ASH LAGOON.

JUSTIFICATION:
THE 1998 POWER RESOURCE PLAN REPORT RECOMMENDS BRANDON #5 LIFE EXTENSION AS NEXT PLANT TO MEET FUTURE LOAD REQUIRMENTS AND INCREASE SYSTEM RELIABILITY.
BASED ON CONSULTANT W.P. LONDON'S PRELIMINARY REPORT, UNIT #5 REQUIRES REFURBISHMENT OF EQUIPMENT, INSTALLATION OF ENVIRONMENTAL PROTECTION EQUIPMENT AND CONSTRUCTION OF A NEW ASH LAGOON IN ORDER TO ASSURE EXTENSION OF OPERATING LIFE TO 2019 AND COMPLIANCE WITH MORE STRINGENT ENVIRONMENTAL STANDARDS.

NOTE: ESTIMATE INCLUDES AN UNAMORTIZED BALANCE OF PRELIMINARY PLANNING STUDIES ESTIMATED AT $.917 MILLION.

REVISION:
CONTINGENCY AMOUNT: $2,637,000 (1997$)

IN SERVICE DATES						Base estimate
2006 04 30	8 892	2010 03 31	2 699	2014 03 31	455	199904 L2
2007 03 31	784	2011 03 31	1 469	2015 03 31	1 205	
2008 03 31	1 696	2012 03 31	864	2016 03 31	473	Work start date
2009 03 31	1 009	2013 03 31	2 071	And On	1 657	2002 04 01

PREV. AUTHORITY Authorized to date:	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
2000/01	1 005	7	78			1 090
2001/02	3 091	285	230			3 606
2002/03	1 807	207	487			2 501
2003/04	432	59	645			1 136
2004/05	432	69	753			1 254
2005/06	5 418	988	1 110			7 516
2006/07	1 701	351	122			2 174
2007/08	1 635	377				2 012
2008/09	1 469	374				1 843
TOTAL	16 990	2 717	3 425			23 132
REV. AMOUNTS:						
Authorized to date:						
Over(under)expend:						
Auth Req.: 2003/04	1 909	5	152			2 066
2004/05	586	63	210			859
2005/06	4 747	610	479			5 836
2006/07	716	108	92			916
2007/08	1 387	242	67			1 696
2008/09	809	160	40			1 009
2009/10	2 116	469	114			2 699
2010/11	1 128	278	63			1 469
2011/12	650	176	38			864
2012/13	1 526	453	92			2 071
2013/14	329	106	20			455
2014/15&on	2 288	903	143			3 334
TOTAL	18 191	3 573	1 510			23 274

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

4249

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number: 01-16-7008

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1996 10	26 992	NEW ITEM.
1997 10	23 291	ESTIMATE FOR ASH LAGOON WORK TRANSFERRED FROM LIFE ASSURANCE (IFF96), WAS ALREADY INCLUDED IN ORIGINAL LIFE EXTENSION WORK.

ASSOCIATED PROJECTS

Budget reference number	Description

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

1999-09-28 11:07 AM

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

COMPLEX STATUS		Complex no.	REVISION STATUS	
☐ Planned	☒ In progress	220	☐ New complex	☐ In service change
			☒ Concept change	☒ Estimate change only

COMPLEX	BRANDON G.S. SWITCHYARD JETAIRE BREAKER REPL

Proposal

Replacement of all thirteen 115kV Jetaire circuit breakers at Brandon G.S.

JUSTIFICATION		Explanation
☐ Load	☐ Service	These breakers have been in service for 40 years and have reached the end of their useful life. Obsolescence (interim system upgrades and their age have decreased their capability), high fault levels, decreasing reliability, and high maintenance costs (8.4 times higher than similar breakers at Bdn with parts very expensive or unavailable) indicate these breakers should be replaced with existing surplus breakers, after their refurbishment.
☐ Safety	☒ Efficiency	
☒ Reliability	☐ Other	

Estimate Level	COMPLEX START (yyyy mm)	IN SERVICE DATES AND AMOUNTS			
L2	1997 04	1999 01 $1306	1999 10 $2287		

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	2,061		122	26	2,157	1,562	595	38
Year 99/00	1,293	34	82		1,409	1,986	-577	-29
00/01								
01/02								
02/03								
03/04								
04/05								
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	3,354	34	204	26	3,566	3,548	18	1

REVISION	Revised to update cash flows. More work was completed in 1998/99 than previously forecast

Reviewed by	yyyy mm dd	Reviewed by	yyyy mm dd
ORIGINATOR	99 11 08	COORDINATOR	
Reviewed by	yyyy mm dd	Approved by	yyyy mm dd
CONSTRUCTOR		VICE-PRESIDENT	99 11 12

H2856/r Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Complex no. 220

Advance or deferral impact

Continued high failure rate.

Factors affecting timing or viability

Schedule for refurbishing the replacements.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Brandon G.S. switchyard Jetaire breaker repl	3,521	3,412	3,480	3,354	-126	-4
TOTAL	3,521	3,412	3,480	3,354	-126	-4

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
96 10	2,582	NEW COMPLEX
9710	2,450	Reflects revised costing methodology with the new financial reporting system.
9810	3,548	SCOPE REVISED TO INCLUDE BUSHING CT ADDITION, PURCHASE OF EIGHT BREAKERS INSTEAD OF REFURBISHING AND SALEABLE SPARE PARTS.
1999 10	3,566	Revised to update cash flows. More work was completed in 1998/99 than previously forecast.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item

Title
BRANDON G.S. SWITCHYARD JETAIRE BREAKER REPLACEMENT

Budget reference number
01-05-7012

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Generation - South	Design	Construction	60158

DESCRIPTION:
REPLACEMENT OF ALL THIRTEEN 115 KV JETAIRE CIRCUIT BREAKERS AT BRANDON GENERATING STATION.

JUSTIFICATION:
THE THIRTEEN 115 KV JETAIRE CIRCUIT BREAKERS AT THE BRANDON GENERATING STATION WERE INSTALLED IN 1957 AND ARE THE ONLY ONES REMAINING ON THE MANITOBA HYDRO SYSTEM. THEIR FAULT INTERRUPTING RATING IS LOW AND SYSTEM PROCEDURES HAVE BEEN PUT INTO PLACE TO REDUCE SYSTEM FAULT LEVELS DURING CERTAIN BREAKER OPERATIONS.

REFERENCE:
REPORT NO. 95-HGE-018.109 (PS96-08)

REVISION:
CASH FLOW ADJUSTED TO REFLECT MORE WORK DONE IN 1998/99 THAN PREVIOUSLY FORECASTED.

IN SERVICE DATES

1999 01 31 1 306
1999 10 31 2 286

Base estimate
199802 L3

Work start date
1997 04 01

	GROSS	ESCALATION	INT CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
PREV AUTHORITY						
Authorized to date:	2 061		122	-26		2 157
1999/00	1 305	45	41			1 391
TOTAL	3 366	45	163	-26		3 548
REV. AMOUNTS:						
Authorized to date:	2 061		122	-26		2 157
Over(under)expend:						
Auth 1999/00 Req.:	1 293	34	82			1 409
TOTAL	3 354	34	204	-26		3 566

Prepared by	yy mm dd	Approved by	yy mm dd	Approved by	yy mm dd
COORDINATOR		COORDINATING MANAGER		ORIGINATING MANAGER	
Estimated by					
ORIGINATOR					4253

1999-08-21 05:15 PM

CAPITAL EXPENDITURE REVISION

Budget reference number 01-05-7012

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1996 10	2 582	NEW ITEM.
1997 10	2 452	SCOPE UNCHANGED, ESTIMATE REFLECTS REVISED COSTING METHODOLOGY IMPLEMENTED WITH THE NEW FINANCIAL REPORTING SYSTEM.
1998 10	3 548	ADVANCED TO LEVEL 3 ESTIMATE. CONSTRUCTION REFURBISHMENT COST HIGHER THAN ANTICIPATED. SCOPE REVISED TO INCLUDE BUSHING CT ADDITION. REVISED ESTIMATES BASED ON RECOMMENDATION TO PURCHASE EIGHT NEW GEC ALSTHOM BREAKERS INSTEAD OF REFURBISHING EIGHT WESTINGHOUSE BR5000 BREAKERS. (REF: MEMO W. PAWLIKEWICH TO N.R. READ 98.05.21). MATERIAL COSTS ESTIMATED AT 174,000 FOR BR5000 PARTS ARE INCLUDED, BUT EXPECTED TO BE REMOVED ONCE A DECISION IS MADE BY POWER SUPPLY AS TO THE DESTINY OF THE SPARE PARTS.

ASSOCIATED PROJECTS

Budget reference number	Description

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	279	6	6			291	291
May	383	9	8			400	691
Jun	385	10	11			406	1 097
Jul	66	2	14			82	1 179
Aug	60	2	14			76	1 255
Sep	61	2	15			78	1 333
Oct	59	3	14			76	1 409
Nov							1 409
Dec							1 409
Jan							1 409
Feb							1 409
Mar							1 409
TOTAL	1 293	34	82			1 409	1 409
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

COMPLEX STATUS: ☐ Planned ☒ In progress

Complex no. 224

REVISION STATUS: ☐ New complex ☒ In service change ☐ Concept change ☒ Estimate change only

COMPLEX	200MW ONTARIO HYDRO SALE

Proposal

Make necessary adjustments to units 1 to 6 at Seven Sisters G.S. to allow conversion of units to synchronous condenser operation.

JUSTIFICATION

☒ Load ☐ Service ☐ Safety ☒ Efficiency ☒ Reliability ☐ Other

Explanation

During low Winnipeg River generation and single contingency outage conditions, additional voltage support is required in Whiteshell area to maintain 200MW sale to Ontario. This item provides for capability to convert Seven Sisters generating units to synchronous condenser operation to provide required voltage support.

Estimate Level	COMPLEX START (yyyy mm)
L3	1995 06

IN SERVICE DATES AND AMOUNTS

1998 03	$2742	1999 03	$711	1999 04	($43)	1999 06	$746
1999 10	$441	2000 10	$441	2001 10	$441	2002 10	$441
2003 10	$441	2004 10	$441	2005 10	$441	2006 10	$441

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	3,941		284	29	4,196	3,995	201	5
Year 99/00	338	1	26		365	1,045	-680	-65
00/01	424	3	8		435	490	-55	-11
01/02	424	5	8		437	492	-55	-11
02/03	424	8	7		439	494	-55	-11
03/04	424	10	7		441	335	106	32
04/05	424	13	8		445		445	
05/06	424	16	8		448		448	
06/07	424	19	9		452		452	
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	7,247	75	365	29	7,658	6,851	807	12

REVISION	Reflects the experience gained while refurbishing the first breaker.

Reviewed by	yyyy mm dd	Reviewed by	yyyy mm dd
ORIGINATOR	99 11 08	COORDINATOR	
Reviewed by	yyyy mm dd	Approved by	yyyy mm dd
CONSTRUCTOR		VICE-PRESIDENT	99 11 25

H2856/r Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Complex no. 224

Advance or deferral impact

Factors affecting timing or viability

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Seven S generator 1-6 synchronous condenser conv	2,731	3,097	3,159	3,239	80	3
Seven S 115kV Breaker and Wall Bushing Upgrade	3,132	3,120	3,182	4,008	826	26
TOTAL	5,863	6,217	6,341	7,247	906	14

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
96 10	2,133	New complex, originally included in complex 95.
9710	6,378	Reflects changes in design, actual costs of first unit conversion, & addition of a 115kV breaker & wall bushing upgrade item.
9810	6,851	Reflects 97/98 overexpenditure .4M. Cashflow revised to reflect extended timeframe of brkr and wall bushing program, and actual costs of first units and associated deficiencies.
1999 10	7,658	Reflects the experience gained while refurbishing the first breaker.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item

74

Title			Budget reference number
SEVEN SISTERS GENERATOR 1-6 SYNCHRONOUS CONDENSER CONVERSION			01-02-5933
Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Planning & Control	Generation - South	Generation - South	60090

DESCRIPTION:
MAKE NECESSARY ADJUSTMENTS TO UNITS 1 TO 6 AT SEVEN SISTERS GENERATING STATION TO ALLOW CONVERSION OF UNITS TO SYNCHRONOUS CONDENSER OPERATION.

JUSTIFICATION:
DURING LOW WINNIPEG RIVER GENERATION AND SINGLE CONTINGENCY OUTAGE CONDITIONS, ADDITIONAL VOLTAGE SUPPORT IS REQUIRED IN WHITESHELL AREA TO MAINTAIN 200 MW SALE TO ONTARIO. THIS ITEM PROVIDES FOR CAPABILITY TO CONVERT SEVEN SISTERS GENERATING UNITS TO SYNCHRONOUS CONDENSER OPERATION TO PROVIDE REQUIRED VOLTAGE SUPPORT.

REFERENCE:
REPORT PSPD 94-1, SYSTEM IMPROVEMENTS TO SUPPORT 200 MW SALE TO ONTARIO HYDRO IN 1998.

REVISION:
WORK SCHEDULED FOR 1999/00 IS COMPLETION OF OUTSTANDING DEFICIENCIES.

IN SERVICE DATES

1998 03 31	2 742
1999 06 30	746

Base estimate: 199610 L3

Work start date: 1995 06 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date	3 201		235	-29		3 407
1999/00	-85					-85
TOTAL	3 116		235	-29		3 322
REV. AMOUNTS:						
Authorized to date: Over(under)expend:	3 201		235	-29		3 407
Auth Req.: 1999/00	38		14			52
TOTAL	3 239		249	-29		3 459

Prepared by yy mm dd COORDINATOR — Approved by yy mm dd — Approved by yy mm dd

Estimated by ORIGINATOR — COORDINATING MANAGER — ORIGINATING MANAGER

4257

1999-08-21 05:15 PM

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 01-02-5933

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1994 10	1 847	NEW ITEM.
1995 10	1 776	SCHEDULE ADVANCED 12 MONTHS TO AVOID CONFLICT WITH UNIT 4 OVERHAUL IN 1998.
1996 10	2 808	SCHEDULE ADVANCED 12 MONTHS TO AVOID CONFLICT WITH UNIT 4 OVERHAUL IN 1998. TO REFLECT CARRY OVER OF FUNDS FROM THE 1995/96 FISCAL YEAR
1997 10	2 840	ESTIMATE REWORKED TO REFLECT CHANGES IN DESIGN AND ACTUAL COSTS OF FIRST UNIT.

ASSOCIATED PROJECTS

Budget reference number	Description
01-02-8071	Seven Sisters 115 kV Breaker and Wall Bushing Upgrade

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	12		5			17	17
May	12		5			17	34
Jun	14		4			18	52
Jul							52
Aug							52
Sep							52
Oct							52
Nov							52
Dec							52
Jan							52
Feb							52
Mar							52
TOTAL	38		14			52	52
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item __ Domestic Item

75

Title
Seven Sisters 115 kV Breaker and Wall Bushing Upgrade

Budget reference number
01-02-8071

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Generation - South	Generation - South	Construction	61365:61367

DESCRIPTION:
Upgrade the short circuit rating of the 16 - 115 kV AT breakers (includes 1 spare) at Seven Sisters G.S. from 3500 MVA to 5000 MVA by reinstalling their pre-insertion resistor switching mechanism. Replace the oil-leaking 115 kV line wall bushings with new spare units.

JUSTIFICATION:
The fault levels at Seven Sisters Generating Station exceed the current interrupting rating of the 115 kV AT breakers. Upgraded breakers will withstand the worst case existing and horizon year's station fault currents. Replacement of the deteriorated 115 kV line wall bushings enhances transmission reliability of the 200 MW sale to Ontario Hydro.

REFERENCE:
Memo: Walter Zurba to Clarence Thio, 1997 07 04 - 'Upgrading the 115 kV system at Seven Sisters G.S.'
Memo: Walter Pawlikewich to John Clouston, 1997 08 28 - 'Seven Sisters G.S. - 115 kV Wall Bushings'

REVISION:
Wall bushing upgrade and pre-insertion resistors completed in 1998/99. Scope of work in 1999/00 is to install one refurbished breaker and to refurbish and re-install a second breaker. In following seven years, refurbish and re-install two breakers per year.

IN SERVICE DATES

1999 03 31	711	2001 10 31	441	2005 10 31	441
1999 04 30	-43	2002 10 31	441	2006 10 31	441
1999 10 31	441	2003 10 31	441		
2000 10 31	441	2004 10 31	441		

Base estimate
199708 L2

Work start date
1997 09 01

PREV. AUTHORITY	GROSS	ESCALATION	INT CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date.	739		49			788
1999/00	857	21	51			929
2000/01	421	27	43			491
2001/02	421	36	36			493
2002/03	421	45	29			495
2003/04	283	37	16			336
TOTAL	3 142	166	224			3 532
REV. AMOUNTS.						
Authorized to date:	739		49			788
Over(under)expend:						
Auth 1999/00	301		11			312
Req. 2000/01	424	2	8			434
2001/02	424	4	8			436
2002/03	424	8	7			439
2003/04	424	11	7			442
2004/05	424	13	8			445
2005/06	424	16	8			448
2006/07	424	19	9			452
TOTAL	4 008	73	115			4 196

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	4259

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 01-02-8071

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1997 10	3 539	New Item.

ASSOCIATED PROJECTS

Budget reference number	Description
01-02-5933	SEVEN SISTERS GENERATOR 1-6 SYNCHRONOUS CONDENSER CONVERSION

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	40	-1	1			40	40
May	40		1			41	81
Jun	40		1			41	122
Jul	40		2			42	164
Aug	40		2			42	206
Sep	50	1	2			53	259
Oct	50		3			53	312
Nov							312
Dec							312
Jan							312
Feb							312
Mar	1		-1				312
TOTAL	301		11			312	312
2000/01 Apr	61					61	61
May	61					61	122
Jun	61		1			62	184
Jul	61		1			62	246
Aug	60	1	2			63	309
Sep	60	1	2			63	372
Oct	60		3			63	435
Nov							435
Dec							435
Jan							435
Feb							435
Mar			-1			-1	434
TOTAL	424	2	8			434	434

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

COMPLEX STATUS: [X] Planned [ ] In progress

Complex no. 227

REVISION STATUS: [ ] New complex [ ] In service change [ ] Concept change [X] Estimate change only

COMPLEX: SITE REMEDIATION - CONTAMINATED CORPORATE FACILITIES

Proposal

Conduct geotechnical investigation of the various contaminated Corporate facilities to deliniate the extent of any contamination on/around the site and prepare a report each with recommendations for cleanup. Remediate contaminated areas to environmentally acceptable limits and issue a final report confirming the site remediated in accordance with applicable environmental regulations.

JUSTIFICATION: [ ] Load [ ] Service [X] Safety [ ] Efficiency [ ] Reliability [X] Other

Explanation

Environmental concerns and/or regulations require that Corporate facilities be investigated and remediated as required to restore them to a level which permits unrestricted use of the site.

Estimate Level	COMPLEX START (yyyy mm)
L1	1997 04

IN SERVICE DATES AND AMOUNTS

2000 03	$1720	2001 03	$812	2002 03	$827	2003 03	$844
2004 03	$861	2005 03	$878	2006 03	$896	2007 03	$914
2008 03	$932	2009 03	$950	2010 03	$969	2011 on	$2330

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	926				926	1,069	-143	-13
Year 99/00	787	6			793	773	20	3
00/01	792	19			811	790	21	3
01/02	793	35			828	805	23	3
02/03	793	51			844	821	23	3
03/04	793	68			861	838	23	3
04/05	793	85			878	855	23	3
05/06	793	103			896	872	24	3
06/07	793	121			914	889	25	3
07/08	793	139			932	907	25	3
08/09	793	158			951	925	26	3
09/10	793	177			970	944	26	3
10/11	793	196			989	963	26	3
11/12	793	216			1,009	982	27	3
12/13	255	75			330	292	38	13
13/14		0			0		0	
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	11,483	1,449			12,932	12,725	207	2

REVISION: Represents 1999 submission.

Reviewed by ORIGINATOR	yyyy mm dd 99 10 02	Reviewed by COORDINATOR	yyyy mm dd
Reviewed by CONSTRUCTOR	yyyy mm dd	Approved by VICE-PRESIDENT	yyyy mm dd 99 11 12

H2856/r Rev 99 03

Complex no. 227

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Advance or deferral impact

Potential for legal actions.

Factors affecting timing or viability

Subject to environmental regulations.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Site remediation of contaminated Corp facilities	10,730	10,905	11,123	11,485	362	3
TOTAL	10,730	10,905	11,123	11,485	362	3

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
96 10	13,534	This is a new complex (prev part of cx 2) which covers Power Supply related site remediation of contaminated Corporate facilities , base 1996, extended work period.
9710	13,277	Revised base year, cost flows, escalation and interest rates.
9810	12,725	Revised to reflect removal of interest from this item.
1999 10	12,932	Represents 1999 submission.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item

76

Title
SITE REMEDIATION OF CONTAMINATED CORPORATE FACILITIES

Budget reference number
08-00-6586

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Power Planning & Operations	Power Planning & Operations	Power Planning & Operations	61427:91190

DESCRIPTION:
1. CONDUCT GEOTECHNICAL INVESTIGATION OF THE VARIOUS CONTAIMINATED COPORATE FACILITIES TO DELINEATE THE EXTENT OF ANY CONTAMINATION ON AND/OR AROUND THE SITE AND PREPARE A SITE INVESTIGATION REPORT ON THE INVESTIGATION INCLUDING RECOMMENDATIONS FOR REMEDIAL ACTION TO CLEAN UP ANY CONTAMINANTS.
2. REMEDIATE ANY CONTAMINATED AREAS IDENTIFIED IN THE SITE INVESTIGATION REPORT TO ENVIRONMENTALLY ACCEPTABLE LIMITS.
3. ISSUE A FINAL REPORT ON THE PROJECT CONFIRMING THE FACILITY AND SURROUNDING AREA WERE REMEDIATED AND ALL AREAS OF THE WORK WERE LEFT IN ACCORDANCE WITH APPLICABLE ENVIRONMENTAL REGULATIONS.

JUSTIFICATION:
DUE TO THE ENVIRONMENTAL CONCERNS AND/OR REGULATIONS THE CORPORATE FACILITIES MUST BE INVESTIGATED, REMEDIATED AS REQUIRED, AND RESTORED TO A LEVEL WHICH PERMITS UNRESTRICTED U SE OF THE SITE AND THE SURROUNDING AREA.

REFERENCE:
OSC REPORT 95-M5.

IN SERVICE DATES						Base estimate
2000 03 31	1 720	2004 03 31	861	2008 03 31	932	199903 L1
2001 03 31	812	2005 03 31	878	2009 03 31	950	
2002 03 31	827	2006 03 31	896	2010 03 31	969	Work start date
2003 03 31	844	2007 03 31	914	And On	2 330	1998 04 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date.	926					926
1999/00	884	33				917
2000/01	741	49				790
2001/02	741	64				805
2002/03	741	80				821
2003/04	741	97				838
2004/05	741	114				855
2005/06	741	131				872
2006/07	741	148				889
2007/08	741	166				907
2008/09	741	184				925
2009/10&on	2 440	739				3 179
TOTAL	10 919	1 805				12 724
REV. AMOUNTS:						
Authorized to date:	926					926
Over(under)expend:						
Auth 1999/00	787	7				794
Req.: 2000/01	792	20				812
2001/02	793	34				827
2002/03	793	51				844
2003/04	793	68				861
2004/05	793	85				878
2005/06	793	103				896
2006/07	793	121				914
2007/08	793	139				932
2008/09	793	157				950
2009/10	793	176				969
2010/11&on	1 843	487				2 330
TOTAL	11 485	1 448				12 933

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR		COORDINATING MANAGER		ORIGINATING MANAGER

1999-08-21 05:30 PM

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 08-00-6586

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1995 09	12 598	NEW ITEM.
1996 10	13 534	BASE YEAR REVISED TO 1996. SCHEDULE EXTENDED OVER LONGER PERIOD.
1997 10	13 277	REVISED BASE YEAR, COSTFLOWS REVISED.

ASSOCIATED PROJECTS

Budget reference number	Description

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	66					66	66
May	66					66	132
Jun	66					66	198
Jul	66					66	264
Aug	66					66	330
Sep	66					66	396
Oct	66					66	462
Nov	66					66	528
Dec	66					66	594
Jan	65	1				66	660
Feb	65	1				66	726
Mar	63	5				68	794
TOTAL	787	7				794	794
2000/01 Apr	66	1				67	67
May	66	1				67	134
Jun	66	1				67	201
Jul	66	2				68	269
Aug	66	2				68	
Sep	66	2				68	
Oct	66	2				68	475
Nov	66	2				68	541
Dec	66	2				68	609
Jan	66	2				68	677
Feb	66	2				68	745
Mar	66	1				67	812
TOTAL	792	20				812	812

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

COMPLEX STATUS: ☐ Planned ☒ In progress

Complex no. 225

REVISION STATUS: ☐ New complex ☒ In service change ☐ Concept change ☐ Estimate change only

COMPLEX	OIL CONTAINMENT - POWER SUPPLY

Proposal

Modifications and/or additions are required to prevent and contain oil spills:

1) southern and northern hydraulic generating stations, install oil/water separators, modify drainage systems, and upgrade sump, fuel storage facilities and dyking systems.

2) converter stations, install an oil containment system to collect and recover any oil spilled within the station.

JUSTIFICATION

☐ Load ☐ Service
☒ Safety ☐ Efficiency
☐ Reliability ☒ Other

Explanation

Previous experience with oil spills requires the Corporation to demonstrate "due diligence" with respect to containing and minimizing the potential for any further occurances. In addition, any plant outage as a result of a spill represents a minimum loss of $5000/hr.

Estimate Level	COMPLEX START (yyyy mm)
L2-3	1994 12

IN SERVICE DATES AND AMOUNTS							
1996 11	$107	1997 03	$2433	1997 04	$864	1997 08	$785
1997 12	$2125	1998 03	$140	1998 04	$128	1998 10	$961
1998 12	$188	2000 11	$931	2001 10	$1726	2003 on	$5194

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	7,757		409		8,166	8,958	-792	-9
Year 99/00	303	4	22		329	644	-315	-49
00/01	550	17	37		604	2,186	-1,582	-72
01/02	2,094	84	75		2,253	4,846	-2,593	-54
02/03	811	53	97		961	860	101	12
03/04	1,378	93	178		1,649		1,649	
04/05	1,426	118	76		1,620		1,620	
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	14,319	369	894		15,582	17,494	-1,912	-11

REVISION Reflects tailrace & splash shield, and 'Oil Spill Containment Working Group' scope reductions, favourable actual costs, and costs to completion.

Reviewed by ORIGINATOR	yyyy mm dd	Reviewed by COORDINATOR	yyyy mm dd
Reviewed by CONSTRUCTOR	yyyy mm dd	Approved by VICE-PRESIDENT	yyyy mm dd 99 11 12

H2856/r Rev 99 03

Complex no. 225

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Advance or deferral impact

Potential for legal action.

Factors affecting timing or viability

Subject to environmental regulations.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Generation South G S's oil spill containment	2,566	2,711	2,765	2,492	-273	-10
Generation North G S's oil spill containment	5,375	5,857	5,974	5,526	-448	-7
Dorsey Stn oil containment system		1,905	1,943	1,579	-364	-19
Henday Stn oil containment system		2,421	2,469	2,075	-394	-16
Radisson Stn oil containment system		2,684	2,738	2,396	-342	-12
Generation North spill response equipment	300	187	191	164	-27	-14
Generation South spill response equipment	93	93	95	89	-6	-6
TOTAL	8,334	15,858	16,175	14,321	-1,854	-11

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
96 10	19,730	New complex (previously part of 81) which covers Power Supply portion of oil containment & two new spill response equipment purchase items, base year 1996.
9710	18,504	Increased for 7 mo deferral of Great Falls, Jenpeg, and Grand Rapids, cost of approved Generation South spill response equipment and decreased for favourable contract prices for
9810	17,494	Reflects 97/98 underexpenditure 0.5M, reduced scope + contract prices at Long Spruce and Limestone, addition of risk analysis by consultant at 3 sites and deferred in-service dates.
1999 10	15,582	Reflects tailrace & splash shield, and 'Oil Spill Containment Working Group' scope reductions, favourable actual costs, and costs to completion.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item

Title	Budget reference number
GENERATION SOUTH GENERATING STATIONS - OIL SPILL CONTAINMENT	01-01-6969

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Generation - South	Generation - South	Generation - South	60094:60098

DESCRIPTION:
MODIFICATIONS ARE REQUIRED AT THE GENERATION SOUTH HYDRAULIC GENERATING STATIONS TO PREVENT OIL SPILLS. MAJOR ITEMS IDENTIFIED AT EACH STATION ARE AS FOLLOWS: PINE FALLS - INSTALLATION OF OIL/WATER SEPARATOR, MODIFICATIONS TO DRAINAGE SYSTEM, DYKING IN 115KV SWITCHYARD. START 95 11 ISD 97 03. GREAT FALLS - OIL CONTAINMENT IN TURBINE PITS, SECOND OIL/WATER SEPARATOR. START 96 11 ISD 98 03 MCARTHUR FALLS - CONVERSION OF EXISTING SUMP TO OIL/WATER SEPARATOR, OIL SKIMMERS, MODIFICATIONS TO STATION DRAINAGE SYSTEM. START 95 11 ISD 97 03. JENPEG - UPGRADE OIL SKIMMER EQUIPMENT, IMPROVE OIL INTERCEPTER, FUEL STORAGE FACILITY UPGRADE. START 96 11 ISD 98 03. GRAND RAPIDS - TRANSFORMER OIL PIT DRAINAGE SYSTEM, MODIFICATIONS TO EXISTING PIPE TRENCH TO FUNCTION AS OIL/WATER SEPARATOR, NEW OIL STORAGE BUILDING, GOVERNOR OIL LEVEL MONITORING, AND TRANSFORMER DECK SPRAY SHIELDS. START 95 11 ISD 97 03.

JUSTIFICATION:
MANITOBA HYDRO HAS HAD TWO OIL SPILLS IN THE LAST FIVE YEARS FROM ITS HYDRAULIC PLANTS. ANY FURTHER SPILLS WILL PROBABLY RESULT IN CHARGES BY MANITOBA ENVIRONMENT AND THE FEDERAL GOVERNMENT AS MANITOBA HYDRO WILL BE CONSIDERED A REPEAT OFFENDER. THE WORK ITEMS HAVE BEEN IDENTIFIED IN VARIOUS ENGINEERING REPORTS. BY COMPLETING THIS WORK, MANITOBA HYDRO WILL HAVE DEMONSTRATED DUE DILIGENCE IN ITS APPROACH TO OIL SPILL CONTAINMENT.

REFERENCE:
MECHANICAL DEPT. REPORT 95-M5 OIL SPILL CONTAINMENT IN CORPORATE FACILITIES REPORT NO. 95-M4 OIL SPILL CONTAINMENT REQUIREMENTS FOR PRODUCTION DIVISION SOUTH - HYDRO AND THERMAL GENERATING STATIONS REPORT 95-M2 MCARTHUR FALLS G.S. - OIL SPILL CONTAINMENT, PREPARED BY K. HUNTER. GRAND RAPIDS G.S.- OIL SPILL PREVENTION AND CONTAINMENT STUDY, FEB/95 PREPARED BY ACRES ENGINEERING.

REVISION:
IN SERVICE DATES FOR GREAT FALLS, AND GRAND RAPIDS PHASE 'B' SCHEDLUED FOR 1999/12 AND 2000/11. ESTIMATE AT GRAND RAPIDS REDUCED TO REFLECT REVISED SCOPE OF WORK (NOT DOING TAILRACE SPLASH SHIELDS).
CONTINGENCY AMOUNT: $100 000

IN SERVICE DATES						Base estimate
Prior Total	1 637	1998 08 31	1	1999 01 31	8	199610 L2
1998 05 31	2	1998 09 30	6	1999 04 30	241	
1998 06 30	4	1998 10 31	2	1999 06 30	133	Work start date
1998 07 31	2	1998 11 30	64	2000 11 30	498	1997 04 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:	1 890		81			1 971
1999/00	848	26	16			890
TOTAL	2 738	26	97			2 861
REV. AMOUNTS:						
Authorized to date:	1 890		81			1 971
Over(under)expend:						
Auth 1999/00	131	2	2			135
Req.: 2000/01	471	14	7			492
TOTAL	2 492	16	90			2 598

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

1999-09-28 11:08 AM

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 01-01-6969

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1995 10	2 602	NEW ITEM.

ASSOCIATED PROJECTS

Budget reference number	Description
01-20-5940	GENERATION NORTH GENERATING STATIONS OIL SPILL CONTAINMENT
03-00-4810	DORSEY STATION - OIL CONTAINMENT SYSTEM
03-00-5923	HENDAY STATION OIL CONTAINMENT SYSTEM
03-00-5924	RADISSON STATION OIL CONTAINMENT SYSTEM
09-00-7805	GENERATION NORTH SPILL RESPONSE EQUIPMENT
09-00-7806	GENERATION SOUTH SPILL RESPONSE EQUIPMENT

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr			2			2	2
May	1					1	3
Jun	1					1	4
Jul	2					2	6
Aug	2					2	8
Sep	31	1				32	40
Oct	31	1				32	72
Nov	31	1				32	104
Dec	31	1				32	136
Jan							136
Feb							136
Mar	1	-2				-1	135
TOTAL	131	2	2			135	135
2000/01 Apr							
May	12					12	12
Jun	12					12	24
Jul	48	2				50	74
Aug	131	3	1			135	209
Sep	84	2	2			88	2
Oct	84	2	2			88	3
Nov	100	5	2			107	492
Dec							492
Jan							492
Feb							492
Mar							492
TOTAL	471	14	7			492	492

1999-09-28 11:08 AM

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item

78

Title			Budget reference number
GENERATION NORTH GENERATING STATIONS OIL SPILL CONTAINMENT			01-20-5940
Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Generation - North	Generation - South	Generation - South	60064:60073

DESCRIPTION:
IN ORDER TO PREVENT OIL SPILLS, MODIFICATIONS AND ADDITIONS TO THE EXISTING FACILITIES ARE REQUIRED AT GENERATION - NORTH HYDRAULIC GENERATING STATIONS AND CONTROL STRUCTURES. THIS WILL INCLUDE: INSTALLATION OF OIL SEPARATORS; MODIFICATION OF THE EXISTING STATION SUMP(S); INSTALLATION OF NEW SUMP PUMPS; CONVERSION OF TAILRACE DECKS TO OIL CONTAINMENT CAPABILITY; INSTALLATION OF PIPING TO DRAIN TAILRACE DECK, TRANSFORMER PITS AND EXISTING SUMP(S) TO OIL SEPARATORS: CONTAINMENT OF HYDRAULIC SYSTEMS FOR HEADGATES; MINOR TRENCH AND STRUCTURE MODIFICATIONS FOR SPILL CONTAINMENT; UPGRADING OF THE EXISTING FUEL STORAGE FACILITIES IN ORDER TO BRING THEM UP TO MEET THE REQUIREMENTS OF THE CURRENT LEGISLATION. SOME OR ALL OF THESE CHANGES ARE REQUIRED AT EACH PLANT.

JUSTIFICATION:
MANITOBA HYDRO HAS HAD TWO OIL SPILLS IN THE LAST FIVE YEARS FROM ITS HYDRAULIC PLANTS. ANY FURTHER SPILLS WILL PROBABLY RESULT IN CHARGES BY MANITOBA ENVIRONMENT AND THE FEDERAL GOVERNMENT AS MANITOBA HYDRO WILL BE CONSIDERED A REPEAT OFFENDER. THE MAJORITY OF MANITOBA HYDRO'S PRODUCTION COMES FROM GENERATION-NORTH. IN THE PAST, PLANT OUTAGE HAS BEEN THE INITIAL RESPONSE TO AN OIL SPILL. THE MINIMUM COST OF A PLANT OUTAGE AT ONE OF THE THREE LARGE PLANTS IS $5000 PER HOUR. THE GENERATION-NORTH PLANTS PRESENT A CHALLENGE WHEN ATTEMPTING TO MINIMIZE THE EFFECT OF AN OIL SPILL BECAUSE: THE HIGH WATER FLOWS THROUGH THE NELSON RIVER WILL HAMPER THE USE OF BOOMS AND WATER CRAFT TO RECLAIM OIL; REMOTE LOCATIONS OF PLANTS AND LOW STAFFING LEVELS INCREASE RESPONSE TIME; IT WILL TAKE APPROXIMATELY 2 DAYS TO GET ASSISTANCE FROM OTHER AGENCIES SUCH AS GENERATION-SOUTH OR THE COAST GUARD; AND THE CLIMATE, IN PARTICULAR THE VERY LOW TEMPERATURES, WILL CHALLENGE OUR ABILITY TO SAFELY WORK OUTSIDE AND ON THE WATER.

REFERENCE:
CH2M HILL ENGINEERING LTD. REPORT DATED OCT/94 AND MECH. DEPT. JULY/95 REPORT 95-M5 'OIL SPILL CONTAINMENT IN CORP. FACILITIES.'

REVISION:
REDUCED ESTIMATE REFLECTS ACTUAL COST AT LIMESTONE AND LONG SPRUCE BEING LESS THAN ESTIMATED. CASHFLOW FOR 1999/00 REFLECTS COMPLETION OF DEFICIENCIES AT KETTLE G.S.

IN SERVICE DATES						Base estimate
Prior Total	4 740	1998 10 31	894	1999 02 28	18	199610 L3
1998 07 31	19	1998 11 30	64	1999 03 31	9	Work start date
1998 08 31	1	1998 12 31	11	1999 04 30	0	1997 04 01
1998 09 30	18	1999 01 31	7	1999 06 30	18	

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:	5 511		272			5 783
1999/00	386					386
TOTAL	5 897		272			6 169
REV. AMOUNTS:						
Authorized to date:	5 511		272			5 783
Over(under)expend:						
Auth 1999/00 Req.:	15	1				16
TOTAL	5 526	1	272			5 799

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

1999-09-28 11:08 AM

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number: 01-20-5940

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1994 10	4 233	NEW ITEM.
1995 10	5 825	INITIAL ESTIMATE WAS BASED ON A PRELIMINARY REPORT BY ENGINEERING CONSULTANT CH2M HILL, AND DID NOT INCLUDE PROJECT MGMT AND CONSTRUCTION SUPERVISION COSTS. NEW ESTIMATE IS BASED ON THE FINAL COSTS INCLUDED IN CH2M HILL REPORT AND IT ALSO INCLUDES PROJECT MANAGEMENT AND CONSTRUCTION SUPERVISION COSTS.

ASSOCIATED PROJECTS

Budget reference number	Description
01-01-6969	GENERATION SOUTH GENERATING STATIONS - OIL SPILL CONTAINMENT
03-00-4810	DORSEY STATION - OIL CONTAINMENT SYSTEM
03-00-5923	HENDAY STATION OIL CONTAINMENT SYSTEM
03-00-5924	RADISSON STATION OIL CONTAINMENT SYSTEM
09-00-7805	GENERATION NORTH SPILL RESPONSE EQUIPMENT
09-00-7806	GENERATION SOUTH SPILL RESPONSE EQUIPMENT

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	5					5	5
May	5					5	10
Jun	5	1				6	16
Jul							16
Aug							16
Sep							16
Oct							16
Nov							16
Dec							16
Jan							16
Feb							16
Mar							16
TOTAL	15	1				16	16
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item

79

Title			Budget reference number
DORSEY STATION - OIL CONTAINMENT SYSTEM			03-00-4810
Originating division	Coordinating division	Constructing division	Project Order Group (Range):
HVDC	HVDC	Construction	61931

DESCRIPTION:
INSTALLATION OF AN OIL CONTAINMENT SYSTEM TO COLLECT AND RECOVER ANY OIL SPILLED WITHIN THE STATION.

JUSTIFICATION:
THE KGS GROUP CONSULTANTS CONDUCTED AN OIL SPILL CONTAINMENT ASSESSMENT AND DETERMINED CONTAINMENT PITS, OIL TRAPS, OIL SEPARATORS AND RETENTION PONDS ARE REQUIRED TO PREVENT SURFACE WATER CONTAINMENT IN THE EVENT OF AN OIL SPILL. ANY OIL SPILLED WITHIN THE STATION WOULD BE CONTAINED, COLLECTED AND RECOVERED BEFORE IT CAN LEAVE THE STATION.

REFERENCE:
OIL SPILL CONTAINMENT WORKING GROUP REPORT 95-M5 ON 'OIL SPILL CONTAINMENT IN CORPORATE FACILITIES' JULY 1995.

REVISION:
DECREASE IN COST DUE TO SCOPE REVISION BY THE OIL SPILL CONTAINMENT WORKING GROUP.
ISD ADVANCED ONE YEAR FROM 2002 TO 2001.
CONTINGENCY AMOUNT: $131,000

IN SERVICE DATES			Base estimate
2001 10 31	1 727		199610 L2
			Work start date 1997 04 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:	36		15			51
1999/00	38		8			46
2000/01	320	28	22			370
2001/02	826	92	77			995
2002/03	687	91	82			860
TOTAL	1 907	211	204			2 322
REV. AMOUNTS:						
Authorized to date:	36		15			51
Over(under)expend:						
Auth 1999/00	113	1	10			124
Req.: 2000/01	53	1	16			70
2001/02	1 377	51	54			1 482
TOTAL	1 579	53	95			1 727

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

1999-09-28 11:08 AM

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 03-00-4810

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1994 10	537	NEW ITEM.
1995 10	2 026	INCREASE IN COST IS DUE TO REVISED ESTIMATES BASED ON THE CONCEPTUAL DESIGN BY THE CONSULTANT.IN-SERVICE DATE DEFERRED FROM 1998 10 31 TO 1999 10 31.
1996 10	2 204	IN-SERVICE DATE DEFERRED FROM 1999 10 31 TO 2001 10 31.
1997 10	2 289	UPDATED ESCALATION AND INTEREST.

ASSOCIATED PROJECTS

Budget reference number	Description
01-01-6969	GENERATION SOUTH GENERATING STATIONS - OIL SPILL CONTAINMENT
01-20-5940	GENERATION NORTH GENERATING STATIONS OIL SPILL CONTAINMENT
03-00-5923	HENDAY STATION OIL CONTAINMENT SYSTEM
03-00-5924	RADISSON STATION OIL CONTAINMENT SYSTEM
09-00-7805	GENERATION NORTH SPILL RESPONSE EQUIPMENT
09-00-7806	GENERATION SOUTH SPILL RESPONSE EQUIPMENT

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	7					7	7
May	24					24	31
Jun	6		1			7	38
Jul	6		1			7	45
Aug	6		1			7	52
Sep	6		1			7	59
Oct	23		1			24	83
Nov	17	1	1			19	102
Dec			1			1	103
Jan	17	1	1			19	122
Feb			1			1	123
Mar	1	-1	1			1	124
TOTAL	113	1	10			124	124
2000/01 Apr			1			1	1
May			1			1	2
Jun			1			1	3
Jul			1			1	4
Aug			1			1	5
Sep			1			1	
Oct			1			1	
Nov			1			1	8
Dec			1			1	9
Jan	18		1			19	28
Feb	18	1	1			20	48
Mar	17		5			22	70
TOTAL	53	1	16			70	70

1999-09-28 11:08 AM

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item

80

Title			Budget reference number
HENDAY STATION OIL CONTAINMENT SYSTEM			03-00-5923
Originating division	Coordinating division	Constructing division	Project Order Group (Range):
HVDC	HVDC	Construction	60120

DESCRIPTION:
INSTALLATION OF AN OIL CONTAINMENT SYSTEM TO COLLECT AND RECOVER ANY OIL SPILLED WITHIN THE STATION.

JUSTIFICATION:
THE KGS GROUP CONSULTANTS CONDUCTED AN OIL SPILL CONTAINMENT ASSESSMENT AND DETERMINED CONTAINMENT PITS, OIL TRAPS AND OIL SEPARATORS ARE REQUIRED TO PREVENT GROUND WATER AND SURFACE WATER CONTAMINATION IN THE EVENT OF AN OIL SPILL. ANY OIL SPILLED WITHIN THE STATION WOULD BE CONTAINED, COLLECTED AND RECOVERED BEFORE IT CAN LEAVE THE STATION.

REFERENCE:
OIL SPILL CONTAINMENT WORKING GROUP REPORT 95-M5 ON OIL SPILL CONTAINMENT IN CORPORATE FACILITIES JULY 1995.

REVISION:
DECREASE IN COST IS DUE TO SCOPE REVISION BY THE OIL SPILL CONTAINMEMT WORKING GROUP.
CONTINGENCY: $179,000

IN SERVICE DATES				Base estimate
2003 10 31	2 365			199610 L2
				Work start date 1997 04 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:	34		15			49
1999/00	37		8			45
2000/01	1 256	98	63			1 417
2001/02	1 096	110	91			1 297
TOTAL	2 423	208	177			2 808
REV. AMOUNTS:						
Authorized to date:	34		15			49
Over(under)expend:						
Auth 1999/00	23		5			28
Req.: 2000/01	14		7			21
2001/02	287	13	10			310
2002/03	425	27	45			497
2003/04	1 292	85	83			1 460
TOTAL	2 075	125	165			2 365

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number: 03-00-5923

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1994 10	390	NEW ITEM.
1995 10	2 535	INCREASE IN COST IS DUE TO REVISED ESTIMATES BASED ON THE CONCEPTUAL DESIGN BY THE CONSULTANT. IN-SERVICE DATE DEFERRED FROM 1997 10 31 TO 1998 10 31.
1996 10	2 723	IN-SERVICE DATE DEFERRED FROM 1998 10 31 TO 2000 10 31. ESTIMATE BASE DATE CHANGED TO 1996
1997 10	2 751	UPDATED ESCALATION AND INTEREST.

ASSOCIATED PROJECTS

Budget reference number	Description
01-01-6969	GENERATION SOUTH GENERATING STATIONS - OIL SPILL CONTAINMENT
01-20-5940	GENERATION NORTH GENERATING STATIONS OIL SPILL CONTAINMENT
03-00-4810	DORSEY STATION - OIL CONTAINMENT SYSTEM
03-00-5924	RADISSON STATION OIL CONTAINMENT SYSTEM
09-00-7805	GENERATION NORTH SPILL RESPONSE EQUIPMENT
09-00-7806	GENERATION SOUTH SPILL RESPONSE EQUIPMENT

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	5					5	5
May	5					5	10
Jun							10
Jul							10
Aug							10
Sep							10
Oct	4	1				5	15
Nov	4	1				5	20
Dec							20
Jan	4	1				5	25
Feb			1			1	26
Mar	1	-3	4			2	28
TOTAL	23		5			28	28
2000/01 Apr			1			1	1
May			1			1	2
Jun			1			1	3
Jul			1			1	4
Aug			1			1	5
Sep			1			1	
Oct			1			1	
Nov			1			1	8
Dec			1			1	9
Jan	5	-1	1			5	14
Feb	5	-1	1			5	19
Mar	4	2	-4			2	21
TOTAL	14		7			21	21

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item

81

Title			Budget reference number
RADISSON STATION OIL CONTAINMENT SYSTEM			03-00-5924
Originating division	Coordinating division	Constructing division	Project Order Group (Range):
HVDC	HVDC	Construction	60121

DESCRIPTION:
INSTALLATION OF AN OIL CONTAINMENT SYSTEM TO COLLECT AND RECOVER ANY OIL SPILLED WITHIN THE STATION.

JUSTIFICATION:
THE KGS GROUP CONSULTANTS CONDUCTED AN OIL SPILL CONTAINMENT ASSESSMENT AND DETERMINED CONTAINMENT PITS, OIL TRAPS AND OIL SEPARATORS ARE REQUIRED TO PREVENT GROUND WATER AND SURFACE WATER CONTAMINATION IN THE EVENT OF AN OIL SPILL. ANY OIL SPILLED WITHIN THE STATION WOULD BE CONTAINED, COLLECTED AND RECOVERED BEFORE IT CAN LEAVE THE STATION.

REFERENCE:
OIL SPILL CONTAINMENT WORKING GROUP REPORT 95-M5 ON OIL SPILL CONTAINMENT IN CORPORATE FACILITIES JULY 1995.

REVISION:
DECREASED IN COST IS DUE TO SCOPE REVISION BY THE OIL SPILL CONTAINMENT WORKING GROUP.
CONTINGENCY: $210,000

IN SERVICE DATES				Base estimate
2004 10 31	2 829			199610 L2
				Work start date 1997 04 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:	34		14			48
1999/00	36	1	7			44
2000/01	348	28	23			399
2001/02	2 268	231	56			2 555
TOTAL	2 686	260	100			3 046
REV. AMOUNTS:						
Authorized to date:	34		14			48
Over(under)expend:						
Auth 1999/00	21	1	5			27
Req.: 2000/01	13		7			20
2001/02	430	20	10			460
2002/03	386	26	52			464
2003/04	86	8	95			189
2004/05	1 426	118	77			1 621
TOTAL	2 396	173	260			2 829

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

1999-09-28 11:09 AM

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number: 03-00-5924

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1994 10	378	NEW ITEM.
1995 10	3 090	INCREASE IN COST IS DUE TO REVISED ESTIMATE BASED ON THE CONCEPTUAL DESIGN BY THE CONSULTANT. IN-SERVICE DATE DEFERRED FROM 1999 10 31 TO 2000 10 31.
1996 10	3 136	IN-SERVICE DATE DEFERRED FROM 2000 10 31 TO 2001 10 31. ESTIMATE BASE DATED CHANGED TO 1996.
1997 10	3 048	IN-SERVICE DATE DEFERRED FROM 2000 10 31 TO 2001 10 31. ESTIMATE BASE DATED CHANGED TO 1996.

ASSOCIATED PROJECTS

Budget reference number	Description
01-01-6969	GENERATION SOUTH GENERATING STATIONS - OIL SPILL CONTAINMENT
01-20-5940	GENERATION NORTH GENERATING STATIONS OIL SPILL CONTAINMENT
03-00-4810	DORSEY STATION - OIL CONTAINMENT SYSTEM
03-00-5923	HENDAY STATION OIL CONTAINMENT SYSTEM
09-00-7805	GENERATION NORTH SPILL RESPONSE EQUIPMENT
09-00-7806	GENERATION SOUTH SPILL RESPONSE EQUIPMENT

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	4	1				5	5
May	4	1				5	10
Jun							10
Jul							10
Aug							10
Sep							10
Oct	4	1				5	15
Nov	4	1				5	20
Dec							20
Jan	4	1				5	25
Feb			1			1	26
Mar	1	-4	4			1	27
TOTAL	21	1	5			27	27
2000/01 Apr			1			1	1
May			1			1	2
Jun			1			1	3
Jul			1			1	4
Aug			1			1	5
Sep			1			1	
Oct			1			1	
Nov			1			1	
Dec			1			1	9
Jan	4		1			5	14
Feb	4		1			5	19
Mar	5		-4			1	20
TOTAL	13		7			20	20

1999-09-28 11:09 AM

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item

82

Title	Budget reference number
GENERATION NORTH SPILL RESPONSE EQUIPMENT	09-00-7805

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Generation - North	Generation - North	Generation - North	61652

DESCRIPTION:
PURCHASE SPILL RESPONSE EQUIPMENT FOR THE GENERATION NORTH DIVISION IN ORDER TO MEET CORPORATE SPILL RESPONSE OBJECTIVES.

JUSTIFICATION:
THE CORPORATE OIL SPILL CONTAINMENT WORKING GROUP'S TERMS OF REFERENCE INCLUDED THE DEVELOPMENT OF EMERGENCY RESPONSE PROCEDURES AND EQUIPMENT PROCUREMENT, STAFFING AND TRAINING. THERE IS PRESENTLY NO CORPORATE INITIATIVE IN PLACE TO EVALUATE THE OVERALL FINANCIAL REQUIREMENTS AND NECESSITY FOR SPILL RESPONSE EQUIPMENT AT VARIOUS FACILITIES. THIS ISSUE WAS THEREFORE ADDRESSED BY THE OSCWG.

REFERENCE:
OIL SPILL CONTAINMENT WORKING GROUP REPORT 95-M5 DATED 1996 01 30. OSC PROGRAM 6(C) SUB-COMIMITTEE DRAFT REPORT DATED 1996 05 16.

REVISION:
REFLECTS ACTUALS TO COMPLETION.

IN SERVICE DATES						Base estimate
1998 04 30	121	1998 12 31	48	1999 04 30	-1	199612 L4
1998 05 31	1	1999 01 31	0			Work start date
1998 10 31	2	1999 02 28	1			1997 04 01
1998 11 30	1	1999 03 31	0			

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:	164		9			173
1999/00	23					23
TOTAL	187		9			196
REV. AMOUNTS:						
Authorized to date:	164		9			173
Over(under)expend:						
Auth Req.:						
TOTAL	164		9			173

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

4277

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number: 09-00-7805

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1998 10	201	ROLLOVER OF APPROVED FUNDS TO 1997/98 FOR PURCHASE OF BALANCE OF EQUIPMENT.
1999 03	171	REFLECTS ACTUALS TO COMPLETION.

ASSOCIATED PROJECTS

Budget reference number	Description
01-01-6969	GENERATION SOUTH GENERATING STATIONS - OIL SPILL CONTAINMENT
01-20-5940	GENERATION NORTH GENERATING STATIONS OIL SPILL CONTAINMENT
03-00-4810	DORSEY STATION - OIL CONTAINMENT SYSTEM
03-00-5923	HENDAY STATION OIL CONTAINMENT SYSTEM
03-00-5924	RADISSON STATION OIL CONTAINMENT SYSTEM
09-00-7806	GENERATION SOUTH SPILL RESPONSE EQUIPMENT

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item

83

Title			Budget reference number
GENERATION SOUTH SPILL RESPONSE EQUIPMENT			09-00-7806
Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Generation - South	Generation - South	Generation - South	61309

DESCRIPTION:
PURCHASE SPILL RESPONSE EQUIPMENT FOR THE GENERATION SOUTH DIVISION IN ORDER TO MEET CORPORATE SPILL RESPONSE OBJECTIVES.

JUSTIFICATION:
THE CORPORATE OIL SPILL CONTAINMENT WORKING GROUP'S TERMS OF REFERENCE INCLUDED THE DEVELOPMENT OF EMERGENCY RESPONSE PROCEDURES AND EQUIPMENT PROCUREMENT, STAFFING AND TRAINING. THERE IS PRESENTLY NO CORPORATE INITIATIVE IN PLACE TO EVALUATE THE OVERALL FINANCIAL REQUIREMENTS AND NECESSITY FOR SPILL RESPONSE EQUIPMENT AT VARIOUS FACILITIES. THIS ISSUE WAS THEREFORE ADDRESSED BY THE OSCWG.

REFERENCE:
OIL SPILL CONTAINMENT WORKING GROUP REPORT 95-M5 DATED 1996 01 30. OSC PROGRAM 6(C) SUB-COMMITTEE DRAFT REPORT DATED 1996 05 16.

REVISION:
REVISED TO REFLECT ACTUALS. ONLY DEFICIENCIES REMAIN.

IN SERVICE DATES				Base estimate
1998 03 31	93	1999 04 30	0	199612 L4
1998 04 30	0			Work start date
1999 02 28	-0			1997 04 01
1999 03 31	0			

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:	89		4			93
1999/00	3					3
TOTAL	92		4			96
REV. AMOUNTS:						
Authorized to date:	89		4			93
Over(under)expend:						
Auth Req.:						
TOTAL	89		4			93

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

1999-09-28 11:10 AM

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number: 09-00-7806

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1997 10	108	REVISED TO THE APPROVED EQUIPMENT REQUIREMENT FOR GENERATION SOUTH STATIONS.

ASSOCIATED PROJECTS

Budget reference number	Description
01-01-6969	GENERATION SOUTH GENERATING STATIONS - OIL SPILL CONTAINMENT
01-20-5940	GENERATION NORTH GENERATING STATIONS OIL SPILL CONTAINMENT
03-00-4810	DORSEY STATION - OIL CONTAINMENT SYSTEM
03-00-5923	HENDAY STATION OIL CONTAINMENT SYSTEM
03-00-5924	RADISSON STATION OIL CONTAINMENT SYSTEM
09-00-7805	GENERATION NORTH SPILL RESPONSE EQUIPMENT

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

COMPLEX STATUS: ☐ Planned ☒ In progress

Complex no. 228

REVISION STATUS: ☐ New complex ☒ In service change ☐ Concept change ☒ Estimate change only

COMPLEX: FIRE PROTECTION PROJECTS - POWER SUPPLY

Proposal

Design and install passive and/or active fire prevention and protection systems at all generating stations, and key transmission terminating stations as outlined by The Fire Prevention and Protection Committee and defined in the Fire Manual Part II.

Locations covered by this capital item complex are;
Pine Falls, McArthur, Kelsey, Limestone, Kettle, and Long Spruce Generating Stations, and Dorsey, Radisson, and Henday Stations.

JUSTIFICATION

☐ Load ☐ Service
☒ Safety ☐ Efficiency
☒ Reliability ☐ Other

Explanation

In accordance with the rules and guidelines established by The Fire Prevention and Protection Committee, implementation of this program will reduce the risk of fire to an acceptable level and mitigate the effects of any such occurance.

Estimate Level	COMPLEX START (yyyy mm)
L3	1990 06

IN SERVICE DATES AND AMOUNTS

1997 10	$811	1997 12	$286	1998 10	$342	1999 01	$1001
1999 06	$143	1999 11	$404	2000 09	$771	2000 10	$771
2000 11	$771	2000 12	$121	2001 03	$1104	2001 08	$153

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	2,380		191		2,571	3,838	-1,267	-33
Year 99/00	440	15	14		469	395	74	19
00/01	2,980	92	17		3,089	2,386	703	29
01/02	526	22	3		551		551	
02/03								
03/04								
04/05								
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	6,326	129	225		6,680	6,619	61	1

REVISION: Revised to include 4 new Wpg R. & Jenpeg FP&P sites, the completion of Kettle, Long Spr, &Radisson, and a reduced construction estimate for Radisson thyristor fire protection upgr.

Reviewed by ORIGINATOR	yyyy mm dd	Reviewed by COORDINATOR	yyyy mm dd
Reviewed by CONSTRUCTOR	yyyy mm dd	Approved by VICE PRESIDENT	yyyy mm dd 99 11 28

H2856/r Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Complex no. 228

Advance or deferral impact

Work well advanced, deferrals not possible.

Factors affecting timing or viability

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Kettle G S fire alarm system	277	277	283	277	-6	-2
Long Spruce G S fire alarm system	315	346	353	315	-38	-11
Limestone G S fire alarm system	374	371	378	374	-4	-1
Dorsey BP 1&2 addressable fire alarm system	656	818	834	750	-84	-10
Radisson Stn addressable fire alarm system	587	578	590	503	-87	-15
Henday Stn addressable fire alarm system	502	572	583	551	-32	-5
Dorsey BP 1 thyristor valves fire prot upgrade		1,078	1,100	1,099	-1	-0
Radisson BP 1 thyristor valves fire prot upgrade		1,283	1,309	1,144	-165	-13
Jenpeg fire prevention and protection				581	581	
Seven Sisters fire prevention and protection				201	201	
Mc Arthur Falls fire prevention and protection				213	213	
Great Falls fire prevention and protection				175	175	
Pine Falls fire prevention and protection				142	142	
TOTAL	2,711	5,323	5,430	6,325	895	16

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
96 10	8,274	Reduction, cancel'n of converter stn valve hall items., & increase, new/upgrade alarm systems for Limestone, Kettle, Long Spruce, Dorsey & Radisson. Prev part Cx 92.
9710	6,538	Reflects revised methodology with the new reporting system, increases in const & design costs, deferred in service dates, and addition of project management & field inspection costs.
9810	6,619	Reflects 1 year deferral of Dorsey and Radisson thyristor valve fire protection upgrade.
1999 10	6,680	Revised to include 4 new Wpg R. & Jenpeg FP&P sites, the completion of Kettle, Long Spr, &Radisson, and a reduced construction estimate for Radisson thyristor fire protection upgr.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item

84

Title: KETTLE G.S. - FIRE ALARM SYSTEM

Budget reference number: 01-20-7009

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Generation - North	Generation - South	Generation - South	60154

DESCRIPTION:
MODIFICATIONS TO THE EXISTING SYSTEMS WILL INCLUDE: EXTENDING THE EXISTING DELUGE PIPING TO ENSURE DIRECT WATER SPRAY ON THE BASE OF THE GENERATOR STEP-UP TRANSFORMER BUSHINGS;ADDITION OF SPRINKLERS ON THE DOWNSTREAM POWERHOUSE WALL AND CONSTRUCTION OF A FIRE BARRIER BLAST WALL BETWEEN UNIT #1 TRANSFORMER AND THE CONTROL ROOM/OFFICE AREA.

JUSTIFICATION:
RECENT FIRES AT KETTLE GENERATING STATION IN STEP-UP TRANSFORMER T9 INDICATED A NEED TOIMPROVE THE EXISTING SYSTEMS TO PREVENT OR LIMIT THE SPREAD OF A FIRE AND TO MEET CURRENT FIRE PROTECTION STANDARDS. IT IS FELT THAT THESE MODIFICATIONS WILL REDUCE THE EXISTING FIRE RISK, THE POSSIBILITY OF EXTENSIVE FIRELOSSES, INTERUPTION OF POWER SUPPLY AND IMPROVE THE OVERALL OPERATING SYSTEM SECURITY

REFERENCE:
MECHANICAL DEPARTMENT REPORT 95-M8

REVISION:
PROJECT COMPLETE. REFLECTS ACTUAL COST TO COMPLETION.

IN SERVICE DATES				Base estimate
1997 12 31	285	1999 04 30	-1	199610 L2
1998 01 31	0			Work start date
1998 02 28	2			1997 04 01
1998 03 31	3			

	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
PREV AUTHORITY Authorized to date	277		12			289
TOTAL	277		12			289
REV. AMOUNTS:						
Authorized to date:	277		12			289
Over(under)expend:						
Auth Req.:						
TOTAL	277		12			289

Prepared by: yy mm dd COORDINATOR — Approved by: yy mm dd Approved by: yy mm dd

Estimated by: ORIGINATOR — COORDINATING MANAGER — ORIGINATING MANAGER

4283

1999-08-21 05:16 PM

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 01-20-7009

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1996 10	366	NEW ITEM
1997 10	281	REFLECTS COST TO COMPLETION.

ASSOCIATED PROJECTS

Budget reference number	Description
01-01-8119	GREAT FALLS G.S. - FIRE PREVENTION/PROTECTION SYSTEM
01-02-8117	SEVEN SISTERS G.S. - FIRE PREVENTION/PROTECTION SYSTEM
01-03-8120	PINE FALLS G.S. - FIRE PREVENTION/PROTECTION SYSTEM
01-04-8118	McARTHUR FALLS G.S. - FIRE PREVENTION/PROTECTION SYSTEM
01-07-4938	KELSEY G.S. - FIRE ALARM SYSTEM (KEGSFP)
01-21-7010	LONG SPRUCE G.S. - FIRE ALARM SYSTEM
01-23-8108	JENPEG FIRE PREVENTION & PROTECTION
01-25-7011	LIMESTONE G.S. - FIRE ALARM SYSTEM
03-00-4809	DORSEY BP 1 & 2 ADDRESSABLE FIRE ALARM SYSTEM
03-00-5925	RADISSON STATION - ADDRESSABLE FIRE ALARM SYSTEM (RADIME6)
03-00-5926	HENDAY STATION ADDRESSABLE FIRE ALARM SYSTEM (HENDME5)
03-00-7221	DORSEY BP1 THYRISTOR VALVES FIRE PROTECTION UPGRADE
03-00-7222	RADISSON THYRISTOR VALVES FIRE PROTECTION UPGRADE

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item

85

Title
LONG SPRUCE G.S. - FIRE ALARM SYSTEM

Budget reference number
01-21-7010

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Generation - North	Generation - South	Generation - South	60160

DESCRIPTION:
MODIFICATIONS TO THE EXISTING SYSTEMS WILL INCLUDE: EXTENDING THE EXISTING DELUGE PIPING TO ENSURE DIRECT WATER SPRAY ON THE BASE OF THE GENERATOR STEP-UP TRANSFORMER BUSHINGS;ADDITION OF SPRINKLERS ON THE DOWNSTREAM POWERHOUSE WALL AND CONSTRUCTION OF A FIRE BARRIER BLAST WALL BETWEEN UNIT #1 TRANSFORMER AND THE CONTROL ROOM/OFFICE AREA.

JUSTIFICATION:
RECENT FIRES AT KETTLE GENEREATING STATION IN STEP-UP TRANSFORMER T9 INDICATED A NEED TO IMPROVE THE EXISTING SYSTEMS TO PREVENT OR LIMIT THE SPREAD OF A FIRE AND TO MEET CURRENT FIRE PROTECTION STANDARDS. IT IS FELT THAT THESE MODIFICATIONS WILL REDUCE THE EXISTING FIRE RISK, THE POSSIBILITY OF EXTENSIVE FIRE LOSSES, INTERUPTION OF POWER SUPPLY AND IMPROVE THE OVERALL OPERATING SYSTEM SECURITY

REFERENCE:
MECHANICAL DEPARTMENT REPORT 95-M8.

REVISION:
REFLECTS COST TO COMPLETION. PROJECT CLOSED OUT.

This BRN contains Deleted, Blocked, or Closed Orders.

IN SERVICE DATES				Base estimate
1998 10 31	321	1999 03 31	0	199610 L2
1998 11 30	2	1999 10 31	0	
1998 12 31	0			Work start date
1999 02 28	0			1997 07 01

	PREV. AUTHORITY Authorized to date:	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
		315		8			323
	1999/00	33					33
TOTAL		348		8			356
REV. AMOUNTS:							
Authorized to date:		315		8			323
Over(under)expend:							
Auth Req.:	1999/00						
TOTAL		315		8			323

Prepared by — yy mm dd — COORDINATOR
Approved by — yy mm dd — COORDINATING MANAGER
Approved by — yy mm dd — ORIGINATING MANAGER
Estimated by — ORIGINATOR

1999-08-21 05:16 PM

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 01-21-7010

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS

ASSOCIATED PROJECTS

Budget reference number	Description
01-01-8119	GREAT FALLS G.S. - FIRE PREVENTION/PROTECTION SYSTEM
01-02-8117	SEVEN SISTERS G.S. - FIRE PREVENTION/PROTECTION SYSTEM
01-03-8120	PINE FALLS G.S. - FIRE PREVENTION/PROTECTION SYSTEM
01-04-8118	McARTHUR FALLS G.S. - FIRE PREVENTION/PROTECTION SYSTEM
01-07-4938	KELSEY G.S. - FIRE ALARM SYSTEM (KEGSFP)
01-20-7009	KETTLE G.S. - FIRE ALARM SYSTEM
01-23-8108	JENPEG FIRE PREVENTION & PROTECTION
01-25-7011	LIMESTONE G.S. - FIRE ALARM SYSTEM
03-00-4809	DORSEY BP 1 & 2 ADDRESSABLE FIRE ALARM SYSTEM
03-00-5925	RADISSON STATION - ADDRESSABLE FIRE ALARM SYSTEM (RADIME6)
03-00-5926	HENDAY STATION ADDRESSABLE FIRE ALARM SYSTEM (HENDME5)
03-00-7221	DORSEY BP1 THYRISTOR VALVES FIRE PROTECTION UPGRADE
03-00-7222	RADISSON THYRISTOR VALVES FIRE PROTECTION UPGRADE

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item

86

Title: LIMESTONE G.S. - FIRE ALARM SYSTEM

Budget reference number: 01-25-7011

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Generation - North	Generation - South	Generation - South	60156

DESCRIPTION:
MODIFICATIONS TO THE EXISTING SYSTEMS WILL INCLUDE: EXTENDING THE EXISTING DELUGE PIPING TO ENSURE DIRECT WATER SPRAY ON THE BASE OF THE GENERATOR STEP-UP TRANSFORMER BUSHINGS; ADDITION OF SPRINKLERS ON THE DOWNSTREAM POWERHOUSE WALL AND CONSTRUCTION OF A FIREBARRIER BLAST WALL BETWEEN UNIT #1 TRANSORMER AND THE CONTROL ROOM/OFFICE AREA.

JUSTIFICATION:
RECENT FIRES AT KETTLE GENERATING STATION IN STEP-UP TRANSFORMER T9 INDICATED A NEED TO IMPROVE THE EXISTING SYSTEMS TO PREVENT OR LIMIT THE SPREAD OF A FIRE AND TO MEET CURRENT FIRE PROTECTION STANDARDS. IT IS FELT THAT THESE MODIFICATIONS WILL REDUCE THE EXISTING FIRE RISK, THE POSSIBILITY OF EXTENSIVE FIRE LOSSES, INTERRUPTION OF POWER SUPPLY AND IMPROVE THE OVERALL OPERATING SYSTEM SECURITY

REFERENCE:
MECHANICAL DEPARTMENT REPORT 95-M8

REVISION:
REFLECTS TENDERED CONTRACT PRICES.

IN SERVICE DATES

1999 11 30 | 404

Base estimate: 199610 L2

Work start date: 1997 07 01

	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
PREV. AUTHORITY Authorized to date	70		4			74
1999/00	307	12	10			329
TOTAL	377	12	14			403
REV. AMOUNTS: Authorized to date	70		4			74
Over(under)expend: Auth 1999/00 Req.:	304	14	12			330
TOTAL	374	14	16			404

Prepared by: yy mm dd COORDINATOR — Approved by: yy mm dd — Approved by: yy mm dd

Estimated by: ORIGINATOR — COORDINATING MANAGER — ORIGINATING MANAGER

1999-08-21 05:16 PM

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 01-25-7011

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1996 10	329	NEW ITEM

ASSOCIATED PROJECTS

Budget reference number	Description
01-01-8119	GREAT FALLS G.S. - FIRE PREVENTION/PROTECTION SYSTEM
01-02-8117	SEVEN SISTERS G.S. - FIRE PREVENTION/PROTECTION SYSTEM
01-03-8120	PINE FALLS G.S. - FIRE PREVENTION/PROTECTION SYSTEM
01-04-8118	McARTHUR FALLS G.S. - FIRE PREVENTION/PROTECTION SYSTEM
01-07-4938	KELSEY G.S. - FIRE ALARM SYSTEM (KEGSFP)
01-20-7009	KETTLE G.S. - FIRE ALARM SYSTEM
01-21-7010	LONG SPRUCE G.S. - FIRE ALARM SYSTEM
01-23-8108	JENPEG FIRE PREVENTION & PROTECTION
03-00-4809	DORSEY BP 1 & 2 ADDRESSABLE FIRE ALARM SYSTEM
03-00-5925	RADISSON STATION - ADDRESSABLE FIRE ALARM SYSTEM (RADIME6)
03-00-5926	HENDAY STATION ADDRESSABLE FIRE ALARM SYSTEM (HENDME5)
03-00-7221	DORSEY BP1 THYRISTOR VALVES FIRE PROTECTION UPGRADE
03-00-7222	RADISSON THYRISTOR VALVES FIRE PROTECTION UPGRADE

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	4		1			5	5
May	50	2	1			53	58
Jun	50	2	1			53	111
Jul	50	3	1			54	165
Aug	50	2	2			54	219
Sep	50	2	2			54	273
Oct	50	3	2			55	328
Nov			2			2	330
Dec							330
Jan							330
Feb							330
Mar							330
TOTAL	304	14	12			330	330
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item

87

Title: JENPEG FIRE PREVENTION & PROTECTION

Budget reference number: 01-23-8108

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Generation - South	Engineering Services-P.S.	Construction	61412

DESCRIPTION:
TO UPGRADE THE FIRE WATER MAIN SUPPLY TO PROVIDE ADEQUATE FLOWS AND PRESSURES IN ORDER TO PROTECT THE STAFFHOUSE AT JENPEG GENERATING STATION IN THE EVENT OF FIRE.

JUSTIFICATION:
IMPLEMENTATION OF THE RECOMMENDED FIRE PREVENTION AND PROTECTION MEASURES WILL REDUCE THE EXISTING FIRE RISK AT JENPEG POWERHOUSE AND THE STAFFHOUSE TO AN ACCEPTABLE LEVEL AND WILL ALSO REDUCE THE POSSIBILITY OF EXTENSIVE FINANCIAL LOSSES.

REFERENCE:
REPORT NO.: ENG. SERVICE 99-M1
FILE NO.: A1-6 (ELECT./MECH. ENG.)

REVISION:
NEW ITEM.

CONTINGENCY AMOUNT: $44 300.

IN SERVICE DATES		Base estimate
1999 12 31	119	199901 L4
2000 03 31	475	Work start date: 1999 07 01

	PREV. AUTHORITY Authorized to date:	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
TOTAL							
REV. AMOUNTS: Authorized to date: Over(under)expend:							
Auth	1999/00	146	3				149
Req.	2000/01	435	10				445
TOTAL		581	13				594

Prepared by: yy mm dd COORDINATOR — Approved by: yy mm dd — Approved by:
Estimated by: ORIGINATOR — COORDINATING MANAGER — ORIGINATING MANAGER

1999-08-21 05:16 PM

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 01-23-8108

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS

ASSOCIATED PROJECTS

Budget reference number	Description
01-01-8119	GREAT FALLS G.S. - FIRE PREVENTION/PROTECTION SYSTEM
01-02-8117	SEVEN SISTERS G.S. - FIRE PREVENTION/PROTECTION SYSTEM
01-03-8120	PINE FALLS G.S. - FIRE PREVENTION/PROTECTION SYSTEM
01-04-8118	McARTHUR FALLS G.S. - FIRE PREVENTION/PROTECTION SYSTEM
01-07-4938	KELSEY G.S. - FIRE ALARM SYSTEM (KEGSFP)
01-20-7009	KETTLE G.S. - FIRE ALARM SYSTEM
01-21-7010	LONG SPRUCE G.S. - FIRE ALARM SYSTEM
01-25-7011	LIMESTONE G.S. - FIRE ALARM SYSTEM
03-00-4809	DORSEY BP 1 & 2 ADDRESSABLE FIRE ALARM SYSTEM
03-00-5925	RADISSON STATION - ADDRESSABLE FIRE ALARM SYSTEM (RADIME6)
03-00-5926	HENDAY STATION ADDRESSABLE FIRE ALARM SYSTEM (HENDME5)
03-00-7221	DORSEY BP1 THYRISTOR VALVES FIRE PROTECTION UPGRADE
03-00-7222	RADISSON THYRISTOR VALVES FIRE PROTECTION UPGRADE

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul	3					3	3
Aug	3					3	6
Sep	5					5	11
Oct	5					5	16
Nov	12					12	28
Dec	39	1				40	68
Jan	52	1				53	121
Feb	20					20	141
Mar	7	1				8	149
TOTAL	146	3				149	149
2000/01 Apr	2					2	2
May	2					2	4
Jun	2					2	6
Jul	13					13	19
Aug	126	3				129	148
Sep	132	4				136	
Oct	158	3				161	
Nov							445
Dec							445
Jan							445
Feb							445
Mar							445
TOTAL	435	10				445	445

1P00 08-21 05-14 PM

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item

88

Title
SEVEN SISTERS G.S. - FIRE PREVENTION/PROTECTION SYSTEM

Budget reference number
01-02-8117

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Generation - South	Generation - South	Generation - South	61421

DESCRIPTION:
Installation of Addressable Fire Alarm System at Seven Sisters Generating Station.

JUSTIFICATION:
The fire alarm systems installed in the four Winnipeg River plants require modifications to eliminate false alarms, to provide visual warnings where auditory alarms cannot be heard, and to update drawings enabling staff to properly trace and repair faults. Consistent false and trouble alarms in a fire protection system results in staff becoming complacent resulting in response delays to fire conditions.

REFERENCE:
Memo W.L. Pawlikewich to M.J. Townsley dated 1998 03 16
Memo M.J. Townsley to W.L. Pawlikewich dated 1999 02 09
Capital Project Justification prepared by A. Simmons dated 99/03/15

REVISION:
New item.

IN SERVICE DATES		Base estimate
2001 03 31	212	199904 L2
		Work start date 2000 05 01

	PREV. AUTHORITY Authorized to date.	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
	TOTAL						
REV. AMOUNTS:							
Authorized to date:							
Over(under)expend:							
Auth Req.:	2000/01	201	7	4			212
	TOTAL	201	7	4			212

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

4291

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 01-02-8117

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS

ASSOCIATED PROJECTS

Budget reference number	Description
01-01-8119	GREAT FALLS G.S. - FIRE PREVENTION/PROTECTION SYSTEM
01-03-8120	PINE FALLS G.S. - FIRE PREVENTION/PROTECTION SYSTEM
01-04-8118	McARTHUR FALLS G.S. - FIRE PREVENTION/PROTECTION SYSTEM
01-07-4938	KELSEY G.S. - FIRE ALARM SYSTEM (KEGSFP)
01-20-7009	KETTLE G.S. - FIRE ALARM SYSTEM
01-21-7010	LONG SPRUCE G.S. - FIRE ALARM SYSTEM
01-23-8108	JENPEG FIRE PREVENTION & PROTECTION
01-25-7011	LIMESTONE G.S. - FIRE ALARM SYSTEM
03-00-4809	DORSEY BP 1 & 2 ADDRESSABLE FIRE ALARM SYSTEM
03-00-5925	RADISSON STATION - ADDRESSABLE FIRE ALARM SYSTEM (RADIME6)
03-00-5926	HENDAY STATION ADDRESSABLE FIRE ALARM SYSTEM (HENDME5)
03-00-7221	DORSEY BP1 THYRISTOR VALVES FIRE PROTECTION UPGRADE
03-00-7222	RADISSON THYRISTOR VALVES FIRE PROTECTION UPGRADE

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May	5					5	5
Jun	5					5	10
Jul	5					5	15
Aug	5					5	
Sep	5					5	
Oct	8	1				9	
Nov	32	1				33	67
Dec	32	2				34	101
Jan	32	1	1			34	135
Feb	36	1	1			38	173
Mar	36	1	2			39	212
TOTAL	201	7	4			212	212

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item

89

Title
McARTHUR FALLS G.S. - FIRE PREVENTION/PROTECTION SYSTEM

Budget reference number
01-04-8118

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Generation - South	Generation - South	Generation - South	61422

DESCRIPTION:
Installation of Addressable Fire Alarm System at McArthur Falls Generating Station.

JUSTIFICATION:
The fire alarm systems installed in the four Winnipeg River plants require modifications to eliminate false alarms, to provide visual warnings where auditory alarms cannot be heard, and to update drawings enabling staff to properly trace and repair faults. Consistent false and trouble alarms in a fire protection system results in staff becoming complacent resulting in response delays to fire conditions.

REFERENCE:
Memo W.L. Pawlikewich to M.J. Townsley dated 1998 03 16
Memo M.J. Townsley to W.L. Pawlikewich dated 1999 02 09
Capital Project Justification prepared by A. Simmons dated 99/03/15

REVISION:
New item.

IN SERVICE DATES		Base estimate
2001 03 31	225	199904 L2
		Work start date
		2000 07 01

	PREV AUTHORITY Authorized to date.	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
TOTAL							
REV. AMOUNTS:							
Authorized to date: Over(under)expend							
Auth Req.:	2000/01	213	8	4			225
TOTAL		213	8	4			225

Prepared by ____ yy mm dd COORDINATOR
Approved by ____ yy mm dd COORDINATING MANAGER
Approved by ____ yy mm dd ORIGINATING MANAGER
Estimated by ____ ORIGINATOR

4293

1999-08-21 05:15 PM

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 01-04-8118

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS

ASSOCIATED PROJECTS

Budget reference number	Description
01-01-8119	GREAT FALLS G.S. - FIRE PREVENTION/PROTECTION SYSTEM
01-02-8117	SEVEN SISTERS G.S. - FIRE PREVENTION/PROTECTION SYSTEM
01-03-8120	PINE FALLS G.S. - FIRE PREVENTION/PROTECTION SYSTEM
01-07-4938	KELSEY G.S. - FIRE ALARM SYSTEM (KEGSFP)
01-20-7009	KETTLE G.S. - FIRE ALARM SYSTEM
01-21-7010	LONG SPRUCE G.S. - FIRE ALARM SYSTEM
01-23-8108	JENPEG FIRE PREVENTION & PROTECTION
01-25-7011	LIMESTONE G.S. - FIRE ALARM SYSTEM
03-00-4809	DORSEY BP 1 & 2 ADDRESSABLE FIRE ALARM SYSTEM
03-00-5925	RADISSON STATION - ADDRESSABLE FIRE ALARM SYSTEM (RADIME6)
03-00-5926	HENDAY STATION ADDRESSABLE FIRE ALARM SYSTEM (HENDME5)
03-00-7221	DORSEY BP1 THYRISTOR VALVES FIRE PROTECTION UPGRADE
03-00-7222	RADISSON THYRISTOR VALVES FIRE PROTECTION UPGRADE

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul	11					11	11
Aug	11					11	22
Sep	11					11	
Oct	12	1				13	
Nov	9	1				10	56
Dec	42	2				44	100
Jan	42	1	1			44	144
Feb	37	2	1			40	184
Mar	38	1	2			41	225
TOTAL	213	8	4			225	225

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item

90

Title			Budget reference number
GREAT FALLS G.S. - FIRE PREVENTION/PROTECTION SYSTEM			01-01-8119
Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Generation - South	Generation - South	Generation - South	61423

DESCRIPTION:
Installation of Addressable Fire Alarm System at Great Falls Generating Station.

JUSTIFICATION:
The fire alarm systems installed in the four Winnipeg River plants require modifications to eliminate false alarms, to provide visual warnings where auditory alarms cannot be heard, and to update drawings enabling staff to properly trace and repair faults. Consistent false and trouble alarms in a fire protection system results in staff becoming complacent resulting in response delays to fire conditions.

REFERENCE:
Memo W.L. Pawlikewich to M.J. Townsley dated 1998 03 16
Memo M.J. Townsley to W.L. Pawlikewich dated 1999 02 09
Capital Project Justification prepared by A. Simmons dated 99/03/15

REVISION:
New item.

IN SERVICE DATES			Base estimate
2001 03 31 184			199904 L2
			Work start date
			1999 05 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:						
TOTAL						
REV. AMOUNTS:						
Authorized to date:						
Over(under)expend:						
Auth Req.: 2000/01	175	6	3			184
TOTAL	175	6	3			184

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	42951

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number: 01-01-8119

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS

ASSOCIATED PROJECTS

Budget reference number	Description
01-02-8117	SEVEN SISTERS G.S. - FIRE PREVENTION/PROTECTION SYSTEM
01-03-8120	PINE FALLS G.S. - FIRE PREVENTION/PROTECTION SYSTEM
01-04-8118	McARTHUR FALLS G.S. - FIRE PREVENTION/PROTECTION SYSTEM
01-07-4938	KELSEY G.S. - FIRE ALARM SYSTEM (KEGSFP)
01-20-7009	KETTLE G.S. - FIRE ALARM SYSTEM
01-21-7010	LONG SPRUCE G.S. - FIRE ALARM SYSTEM
01-23-8108	JENPEG FIRE PREVENTION & PROTECTION
01-25-7011	LIMESTONE G.S. - FIRE ALARM SYSTEM
03-00-4809	DORSEY BP 1 & 2 ADDRESSABLE FIRE ALARM SYSTEM
03-00-5925	RADISSON STATION - ADDRESSABLE FIRE ALARM SYSTEM (RADIME6)
03-00-5926	HENDAY STATION ADDRESSABLE FIRE ALARM SYSTEM (HENDME5)
03-00-7221	DORSEY BP1 THYRISTOR VALVES FIRE PROTECTION UPGRADE
03-00-7222	RADISSON THYRISTOR VALVES FIRE PROTECTION UPGRADE

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May	6					6	6
Jun	6					6	12
Jul	6					6	18
Aug	6					6	
Sep	6					6	
Oct	6					6	
Nov							36
Dec	9	1				10	46
Jan	43	2				45	91
Feb	43	1	1			45	136
Mar	44	2	2			48	184
TOTAL	175	6	3			184	184

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item

91

Title
PINE FALLS G.S. - FIRE PREVENTION/PROTECTION SYSTEM

Budget reference number
01-03-8120

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Generation - South	Generation - South	Generation - South	61424

DESCRIPTION:
Installation of Addressable Fire Alarm System at Pine Falls Generating Station.

JUSTIFICATION:
The fire alarm systems installed in the four Winnipeg River plants require modifications to eliminate false alarms, to provide visual warnings where auditory alarms cannot be heard, and to update drawings enabling staff to properly trace and repair faults. Consistent false and trouble alarms in a fire protection system results in staff becoming complacent resulting in response delays to fire conditions.

REFERENCE:
Memo W.L. Pawlikewich to M.J. Townsley dated 1998 03 16
Memo M.J. Townsley to W.L. Pawlikewich dated 1999 02 09
Capital Project Justification prepared by A. Simmons dated 99/03/15

REVISION:
New item.

IN SERVICE DATES		Base estimate
2000 08 31	150	199904 L2
		Work start date
		1999 08 01

	PREV. AUTHORITY Authorized to date	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
TOTAL							
REV. AMOUNTS:							
Authorized to date:							
Over(under)expend:							
Auth 1999/00		51	1	1			53
Req.: 2000/01		91	3	3			97
TOTAL		142	4	4			150

Prepared by yy mm dd COORDINATOR
Approved by yy mm dd
Approved by yy mm dd
Estimated by ORIGINATOR
COORDINATING MANAGER
ORIGINATING MANAGER

1999-08-21 05:15 PM

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 01-03-8120

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS

ASSOCIATED PROJECTS

Budget reference number	Description
01-01-8119	GREAT FALLS G.S. - FIRE PREVENTION/PROTECTION SYSTEM
01-02-8117	SEVEN SISTERS G.S. - FIRE PREVENTION/PROTECTION SYSTEM
01-04-8118	McARTHUR FALLS G.S. - FIRE PREVENTION/PROTECTION SYSTEM
01-07-4938	KELSEY G.S. - FIRE ALARM SYSTEM (KEGSFP)
01-20-7009	KETTLE G.S. - FIRE ALARM SYSTEM
01-21-7010	LONG SPRUCE G.S. - FIRE ALARM SYSTEM
01-23-8108	JENPEG FIRE PREVENTION & PROTECTION
01-25-7011	LIMESTONE G.S. - FIRE ALARM SYSTEM
03-00-4809	DORSEY BP 1 & 2 ADDRESSABLE FIRE ALARM SYSTEM
03-00-5925	RADISSON STATION - ADDRESSABLE FIRE ALARM SYSTEM (RADIME6)
03-00-5926	HENDAY STATION ADDRESSABLE FIRE ALARM SYSTEM (HENDME5)
03-00-7221	DORSEY BP1 THYRISTOR VALVES FIRE PROTECTION UPGRADE
03-00-7222	RADISSON THYRISTOR VALVES FIRE PROTECTION UPGRADE

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug	10					10	10
Sep	10					10	20
Oct	10					10	30
Nov							30
Dec							30
Jan							30
Feb	3					3	33
Mar	18	1	1			20	53
TOTAL	51	1	1			53	53
2000/01 Apr	21					21	21
May	21		1			22	43
Jun	23		1			24	67
Jul	23	1	1			25	92
Aug	3	2				5	97
Sep							
Oct							97
Nov							97
Dec							97
Jan							97
Feb							97
Mar							97
TOTAL	91	3	3			97	97

1999-08-31 05:15 PM

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item

92

Title			Budget reference number
DORSEY BP 1 & 2 ADDRESSABLE FIRE ALARM SYSTEM			03-00-4809
Originating division	Coordinating division	Constructing division	Project Order Group (Range):
HVDC	HVDC	Construction	60104

DESCRIPTION:
REPLACE THE EXISTING ZONE TYPE FIRE ALARM SYSTEM WITH AN ADDRESSABLE TYPE. THE MAIN FIRE PANELS IN THE CONTROL ROOM AND ALL THE DETECTOR HEADS THROUGHOUT THE STATION WILL BE REPLACED EXCEPT WHERE A REMOTE FIRE PANEL EXISTS. THESE ARE THE VALVE HALLS, HALON SYSTEMS, CONVERTER TRANSFORMERS, AND SMOOTHING REACTORS.

JUSTIFICATION:
THE EXISTING ZONE TYPE FIRE ALARM SYSTEMS ARE 17 TO 22 YEARS OLD. THEY ARE REACHING THE END OF THEIR USEABLE LIFE, BECOMING UNRELIABLE AND DIFFICULT TO MAINTAIN DUE TO UNAVAILABILITY OF PARTS. THE NEW ADDRESSABLE TYPE FIRE ALARM SYSTEM IS VIRTUALLY MAINTENANCE FREE AND VERY RELIABLE. THUS IT WILL PROVIDE SUBSTANTIAL MAINTENANCE COST SAVINGS, IMPROVED RELIABILITY, AND IMPROVED RESPONSE TIME TO FIRES.

REFERENCE:
REPORT NO. PS94-06 BIPOLES 1 & 2 FIRE ALARM SYSTEM REPLACEMENT.

REVISION:
ESTIMATE DECREASED TO REFLECT ACTUALS.
PROJECT COMPLETE.
CONTINGENCY AMOUNT: $11 200.

This BRN contains Deleted, Blocked, or Closed Orders.

IN SERVICE DATES						Base estimate
1997 10 31	811	1998 02 28	0	1998 06 30	1	199706 L3
1997 11 30	1	1998 03 31	0	1998 08 31	6	
1997 12 31	0	1998 04 30	2	1998 09 30	6	Work start date
1998 01 31	1	1998 05 31	1	1999 04 30	0	1997 04 01

	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
PREV. AUTHORITY Authorized to date:	750		79			829
TOTAL	750		79			829
REV. AMOUNTS: Authorized to date:	750		79			829
Over(under)expend:						
Auth Req.:						
TOTAL	750		79			829

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

1999-10-22 09:50 AM

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number: 03-00-4809

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1994 10	530	NEW ITEM.
1995 10	688	IN-SERVICE DATE DEFERRED FROM 1995 11 30 TO 1996 06 30. ESTIMATE UPGRADED FROM L2 TO L3.
1997 10	940	BASE DATE UPDATED AND RE-ESTIMATED. INCREASE DUE TO HIGHER ACTIVITY AND OVERHEAD RATES. ISD DEFERRED FROM 1997 01 31 TO 1997 12 31.

ASSOCIATED PROJECTS

Budget reference number	Description
01-01-8119	GREAT FALLS G.S. - FIRE PREVENTION/PROTECTION SYSTEM
01-02-8117	SEVEN SISTERS G.S. - FIRE PREVENTION/PROTECTION SYSTEM
01-03-8120	PINE FALLS G.S. - FIRE PREVENTION/PROTECTION SYSTEM
01-04-8118	McARTHUR FALLS G.S. - FIRE PREVENTION/PROTECTION SYSTEM
01-07-4938	KELSEY G.S. - FIRE ALARM SYSTEM (KEGSFP)
01-20-7009	KETTLE G.S. - FIRE ALARM SYSTEM
01-21-7010	LONG SPRUCE G.S. - FIRE ALARM SYSTEM
01-23-8108	JENPEG FIRE PREVENTION & PROTECTION
01-25-7011	LIMESTONE G.S. - FIRE ALARM SYSTEM
03-00-5925	RADISSON STATION - ADDRESSABLE FIRE ALARM SYSTEM (RADIME6)
03-00-5926	HENDAY STATION ADDRESSABLE FIRE ALARM SYSTEM (HENDME5)
03-00-7221	DORSEY BP1 THYRISTOR VALVES FIRE PROTECTION UPGRADE
03-00-7222	RADISSON THYRISTOR VALVES FIRE PROTECTION UPGRADE

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — 93 Domestic Item

Title
RADISSON STATION - ADDRESSABLE FIRE ALARM SYSTEM (RADIME6)

Budget reference number
03-00-5925

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
HVDC	HVDC	Construction	60114

DESCRIPTION:
REPLACE THE EXISTING ZONE TYPE FIRE ALARM SYSTEM WITH AN ADDRESSABLE TYPE. THE MAIN FIRE PANELS IN THE CONTROL ROOM AND ALL THE DETECTOR HEADS THROUGHOUT THE STATION WILL BE REPLACED EXCEPT WHERE A REMOTE FIRE PANEL EXISTS. THESE ARE THE VALVE HALLS, HALON SYSTEMS, CONVERTER TRANSFORMERS AND SMOOTHING REACTORS.

JUSTIFICATION:
THE EXISTING ZONE TYPE FIRE ALARM SYSTEMS ARE 17 TO 22 YEARS OLD. THEY ARE REACHING THE END OF THEIR USEABLE LIFE, BECOMING UNRELIABLE AND DIFFICULT TO MAINTAIN DUE TO UNAVAILABILITY OF PARTS. THE NEW ADDRESSABLE TYPE FIRE ALARM SYSTEM IS VIRTUALLY MAINTENANCE FREE AND VERY RELIABLE. THUS IT WILL PROVIDE SUBSTANTIAL MAINTENANCE COST SAVINGS, IMPROVED RELIABILITY AND IMPROVED RESPONSE TIME TO FIRES.

REFERENCE:
REPORT NO. PS94-06 BIPOLES 1 & 2 FIRE ALARM SYSTEM REPLACEMENT.

REVISION:
UPDATED ESCALATION AND INTEREST.

IN SERVICE DATES

1999 01 31	550
1999 02 28	4
1999 03 31	3
1999 04 30	-0

Base estimate
199706 L3

Work start date
1997 04 01

	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
PREV. AUTHORITY Authorized to date:	503		54			557
1999/00	51					51
TOTAL	554		54			608
REV. AMOUNTS:						
Authorized to date:	503		54			557
Over(under)expend:						
Auth Req.:						
TOTAL	503		54			557

Prepared by: yy mm dd COORDINATOR — Approved by: yy mm dd — Approved by: yy mm dd

Estimated by: ORIGINATOR — COORDINATING MANAGER — ORIGINATING MANAGER

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 03-00-5925

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1994 10	409	NEW ITEM.
1995 10	513	ESTIMATE REVISED BASED ON DORSEY DETAIL ESTIMATES.
1997 10	616	BASE DATE UPDATED . ISD DEFERRED FROM 1997 03 31 T0 1998 06 30.

ASSOCIATED PROJECTS

Budget reference number	Description
01-01-8119	GREAT FALLS G.S. - FIRE PREVENTION/PROTECTION SYSTEM
01-02-8117	SEVEN SISTERS G.S. - FIRE PREVENTION/PROTECTION SYSTEM
01-03-8120	PINE FALLS G.S. - FIRE PREVENTION/PROTECTION SYSTEM
01-04-8118	McARTHUR FALLS G.S. - FIRE PREVENTION/PROTECTION SYSTEM
01-07-4938	KELSEY G.S. - FIRE ALARM SYSTEM (KEGSFP)
01-20-7009	KETTLE G.S. - FIRE ALARM SYSTEM
01-21-7010	LONG SPRUCE G.S. - FIRE ALARM SYSTEM
01-23-8108	JENPEG FIRE PREVENTION & PROTECTION
01-25-7011	LIMESTONE G.S. - FIRE ALARM SYSTEM
03-00-4809	DORSEY BP 1 & 2 ADDRESSABLE FIRE ALARM SYSTEM
03-00-5926	HENDAY STATION ADDRESSABLE FIRE ALARM SYSTEM (HENDME5)
03-00-7221	DORSEY BP1 THYRISTOR VALVES FIRE PROTECTION UPGRADE
03-00-7222	RADISSON THYRISTOR VALVES FIRE PROTECTION UPGRADE

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item _ Domestic Item

94

Title: HENDAY STATION ADDRESSABLE FIRE ALARM SYSTEM (HENDME5)

Budget reference number: 03-00-5926

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
HVDC	HVDC	Construction	60106

DESCRIPTION:
REPLACE THE EXISTING ZONE TYPE FIRE ALARM SYSTEM WITH AN ADDRESSABLE TYPE. THE MAIN FIRE PANELS IN THE CONTROL ROOM AND ALL THE DETECTOR HEADS THROUGHOUT THE STATION WILL BE REPLACED EXCEPT WHERE A REMOTE FIRE PANEL EXISTS. THESE ARE THE VALVE HALLS, HALON SYSTEMS, CONVERTER TRANSFORMERS, AND SMOOTHING REACTORS.

JUSTIFICATION:
THE EXISTING ZONE TYPE FIRE ALARM SYSTEMS ARE 17 TO 22 YEARS OLD. THEY ARE REACHING THE END OF THEIR USEABLE LIFE, BECOMING UNRELIABLE AND DIFFICULT TO MAINTAIN DUE TO UNAVAILABILITY OF PARTS. THE NEW ADDRESSABLE TYPE FIRE ALARM SYSTEM IS VIRTUALLY MAINTENANCE FREE AND VERY RELIABLE. THUS IT WILL PROVIDE SUBSTANTIAL MAINTENANCE COST SAVINGS, IMPROVED RELIABILITY, AND IMPROVED RESPONSE TIME TO FIRES.

REFERENCE:
REPORT NO. PS94-06 BIPOLES 1 & 2 FIRE ALARM SYSTEM REPLACEMENT.

REVISION:
UPDATED ESCALATION AND INTEREST.
CONTINGENCY AMOUNT: $30 000.

IN SERVICE DATES

1999 01 31	449
1999 02 28	18
1999 03 31	28
1999 06 30	90

Base estimate: 199706 L4

Work start date: 1997 04 01

	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
PREV. AUTHORITY Authorized to date:	462		33			495
1999/00	117					117
TOTAL	579		33			612
REV. AMOUNTS:						
Authorized to date:	462		33			495
Over(under)expend:						
Auth Req.: 1999/00	89	1				90
TOTAL	551	1	33			585

Prepared by: yy mm dd COORDINATOR

Approved by: yy mm dd COORDINATING MANAGER

Approved by: yy mm dd ORIGINATING MANAGER

Estimated by: ORIGINATOR

1999-08-21 05:20 PM

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number: 03-00-5926

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1994 10	317	NEW ITEM.
1995 10	394	IN-SERVICE DATE DEFERRED FROM 1996 11 30 TO 1997 03 31. ESTIMATE REVISED BASED ON DORSEY DETAIL ESTIMATES.
1997 10	538	BASE DATE UPDATED AND RE-ESTIMATED BASED ON DORSEY'S ACTUALS. IN-SERVICE DATE DEFERRED FROM 1997 07 31 TO 1998 10 31.

ASSOCIATED PROJECTS

Budget reference number	Description
01-01-8119	GREAT FALLS G.S. - FIRE PREVENTION/PROTECTION SYSTEM
01-02-8117	SEVEN SISTERS G.S. - FIRE PREVENTION/PROTECTION SYSTEM
01-03-8120	PINE FALLS G.S. - FIRE PREVENTION/PROTECTION SYSTEM
01-04-8118	McARTHUR FALLS G.S. - FIRE PREVENTION/PROTECTION SYSTEM
01-07-4938	KELSEY G.S. - FIRE ALARM SYSTEM (KEGSFP)
01-20-7009	KETTLE G.S. - FIRE ALARM SYSTEM
01-21-7010	LONG SPRUCE G.S. - FIRE ALARM SYSTEM
01-23-8108	JENPEG FIRE PREVENTION & PROTECTION
01-25-7011	LIMESTONE G.S. - FIRE ALARM SYSTEM
03-00-4809	DORSEY BP 1 & 2 ADDRESSABLE FIRE ALARM SYSTEM
03-00-5925	RADISSON STATION - ADDRESSABLE FIRE ALARM SYSTEM (RADIME6)
03-00-7221	DORSEY BP1 THYRISTOR VALVES FIRE PROTECTION UPGRADE
03-00-7222	RADISSON THYRISTOR VALVES FIRE PROTECTION UPGRADE

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	22					22	22
May	18		1			19	41
Jun	49					49	90
Jul							90
Aug							90
Sep							90
Oct							90
Nov							90
Dec							90
Jan							90
Feb							90
Mar							90
TOTAL	89		1			90	90
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item 95

Title			Budget reference number
DORSEY BP1 THYRISTOR VALVES FIRE PROTECTION UPGRADE			03-00-7221
Originating division: HVDC	Coordinating division: HVDC	Constructing division: Construction	Project Order Group (Range): 61005

DESCRIPTION:
DESIGN AND RETROFIT FIRE PROTECTION DEVICES TO IMPROVE THE FIRE RESISTANCE ON THYRISTOR VALVE TOWERS IN VALVE GROUPS 11, 12, AND 13.

JUSTIFICATION:
VALVE HALLS FIRE RISK IS A MAJOR CONCERN. THE ORIGINAL DESIGN PROVIDED BY GEC-A SATISFIED THE REQUIREMENTS OF M.H. SPECIFICATIONS. THERE HAS BEEN A HISTORY OF MAJOR VALVE FIRES SUCH AS ITAIPU, RIHAND, AND SYLMAR SUBSEQUENT TO THE ISSUE OF OUR BP1 VALVE REPLACEMENT SPECIFICATION. ON OUR REQUEST, GEC-A SUBMITTED A PROPOSAL TO IMPROVE THE FIRE RESISTANCE OF THYRISTOR VALVE TOWERS IN POLE 1 OF BIPOLE 1. THIS CER COVERS THE COST OF IMPLEMENTING 'LEVEL ONE' PROTECTION OF THE REPORT.

REFERENCE:
REPORT HVDC 96-10 ON BIPOLE 1, THYRISTOR VALVES FIRE PROTECTION UPGRADE AND MEMO FROM I.H. McKAY TO A.M. SNYDER DATED 1998 09 03.

REVISION:
SLIGHT DECREASE IN ESTIMATE DUE TO ACTIVITY RATE CHANGE.

IN SERVICE DATES				Base estimate
2000 09 30	378			199707 L2
2000 10 31	378			Work start date
2000 11 30	378			1999 11 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:	2					2
1999/00	52	4	2			58
2000/01	1 024	68	2			1 094
TOTAL	1 078	72	4			1 154
REV. AMOUNTS:						
Authorized to date:	2					2
Over(under)expend:						
Auth 1999/00	19	1				20
Req.: 2000/01	1 078	33	1			1 112
TOTAL	1 099	34	1			1 134

Prepared by yy mm dd COORDINATOR — Approved by yy mm dd — Approved by yy mm dd

Estimated by ORIGINATOR — COORDINATING MANAGER — ORIGINATING MANAGER

4305

1999-08-21 05:23 PM

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number
03-00-7221

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1997 10	1 135	ISD DEFERRED FROM 1998 TO 1999.

ASSOCIATED PROJECTS

Budget reference number	Description
01-01-8119	GREAT FALLS G.S. - FIRE PREVENTION/PROTECTION SYSTEM
01-02-8117	SEVEN SISTERS G.S. - FIRE PREVENTION/PROTECTION SYSTEM
01-03-8120	PINE FALLS G.S. - FIRE PREVENTION/PROTECTION SYSTEM
01-04-8118	McARTHUR FALLS G.S. - FIRE PREVENTION/PROTECTION SYSTEM
01-07-4938	KELSEY G.S. - FIRE ALARM SYSTEM (KEGSFP)
01-20-7009	KETTLE G.S. - FIRE ALARM SYSTEM
01-21-7010	LONG SPRUCE G.S. - FIRE ALARM SYSTEM
01-23-8108	JENPEG FIRE PREVENTION & PROTECTION
01-25-7011	LIMESTONE G.S. - FIRE ALARM SYSTEM
03-00-4809	DORSEY BP 1 & 2 ADDRESSABLE FIRE ALARM SYSTEM
03-00-5925	RADISSON STATION - ADDRESSABLE FIRE ALARM SYSTEM (RADIME6)
03-00-5926	HENDAY STATION ADDRESSABLE FIRE ALARM SYSTEM (HENDME5)
03-00-7222	RADISSON THYRISTOR VALVES FIRE PROTECTION UPGRADE

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov	4					4	4
Dec	4					4	8
Jan	4					4	12
Feb	4					4	16
Mar	3	1				4	20
TOTAL	19	1				20	20
2000/01 Apr	4					4	4
May	4					4	8
Jun	4					4	12
Jul	4					4	16
Aug	13					13	2[illegible]
Sep	334	10				344	3[illegible]
Oct	334	11				345	7[illegible]
Nov	369	11				380	1 098
Dec	12	1	1			14	1 112
Jan							1 112
Feb							1 112
Mar							1 112
TOTAL	1 078	33	1			1 112	1 112

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item ___ Domestic Item

96

Title
RADISSON THYRISTOR VALVES FIRE PROTECTION UPGRADE

Budget reference number
03-00-7222

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
HVDC	HVDC	Construction	61006

DESCRIPTION:
DESIGN AND RETROFIT FIRE PROTECTION DEVICES TO IMPROVE THE FIRE RESISTANCE OF THYRISTOR VALVE TOWERS IN VALVE GROUPS 11, 12 AND 13.

JUSTIFICATION:
VALVE HALLS FIRE RISK IS A MAJOR CONCERN. THE ORIGINAL DESIGN PROVIDED BY GEC-A SATISFIED THE REQUIREMENTS OF M.H. SPECIFICATIONS. THERE HAS BEEN A HISTORY OF MAJOR FIRES SUCH AS ITAIPU, RIHAND, AND SYLMAR SUBSEQUENT TO THE ISSUE OF OUR BP1 VALVE REPLACEMENT SPECIFICATION. ON OUR REQUEST, GEC-A SUBMITTED A PROPOSAL TO IMPROVE THE FIRE RESISTANCE OF THYRISTOR VALVE TOWERS IN POLE 1. THIS CER COVERS THE COST OF IMPLEMENTING 'LEVEL ONE' PROTECTION OF THE REPORT.

REFERENCE:
REPORT HVDC 96-10 ON BIPOLE 1, THYRISTOR VALVES FIRE PROTECTION UPGRADE AND MEMO FROM I.H. McKAY TO A.M. SNYDER DATED 1998 09 03.

REVISION:
DECREASE A RESULT OF CORRECTION TO CONSTRUCTION'S ESTIMATE.

IN SERVICE DATES		Base estimate
2000 09 30	393	199812 L2
2000 10 31	393	
2000 11 30	395	Work start date
		1999 04 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:	2					2
1999/00	71	5	3			79
2000/01	1 210	81	2			1 293
TOTAL	1 283	86	5			1 374
REV. AMOUNTS.						
Authorized to date:	2					2
Over(under)expend:						
Auth 1999/00	28		1			29
Req 2000/01	1 114	34	2			1 150
TOTAL	1 144	34	3			1 181

Prepared by: yy mm dd COORDINATOR
Approved by: yy mm dd COORDINATING MANAGER
Approved by: yy mm dd ORIGINATING MANAGER
Estimated by: ORIGINATOR

1999-08-31 05:23 PM

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 03-00-7222

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1997 10	1 357	ISD DEFERRED FROM 1998 TO 1999.

ASSOCIATED PROJECTS

Budget reference number	Description
01-01-8119	GREAT FALLS G.S. - FIRE PREVENTION/PROTECTION SYSTEM
01-02-8117	SEVEN SISTERS G.S. - FIRE PREVENTION/PROTECTION SYSTEM
01-03-8120	PINE FALLS G.S. - FIRE PREVENTION/PROTECTION SYSTEM
01-04-8118	McARTHUR FALLS G.S. - FIRE PREVENTION/PROTECTION SYSTEM
01-07-4938	KELSEY G.S. - FIRE ALARM SYSTEM (KEGSFP)
01-20-7009	KETTLE G.S. - FIRE ALARM SYSTEM
01-21-7010	LONG SPRUCE G.S. - FIRE ALARM SYSTEM
01-23-8108	JENPEG FIRE PREVENTION & PROTECTION
01-25-7011	LIMESTONE G.S. - FIRE ALARM SYSTEM
03-00-4809	DORSEY BP 1 & 2 ADDRESSABLE FIRE ALARM SYSTEM
03-00-5925	RADISSON STATION - ADDRESSABLE FIRE ALARM SYSTEM (RADIME6)
03-00-5926	HENDAY STATION ADDRESSABLE FIRE ALARM SYSTEM (HENDME5)
03-00-7221	DORSEY BP1 THYRISTOR VALVES FIRE PROTECTION UPGRADE

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov	5					5	5
Dec	5					5	10
Jan	7					7	17
Feb	7					7	24
Mar	4		1			5	29
TOTAL	28		1			29	29
2000/01 Apr	5					5	5
May	5					5	10
Jun	5					5	15
Jul	5					5	20
Aug	24	1				25	
Sep	334	9	1			344	
Oct	334	10				344	7
Nov	380	10				390	1 123
Dec	22	4	1			27	1 150
Jan							1 150
Feb							1 150
Mar							1 150
TOTAL	1 114	34	2			1 150	1 150

1999-08-31 05:27 PM

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

COMPLEX STATUS: ☐ Planned ☒ In progress

Complex no. 13

REVISION STATUS: ☐ New complex ☒ In service change ☒ Concept change ☐ Estimate change only

COMPLEX: BUILDINGS - POWER SUPPLY

Proposal

1. Construct a 23500sq.ft. service building for admin, maintenance, and stores for Wpg R. gen. stations. (1998/99-1999/00)
2. Construct 32 permanent housing units, and a 6 point infrastructure renewal (5 yr plans) at Gillam. (1995/96-2000-01)
3. Build 18 new single family homes in Gillam to replace temporary modular units that cannot be rehabilitated. (1993/94-1994/95)
4. Construct a staffhouse at Grand Rapids containing 12 single and 4 suites, kitchen, dining, rec. and lounge. (1996/97-1997/98)

JUSTIFICATION

☐ Load ☒ Service
☐ Safety ☐ Efficiency
☐ Reliability ☒ Other

Explanation

To consolidate staff currently leasing space or conducting activities from substandard facilities, the corporation has a sequenced program of major building additions staged at one per year. In addition, the corporation is continuing to provide accommodations at remote or northern locations where acceptable alternatives or conditions are unavailable. Gillam housing requirements are: Production North (26), Construction (4), and Northern Region (2). Gillam infrastructure evaluation lists substandard: water quality, sewage treatment, fire hydrants, rec facility, and trailer park insulation.

Estimate Level	COMPLEX START (yyyy mm)
L2	1990 08

IN SERVICE DATES AND AMOUNTS

1997 03	$6970	1997 11	$5404	1998 01	$4416	1998 02	$278
1998 04	$208	1998 07	$377	1999 02	$294	1999 04	$4817
1999 10	$1945	2000 01	$3399	2000 10	$2341	2001 on	$8359

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	18,318		818	1	19,135	19,078	57	0
Year 99/00	5,418	132	190		5,740	5,955	-215	-4
00/01	2,194	99	52		2,345	3,907	-1,562	-40
01/02	2,564	176	79		2,819	3,868	-1,049	-27
02/03	3,141	290	124		3,555	2,182	1,373	63
03/04	1,554	185	21		1,760		1,760	
04/05								
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	33,189	882	1,284	1	35,354	34,990	364	1

REVISION: Reflects add'n of mezzanine & furniture for Wpg R stores, increased cost of concrete at Gillam, deferral of Grd Rpds & Gillam infrastructure upgrade work,& est's adj to actuals.

Reviewed by ORIGINATOR	yyyy mm dd	Reviewed by COORDINATOR	yyyy mm dd
Reviewed by CONSTRUCTOR	yyyy mm dd	Approved by VICE-PRESIDENT	yyyy mm dd 4309 97 11 12

H2856/r Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Complex no. 13

Advance or deferral impact

Continuation of leased premises

Factors affecting timing or viability

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE	
					Amount	%
Winnipeg River Operating Ctr	2,597	3,995	4,075	4,364	289	7
Gillam Infrastructure Upgrade	11,062	14,638	14,931	14,593	-338	-2
Grand Rapids Infrastructure Upgrades		2,067	2,108	2,105	-3	-0
Gillam Permanent Housing	10,864	7,491	7,641	7,706	65	1
Grand Rapids GS - Staff House Replacement	4,254	4,378	4,466	4,422	-44	-1
TOTAL	28,777	32,569	33,221	33,190	-31	-0

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
9510	59,891	Complex increased to include Gillam Permanent Housing, and Gillam Infrastructure Upgrade.
9610	33,372	Radisson Storage & Equip Bldg added, Northern & Central Region Offices cancelled, & Trades Training Ctr & 820 Taylor Ave Refurbish moved to Complex 231.
9710	31,024	Reflects removal of completed 18 temporary housing units item, scope increased to include paving, recirculation loop,and staffhouse conversion to appartments.
9810	34,990	Reflects 97/98 underexpenditure 1.1M, add'n of Grd Rpds Hybord sewer + water rehab, cancell'n of Radisson equip bldg , inc scope to Wpg R Op Ctr + Gillam,+ deferrals to Gillam.
1999 10	35,354	Reflects add'n of mezzanine & furniture for Wpg R stores, increased cost of concrete at Gillam, deferral of Grd Rpds & Gillam infrastructure upgrade work, & est's adj to actuals.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item ___ Domestic Item 97

Title			Budget reference number
WINNIPEG RIVER OPERATING CENTRE			01-01-5943
Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Generation - South	Generation - South	Generation - South	60086

DESCRIPTION:
CONSTRUCTION OF A 23,500 SQ. FT. SERVICE BUILDING TO ACCOMODATE ADMINISTRATION, MAINTENANCE, AND STORES FUNCTIONS FOR THE WINNIPEG RIVER GENERATING STATIONS.

JUSTIFICATION:
THE PRESENT GREAT FALLS ADMINISTRATION, MAINTENANCE, AND STORES FACILITY COMPRISES A TOTAL OF 19 BUILDINGS. MANY ARE OF THE SAME VINTAGE AS THE GENERATING STATION. MOST OF THE BUILDINGS WERE NOT DESIGNED FOR THE PURPOSES THAT THEY ARE BEING USED FOR TODAY. DUE TO THEIR AGE THE BUILDINGS ARE NOT ENERGY EFFICIENT, AND LACK PROPER HEATING, LIGHTING, AND VENTILATION. MOST DO NOT MEET TODAY'S FIRE REGULATIONS. DUE TO THE PRESENT BUILDINGS BEING SCATTERED OVER A WIDE AREA FACILITIES SUCH AS LUNCH ROOMS AND WASHROOMS ARE DUPLICATED IN MANY AREAS. THE TOTAL AREA OF THE PRESENT FACILITIES IS 29,500 SQ. FT.

REFERENCE:
REPORT PD 92-02 DATED 1992 02 07. MEMO FROM D.W.ANDREY TO R.CAMPBELL DATED 1992 01 31. MEMO FROM M.J.MINOR TO L.P.JONASSEN DATED 1992 03 23. MEMO FROM D.W.ANDREY TO R.E.HLADY DATED 1993 06 15.

REVISION:
INCREASE REFLECTS ADDITION OF MEZZANINE IN STORES AREA, ADDITIONAL COST FOR FURNITURE AND ADDITIONAL COST FOR ARCHITECHUAL SERVICES.

IN SERVICE DATES

1999 03 31	-45					Base estimate 199610 L3
1999 04 30	4 686					Work start date 1997 04 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date	3 906		247			4 153
1999/00	94	10	26			130
TOTAL	4 000	10	273			4 283
REV AMOUNTS.						
Authorized to date: Over(under)expend	3 906		247			4 153
Auth Req.: 1999/00	458	1	29			488
TOTAL	4 364	1	276			4 641

Prepared by yy mm dd COORDINATOR Approved by yy mm dd Approved by yy mm dd

Estimated by ORIGINATOR COORDINATING MANAGER ORIGINATING MANAGER

4311

1999-08-21 05:14 PM

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 01-01-5943

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1994 10	3 155	PROJECT TRANSFERRED FROM DOMESTIC BUDGET BRN:9201-01-0014 AND ISD DEFERRED 3 YEARS.
1995 10	3 046	REDUCED ESCALATION AND MINOR ADJUSTMENTS TO LABOUR OVERHEADS.

ASSOCIATED PROJECTS

Budget reference number	Description
01-08-8091	Grand Rapids Infra Structure Upgrades
01-20-6970	GILLAM INFRASTRUCTURE UPGRADE
03-00-7216	RADISSON C.S. - HI-BAY/TEST/EQUIPMENT BUILDING
08-00-6581	GILLAM PERMANENT HOUSING
08-00-8029	GRAND RAPIDS G.S. - STAFFHOUSE REPLACEMENT

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	118	1	29			148	148
May	177					177	325
Jun	163					163	488
Jul							488
Aug							488
Sep							488
Oct							488
Nov							488
Dec							488
Jan							488
Feb							488
Mar							488
TOTAL	458	1	29			488	488
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item 98

Title: GILLAM INFRASTRUCTURE UPGRADE

Budget reference number: 01-20-6970

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Generation - North	Generation - North	Generation - North	61627:61689

DESCRIPTION:
A FIVE YEAR PLAN FOR INFRASTRUCTURE RENEWAL AT THE GILLAM TOWNSITE IS IDENTIFIED AND DIVIDED INTO SIX COMPONENTS:
(1) WATER TREATMENT PLANT
(2) SEWAGE TREATMENT PLANT
(3) WATER & SEWER LINE REHABILITATION
(4) ASPHALT REPAIRS
(5) RECREATION CENTRE REFURBISHMENT
(6) TRAILER PARK IMPROVEMENTS

JUSTIFICATION:
A SITE EVALUATION BY REID CROWTHER & PARTNERS STATES THAT THE QUALITY OF DRINKING WATER DOES NOT MEET CURRENT CANADIAN DRINKING WATER GUIDELINES. THE SEWAGE TREATMENT PLANT DESIGNED TO TREAT 250,000 IPGD IS UNABLE TO TREAT THE 400,000 IPGD DAILY INFLOWS. THE LGD OF GILLAM DOESN'T HAVE SUFFICIENT HYDRANTS OR WATERLINE VALVE SPACING TO MEET MINIMUM FIRE PROTECTION COVERAGE. REPAIRS WOULD REQUIRE EXCAVATIONS THROUGH EXISTING ASPHALT ROADWAYS. THE RECREATIONAL FACILITY HAS REACHED AN AGE OF PHYSICAL AND PROGRAMMATIC WEARINESS. THE FAULTS ARE NOT SERIOUS AND THERE IS STRONG POTENTIAL TO REGENERATE THE CENTRE. THE TRAILER PARK ORIGINALLY ESTABLISHED AS TEMPORARY HOUSING DOES NOT HAVE FROST PROTECTION FOR THE WATER AND SEWER RESULTING IN FREEZING AND RUPTURES OF SERVICE LINES.

REFERENCE:
REID CROWTHER & PARTNERS LTD. REPORTS MARCH 1993, APRIL 1994, APRIL 1995, AND MAY 1995. MEMO G.A. MAHER TO H.J. CLOUSTON 1995 07 07. MEMO G.A. MAHER TO H.J. CLOUSTON DATED 1996 05 28; MEMO H.J. CLOUSTON TO A.M. SNYDER 1997 03 03.

REVISION:
CHANGE IN SEWAGE TREATMENT PLANT CASH FLOW, WORK TO BE DONE IN 1999/00 RATHER THAN 1998/99 AND 1999/00. PHASES 2 AND 3 OF WATER AND SEWER LINE REHABILITATION DEFERRED ONE YEAR. RECREATION CENTRE CASH FLOWED OVER TWO YEARS INSTEAD OF THREE. TRAILER PARK IMPROVEMENTS PHASE 2 DEFERRED ONE YEAR TO 2001/02. DECREASED ESTIMATE DUE TO LOWER THAN FORECAST COSTS FOR THE WATER TREATMENT.

IN SERVICE DATES

						Base estimate
Prior Total	6 529	1999 03 31	88	2000 09 30	194	199706 L3
1998 04 30	110	1999 04 30	51	2000 10 31	2 147	
1998 05 31	69	1999 10 31	1 808	2001 09 30	198	Work start date
1999 02 28	-31	2000 01 31	3 399	2001 11 30	688	1997 04 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:	6 949		168			7 117
1999/00	4 655	122	184			4 961
2000/01	2 080	101	37			2 218
2001/02	979	66	20			1 065
TOTAL	14 663	289	409			15 361
REV. AMOUNTS:						
Authorized to date:	6 949		168			7 117
Over(under)expend:						
Auth 1999/00	4 830	132	158			5 120
Req.: 2000/01	1 995	88	43			2 126
2001/02	819	55	13			887
TOTAL	14 593	275	382			15 250

Prepared by: yy mm dd COORDINATOR — Approved by: yy mm dd — Approved by: yy mm dd

Estimated by: ORIGINATOR — COORDINATING MANAGER — ORIGINATING MANAGER

1999-08-21 05:16 PM

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number: 01-20-6970

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1996 10	11 710	REVISED ESCALATION AND INTEREST RATES AND RE-CASHFLOWED.
1997 10	12 388	BASE DATE UPDATED AND RECASHFLOWED.
1998 10	15 362	SCOPE AND ESTIMATE INCREASED TO REFLECT REPLACEMENT OF SEWAGE TREATMENT PLANT. RECREATION CENTRE DEFERRED ONE YEAR TO 1999 AND ASPHALT REPAIRS DEFERRED TO 2000. BASE DATE UPDATED.
1999 03	15 220	CHANGE IN SEWAGE TREATMENT PLANT CASH FLOW, WORK TO BE COMPLETED IN 1999/00 RATHER THAN 1998/99 AND 1999/00. PHASES 2 AND 3 OF WATER AND SEWER LINE REHABILITATION DEFERRED ONE YEAR. RECREATION CENTRE CASH FLOWED OVER TWO YEAR RATHER THAN THREE. TRAILER PARK IMPROVEMENTS PHASE 2 DEFERREDONE YEAR TO 2001/02. DECREASED ESTIMATE DUE TO LOWER THAN FORECAST COSTS FOR THE WATER TREATMENT PLANT.

ASSOCIATED PROJECTS

Budget reference number	Description
01-01-5943	WINNIPEG RIVER OPERATING CENTRE
01-08-8091	Grand Rapids Infra Structure Upgrades
03-00-7216	RADISSON C.S. - HI-BAY/TEST/EQUIPMENT BUILDING
08-00-6581	GILLAM PERMANENT HOUSING
08-00-8029	GRAND RAPIDS G.S. - STAFFHOUSE REPLACEMENT

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	126	2	2			130	130
May	375	9	3			387	517
Jun	750	18	6			774	1 291
Jul	750	19	11			780	2 071
Aug	750	20	17			787	2 858
Sep	750	21	22			793	3 651
Oct	750	22	28			800	4 451
Nov	375	12	20			407	4 858
Dec	75	3	23			101	4 959
Jan	75	3	24			102	5 061
Feb	28	1	1			30	5 091
Mar	26	2	1			29	5 120
TOTAL	4 830	132	158			5 120	5 120
2000/01 Apr	28		2			30	30
May	138	5	2			145	175
Jun	276	11	3			290	465
Jul	349	15	5			369	834
Aug	510	24	7			541	1 375
Sep	473	22	11			506	1
Oct	138	7	13			158	2
Nov	28	1				29	2 058
Dec	28	1				29	2 097
Jan	27	2				29	2 126
Feb							2 126
Mar							2 126
TOTAL	1 995	88	43			2 126	2 126

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item

99

Title			Budget reference number
Grand Rapids Infra Structure Upgrades			01-08-8091
Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Generation - South	Generation - South	Generation - South	61389

DESCRIPTION:
Upgrade the Grand Rapids Infra Structure, and have the powerhouse untreated sewage effluent piped to the townsite lagoon.

JUSTIFICATION:
1) The townsite sewer system is overtaxed during periods of heavy rainfall and high ground water resulting in house basement flooding.
2) The townsite domestic water quality is below standards as a result of a deteriorating softening system, inconsistent concentrations of chlorine and corroding water lines and storage tank. Many residents have stopped drinking the water and now haul in water for drinking and food preparation.
3) The townsite water system reliability is compromised by a single well pump and a limited chlorinated fire water supply.
4)The powerhouse aging septic sewage system should be proactively upgraded to reduce environmental pollution risks and to reduce maintenance costs.

REFERENCE:
UMA's report dated November 1997.
PP&O Report 97/6

REVISION:
Construction deferred to 2000/2001 to allow for full scoping of work to be done.

Contingency Amount: $328 000.

IN SERVICE DATES				Base estimate
2002 12 31	2 411			199805 L3
				Work start date
				1998 05 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:	7					7
1999/00	704	17	36			757
2000/01	620	28	100			748
2001/02	431	28	155			614
2002/03	307	28	106			441
TOTAL	2 069	101	397			2 567
REV. AMOUNTS:						
Authorized to date:	7					7
Over(under)expend:						
Auth 1999/00			1			1
Req.: 2000/01	74	4	3			81
2001/02	877	54	49			980
2002/03	1 147	96	99			1 342
TOTAL	2 105	154	152			2 411

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

1999-09-30 08:46 AM

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 01-08-8091

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS

ASSOCIATED PROJECTS

Budget reference number	Description
01-01-5943	WINNIPEG RIVER OPERATING CENTRE
01-20-6970	GILLAM INFRASTRUCTURE UPGRADE
03-00-7216	RADISSON C.S. - HI-BAY/TEST/EQUIPMENT BUILDING
08-00-6581	GILLAM PERMANENT HOUSING
08-00-8029	GRAND RAPIDS G.S. - STAFFHOUSE REPLACEMENT

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar			1			1	1
TOTAL			1			1	1
2000/01 Apr							
May	7					7	7
Jun	7					7	14
Jul	7					7	21
Aug	7					7	28
Sep	7					7	
Oct	7					7	
Nov	7					7	49
Dec	7					7	56
Jan	7	1				8	64
Feb	7		1			8	72
Mar	4	3	2			9	81
TOTAL	74	4	3			81	81

1999-09-30 08:46 AM

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item 100

Title
GILLAM PERMANENT HOUSING

Budget reference number
08-00-6581

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Generation - North	Generation - North	Generation - North	61626:61692

DESCRIPTION:
THE GILLAM HOUSING ALLOCATION COMMITTEE HAS BEEN REVIEWING THE PERMANENT HOUSING NEEDS FOR GILLAM. THE COMMITTEE ASSESSED THE CURRENT AND FUTURE HOUSING REQUIREMENTS FOR (A) PRODUCTION DIVISION - NORTH (B) CONSTRUCTION DIVISION (C) NORTHERN REGION THEIR STUDY INDICATES THAT AN ADDITIONAL 32 HOUSING UNITS WILL BE REQUIRED TO SATISFY THE PRESENT HOUSING REQUIREMENTS.

AS PER A MEMO DATED 1996 12 11 FROM H.J. CLOUSTON TO A.M. SNYDER, THE EXISTING STAFFHOUSE IS BEING CONVERTED INTO CONDOMINIUM APARTMENT UNITS. THIS CONVERSION WILL REPLACE 8 OF THE 32 HOUSING UNITS.

JUSTIFICATION:
CURRENTLY THERE ARE 32 EMPLOYEES ON CONVENTIONAL HOUSING LISTS. DUE TO VACANCY RATES AND HOURLY STAFFING LEVELS, 26 UNITS WILL BE REQUIRED AND WILL NOT DECREASE IN THE FUTURE. THE CONSTRUCTION DIVISION REQUIRES 4 UNITS AND 2 ADDITIONAL UNITS ARE REQUIRED FOR NORTHERN REGION'S REQUIREMENTS.

REFERENCE:
MEMO DATED 1995 07 13 FROM H.J. CLOUSTON TO R.O. LAMBERT - GILLAM HOUSING REQUIREMENTS; MEMO DATED 1996 12 11 FROM H.J. CLOUSTON TO A.M. SNYDER - GILLAM STAFFHOUSE CONVERSION PROJECT.

REVISION:
FUTURE HOUSING RE-ESTIMATED AND DEFERRED ONE YEAR. INCREASED COSTS ON THE APARTMENT BUILDING GARAGES DUE TO PERFORMING THE WORK IN-HOUSE, PROVIDING ON-THE-JOB TRAINING AND BECAUSE THE LATENESS IN THE START OF THE WORK INCREASED THE COSTS OF THE CONCRETE.

IN SERVICE DATES						Base estimate
Prior Total	2 754	1998 12 31	0	1999 08 31	137	199706 L3
1998 07 31	3	1999 02 28	302	2001 10 31	1 089	
1998 08 31	4	1999 03 31	35	2002 10 31	2 213	Work start date
1998 11 30	10	1999 04 30	0	2003 10 31	1 752	1997 06 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:	3 034		72			3 106
1999/00	73	6	6			85
2000/01	868	55	18			941
2001/02	1 995	169	25			2 189
2002/03	1 555	166	20			1 741
TOTAL	7 525	396	141			8 062
REV. AMOUNTS:						
Authorized to date:	3 034		72			3 106
Over(under)expend:						
Auth 1999/00	131		2			133
Req.: 2000/01	125	7	5			137
2001/02	868	66	17			951
2002/03	1 994	193	26			2 213
2003/04	1 554	184	21			1 759
TOTAL	7 706	450	143			8 299

Prepared by: yy mm dd COORDINATOR
Approved by: yy mm dd Approved by: yy mm dd
Estimated by: ORIGINATOR — COORDINATING MANAGER — ORIGINATING MANAGER

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 08-00-6581

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1995 10	7 649	NEW ITEM.
1996 10	7 670	REVISED CONSTRUCTION SCHEDULE.
1997 10	7 619	BASE DATE UPDATED. STAFFHOUSE CONVERSION TO CONDOMINIUM APARTMENT UNITS WILL REPLACE 8 UNITS SCHEDULED FOR 1997/98.
1998 10	7 969	FUTURE HOUSING RE-ESTIMATED AND DEFERRED ONE YEAR.

ASSOCIATED PROJECTS

Budget reference number	Description
01-01-5943	WINNIPEG RIVER OPERATING CENTRE
01-08-8091	Grand Rapids Infra Structure Upgrades
01-20-6970	GILLAM INFRASTRUCTURE UPGRADE
03-00-7216	RADISSON C.S. - HI-BAY/TEST/EQUIPMENT BUILDING
08-00-8029	GRAND RAPIDS G.S. - STAFFHOUSE REPLACEMENT

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	30					30	30
May	30	1				31	61
Jun	30	1				31	92
Jul	14	-1	1			14	106
Aug	14		1			15	121
Sep	13	-1				12	133
Oct							133
Nov							133
Dec							133
Jan							133
Feb							133
Mar							133
TOTAL	131		2			133	133
2000/01 Apr							
May	9					9	9
Jun							9
Jul							9
Aug	33	2				35	44
Sep	25	2				27	
Oct	25	2				27	
Nov	33	2	1			36	134
Dec			1			1	135
Jan			1			1	136
Feb			1			1	137
Mar		-1	1				137
TOTAL	125	7	5			137	137

1999-08-21 05:30 PM

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item

101

Title
GRAND RAPIDS G.S. - STAFFHOUSE REPLACEMENT

Budget reference number
08-00-8029

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
neration - South	Generation - South	Construction	60153

DESCRIPTION:
CONSTRUCTION OF A NEW STAFFHOUSE FACILITY TO REPLACE THE EXISTING BUILDING WHICH WAS ORIGINALLY DESIGNED AS A HOSPITAL IN 1960 AND DOES NOT PROVIDE THE REQUIRED FACILITIES OF A MODERN STAFFHOUSE. THE NEW STAFFHOUSE WILL CONTAIN 12 SINGLE ROOMS AND 4 SUITES AS WELL AS KITCHEN, DINING ROOM, RECREATION AND LOUNGE FACILITIES. CONSTRUCT 2 VEHICLE GARAGES IN CONJUNCTION WITH THE STAFFHOUSE, EACH GARAGE HAVING SPACE FOR 4 CARS.

JUSTIFICATION:
THE EXISTING STAFFHOUSE WAS BUILT AS A HOSPITAL DURING THE CONSTRUCTION OF THE GRAND RAPIDS GENERATING STATION AND WAS CONVERTED TO A STAFFHOUSE FOR OPERATING STAFF. MOST OF THE EXISTING ROOMS ARE SMALL AND DO NOT CONTAIN ANY BATHROOM OR STORAGE SPACE. THE KITCHEN AND DINING ROOM FACILITIES ARE OUTDATED AND TOO SMALL. THE NEW STAFFHOUSE WILL CONTAIN SUFFICIENT SINGLE ROOMS TO REPLACE A SIX ROOM TEMPORARY DORMITORY THAT IS PRESENTLY IN USE. A NEW STAFFHOUSE IS RECOMMENDED AS REHABILITATION OF THE EXISTING BUILDING WOULD RESULT IN EFFECTIVELY SALVAGING LITTLE MORE THAN THE STRUCTURAL FRAME OF THIS BUILDING AND WOULD NOT PROVIDE FOR THE DESIGN OF A MODERN STAFFHOUSE.

REFERENCE:
REPORT PD 86-15 TITLED GRAND RAPIDS STAFF ACCOMMODATION REPORT PD 88-01 TITLED PRODUCTION DIVISION STAFF ACCOMMODATIONS.

REVISION:
REFLECTS TOTAL COST ON JOB COMPLETION.

IN SERVICE DATES						Base estimate
Prior Total	4 465	1998 09 30	2	1999 01 31	0	199610 L3
1998 06 30	36	1998 10 31	-2	1999 02 28	1	
1998 07 31	240	1998 11 30	0	1999 03 31	2	Work start date
1998 08 31	3	1998 12 31	4	1999 04 30	1	1997 04 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:	4 422		330			4 752
1999/00	-37					-37
TOTAL	4 385		330			4 715
REV. AMOUNTS:						
Authorized to date:	4 422		330			4 752
Over(under)expend:						
Auth Req.:						
TOTAL	4 422		330			4 752

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR		COORDINATING MANAGER		ORIGINATING MANAGER

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 08-00-8029

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1988 12	2 630	NEW ITEM.
1989 11	2 583	MINOR ESTIMATE CHANGE.
1990 10	2 571	BASE DATE AND ESTIMATE REVISED FROM 1989 TO 1990.
1991 10	2 726	PROJECT SCOPE REVISED TO PROVIDE A NEW STAFFHOUSE.
1992 10	5 030	PROJECT COST BASED ON A 17 000 SQUARE FT. STAFFHOUSE. ISD DEFERRED BY 2 YEARS.
1993 10	5 120	BASE ESTIMATE CHANGED TO 1993 $, SLIGHT INCREASE IN SCOPE OF WORK, ISD DEFERRED BY 1 YEAR.
1994 10	5 057	REDUCED ESCALATION AND ISD DEFERRED ONE YEAR.
1995 10	5 373	REFLECTS INCREASED ARCHITECTURAL FEES TO REVISE THE BUILDINGLAYOUT TO 20 SINGLE ROOMS.

ASSOCIATED PROJECTS

Budget reference number	Description
01-01-5943	WINNIPEG RIVER OPERATING CENTRE
01-08-8091	Grand Rapids Infra Structure Upgrades
01-20-6970	GILLAM INFRASTRUCTURE UPGRADE
03-00-7216	RADISSON C.S. - HI-BAY/TEST/EQUIPMENT BUILDING
08-00-6581	GILLAM PERMANENT HOUSING

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

COMPLEX STATUS: ☐ Planned ☒ In progress

Complex no. 990

REVISION STATUS: ☐ New complex ☒ In service change ☒ Concept change ☐ Estimate change only

COMPLEX: PRELIMINARY PLANNING STUDIES

Proposal

Carry out assessments, conceptual designs and planning studies of potential supply options, and associated transmission. Areas of study include establishment of design parameters, structure layouts, support facilities, hydraulic model testing, exploration, data collection, environmental assessments and public input, schedules and cost estimates.

JUSTIFICATION

☐ Load ☐ Service
☐ Safety ☐ Efficiency
☐ Reliability ☒ Other

Explanation

In order to plan the development of the Province's resource potential and related projects, office studies, environmental assessments and field exploration have to be carried out. The results and technical designs are required to support the planning process.

Estimate Level	COMPLEX START (yyyy mm)
L2	1993 04

IN SERVICE DATES AND AMOUNTS

1999 03	$5410	2000 03	$16131	2001 03	$16494	2002 03	$3111
2003 03	$2651	2003 04	($1774)	2004 03	$2681	2005 03	$2764
2006 03	$2818	2007 03	$9690	2008 03	$9051	2009 on	$71966

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	5,410				5,410	8,097	-2,687	-33
Year 99/00	16,005	125			16,130	16,112	18	0
00/01	16,123	371			16,494	1,955	14,539	744
01/02	2,982	129			3,111	2,289	822	36
02/03	2,493	158			2,651	2,239	412	18
03/04	697	209			906	2,258	-1,352	-60
04/05	2,501	263			2,764	2,290	474	21
05/06	2,501	317			2,818	3,016	-198	-7
06/07	8,364	1326			9,690	5,963	3,727	63
07/08	7,658	1394			9,052	6,062	2,990	49
08/09	15,703	3233			18,936	8,241	10,695	130
09/10	-16,056	1653			-14,403	-14,863	460	-3
10/11	2,228	540			2,768	2,316	452	20
11/12	-15,505	543			-14,962	2,400	-17,362	-723
12/13	2,028	594			2,622	2,557	65	3
13/14	1,978	629			2,607	2,759	-152	-6
14/15	2,078	716			2,794	2,938	-144	-5
15/16	2,078	771			2,849	398	2,451	616
16/17	2,078	827			2,905	2,402	503	21
17/18	2,078	885			2,963	2,665	298	11
18/19	2,078	943			3,021		3,021	
Beyond	34,642	25224			59,866	50,100	9,766	19
TOTAL	100,142	40,850			140,992	112,194	28,798	26

REVISION: REFLECTS REQUIREMENT OF THE 1999 POWER RESOURCE PLAN.

Reviewed by ORIGINATOR	yyyy mm dd 99 11 02	Reviewed by COORDINATOR	yyyy mm dd
Reviewed by CONSTRUCTOR	yyyy mm dd	Approved by VICE-PRESIDENT	yyyy mm dd 99 11 12

PRELIMINARY PLANNING STUDIES

(in thousands of dollars)

	PREV.	99/00	00/01	01/02	02/03	03/04	04/05	05/06	06/07	07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	TOTAL
BURNTWOOD RIVER:																						
Wuskwatim G.S.	14,547	6,945	7,406	236	241	246	251	256	1,656	799	4,467	6,654	309									44,013
Manasan G.S.	6,531	835	674	301	307	313	319	325	331	338	344	351	358	365	372	379	386	394	402	409	417	14,451
First Rapids G.S.	5,493	113	90	164	167	170	173	176	179	182	185	188	191	195	198	201	205	209	212	216	220	9,127
NELSON RIVER:																						
Kettle Runner	187																					187
Birthday Rapids	12,326																					12,326
Gull Rapids	10,362	3,949	3,254	259	264	269	275	280	286	292	297	303	309	316	322	328	335	342	349	355	363	23,109
Gillam Island																						
Conawapa/BP3	22,759	260	329	105	107	109	111	113	5,817	5,933	12,104											47,747
OTHER:																						
East Channel/Sea River Fall	618																					618
Future Developments	1,881	147	80	154	157	160	163	167	170	173	177	180	184	188	191	195	199	203	207	211	216	5,403
Wpg-Bdn T/L	482																					482
Moose Lake	645																					645
Ear Falls/Lac Seul Dam																						
Sprague	9																					9
Mandan T/L	6,135																					6,135
Brandon #5 Licence Renewal	365	461	464	541	256																	2,087
Combustion Turbine #1	481					261	266	271	277	282	288	294	299	305	311	318	324	331	337	344	351	5,340
Notigi	3,205	2,593	2,854	258	262	266	271	275														9,984
SSM Proposal Evaluation	1,523	791	1,303	1,034	856	874	891	909	927	1,004	1,024	1,045	1,066	1,151	1,174	1,131	1,289	1,314	1,341	1,368	1,395	23,410
HVDC Trans Damper																						
Hydraulic Plant Relicensing																						
Non-Utility Generation	20	37	40	60	34	35	45	46	47	48	49	50	51	52	53	54	55	56	58	59	60	1,009
Electrode Line Reliability Study	50																					50
Chater Station - Land Purchase	425																					425
LGD Churchill																						
Environmental Costing	90																					90
TOTAL EXPENDITURES	88,134	16,131	16,494	3,112	2,651	2,703	2,765	2,818	9,690	9,051	18,935	9,065	2,767	2,572	2,621	2,606	2,793	2,849	2,906	2,962	3,022	206,647
UNAMORTIZED STUDY COSTS TRANSFERRED TO CAPITAL: (Non-Cash)																						
BURNTWOOD RIVER:																						
Wuskwatim G.S. (01-27-6001)														-17,533								-17,533
NELSON RIVER:																						
Conawapa (01-26-8124)												-23,468										-23,468
OTHER:																						
Brandon #5 Life Extension (01-16-7008)						-1,796																-1,796
TOTAL COSTS TO CAPITAL						-1,796						-23,468		-17,533								-42,797
NET PLANNING STUDIES	88,134	16,131	16,494	3,112	2,651	907	2,765	2,818	9,690	9,051	18,935	-14,403	2,767	-14,961	2,621	2,606	2,793	2,849	2,906	2,962	3,022	163,850

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item

102

Title			Budget reference number
PLANNING STUDIES - DEFERRED CAPITAL			01-50-1001
Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Power Planning & Operations	Power Planning & Operations	Power Planning & Operations	61507:80002

DESCRIPTION:
CARRY OUT ASSESSMENTS, CONCEPTUAL DESIGNS AND PLANNING STUDIES OF POTENTIAL SUPPLY OPTIONS AND ASSOCIATED TRANSMISSION. AREAS OF STUDY INCLUDE ESTABLISHMENT OF DESIGN PARAMETERS, STRUCTURE LAYOUTS, SUPPORT FACILITIES, HYDRAULIC MODEL TESTING, EXPLORATION, DATA COLLECTION, ENVIRONMENTAL ASSESSMENTS AND PUBLIC INPUT, SCHEDULES AND COST ESTIMATES.

JUSTIFICATION:
IN ORDER TO PLAN THE DEVELOPMENT OF THE PROVINCE'S RESOURCE POTENTIAL AND RELATED PROJECTS, OFFICE STUDIES, ENVIRONMENTAL ASSESSMENTS AND FIELD EXPLORATION HAVE TO BE CARRIED OUT. THE RESULTS AND TECHNICAL DESIGNS ARE REQUIRED TO SUPPORT THE PLANNING PROCESS.

REVISION:
REFLECTS REQUIREMENT OF THE 1999 POWER RESOURCE PLAN.

IN SERVICE DATES						Base estimate
1999 03 31	5 410	2003 03 31	2 651	2006 03 31	2 818	199903 L2
2000 03 31	16 131	2003 04 30	-1 774	2007 03 31	9 690	
2001 03 31	16 494	2004 03 31	2 681	2008 03 31	9 051	Work start date
2002 03 31	3 111	2005 03 31	2 764	And On	71 966	1999 04 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:	5 410					5 410
1999/00	16 013	99				16 112
2000/01	1 890	65				1 955
2001/02	2 189	100				2 289
2002/03	2 109	130				2 239
2003/04	2 096	162				2 258
2004/05	2 096	194				2 290
2005/06	2 772	244				3 016
2006/07	5 587	376				5 963
2007/08	5 637	425				6 062
2008/09	7 766	475				8 241
2009/10&on	33 742	19 930				53 672
TOTAL	87 307	22 200				109 507
REV. AMOUNTS:						
Authorized to date:	5 410					5 410
Over(under)expend:						
Auth 1999/00	16 006	125				16 131
Req.: 2000/01	16 123	371				16 494
2001/02	2 982	129				3 111
2002/03	2 493	158				2 651
2003/04	697	209				906
2004/05	2 501	263				2 764
2005/06	2 501	317				2 818
2006/07	8 364	1 326				9 690
2007/08	7 658	1 393				9 051
2008/09	15 703	3 233				18 936
2009/10	-16 056	1 653				-14 403
2010/11&on	35 767	31 667				67 434
TOTAL	100 149	40 844				140 993

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

1999-10-14 11:23 AM

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 01-50-1001

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1989 10	132 927	REFLECTS CONAWAPA 1999, WUSKWATIM 2014, NO O.H. 1000 MW SALE.
1990 05	86 984	REFLECTS O.H. 1000 MW SALE, NSP/USA DIVERSITY AND RESULTING GENERATIO SEQUENCE.
1990 10	272 092	REFLECTS FUNDS REQUIRED FOR ADDITIONAL DATA TO DEVELOP ALTERNATIVE SCENARIOS.
1991 10	156 354	REFLECTS CURRENT POWER RESOURCE PLAN. DEFERRAL OF WUSKWATIMBY 5 YEARS AND GULL BY 4 YEARS.
1992 10	88 896	REFLECTS CURRENT POWER RSOURCE PLAN.
1993 03	103 311	REFLECTS 1000 MW ONTARIO HYDRO SALE CANCELLATION & REVISED GENERATION SEQUENCE.
1993 06	101 977	REFLECTS CARRY OVER FUNDS FROM 92/93 FISCAL YEAR AND REDUCEDFORECAST DUE TO REVISED ESTIMATES.
1993 10	53 830	EXPENDITURES REFLECT THE STUDIES ASSOCIATED WITH THE DEVELOPMENTS PROJECTED WITH THE 1993 LOAD FORECAST.
1994 10	54 229	EXPENDITURES REFLECT THE STUDIES ASSOCIATED WITH THE DEVELOPMENTS PROJECTED WITH THE 1994 LOAD FORECAST.
1995 10	30 765	EXPENDITURES REFLECT THE STUDIES ASSOCIATED WITH THE DEVELOPMENTS PROJECTED WITH THE 1995 LOAD FORECAST.
1996 10	14 580	EXPENDITURES REFLECT THE STUDIES ASSOCIATED WITH THE DEVELOPMENTS PROJECTED WITH THE 1996 LOAD FORECAST.
1997 10	70 788	EXPENDITURES REFLECT THE STUDIES ASSOCIATED WITH THE DEVELOPMENTS PROJECTED WITH THE 1997 LOAD FORECAST.
1999 10	150 264	REFLECTS REQUIREMENT OF THE partially updated 1998 POWER RESOURCE PLAN.

ASSOCIATED PROJECTS

Budget reference number	Description

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	1 111					1 111	1 111
May	1 134	2				1 136	2 247
Jun	1 183	3				1 186	3 433
Jul	1 473	7				1 480	4 913
Aug	1 522	9				1 531	6 444
Sep	1 545	11				1 556	8 000
Oct	1 326	11				1 337	9 337
Nov	1 326	12				1 338	10 675
Dec	1 325	15				1 340	12 015
Jan	1 325	16				1 341	13 356
Feb	1 324	18				1 342	14 698
Mar	1 412	21				1 433	16 131
TOTAL	16 006	125				16 131	16 131
2000/01 Apr	1 180	17				1 197	1 197
May	1 195	19				1 214	2 411
Jun	1 247	21				1 268	3 679
Jul	1 437	28				1 465	5 144
Aug	1 469	31				1 500	6 644
Sep	1 484	33				1 517	8 1
Oct	1 339	32				1 371	9
Nov	1 338	34				1 372	10 9
Dec	1 337	36				1 373	12 277
Jan	1 337	37				1 374	13 651
Feb	1 336	39				1 375	15 026
Mar	1 424	44				1 468	16 494
TOTAL	16 123	371				16 494	16 494

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

COMPLEX STATUS	Complex no.	REVISION STATUS
☐ Planned ☒ In progress	121 - 129	☐ New complex ☐ In service change ☐ Concept change ☒ Estimate change only

COMPLEX	DOMESTIC ITEM - POWER SUPPLY

Proposal

This complex consists of several hundred projects which are not identified as Major Items and whose individual cost is of a relatively small amount. The majority of projects are required to provide safe reliable and efficient power supply and HVDC facilities, and to replace plant facilities whose useful life has been exceeded.

JUSTIFICATION	Explanation
☒ Load ☒ Service ☒ Safety ☒ Efficiency ☒ Reliability ☒ Other	Enhancements or rehabilitation to the power supply facilities will ensure a safe reliable and efficient source of energy.

Estimate Level	COMPLEX START (yyyy mm)
L2	1996 04

IN SERVICE DATES AND AMOUNTS							
1999 03 31	$9824	2000 03 31	$10020	2001 03 31	$10220	2002 03 31	$10465
2003 03 31	$10715	2004 03 31	$10960	2005 03 31	$11208	2006 03 31	$11458
2007 03 31	$11713	2008 03 31	$11969	2009 03 31	$12237	2010 03 31	$12509

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend						9,824	-9,824	-100
Mar 99/00	9,485	56	468		10,009	10,020	-11	-0
00/01	9,565	186	471		10,222	10,220	2	0
01/02	9,722	267	476		10,465	10,465	0	0
02/03	9,795	444	476		10,715	10,715	0	0
03/04	9,624	906	185		10,715	10,960	-245	-2
04/05	9,651	1120	189		10,960	11,208	-248	-2
05/06	9,674	1338	196		11,208	11,458	-250	-2
06/07	9,694	1562	202		11,458	11,713	-255	-2
07/08	9,715	1791	207		11,713	11,969	-256	-2
08/09	9,732	2024	213		11,969	12,237	-268	-2
09/10	9,750	2264	223		12,237	12,509	-272	-2
10/11	9,770	2509	230		12,509	12,794	-285	-2
11/12	9,793	2761	240		12,794	13,079	-285	-2
12/13	9,813	3018	248		13,079	13,374	-295	-2
13/14	9,833	3282	259		13,374	13,667	-293	-2
14/15	9,852	3551	264		13,667	13,969	-302	-2
15/16	9,874	3827	268		13,969	14,281	-312	-2
16/17	9,897	4110	274		14,281	14,603	-322	-2
17/18	9,920	4401	282		14,603	14,934	-331	-2
18/19	9,945	4700	289		14,934		14,934	
Beyond								
TOTAL	195,104	44,117	5,660		244,881	243,999	882	0

REVISION	Reflects current forecast costs for the Power Supply Group.

Reviewed by ORIGINATOR	yyyy mm dd	Reviewed by COORDINATOR	yyyy mm dd
Reviewed by CONSTRUCTOR	yyyy mm dd	Approved by VICE-PRESIDENT	yyyy mm dd 99 11 12

H2856/r Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Complex no. 121 - 129

Advance or deferral impact

Requirements are necessary to meet capacity and energy demands, in accordance with our system design criteria and/or commitments.

Factors affecting timing or viability

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE	
					Amount	%
TOTAL						

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
9510	2,681,204	Reflects reduced load growth.
9610	255,760	This item reflects current forecast costs attributable to the Power Supply Group.
1997 10	252,399	REFLECTS POWER SUPPLY'S REVISED SHARE OF THE DOMESTIC FORECAST BASED ON CURRENT RATES.
1998 10	243,999	Reflects Power Supply's revised share of the Domestic Forecast based on current rates.
1999 10	244,881	Reflects current forecast costs for the Power Supply Group.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

CUSTOMER SERVICE

COMPLEX	BUDGET REFERENCE DESCRIPTION	BRN #	PAGE
	MAJOR ITEMS		
991	DEMAND SIDE MANAGEMENT CAPITAL COSTS	01-98-1088	103
97	AUTOMATIC METER READING IMPLEMENTATION	05-00-3016	104
141-149	**DOMESTIC ITEM - CUSTOMER SERVICE**		

CORPORATE GROUP

	MAJOR ITEMS		
230	FIRE PROTECTION PROJECTS		
	FIRE PREVENTION AND PROTECTION H.O.	08-00-5564	105
	FIRE PREVENTION AND PROTECTION WSC	08-00-5565	106
231	CORPORATE BUILDING PROGRAM		
	INTEGRATED TRADES TRAINING CENTRE PROPERTY AND BUILDING	08-00-5568	107
	REFURBISH 820 TAYLOR AVENUE BUILDING	08-00-7058	108
244	YEAR 2000 CONVERSION	09-00-8822	109
245	NEW CUSTOMER SERVICE SYSTEM	09-00-8821	110
111-119	**DOMESTIC ITEM - CORPORATE GROUP**		

** Volume 2 contains Transmission & Distribution items

CAPITAL EXPE[illegible]RECAST (CEF99-1)
(IN MIL[illegible]DOLLARS)
FOR THE YEA[illegible]1999/00 TO 2018/19

		Total	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	20 year Forecast
CUSTOMER SERVICE																							
991	DEMAND SIDE MANAGEMENT CAPITAL COSTS		8.2	10.1	10.4	9.2	9.3	7.2	7.3	7.2	7.4	7.5	5.3	5.4	5.5	5.6	5.7	5.8	5.7	5.8	5.9	6.0	140.7
97	AUTOMATIC METER READING IMPLEMENTATION	30.5		0.1	2.1	3.2	3.3	3.1	3.4	3.5	3.5	6.2	2.3										30.5
	DOMESTIC ITEMS - CUSTOMER SERVICE		33.7	30.3	31.3	32.5	35.0	36.1	37.1	38.1	39.1	40.2	41.3	42.5	43.7	44.9	46.1	47.4	48.8	50.2	51.6	52.9	823.0
	SUB-TOTAL CUSTOMER SERVICE		**41.9**	**40.5**	**43.8**	**44.9**	**47.6**	**46.3**	**47.8**	**48.8**	**50.1**	**54.0**	**49.0**	**47.9**	**49.2**	**50.5**	**51.8**	**53.2**	**54.4**	**56.0**	**57.5**	**58.9**	**994.2**

CAPITAL EXPENDITURE FORECAST REVISIONS (CEF99-1)
(IN MILLION[illegible]OLLARS)
FOR THE YE[illegible]TO 2018/19

		2000	2001	2002	2003	2004	2005	[illegible]	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	201[illegible]	2019	20 year Forecast
CUSTOMER SERVICE																						
991	DEMAND SIDE MANAGEMENT CAPITAL COSTS	(0.0)	2.1	2.2	1.0	2.0	1.6	1.8	1.7	1.8	2.0	0.8	0.6	0.8	0.8	0.8	0.9	1.0	1.0	1.0	1.1	25.0
97	AUTOMATIC METER READING IMPLEMENTATION		(1.5)	(0.9)	(0.1)	(0.0)	(0.0)	(0.1)	(0.0)	(0.1)	(0.1)	2.3										(0.6)
	DOMESTIC ITEMS - CUSTOMER SERVICE	0.1	(1.4)	(1.5)	(1.5)																	(4.4)
	SUB-TOTAL CUSTOMER SERVICE	0.1	(0.8)	(0.2)	(0.6)	1.9	1.6	1.7	1.6	1.6	1.9	3.1	0.6	0.8	0.8	0.8	0.9	1.0	1.0	1.0	1.1	20.0

MANITOBA HYDRO
IFF99 - DSM BUDGET

	ACTUAL TO 1998/99	1999/00	2000/01	2001/02	2002/03	2003/04	2004/05	IFF99 1999$ to 2004/05	IFF98 1998$ to 2004/05	Variance
RESIDENTIAL										
82019 Residential Comprehensive	1,732	445	666	719	773	835	894	8,064	2,302	3,762
82010 New Homes - Insulation/Air Seal	565	315	220	228	231	232	232	2,021	3,468	(1,447)
82003 Heat Recovery Ventilators	2	25	25	25	25	25	25	152	257	(105)
82011 Appliances	207	25	25	25	25	25	25	357	417	(60)
Water Heater Program	957	77	77	77	77	77	77	1,419	2,371	(952)
Hot Water Tank Rental Program	100	-	-	-	-	-	-	100	100	(0)
82035 Power Saver Cords	-	5	5	5	5	5	5	30	2,034	(2,004)
82020 Outdoor Timers	752	13	13	13	13	13	-	817	929	(112)
Subtotal	4,314	905	1,031	1,090	1,149	1,212	1,258	10,959	11,878	(919)
COMMERCIAL										
82016 Lighting	10,102	1,328	1,693	1,897	170	120	120	15,430	15,353	77
82005 Commercial Construction	2,814	896	1,338	1,068	1,322	1,549	144	9,129	8,880	2,249
Heat Lamps/Demand Cont	818	-	-	-	-	-	-	818	818	-
82004 Livestock Waterer	301	-	-	-	-	-	-	301	339	(38)
82018 Agricultural Heat Pads	154	208	233	234	234	15	6	1,084	824	260
82015 Internal Retrofit	1,043	179	186	186	188	188	188	2,158	2,760	(602)
Subtotal	15,032	2,611	3,450	3,383	1,914	1,872	458	28,720	26,774	1,946
INDUSTRIAL										
82014 Performance Optimization	2,192	803	860	862	808	694	196	6,415	7,961	(1,546)
82017 High Efficiency Motors	2,672	270	257	281	313	325	321	4,439	4,655	(216)
82013 Industrial Retrofit	1,336	473	600	743	982	982	982	6,098	7,014	(916)
82008 Quality Motor Repair	70	-	-	-	-	-	-	70	1,354	(1,284)
Subtotal	6,270	1,546	1,717	1,886	2,103	2,001	1,499	17,022	20,984	(3,962)
CONSERVATION SUBTOTAL	25,616	5,062	8,198	6,359	5,166	5,085	3,215	56,701	59,636	(2,935)
RATES										
82007 Curtailable Rates	5,836	1,423	1,401	1,380	1,367	1,345	1,324	14,076	6,136	7,940
82083 Time of Use Rates	-	253	51	52	52	52	52	512	583	(71)
Subtotal	5,836	1,676	1,452	1,432	1,419	1,397	1,376	14,588	6,719	7,869
Subtotal of Programs	31,452	6,738	7,650	7,791	6,585	6,482	4,591	71,289	66,355	4,934
Support Activity & Contingency										
82002 Program Audits	202	145	145	146	146	146	146	1,076	1,005	71
82021 Commercial Baseline	185	125	125	125	125	125	125	935	308	627
82023 P. S. Communications	8,176	748	699	701	701	701	701	10,427	9,920	507
82022 DSM Tracking System	343	40	40	40	40	40	40	583	630	(47)
Residential Baseline	344	-	-	-	-	-	-	344	344	-
Load Research	1,748	-	-	-	-	-	-	1,748	1,748	-
82024 Integrated Plan/Targets	1,532	138	138	140	140	140	140	2,368	3,076	(708)
82009 Retrofit Demos	1,585	57	57	57	57	57	57	1,927	1,856	71
82025 DSM Administration	1,230	84	84	85	85	85	85	1,738	2,211	(473)
Technology Database	-	-	-	-	-	-	-	-	-	-
Contingency	-	87	933	908	788	778	589	4,063	2,033	2,030
Subtotal	13,344	1,404	2,221	2,202	2,082	2,072	1,883	25,208	23,131	2,077
TRC OPTION UTILITY COST SUBTOTAL	44,796	8,142	9,871	9,993	8,667	8,554	6,474	96,497	89,486	7,011
HPS CONVERSIONS - DEFERRED ASSET										
Street Lighting	2,785	-	-	-	-	-	-	2,785	2,785	-
Sentinel Lighting	1,178	-	-	-	-	-	-	1,178	1,178	-
HPS CONVERSIONS - PLANT IN SERVICE										
Street Lighting	5,564	-	-	-	-	-	-	5,564	5,564	-
Sentinel Lighting	1,332	-	-	-	-	-	-	1,332	1,332	-
TRC OPTION UTILITY COST - GROSS	55,655	8,142	9,871	9,993	8,667	8,554	6,474	107,356	100,345	7,011
CUSTOMER CONTRIBUTIONS	(3,356)	-	-	-	-	-	-	(3,356)	(3,356)	-
TOTAL UTILITY COST - NET	52,299	8,142	9,871	9,993	8,667	8,554	6,474	104,000	96,989	7,011
ESCALATION		55	229	426	550	725	689	2,674	2,514	160
TOTAL		8,197	10,100	10,419	9,217	9,279	7,163			
CUMULATIVE	52,299	60,496	70,596	81,015	90,232	99,511	106,674	106,674	99,503	7,171
				1998/99 Actual/Budget				(4,521)	(6,187)	1,666
				Actuals to 1997/98				(47,778)	(47,778)	-
				CER totals to 2003/04				54,375	45,538	8,837

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

COMPLEX STATUS: ☐ Planned ☒ In progress

Complex no. 991

REVISION STATUS: ☐ New complex ☐ In service change ☒ Concept change ☐ Estimate change only

COMPLEX	DEMAND SIDE MANAGEMENT COSTS - 221

Proposal

To promote conservation of electricity when it can be acheived more economically than supply and to conduct all corporate activities to minimize adverse environmental impacts.

JUSTIFICATION

☐ Load ☐ Service ☐ Safety ☒ Efficiency ☐ Reliability ☐ Other

Explanation

Energy conservation can be economically efficient and environmentally beneficial. Manitoba Hydro is committed to promoting conservation of electricity when it can be acheived more economically than supply. The strategic objective is a reduction in Manitoba Hydro's peak load of 316 MW and firm annual energy requirement of 1249 GW.h by the year 2011/12.

Estimate Level	COMPLEX START (yyyy mm)
L3	1993 04

IN SERVICE DATES AND AMOUNTS							
1999 03	$4521	2000 03	$8197	2001 03	$10100	2002 03	$10419
2003 03	$9217	2004 03	$9279	2005 03	$7163	2006 03	$7308
2007 03	$7243	2008 03	$7443	2009 03	$7548	09/10 on	$206194

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	4,521				4,521	12,137	-7,616	-63
Year 99/00	8,142	55			8,197	8,209	-12	-0
00/01	9,871	229			10,100	8,012	2,088	26
01/02	9,993	426			10,419	8,220	2,199	27
02/03	8,667	550			9,217	8,219	998	12
03/04	8,554	725			9,279	7,303	1,976	27
04/05	6,474	689			7,163	5,573	1,590	29
05/06	6,476	833			7,309	5,484	1,825	33
06/07	6,292	951			7,243	5,565	1,678	30
07/08	6,339	1104			7,443	5,676	1,767	31
08/09	6,302	1246			7,548	5,511	2,037	37
09/10	4,374	969			5,343	4,526	817	18
10/11	4,341	1068			5,409	4,833	576	12
11/12	4,341	1176			5,517	4,674	843	18
12/13	4,302	1275			5,577	4,762	815	17
13/14	4,302	1386			5,688	4,851	837	17
14/15	4,302	1500			5,802	4,942	860	17
15/16	4,130	1552			5,682	4,698	984	21
16/17	4,130	1665			5,795	4,786	1,009	21
17/18	4,130	1781			5,911	4,876	1,035	21
18/19	4,130	1900			6,030		6,030	
Beyond	82,603	66835			149,438	85,186	64,252	75
TOTAL	206,716	87,915			294,631	208,043	86,588	42

REVISION

Based on saving 334 MW/1229 GW.H by the year 2011/12 (approved option 4). Additional funds are required beyond the 2012 period to promote the DSM program.

Reviewed by ORIGINATOR	yyyy mm dd 99 11 12	Reviewed by COORDINATOR	yyyy mm dd
Reviewed by CONSTRUCTOR	yyyy mm dd	Approved by VICE PRESIDENT	yyyy mm dd 99 11 33 18

H2856/r Rev 99 03

Complex no. 991

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Advance or deferral impact

Delays in the DSM implementation schedule could influence future generation sequence timing.

Factors affecting timing or viability

Avoided utility cost of supplying customers; Economic tests used to measure cost effectiveness; technological change; Customer needs and expectations; Government Legislation - Codes.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE	
					Amount	%
TOTAL						

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
9510	240,682	Reflects the all Economic Lost Opportunities Option as recommended in the 1995 Power Resource Plan Report.
9610	174,425	Reflects the all Economic Lost Opportunities Option as recommended in the 1996 Power Resource Plan Report.
9710	298,393	THIS REVISION IS BASED ON THE ALL ECONOMIC LOST OPPORTUNITIES OPTION AS RECOMMENDED IN THE 1997 POWER RESOURCE PLAN.
1998 10	208,039	Based on saving 316 MW/1249 GW.H by the year 2011/12. Additional funds are required beyond the 2012 period to promote the DSM program.
1999 10	294,631	Based on saving 334 MW/1229 GW.H by the year 2011/12 (approved option 4). Additional funds are required beyond the 2012 period to promote the DSM program.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item

103.

Title	Budget reference number
Demand-Side Management Capital Costs	01-98-1088

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
V.P. Customer Service	V.P. Customer Service	V.P. Customer Service	82000:83200

ESCRIPTION:
o encourage energy efficiency in Manitoba Hydro customers.

JUSTIFICATION:
To promote conservation of electricity.

REFERENCE:
Report entitled 'Power Smart Resource Options for the 1999 Corporate Plan'.

REVISION:
Based on saving 182 MW/799 GW.H through programs and an additional 152 MW/430 GW.H through basic customer services and information by the year 2011/12 (approved Option 4). Additional funds are required beyond the 2012 period to promote the DSM program.

IN SERVICE DATES						Base estimate
1999 03 31	4 521	2003 03 31	9 217	2007 03 31	7 243	199804 L3
2000 03 31	8 197	2004 03 31	9 279	2008 03 31	7 443	
2001 03 31	10 100	2005 03 31	7 163	2009 03 31	7 548	Work start date
2002 03 31	10 419	2006 03 31	7 308	And On	206 194	1998 04 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:	4 521					4 521
1999/00	8 074	135				8 209
2000/01	7 729	283				8 012
2001/02	7 829	391				8 220
2002/03	7 675	544				8 219
2003/04	6 685	618				7 303
2004/05	5 002	571				5 573
2005/06	4 825	659				5 484
2006/07	4 800	765				5 565
2007/08	4 801	875				5 676
2008/09	4 570	941				5 511
2009/10&on	82 553	45 580				128 133
TOTAL	149 064	51 362				200 426
REV. AMOUNTS:						
Authorized to date:	4 521					4 521
Over(under)expend:						
Auth 1999/00	8 142	55				8 197
Req.: 2000/01	9 871	229				10 100
2001/02	9 993	426				10 419
2002/03	8 667	550				9 217
2003/04	8 554	725				9 279
2004/05	6 474	689				7 163
2005/06	6 476	832				7 308
2006/07	6 292	951				7 243
2007/08	6 339	1 104				7 443
2008/09	6 302	1 246				7 548
2009/10	4 374	970				5 344
2010/11&on	120 708	80 142				200 850
TOTAL	206 713	87 919				294 632

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

1999-09-28 11:11 AM

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 01-98-1088

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1990 10	359 811	NEW ITEM.
1991 10	655 473	HIGHER COSTS TO INCREASE PEAK LOAD REDUCTION FROM 100 MW TO 264 MW
1992 10	872 214	HIGHER COSTS TO INCREASE PEAK LOAD REDUCTION FROM 264 MW TO 285 MW BASED ON LONG RANGE PLAN.
1993 06	866 833	SELECTIVE REVISION TO REDUCE COSTS AND REVISE CASH FLOWS TO REFLECT CURRENT STATUS OF WORK.
1993 10	512 642	LOWER COSTS DUE TO IMPLEMENTATION OF SCHEDULE DEFERRALS AND ENERGY SAVINGS REDUCED FROM 1049 TO 822 GW.H
1994 06	509 794	CARRYOVER OF 2.848 MILLION IS NOT REQUIRED.
1994 10	338 753	INCORPORATION OF MARKET TRANSFORMATION AND REDUCED ESCALATION.
1995 06	336 057	2.696 MILLION OF THE UNDER EXPENDITURE IS NOT REQUIRED.
1995 10	240 682	INCORPORATING ALL LOST OPPORTUNITIES.
1996 10	170 990	TO REFLECT REVISED ALL ECONOMIC LOST OPPORTUNITIES OPTION.

ASSOCIATED PROJECTS

Budget reference number	Description
01-98-8127	Demand-Side Management Capital Costs

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	679					679	679
May	679	1				680	1 359
Jun	679	2				681	2 040
Jul	679	2				681	2 721
Aug	679	3				682	3 403
Sep	679	4				683	4 086
Oct	678	5				683	4 769
Nov	678	6				684	5 453
Dec	678	7				685	6 138
Jan	678	8				686	6 824
Feb	678	8				686	7 510
Mar	678	9				687	8 197
TOTAL	8 142	55				8 197	8 197
2000/01 Apr	823	13				836	836
May	823	14				837	1 673
Jun	823	15				838	2 511
Jul	823	16				839	3 350
Aug	823	17				840	4 190
Sep	823	18				841	5 0[illegible]
Oct	822	20				842	5 8[illegible]
Nov	822	21				843	6 716
Dec	822	22				844	7 560
Jan	822	23				845	8 405
Feb	822	24				846	9 251
Mar	823	26				849	10 100
TOTAL	9 871	229				10 100	10 100

1999-09-28 11:11 AM

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

COMPLEX STATUS	Complex no.	REVISION STATUS
[X] Planned [ ] In progress	97	[ ] New complex [X] In service change [ ] Concept change [ ] Estimate change only

COMPLEX	AUTOMATIC METER READING IMPLEMENTATION

Proposal

PURCHASE AND INSTALLATION OF AN AUTOMATIC METER READING (AMR) COMMUNICATION NETWORK TO REMOTELY READ AND ELECTRONICALLY DISSEMINATE READINGS AND OTHER RELEVANT CUSTOMER INFORMATION TO THE APPROPRIATE DEPARTMENT OR DIVISION.

JUSTIFICATION		Explanation
[ ] Load	[X] Service	AMR WILL SATISFY THE ON-GOING NEED FOR METER READINGS IN SUPPORT OF BILLINGS AS WELL AS PROVIDING " ON DEMAND" READINGS TO RESPOND TO CUSTOMER INQUIRIES. OTHER BENEFITS INCLUDE; POWER OUTAGE ALARMS, DEFECTIVE METER/ THEFT OF SERVICE, FLEXIBLE TIMING AND CONSOLIDATION OF BILLINGS.
[ ] Safety	[X] Efficiency	
[ ] Reliability	[ ] Other	

Estimate Level	COMPLEX START (yyyy mm)
L1	2001 01

IN SERVICE DATES AND AMOUNTS							
2001 03	$99	2002 03	$2078	2003 03	$3167	2004 03	$3266
2005 03	$3068	2006 03	$3365	2007 03	$3464	2008 03	$3464
2009 03	$6265	2010 03	$2276				

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend								
Year 99/00								
00/01	97	2			99	1,550	-1,451	-94
01/02	1,994	84			2,078	3,011	-933	-31
02/03	2,978	189			3,167	3,244	-77	-2
03/04	3,011	255			3,266	3,309	-43	-1
04/05	2,773	295			3,068	3,092	-24	-1
05/06	2,982	383			3,365	3,442	-77	-2
06/07	3,009	455			3,464	3,511	-47	-1
07/08	2,950	514			3,464	3,581	-117	-3
08/09	5,206	1029			6,235	6,381	-146	-2
09/10	1,863	413			2,276		2,276	
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	26,863	3,619			30,482	31,121	-639	-2

REVISION	Reflects cashflow adjusted for revised schedule.

Reviewed by ORIGINATOR	yyyy mm dd 99 11 17	Reviewed by COORDINATOR	yyyy mm dd
Reviewed by CONSTRUCTOR	yyyy mm dd	Approved by VICE-PRESIDENT	yyyy mm dd 99 11

H2856/r Rev 99 03

Complex no. 97

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Advance or deferral impact

Factors affecting timing or viability

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
AUTOMATIC METER READING (AMR)		26,265	26,790	26,863	73	0
TOTAL		26,265	26,790	26,863	73	0

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
9510	32,047	Base year adjusted to 1995
9610	31,706	Schedule, cash flow, and base year revised.
9710	30,099	Schedule, cash flow, and base year revised.
1998 10	31,121	Deferred two years.
1999 10	30,482	Reflects cashflow adjusted for revised schedule.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

[X] Major Item [ ] Domestic Item

104

Title			Budget reference number
AUTOMATIC METER READING IMPLEMENTATION			05-00-3016
Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Finance & Admin - Customer Serv	Finance & Admin - Customer Serv	Finance & Admin - Customer Serv	82041

DESCRIPTION:
PURCHASE AND INSTALLATION OF AN AUTOMATIC METER READING (AMR) COMMUNICATION NETWORK TO REMOTELY READ AND ELECTRONICALLY DISSEMINATE METER READINGS AND OTHER RELEVANT CUSTOMER INFORMATION TO THE APPROPRIATE DEPARTMENT OR DIVISION.

JUSTIFICATION:
THIS AMR SYSTEM WOULD SATISFY THE ONGOING NEED FOR ROUTINE METER READINGS FOR CUSTOMER BILLING AS WELL AS PROVIDE 'ON DEMAND' READINGS TO ANSWER CUSTOMER INQUIRIES. OTHER BENEFICAL FEATURES OF THE AMR SYSTEM INCLUDE:

- CUSTOMER AND SYSTEM POWER OUTAGE ALARMS
- DEFECTIVE METER AND THEFT OF SERVICE DETECTION
- MORE FLEXIBILITY IN THE TIMING AND CONSOLIDATION OF BILLINGS.

THE COMMUNICATION NETWORK WOULD ALSO SUPPORT A NUMBER OF POTENTIAL USES OF CURRENT INTEREST INCLUDING:

- DEMAND SIDE MANAGEMENT DATA
- LOAD RESEARCH DATA FOR RATE PLANNING
- TIME OF USE BILLING
- DISTRIBUTION AUTOMATION
- TRANSFORMER LOAD MANAGEMENT

REVISION:
CASHFLOW ADJUSTED FOR REVISED SCHEDULE.
BASE YEAR REVISED TO 1996.

IN SERVICE DATES						Base estimate
2001 03 31	99	2005 03 31	3 068	2009 03 31	6 235	199610 L1
2002 03 31	2 078	2006 03 31	3 365	2010 03 31	2 276	Work start date
2003 03 31	3 167	2007 03 31	3 464			1999 01 01
2004 03 31	3 266	2008 03 31	3 464			

PREV. AUTHORITY Authorized to date:	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
2000/01	1 434	116				1 550
2001/02	2 731	280				3 011
2002/03	2 884	360				3 244
2003/04	2 884	425				3 309
2004/05	2 642	450				3 092
2005/06	2 884	558				3 442
2006/07	2 884	627				3 511
2007/08	2 884	697				3 581
2008/09	5 038	1 343				6 381
TOTAL	26 265	4 856				31 121
REV. AMOUNTS: Authorized to date: Over(under)expend:						
Auth Req.: 2000/01	97	2				99
2001/02	1 994	84				2 078
2002/03	2 978	189				3 167
2003/04	3 011	255				3 266
2004/05	2 773	295				3 068
2005/06	2 982	383				3 365
2006/07	3 009	455				3 464
2007/08	2 950	514				3 464
2008/09	5 206	1 029				6 235
2009/10	1 863	413				2 276
TOTAL	26 863	3 619				30 482

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

1999-10-14 11:35 AM

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 05-00-3016

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1994 08	32 047	NEW ITEM.
1995 10	32 047	REVISED BASE YEAR TO 1995.
1996 10	31 706	REVISED BASE YEAR TO 1996.

ASSOCIATED PROJECTS

Budget reference number	Description

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr	8					8	8
May	8					8	16
Jun	8					8	24
Jul	8					8	32
Aug	8					8	4[illegible]
Sep	8					8	[illegible]
Oct	8					8	[illegible]
Nov	8					8	64
Dec	8					8	72
Jan	8					8	80
Feb	8					8	88
Mar	9	2				11	99
TOTAL	97	2				99	99

1999-10-14 11:35 AM

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

COMPLEX STATUS: ☐ Planned ☒ In progress

Complex no. 141 - 149

REVISION STATUS: ☐ New complex ☐ In service change ☒ Concept change ☐ Estimate change only

COMPLEX: DOMESTIC ITEM - CUSTOMER SERVICE

Proposal

This complex consists of minor projects which are not identified as Major Items and whose individual cost is of a relatively small amount. The majority of projects are required to supply service to residential, farm, commercial and industrial customers and to replace plant facilities whose useful life has been exceeded.

JUSTIFICATION: ☒ Load ☒ Service ☒ Safety ☒ Efficiency ☒ Reliability ☒ Other

Explanation

The Corporation has incurred consistant expenditures in the past to meet customer service requirements. The residential, farm, commercial and industrial loads are expected to grow at an 20 year average rate of 1.5% per annum and will require a program of additions and replacements at the customer service point to accommodate these anticipated changes.

Estimate Level	COMPLEX START (yyyy mm)
L2	1996 04

IN SERVICE DATES AND AMOUNTS

1999 03 31	$29702	2000 03 31	$33665	2001 03 31	$31718	2002 03 31	$32840
2003 03 31	$33998	2004 03 31	$35045	2005 03 31	$36069	2006 03 31	$37087
2007 03 31	$38120	2008 03 31	$39145	2009 03 31	$40214	2010 03 31	$41332

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend						29,702	-29,702	-100
Year 99/00	40,054	235	249	6,801	33,737	33,665	72	0
00/01	37,603	742	229	8,300	30,274	31,718	-1,444	-5
01/02	38,285	1123	232	8,300	31,340	32,840	-1,500	-5
02/03	39,200	1740	232	8,674	32,498	33,998	-1,500	-4
03/04	39,558	2859	760	9,179	33,998	35,045	-1,047	-3
04/05	39,983	3561	784	9,283	35,045	36,069	-1,024	-3
05/06	40,338	4284	816	9,369	36,069	37,087	-1,018	-3
06/07	40,658	5028	848	9,447	37,087	38,120	-1,033	-3
07/08	40,975	5797	872	9,524	38,120	39,145	-1,025	-3
08/09	41,246	6584	905	9,590	39,145	40,214	-1,069	-3
09/10	41,526	7398	949	9,659	40,214	41,332	-1,118	-3
10/11	41,836	8244	986	9,734	41,332	42,535	-1,203	-3
11/12	42,194	9127	1,035	9,821	42,535	43,705	-1,170	-3
12/13	42,498	10028	1,074	9,895	43,705	44,936	-1,231	-3
13/14	42,822	10962	1,126	9,974	44,936	46,041	-1,105	-2
14/15	43,111	11917	1,157	10,144	46,041	47,416	-1,375	-3
15/16	43,450	12916	1,177	10,127	47,416	48,759	-1,343	-3
16/17	43,809	13954	1,211	10,215	48,759	50,158	-1,399	-3
17/18	44,176	15028	1,258	10,304	50,158	51,602	-1,444	-3
18/19	44,562	16144	1,294	10,398	51,602		51,602	
Beyond								
TOTAL	827,884	147,671	17,194	188,738	804,011	804,087	-76	-0

REVISION: Reflects current forecast costs for Customer Service and Marketing.

Reviewed by ORIGINATOR	yyyy mm dd 99 11 17	Reviewed by COORDINATOR	yyyy mm dd		
Reviewed by CONSTRUCTOR	yyyy mm dd	Approved by VICE PRESIDENT	yyyy mm dd 99 11 18		

H2856/r Rev 99 03

Complex no.
141 - 149

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Advance or deferral impact

Requirements are necessary to meet capacity and energy demands, in accordance with our system design criteria and/or commitments.

Factors affecting timing or viability

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE	
					Amount	%
TOTAL						

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
9510	2,681,204	Reflects reduced load growth.
9610	461,809	This item reflects current forecast costs attributable to Customer Service and Marketing.
1997 10	519,305	Reflects re-apportionment of DWO between T&D and Customer Service.
1998 10	804,087	Annual forecast adjusted to reflect the revised costing methodology impacts based on experience to date.
1999 10	804,011	Reflects current forecast costs for Customer Service and Marketing.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

CUSTOMER SERVICE

COMPLEX	BUDGET REFERENCE DESCRIPTION	BRN #	PAGE
	MAJOR ITEMS		
991	DEMAND SIDE MANAGEMENT CAPITAL COSTS	01-98-1088	103
97	AUTOMATIC METER READING IMPLEMENTATION	05-00-3016	104
141-149	**DOMESTIC ITEM - CUSTOMER SERVICE**		

CORPORATE GROUP

	MAJOR ITEMS		
230	FIRE PROTECTION PROJECTS		
	FIRE PREVENTION AND PROTECTION H.O.	08-00-5564	105
	FIRE PREVENTION AND PROTECTION WSC	08-00-5565	106
231	CORPORATE BUILDING PROGRAM		
	INTEGRATED TRADES TRAINING CENTRE PROPERTY AND BUILDING	08-00-5568	107
	REFURBISH 820 TAYLOR AVENUE BUILDING	08-00-7058	108
244	YEAR 2000 CONVERSION	09-00-8822	109
245	NEW CUSTOMER SERVICE SYSTEM	09-00-8821	110
111-119	**DOMESTIC ITEM - CORPORATE GROUP**		

** Volume 2 contains Transmission & Distribution items

CAPITAL EXPEN[illegible]RECAST (CEF99-1)
(IN MILLIO[illegible] DOLLARS)
FOR THE YEARS 1999/00 TO 2018/19

		Total	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	20 year Forecast
CORPORATE GROUP																							
230	FIRE PROTECTION PROJECTS	1.0	0.7	0.3																			1.0
231	CORPORATE BUILDING PROGRAM	17.2	0.0				15.1	2.1															17.2
244	YEAR 2000 CONVERSION	8.8	6.8	2.0																			8.8
245	NEW CUSTOMER SERVICE SYSTEM	8.0			0.3	2.6	5.1																7.9
	DOMESTIC ITEMS - CORPORATE GROUP		23.0	23.6	22.2	24.8	25.7	26.2	26.8	27.3	27.9	28.4	29.0	29.6	30.2	30.8	31.5	32.1	32.8	33.4	34.1	35.0	574.4
	SUB-TOTAL CORPORATE GROUP		**30.5**	**25.9**	**22.6**	**27.3**	**45.9**	**28.3**	**26.8**	**27.3**	**27.9**	**28.4**	**29.0**	**29.6**	**30.2**	**30.8**	**31.5**	**32.1**	**32.8**	**33.4**	**34.1**	**35.0**	**609.3**
	TOTAL CAPITAL EXPENDITURES		**301.3**	**270.0**	**272.7**	**274.3**	**315.4**	**312.0**	**311.3**	**252.6**	**252.7**	**252.5**	**279.8**	**297.1**	**392.6**	**424.3**	**597.5**	**956.7**	**1,247.2**	**1,334.4**	**1,045.1**	**784.9**	**10,174.4**

CAPITAL EXPENDITURE FORECAST REVISIONS (CEF99-1)
(IN MILLI[illegible]DOLLARS)
FOR THE Y[illegible]0 TO 2018/19

		2000	2001	2002	2003	2004	2005	[illegible]	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	20[illegible]	2019	20 year Forecast
CORPORATE GROUP																						
230	FIRE PROTECTION PROJECTS	(0.0)	(0.0)																			(0.0)
231	CORPORATE BUILDING PROGRAM	0.0				(0.1)	(0.0)															(0.1)
244	YEAR 2000 CONVERSION	0.0	(0.7)																			(0.7)
245	NEW CUSTOMER SERVICE SYSTEM			(0.0)	(0.0)	(0.0)																(0.1)
	DOMESTIC ITEMS - CORPORATE GROUP	5.1	(0.4)	(0.4)	(0.4)																	3.9
	SUB-TOTAL CORPORATE GROUP	5.1	(1.1)	(0.4)	(0.4)	(0.2)	(0.0)															3.0
	TOTAL CAPITAL EXPENDITURES	**(12.7)**	**(5.0)**	**(5.1)**	**(9.3)**	**6.5**	**(3.5)**	**18.1**	**16.2**	**25.7**	**24.2**	**32.5**	**50.0**	**117.4**	**37.6**	**168.7**	**516.3**	**999.7**	**1,089.5**	**819.9**	**454.3**	**4,341.1**

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

COMPLEX STATUS: ☐ Planned ☒ In progress

Complex no. 230

REVISION STATUS: ☐ New complex ☒ In service change ☐ Concept change ☒ Estimate change only

COMPLEX	FIRE PROTECTION PROJECTS - CORPORATE GROUP

Proposal

Design and install passive and/or active fire prevention and protection systems at all generating stations, key transmission terminating stations and strategic buildings (Head Office/ Operating Centre) as outlined by The Fire Prevention and Protection Committee and defined in the Fire Manual Part II.

Locations covered by this capital item complex are; Head Office and Waverley SC.

JUSTIFICATION

☐ Load ☐ Service
☒ Safety ☐ Efficiency
☐ Reliability ☐ Other

Explanation

In accordance with the rules and guidelines established by The Fire Prevention and Protection Committee, implementation of this program will reduce the risk of fire to an acceptable level and mitigate the effects of any such occurance.

Estimate Level	COMPLEX START yyyy mm
L3	1996 04

IN SERVICE DATES AND AMOUNTS					
1999 10	$751	2000 10	$347		

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	135		10		145	100	45	45
Year 99/00	631	25	17		673	683	-10	-1
00/01	258	15	7		280	293	-13	-4
01/02								
02/03								
03/04								
04/05								
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	1,024	40	34		1,098	1,076	22	2

REVISION	Reflects current activity rates.

Reviewed by ORIGINATOR	yyyy mm dd	Reviewed by COORDINATOR	yyyy mm dd
Reviewed by CONSTRUCTOR	yyyy mm dd	Approved by VICE-PRESIDENT	yyyy mm dd 99 11 12

H2856/r Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Complex no. 230

Advance or deferral impact

Work well advanced, deferrals not possible.

Factors affecting timing or viability

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Fire Prevention & Protection - H.O.	751	746	761	751	-10	-1
Fire Prevention & Protection - WSC		271	276	273	-3	-1
TOTAL	751	1,017	1,037	1,024	-13	-1

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
96 10	671	New complex (previously part of FP&P cx 92) which covers the Corporate Group portion of FP&P.
9710	740	PROJECT STARTS DELAYED ONE YEAR.
1998 10	1,076	Reflects deferral of Waverley Service Centre one year, Head Office two years, and rescheduled work at HO.
1999 10	1,098	Reflects current activity rates.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item

105

Title
FIRE PREVENTION AND PROTECTION - H.O.

Budget reference number
08-00-5564

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Human Resources	Human Resources	Human Resources	80035

DESCRIPTION:
THIS ITEM IS INTENDED TO PROVIDE FINANCIAL COVERAGE FOR FIRE PREVENTION AND PROTECTION AT 820 TAYLOR AVENUE.

JUSTIFICATION:
THIS ITEM PROVIDES FOR ADDITIONS AND IMPROVEMENTS TO FIRE PREVENTION AND PROTECTION AS RECOMMENDED IN REPORTS 88-M1, 88-M2 AND 88-M3.

REFERENCE:
INTEROFFICE MEMORANDUM (WITH ATTACHED REPORT 94-M1) FROM F.K. WONNICK, DIVISION MANAGER SERVICES, TO D.L. RIEHL, VICE-PRESIDENT PERSONNEL & SERVICES, DATED 1994 07 07.

REVISION:
1999 SUBMISSION.

IN SERVICE DATES		Base estimate
1999 10 31	462	199707 L3
2000 10 31	347	Work start date
		1997 08 01

PREV AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date	135		10			145
1999/00	335	16				351
2000/01	272	18	3			293
TOTAL	742	34	13			789
REV. AMOUNTS:						
Authorized to date:	135		10			145
Over(under)expend:						
Auth 1999/00	358	15	11			384
Req. 2000/01	258	15	7			280
TOTAL	751	30	28			809

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR		COORDINATING MANAGER		ORIGINATING MANAGER

1999-08-21 05:30 PM

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 08-00-5564

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1994 10	376	NEW ITEM
1995 10	385	1995 SUBMISSION.
1996 10	397	1996 SUBMISSION

ASSOCIATED PROJECTS

Budget reference number	Description
08-00-5565	FIRE PREVENTION AND PROTECTION - WSC

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	30	1	1			32	32
May	30	1	1			32	64
Jun	30	1	1			32	96
Jul	30	1	2			33	129
Aug	30	1	2			33	162
Sep	30	1	2			33	195
Oct	30	1	2			33	228
Nov	30	2	-1			31	259
Dec	30	1				31	290
Jan	30	1				31	321
Feb	30	1				31	352
Mar	28	3	1			32	384
TOTAL	358	15	11			384	384
2000/01 Apr	21	2				23	23
May	21	1	1			23	46
Jun	21	1	1			23	69
Jul	21	2	1			24	93
Aug	21	2	1			24	117
Sep	21	2	1			24	141
Oct	21	2	1			24	165
Nov	21	2				23	188
Dec	21	2				23	211
Jan	21	2				23	234
Feb	21	2				23	257
Mar	27	-5	1			23	280
TOTAL	258	15	7			280	280

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item _ Domestic Item

106

Title
FIRE PREVENTION AND PROTECTION - WSC

Budget reference number
08-00-5565

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Human Resources	Human Resources	Human Resources	80034

DESCRIPTION:
THIS ITEM IS INTENDED TO PROVIDE FINANCIAL COVERAGE FOR FIRE PREVENTION AND PROTECTION AT WAVERLEY SERVICE CENTRE.

JUSTIFICATION:
ADDITIONS AND IMPROVEMENTS TO FIRE PREVENTION AND PROTECTION AS RECOMMENDED IN REPORTS 88-M1, 88-M2 AND 88-M3.

REFERENCE:
INTEROFFICE MEMO FROM F.K. WONNICK, DIVISION MANAGER SERVICES TO D.L. RIEHL, VICE-PRESIDENT PERSONNEL & SERVICES, DATED 1994 07 07.

REVISION:
1999 SUBMISSION.

IN SERVICE DATES

1999 10 31 | 289

Base estimate
199610 L3

Work start date
1997 12 01

	PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date:	1999/00	271	11	6			288
	TOTAL	271	11	6			288
REV. AMOUNTS:							
Authorized to date:							
Over(under)expend:							
Auth Req.:	1999/00	273	10	6			289
	TOTAL	273	10	6			289

Prepared by: yy mm dd COORDINATOR
Approved by: yy mm dd
Approved by: yy mm dd
Estimated by: ORIGINATOR
COORDINATING MANAGER
ORIGINATING MANAGER

1999-08-21 05:30 PM

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 08-00-5565

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1995 10	262	1995 SUBMISSION.
1996 10	281	1996 SUBMISSION.

ASSOCIATED PROJECTS

Budget reference number	Description
08-00-5564	FIRE PREVENTION AND PROTECTION - H.O.

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	39	1				40	40
May	39	2				41	81
Jun	39	1	1			41	122
Jul	39	1	1			41	163
Aug	39	2	1			42	205
Sep	39	2	1			42	247
Oct	39	1	2			42	289
Nov							289
Dec							289
Jan							289
Feb							289
Mar							289
TOTAL	273	10	6			289	289
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

COMPLEX STATUS: ☐ Planned ☒ In progress

Complex no. 231

REVISION STATUS: ☐ New complex ☒ In service change ☐ Concept change ☒ Estimate change only

COMPLEX: BUILDINGS - CORPORATE GROUP

Proposal

Refurbish existing 205000sq.ft. Head Office (HO) mech/elec, HVAC, fire protection and curtain walls. (2003/04-2004/05)

JUSTIFICATION: ☐ Load ☐ Service ☒ Safety ☒ Efficiency ☐ Reliability ☐ Other

Explanation

Refurbishing HO will provide improved security & fire protection, modern communication, power & HVAC control systems and reduced energy consumption.

Estimate Level	COMPLEX START (yyyy mm)
L3	2003 04

IN SERVICE DATES AND AMOUNTS			
2004 04 $17170			

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend								
Year 99/00								
00/01								
01/02								
02/03								
03/04	12,584	1400	1,130		15,114	15,223	-109	-1
04/05	1,718	229	108		2,055	2,071	-16	-1
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	14,302	1,629	1,238		17,169	17,294	-125	-1

REVISION: Updated escalation and interest

Reviewed by ORIGINATOR	yyyy mm dd	Reviewed by COORDINATOR	yyyy mm dd
Reviewed by CONSTRUCTOR	yyyy mm dd	Approved by VICE-PRESIDENT	yyyy mm dd 99 11 12

H2856/r Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Complex no. 231

Advance or deferral impact

Continuation of existing inefficiencies.

Factors affecting timing or viability

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Refurbish 820 Taylor Ave Bldg.		14,302	14,588	14,302	-286	-2
TOTAL		14,302	14,588	14,302	-286	-2

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
96 10	20,409	New complex (previously part of complex 13) which covers the Corporate Group building program, base year 1996. Training centre ISD deferred to 97 08 03.
9710	20,036	Revised scope of work to include office furnishings in 1997/98 and site improvements in 1998/99. Base estiment for H.O. refurbishment.
1998 10	20,666	Reflects funds required to complete Training Ctr minor deficien cies, and two year deferral of Taylor Ave refurbishment.
1999 10	17,169	Updated escalation and interest on the Head Office refurbishment.Training Center complete and deleted from complex.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item

107

Title
INTEGRATED TRADES TRAINING CENTRE PROPERTY AND BUILDING

Budget reference number
08-00-5568

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Human Resources	Generation - South	Construction	80033

DESCRIPTION:
ACQUIRE 160 ACRES OF LAND IN 1994/95, PERFORM ENGINEERING AND ARCHITECTURAL DESIGN FOR SITE IMPROVEMENTS, COMMUNICATION AND 3 PHASE POWER SUPPLY TO BE PROVIDED IN 1995/96. IN 1995/96 & 1996/97 PERFORM SITE IMPROVEMENTS, CONSTRUCT POWER SUPPLY AND COMMUNICATION SYSTEM, AND CONTRACT FOR CONSTRUCTION OF A 25 000 SQUARE FOOT BUILDING TO ACCOMMODATE TRADES AND TRANSMISSION LINE MAINTENANCE TRAINING.

JUSTIFICATION:
LINE DEPARTMENT AND TASK FORCE REVIEWS HAVE CONFIRMED THAT PROPERLY SEQUENCED PERFORMANCE BASED TRAINING, DELIVERED BY TRAINED INSTRUCTORS IN A FACILITY HAVING PROPER FORMAL AND PRACTICAL TRAINING AREAS, AND REAL WORLD SIMULATION OF TRANSMISSION AND DISTRIBUTION SYSTEMS AND EQUIPMENT, IS ESSENTIAL TO ENSURE CONSISTENCY AND QUALITY IN THE TRAINING PROVIDED TO CORPORATE TRADES STAFF. THIS ITEM REFLECTS THE RECOMMENDATIONS OF THE TASK FORCE AND DIRECTION FROM EXECUTIVE MANAGEMENT. DEFINES FUNDS TO PURCHASE A SITE (YET TO BE DEFINED) IN FISCAL YEAR 1994/95 AND CONSTRUCT A 25,000 SQUARE FOOT PORTION OF THE TRAIN ING CENTRE IN 1995/96 & 1996/97.

REVISION:
REMAINING FUNDS REQUIRED TO COMPLETE MINOR DEFICIENCIES.

IN SERVICE DATES						Base estimate
Prior Total	3 324	1998 08 31	0	1999 01 31	1	199610 L4
1998 05 31	11	1998 10 31	1	1999 02 28	3	
1998 06 30	1	1998 11 30	1	1999 03 31	0	Work start date
1998 07 31	1	1998 12 31	2	1999 07 31	36	1997 04 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date	3 142		204			3 346
1999/00	26					26
TOTAL	3 168		204			3 372
REV. AMOUNTS:						
Authorized to date:	3 142		204			3 346
Over(under)expend:						
Auth Req.: 1999/00	33	2				35
TOTAL	3 175	2	204			3 381

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

4352

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 08-00-5568

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1994 08	3 528	NEW ITEM.
1995 10	3 533	REFLECTS REVISED INTEREST & ESCALATION RATES.
1997 10	3 350	Revised scope of work to include office furnishings in 1997/98 and site improvements in 98/99.

ASSOCIATED PROJECTS

Budget reference number	Description
08-00-7058	REFURBISH 820 TAYLOR AVE BUILDING

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	8	1				9	9
May	8	1				9	18
Jun	8	1				9	27
Jul	9	-1				8	35
Aug							35
Sep							35
Oct							35
Nov							35
Dec							35
Jan							35
Feb							35
Mar							35
TOTAL	33	2				35	35
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item 108

Title
REFURBISH 820 TAYLOR AVE BUILDING

Budget reference number
08-00-7058

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Human Resources	Design	Construction	80045

DESCRIPTION:
THE HEAD OFFICE BUILDING WAS CONSTRUCTED IN 1956, WITH MAJOR ADDITIONS IN 1962 AND 1967. ONCE STAFF CAN BE RELOCATED TO NEW SPACE PROPOSED TO BE IN SERVICE IN 2001, IT IS PROPOSED TO REFURBISH THE MECHANICAL SYSTEMS, PARTICULARLY THE HEATING, VENTILATING AND AIR CONDITIONING (HVAC) COMPONENTS (REPLACE WITH ENERGY CONSERVING SYSTEMS) PLUS THE ELECTRICAL DISTRIBUTION, THE NORTH AND EAST PERIMETER CURTAIN WALL AND INSTALL FIRE SPRINKLER AND SMOKE CONTROL SYSTEMS AS REQUIRED TO SATISFY CURRENT STANDARDS AND DESIGN PRACTICES.

JUSTIFICATION:
TECHNOLOGICAL DEVELOPMENTS SINCE THE 1960'S HAVE PROVIDED ENERGY EFFICIENT THERMAL INSULATING CURTAIN WALL SYSTEMS AND SYSTEMS TO RECLAIM INTERNALLY GENERATED BUILDING CORE HEAT FOR USE IN PERIMETER HEATING. IMPROVED TEMPERATURE CONTROL AND SIMULATANEOUS HEATING AND COOLING FOR DIFFERENT PARTS OF A BUILDING ARE NOW THE NORM. REFURBISHING WILL PROVIDE IMPROVED SECURITY AND FIRE PROTECTION, MODERN COMMUNICATION, POWER AND HVAC CONTROL SYSTEMS, AS WELL AS REDUCED ENERGY CONSUMPTION.

REVISION:
1997 SUBMISSION. BASE YEAR REVISED FROM 1996 TO 1997.

IN SERVICE DATES		Base estimate
2004 04 30	17 170	199707 L2
		Work start date
		2001 04 01

PREV AUTHORITY Authorized to date	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
2003/04	12 584	1 517	1 121			15 222
2004/05	1 718	246	107			2 071
TOTAL	14 302	1 763	1 228			17 293
REV. AMOUNTS:						
Authorized to date:						
Over(under)expend						
Auth 2003/04	12 584	1 401	1 130			15 115
Req 2004/05	1 718	229	108			2 055
TOTAL	14 302	1 630	1 238			17 170

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	

4354

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 08-00-7058

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1986 07	13 935	NEW ITEM
1988 11	14 300	IN-SERVICE DEFERRED 12 MONTHS. BASE DATE UPDATED FROM 1986 TO 1988. REFLECTS REVISED ESCALATION AND INTEREST RATES.
1990 10	16 625	IN-SERVICE DEFERRED BY 12 MONTHS.
1991 10	17 421	IN-SERVICE DEFERRED BY 24 MONTHS.
1992 10	16 843	IN-SERVICE DATE DEFERRED BY 2 YEARS.
1993 10	18 532	PROJECT DEFERRED 3 YEARS.
1994 10	17 494	REDUCED INTEREST AND ESCALATION RATES. BASE YEAR REVISED.
1995 10	17 464	BASE YEAR REVISED FROM 1995 TO 1996.
1996 10	17 110	BASE YEAR REVISED FROM 1995 TO 1996.

ASSOCIATED PROJECTS

Budget reference number	Description
08-00-5568	INTEGRATED TRADES TRAINING CENTRE PROPERTY AND BUILDING

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

COMPLEX STATUS	Complex no.	REVISION STATUS
☐ Planned ☒ In progress	244	☐ New complex ☒ In service change ☒ Concept change ☐ Estimate change only

COMPLEX	YEAR 2000 CONVERSION

Proposal

Convert existing computer application programs (ie Customer Service System, Human Resources System, Plant Maintenance System, CADD and computational) NETWORK and PC HARDWARE / SOFTWARE systems to year 2000 compatability. To provide replacements, repair,consulting, or contracting for the year 2000 embedded system failures or performance issues for power system equipment in all business units.

JUSTIFICATION

☐ Load ☒ Service
☐ Safety ☒ Efficiency
☒ Reliability ☐ Other

Explanation

Current software / hardware systems have not been programmed to recognize the year 2000. This will result in all systems failing to operate as programmed. In addition funding is required to replace or repair candidatres for year 2000 failures or loss of performance such as power system equip used in energy mgmt,process control, monitoring, metering , data acquisition, communication, and protection equipment.

Estimate Level	COMPLEX START (yyyy mm)
L2	1997 09

IN SERVICE DATES AND AMOUNTS					
2000 03	$10933	2001 03	$2027		

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend	4,137		34		4,171	4,183	-12	-0
Year 99/00	6,763				6,763	6,751	12	0
00/01	2,027				2,027	2,762	-735	-27
01/02								
02/03								
03/04								
04/05								
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	12,927		34		12,961	13,696	-735	-5

REVISION	Revised to reflect a reduction in interest. Components are placed in service as soon as they are received.

Reviewed by ORIGINATOR	yyyy mm dd 1999 11 10	Reviewed by COORDINATOR	yyyy mm dd		
Reviewed by CONSTRUCTOR	yyyy mm dd	Approved by VICE-PRESIDENT	yyyy mm dd 99 11 12		

H2856/r Rev 99 03

Complex no. 244

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Advance or deferral impact

Systems will fail to operate as programmed.

Factors affecting timing or viability

Arrival of Jan 1, 2000.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE	
					Amount	%
Year 2000 conversion.	12,927	12,075	12,317	12,927	610	5
TOTAL	12,927	12,075	12,317	12,927	610	5

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
1997 10	5,977	New complex, transferred from the Domestic Budget.
1998 10	13,696	Reflects 97/98 underexpenditure 1.3M, and addition of a new item to provide funding for repair or replacement of year 2000 affected embedded systems.
1999 10	12,961	Revised to reflect a reduction in interest. Components are placed in service as soon as they are received.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — 109 Domestic Item

Title
YEAR 2000 CONVERSION

Budget reference number
09-00-8822

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Information Technology Services	Information Technology Services	Information Technology Services	70569:74227

DESCRIPTION:
TO PROVIDE CORPORATE YEAR 2000 SOFTWARE CONVERSIONS (INCLUDING CSS, PAYPERS, AMPS, MINOR SYSTEMS, NETWORK AND PC HARDWARE/SOFTWARE REPLACEMENTS) AND EMBEDDED SYSTEM REPLACEMENTS, REPAIR, CONSULTING, OR CONTRACTING FOR ALL SYSTEMS WITH YEAR 2000 FAILURES OR PERFORMANCE ISSUES IN ALL BUSINESS UNITS.

JUSTIFICATION:
POWER SYSTEM EQUIPMENT USED IN ENERGY MANAGEMENT, PROCESS CONTROL, MONITORING, METERING, DATA ACQUISITION, COMMUNICATION, AND PROTECTION WHICH PROCESS DATES ARE CANDIDATES FOR YEAR 2000 FAILURES OR LOSS OF PERFORMANCE. IN ADDITION THE CURRENT HARDWARE AND SOFTWARE USED IN BUSINESS AND ENGINEERING COMPUTER SYSTEMS HAS NOT BEEN PROGRAMMED TO RECOGNIZE THE YEAR 2000. THIS WILL RESULT IN FAILURE OF ALL OF THESE SYSTEMS TO OPERATE.

REVISION:
THIS ITEM COVERS THE HARDWARE PURCHASES, SOFTWARE PURCHASES AND CONSULTING ESTIMATES ONLY.

This BRN contains Deleted, Blocked, or Closed Orders.

IN SERVICE DATES		Base estimate
2000 03 31	10 933	199707 L2
2001 03 31	2 028	Work start date
		1997 09 01

PREV. AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Authorized to date	4 137		34			4 171
1999/00	6 153	190	420			6 763
2000/01	2 000	100	662			2 762
TOTAL	12 290	290	1 116			13 696
REV. AMOUNTS:						
Authorized to date:	4 137		34			4 171
Over(under)expend:						
Auth 1999/00	6 763					6 763
Req. 2000/01	2 027					2 027
TOTAL	12 927		34			12 961

Prepared by	yy mm dd	COORDINATOR	Approved by	yy mm dd	Approved by	yy mm dd
Estimated by		ORIGINATOR	COORDINATING MANAGER		ORIGINATING MANAGER	4358

1999-08-31 05:30 PM

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 09-00-8822

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1997 07	5 977	THIS ITEM HAS BEEN TRANSFERRED FROM THE DOMESTIC BUDGET.
1998 10	4 460	THIS ITEM COVERS THE HARDWARE PURCHASES, SOFTWARE PURCHASES AND CONSULTING ESTIMATES ONLY.

ASSOCIATED PROJECTS

Budget reference number	Description

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr	564					564	564
May	564					564	1 128
Jun	564					564	1 692
Jul	564					564	2 256
Aug	564					564	2 820
Sep	564					564	3 384
Oct	564					564	3 948
Nov	564					564	4 512
Dec	564					564	5 076
Jan	564					564	5 640
Feb	564					564	6 204
Mar	559					559	6 763
TOTAL	6 763					6 763	6 763
2000/01 Apr	169					169	169
May	169					169	338
Jun	169					169	507
Jul	169					169	676
Aug	169					169	845
Sep	169					169	1 01
Oct	169					169	1 18
Nov	169					169	1 352
Dec	169					169	1 521
Jan	169					169	1 690
Feb	169					169	1 859
Mar	168					168	2 027
TOTAL	2 027					2 027	2 027

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

COMPLEX STATUS: [X] Planned [ ] In progress

Complex no. 245

REVISION STATUS: [ ] New complex [X] In service change [ ] Concept change [ ] Estimate change only

COMPLEX: NEW CUSTOMER SERVICE SYSTEM

Proposal
To replace the existing mainframe Customer Service System, Meter Records System,Miscellaneous Billing System, and Street Light System with a modern customer system.

JUSTIFICATION: [ ] Load [X] Service [ ] Safety [X] Efficiency [X] Reliability [ ] Other

Explanation
These existing systems require extensive modifications, as well as various current and upcoming business functions.

Estimate Level	COMPLEX START yyyy mm
L3	2001 04

IN SERVICE DATES AND AMOUNTS

2004 03	$7943			

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend								
Year 99/00								
00/01								
01/02	298	24	13		335	339	-4	-1
02/03	2,202	227	125		2,554	2,578	-24	-1
03/04	4,100	514	439		5,053	5,095	-42	-1
04/05								
05/06								
06/07								
07/08								
08/09								
09/10								
10/11								
11/12								
12/13								
13/14								
14/15								
15/16								
16/17								
17/18								
18/19								
Beyond								
TOTAL	6,600	765	577		7,942	8,012	-70	-1

REVISION: Revised to reflect current escalation and interest rates.

Reviewed by ORIGINATOR	yyyy mm dd 1999 11 10	Reviewed by COORDINATOR	yyyy mm dd
Reviewed by CONSTRUCTOR	yyyy mm dd	Approved by VICE-PRESIDENT	yyyy mm dd 99 11 12

H2856/r Rev 99 03

Complex no. 245

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

Advance or deferral impact

Current information indicates that these systems will become totally non functional as of Jan 1, 2000.

Factors affecting timing or viability

Unavailability of an economical upgrade to current software, making it year 2000 compatible, and more powerful.
Various current and upcoming business functions.

COMPLEX SPECIFICS:

PROJECT	ORIGINAL COMMITTED BASE COST	PREVIOUS ESTIMATE BASE 1998	PREVIOUS ESTIMATE BASE 1999	CURRENT ESTIMATE BASE 1999	ESTIMATE CHANGE Amount	ESTIMATE CHANGE %
Customer Service System		6,600	6,732	6,600	-132	-2
TOTAL		6,600	6,732	6,600	-132	-2

FORECAST HISTORY (IN THOUSANDS OF DOLLARS):

APPROVED yyyy | mm	TOTAL AMOUNT	AMENDMENT
1997 10	6,851	New item.
1998 10	8,012	Deferred spending until 2000/01. ISD deferred 2 years.
1999 10	7,942	Revised to reflect current escalation and interest rates.

ASSOCIATED COMPLEXES OR REFERENCE REPORTS:

REFERENCE NUMBER	DESCRIPTION

MajCER(1) Rev. 98 11

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

X Major Item — Domestic Item

110

Title
CUSTOMER SERVICE SYSTEM

Budget reference number
09-00-8821

Originating division	Coordinating division	Constructing division	Project Order Group (Range):
Corporate Controller	Corporate Controller	Corporate Controller	82050

DESCRIPTION:
To replace the existing mainframe Customer Service System, Meter Records System, Miscellaneous Billing System, and Street Light System with an improved customer system.

JUSTIFICATION:
The present Customer Service System (CSS) has been in service for approximately 13 years, however the underlying technology is approaching 17 years of age. The CSS has limited capabilities in, or would require extensive reworking to provide:
-billing of services other than electricity
-billing on alternative industrial/commercial rate structures
-integration of operational requirements (eg. interface with MAPINFO and TVD for outage location and associated customer contact), user programming capabilities, online updates, and consistency with other software
-offering of 'choice' items such as French Language, consolidated billing, and bill detail

Replacement of the CSS would allow the integration of other systems (Meter Records, Miscellaneous Billing, Street Light Systems) and provide flexibility and capacity for improved customer service and marketing initiatives necessary to fulfil our mandate.

REVISION:
Deferred spending until 2000/01.

IN SERVICE DATES

2004 03 31 — 7 943

Base estimate
199704 L3

Work start date
2000 04 01

PREV. AUTHORITY Authorized to date:	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
2001/02	298	27	13			338
2002/03	2 202	252	125			2 579
2003/04	4 100	559	436			5 095
TOTAL	6 600	838	574			8 012
REV. AMOUNTS:						
Authorized to date:						
Over(under)expend:						
Auth 2001/02	298	24	13			335
Req 2002/03	2 202	228	125			2 555
2003/04	4 100	514	439			5 053
TOTAL	6 600	766	577			7 943

Prepared by — yy mm dd — COORDINATOR
Approved by — yy mm dd — COORDINATING MANAGER
Approved by — yy mm dd — ORIGINATING MANAGER
Estimated by — ORIGINATOR

4362

1999-08-21 05:30 PM

MajCER(2) Rev. 97 09

CAPITAL EXPENDITURE REVISION

Budget reference number 09-00-8821

FORECAST HISTORY (in thousands of dollars)

Approved yy mm	TOTAL AMOUNT	COMMENTS
1997 08	12 907	New item

ASSOCIATED PROJECTS

Budget reference number	Description

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
1999/00 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							
2000/01 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

H2856/f Rev 99 03

CAPITAL EXPENDITURE FORECAST COMPLEX

(IN THOUSANDS OF DOLLARS)

COMPLEX STATUS	Complex no.	REVISION STATUS
☐ Planned ☒ In progress	111 - 119	☐ New complex ☐ In service change ☐ Concept change ☒ Estimate change only

COMPLEX	DOMESTIC ITEM - CORPORATE

Proposal

TO PROVIDE INFORMATION TECHNOLOGY HARDWARE, SOFTWARE, APPLICATION DEVELOPMENT AND OTHER RELATED SERVICES TO THE CORPORATION.

JUSTIFICATION	Explanation
☒ Load ☒ Service ☒ Safety ☒ Efficiency ☒ Reliability ☒ Other	COMPUTER SYSTEM ENHANCEMENTS ARE REQUIRED THROUGHOUT THE CORPORATION TO ACHIEVE ONGOING IMPROVEMENTS IN RESOURCE PRODUCTIVITY AND RELIABILITY.

Estimate Level	COMPLEX START (yyyy mm)
L2	1996 04

IN SERVICE DATES AND AMOUNTS							
1999 03 31	$18592	2000 03 31	$17960	2001 03 31	$24183	2002 03 31	$22623
2003 03 31	$25179	2004 03 31	$25692	2005 03 31	$26219	2006 03 31	$26757
2007 03 31	$27300	2008 03 31	$27858	2009 03 31	$28434	2010 03 31	$29016

ESTIMATE	BASE COST	ESCALATION	INTEREST CAPITALIZED	SALVAGE/ CONTRIB	TOTAL NET COST	Previous Net Cost	NET CHANGE Amount	NET CHANGE %
Prev Expend						18,592	-18,592	-100
Year 99/00	22,697	125	178		23,000	17,960	5,040	28
00/01	23,157	455	170		23,782	24,183	-401	-2
01/02	21,398	655	170		22,223	22,623	-400	-2
02/03	23,667	915	197		24,779	25,179	-400	-2
03/04	22,615	2129	435		25,179	25,692	-513	-2
04/05	22,624	2624	444		25,692	26,219	-527	-2
05/06	22,631	3130	458		26,219	26,757	-538	-2
06/07	22,638	3647	472		26,757	27,300	-543	-2
07/08	22,644	4174	482		27,300	27,858	-558	-2
08/09	22,650	4711	497		27,858	28,434	-576	-2
09/10	22,656	5260	518		28,434	29,016	-582	-2
10/11	22,662	5820	534		29,016	29,616	-600	-2
11/12	22,669	6391	556		29,616	30,224	-608	-2
12/13	22,676	6975	573		30,224	30,850	-626	-2
13/14	22,683	7570	597		30,850	31,475	-625	-2
14/15	22,689	8177	609		31,475	32,108	-633	-2
15/16	22,696	8797	615		32,108	32,760	-652	-2
16/17	22,703	9430	627		32,760	33,434	-674	-2
17/18	22,711	10076	647		33,434	34,115	-681	-2
18/19	22,719	10736	660		34,115		34,115	
Beyond								
TOTAL	453,585	101,797	9,439		564,821	554,395	10,426	2

REVISION	Reflects current forecast costs for information technology and related system additions and enhancements throughout the Corporation.

Reviewed by ORIGINATOR	yyyy mm dd	Reviewed by COORDINATOR	yyyy mm dd
Reviewed by CONSTRUCTOR	yyyy mm dd	Approved by VICE-PRESIDENT	yyyy mm dd 99 11 17

CORP GROUP DOMESTIC CAPITAL FORECAST (CEF99-1)

CAPITAL REQUIREMENTS	1999/00	2000/01	2001/02
INFO TECH HARDWARE			
NETWORK	2.2	2.5	2.5
INFRASTRUCTURE	1.2	1.3	1.3
PCs	3.4	3.5	3.6
INFO TECH SOFTWARE			
SOFTWARE	0.6	0.6	0.6
PS /CAD HRDWR/SOFTWR	0.5	0.5	0.5
ENG HW/WRKSTNS/SOFTWR	0.6	0.6	0.6
APPLICATION DEVELOPMENT			
PROJ & CAP MGMT (SAP)	4.3	1.6	0.0
NT NETWRK OP SYSTEM	1.4	0.4	0.0
PAYPERS	0.5	3.6	5.9
ELECTRONIC OFFICE	0.6	0.0	0.0
ENTERPRISE MGMT SYST	0.9	0.7	0.0
BUSINESS CONT PLNG	0.5	0.2	0.0
SAP ARCHIVING	0.5	1.0	1.0
SAP REPORTING	0.0	1.0	0.0
SAP 4.5 UPGRADE	0.0	1.0	0.0
FINFOR REPLCMT	0.0	0.7	0.0
MS OFFICE	0.0	0.0	2.0
MISC OTHERS	0.3	0.5	1.6
OTHER(UNSPECIFIED)	5.5	4.5	3.0
TOTAL CG DOMESTIC	23.0	24.2	22.6

Tab 39

Addendum to Item
Meeting No. 78

MINISTER RESPONSIBLE
FOR MANITOBA HYDRO

Legislative Building
Winnipeg, Manitoba, CANADA
R3C 0V8

SEP 2 0 2007

Mr. Vic Schroeder
Chairman
The Manitoba Hydro-Electric Board
820 Taylor Avenue
Winnipeg Manitoba R3C 2P4

Dear Mr. Schroeder:

Please accept the following as further clarification on the Government of Manitoba's view respecting Manitoba Hydro's plans to build a third Bipole transmission line, and the ongoing planning and other community development activities on the east side of Lake Winnipeg.

As you are aware, in August 2000, our government announced our intention to initiate Broad Area Planning on the east side of Lake Winnipeg. This followed shortly after our government's acceptance of the Consultation on Sustainable Development Implementation (COSDI) Report, which recommended, among other things, the creation of Broad Area Plans.

The east side of Lake Winnipeg was chosen for broad area planning for many reasons, including:

- the area is a unique and environmentally spectacular area, containing a vast expanse of undeveloped, contiguous, boreal forest (one of the largest in North America);
- the east side is home to a population that is 96% First Nation;
- the east side provides one of the largest habitats for the threatened woodland caribou and is home to the Bloodvein River (a Canadian Heritage River), as well as the Manigotagan River – both renowned for their marvelous natural and recreational significance;
- access to transportation networks and many economic opportunities are more limited than in other parts of the province; and
- the east side, like other remote areas, has already begun to feel the effects of climate change in reducing the viability of winter roads that bring in vital supplies, and applying pressure on the boreal forest.

More recently, the east side has been identified as a prime candidate for United Nations World Heritage Site designation, on the basis of both cultural and natural significance – one of only very few sites throughout the world to be nominated for both criteria.

significance – one of only very few sites throughout the world to be nominated for both criteria.

The objective of the original East Side Planning Initiative (ESPI), now known as Wabanong Nakaygum Okimawin (WNO), was to bring together local communities, First Nations, industry and environmental organizations to develop a vision for land and resource use in the area that respects both the value of the boreal forest and the needs of local communities.

As part of the planning initiative, Ministers and the Premier participated in community meetings throughout the region – in total, 80 separate east side community meetings were held. Through this process, we learned a great deal about the views of east side residents, their plans, their hopes, their concerns and their dreams about the future of their families, their communities, their traditional economies, their environment and their sacred and natural areas.

It was clear through this process that there was no consensus view on building a new HVDC Bipole transmission line through the east side. This lack of consensus was subsequently reflected in *"Promises to Keep...": Towards a Broad Area Plan for the East Side of Lake Winnipeg*, which was received on November 14, 2004, and represents a framework for a broad area plan. As a result, we have been working with Manitoba Hydro to find a routing option that respects First Nations planning.

As documented in the ESPI final report, the planning process found very strong support for traditional land use planning, for clear processes for First Nations involvement in decision-making, and for sustainable community and economic development initiatives.

Among other initiatives, our government has been active with the Government of Ontario and the four First Nations of Poplar River, Little Grand Rapids, Paunigassi and Pikangikum in pursuing UNESCO World Heritage designation for lands on the east side of Lake Winnipeg in Manitoba and Northwestern Ontario. The proposed World Heritage Site is 4.3 million hectares and encompasses the traditional territories of the four First Nation communities, Atikaki Provincial Wilderness Park in Manitoba and Woodland Provincial Park in Ontario.

Pimachiowan-Aki non-profit corporation has been established to lead next steps in the designation process. It is our strong hope that the east side will be appropriately recognized alongside other legendary UNESCO sites, such as Machu Picchu in Peru, the Great Barrier Reef in Australia, Acropolis in Greece, the Taj Mahal in India and the Grand Canyon in Arizona.

Through strong First Nation leadership, gaining international recognition for this globally significant area will raise awareness and interest in the east side well beyond our borders, creating opportunities for education about the region and its people, community capacity building, conservation activities, tourism, related training and marketing of local products and services.

The Government of Manitoba and WNO First Nations also recently signed (April 3, 2007) an historic agreement, the *WNO Accord*, confirming a government-to-government relationship between its parties. The WNO Accord reinforces the foundation for

comprehensive traditional land-use planning and confirms a commitment to develop a shared vision for the east side of Lake Winnipeg.

It is now the goal of the WNO to develop a broad area plan for the east side, with the next critical step being traditional land-use planning. To this end, the Province has committed $2.5 million, which First Nations on the east side will use for traditional land-use planning. The WNO Accord outlines guidelines for working together and ensuring that First Nation governments are involved in decisions that will affect their communities and traditional territories.

Planning on the east side will be done in a manner consistent with the principles of the WNO Accord. We anticipate that it will take a number of years to complete planning activities contemplated in the Accord with First Nations on the east side in a spirit of mutual recognition, respect and reconciliation, as we have committed to do.

As announced during the recent provincial election, our government has also made a commitment to protect the east side by introducing new legislation, to be drafted in consultation with First Nations. The intent of the new legislation will be to enable First Nations to develop land use plans to guide development on the east side and to create new protected area designations, which will ensure the area is protected in a way that is consistent with the establishment of a UNESCO World Heritage Site.

We are also moving forward with our commitment to build the first leg of an all-weather road on the east side, which will serve a critical infrastructure need in the region, improving access to food and other needed supplies, and opening the way for other sustainable community economic development.

With respect to Bipole III, I understand that your Board directed the corporation to explore alternatives to the east side in 2004; and more recently, contracted with CMC Consultants Inc. (Mr. Dave Farlinger) to carryout an external review of routing options. The CMC Consultants Inc. study reaffirms that there are routing options other than the east side that can provide desired system reliability enhancements, and will also serve to accommodate future new generation. The study also highlights that an east side routing for Bipole III would be problematic in several respects, including:

- An east side route would dissect boreal forest that is significantly in-tact and of high ecological integrity;
- An east side route has strong potential to undermine First Nations-led efforts to achieve UNESCO World Heritage designation;
- An east side route would be a sub-optimal choice in terms of habitat for the threaten woodland caribou;
- There is already significant demonstrated opposition to an east side route, which has the potential to translate into a long and divisive licencing process, with unbudgeted costs and delays;
- An east side route would present significant threats to corporate image, including in export markets; and
- Pursuing an east side route for Bipole III would require that detailed routing work be carried out in advance or concurrently with First Nations land-use planning. This is clearly at odds with Manitoba's commitment to an approach of careful up-front planning first.

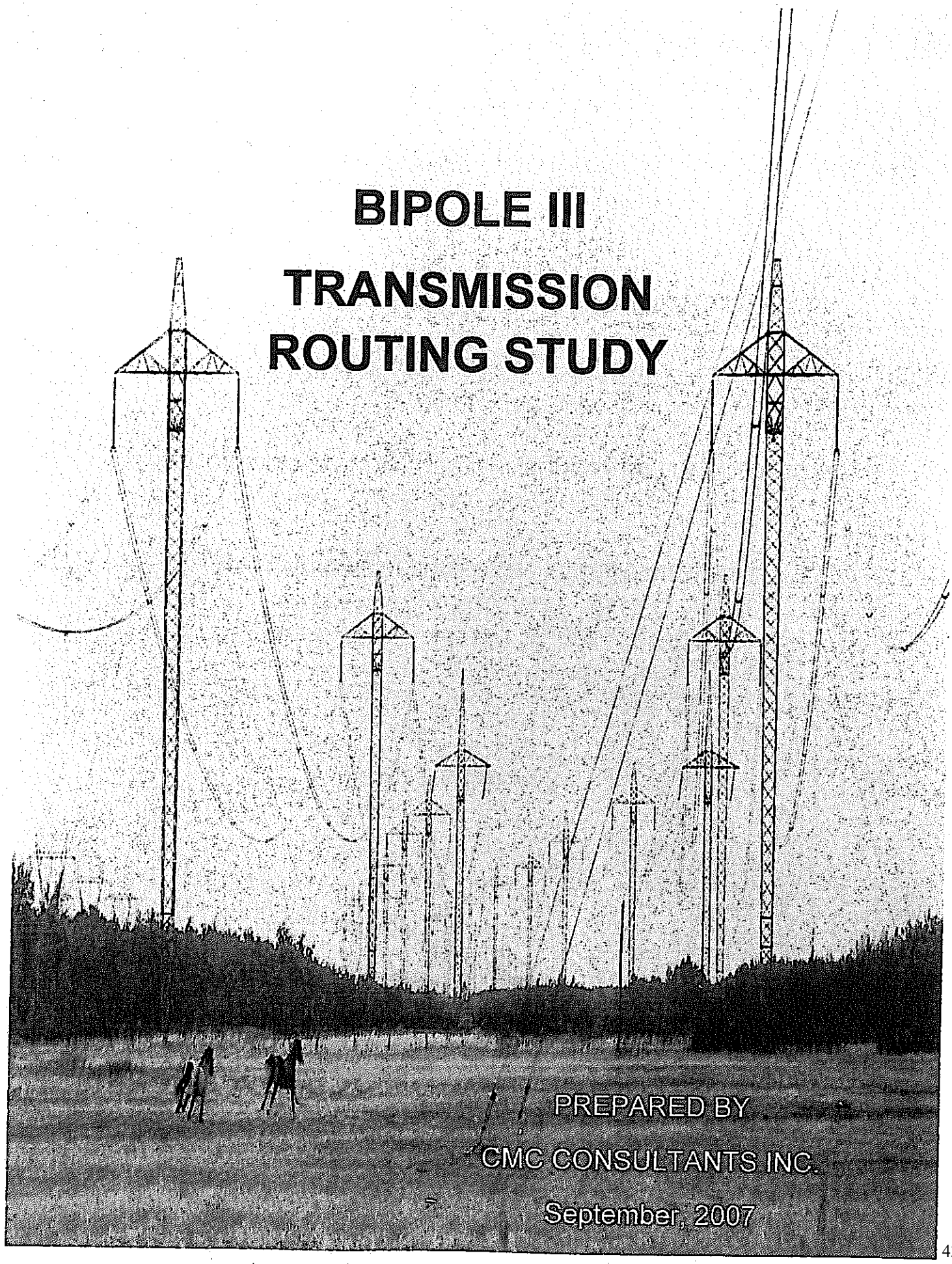
It is the policy of the Manitoba Government to make its government decisions about development on the east side in a manner consistent with the above-noted commitments and initiatives. The Manitoba Government does not regard an east side Bipole III as being consistent with these commitments and initiatives. We recognize the importance of the Bipole III initiative to improving system reliability and accommodating future northern generation. We would encourage the corporation to move ahead with required consultations and planning for an alternative Bipole III route.

Yours truly,

Greg Selinger
Minister

Tab 40

BIPOLE III TRANSMISSION ROUTING STUDY



PREPARED BY

CMC CONSULTANTS INC.

September, 2007

BIPOLE III TRANSMISSION ROUTING STUDY

REVIEW OF SOCIO-ECONOMIC AND ENVIRONMENTAL CONSIDERATIONS

AND

POTENTIAL ROLES OF ENVIRONMENTAL ORGANIZATIONS

CMC Consultants Inc.

September 2007

Table of Contents

1.0	Introduction	1
2.0	Need for Bipole III Line	3
2.1	Present Situation	3
2.2	Options to Improve Security of the Present System	3
	2.2.1 The "East" Corridor	4
	2.2.2 The "Interlake" Corridor	4
	2.2.3 The "West" Corridor	5
2.3	Intermediate Future Development	5
2.4	Ultimate Development	6
3.0	The Environmental Landscape of Alternative Routes	7
3.1	Differences among Potential Biophysical Impacts	7
	3.1.1 Ecological Integrity	8
	3.1.2 Ecologically Sensitive Areas and Protected Areas	9
	3.1.3 Rare, Threatened and Endangered Wildlife, Habitats & Flora	10
	3.1.4 Disturbance to Fur-bearing and Other Wildlife Populations	12
3.1.5	Aquatic Habitats and Stream Crossings	13
	3.1.6 Impacts on Carbon Stocks	13
3.2	Differences among Potential Socio-Economic Impacts	13
4.0	Considerations Associated with Different Routing Options	15
4.1	Opposition in Built-Up Areas	15
4.2	The Evolving Nature of Resources Management Areas	16
4.3	Current Partnerships	16
4.4	The East Side "Address"	17
4.5	The East Side Planning Initiative/WNO	17
4.6	WNO and the Transmission Life	18
4.7	The Government Role in Planning	19
5.0	Impact on Other Initiatives in the Area	21
5.1	UNESCO World Heritage Site	21
5.2	Roads and Other Initiatives	23
5.3	Manitoba Model Forest	23
5.4	Minnesota Legislation	23
6.0	Scope of Interest of Environmental Organizations	25
6.1	Nature of the Debate	25
6.2	Commitments	26
6.3	The Risk of Creating a Cause Celebre	26
6.4	Environmental Organizations	28
	6.4.1 Local Environmental Groups	28
	6.4.2 National Environmental Groups	28
	6.4.3 International Environmental Groups	29
APPENDIX I		33
APPENDIX II		34

1. Introduction

There is an immediate need to increase the reliability of Manitoba Hydro's HVdc transmission system. This system transmits over 70% of the peak power requirements of the province along a single corridor through the Interlake. By North American standards this poses an unacceptable risk to the utility's customers. To improve the security of the HVdc system, Manitoba Hydro is proposing to build a new transmission line – the Bipole III Line.

The two primary routing alternatives for the Bipole III Line are the east side of Lake Winnipeg or west of Lake Winnipegosis and Lake Manitoba. From an increased security and economic perspective, the preferred route would be located on the east side of Lake Winnipeg. However, there are other considerations, which are addressed in this report, that make the choice of a preferred route difficult.

This report provides an overview of major issues related to the alternatives of routing the Bipole III Line on either the east or west side of the province. It is not intended to be a scaled down site selection and environmental impact study. The report considers issues on a highly generalized and comparative basis. It draws upon existing reports and narrowly based interviews, and was completed within a very short timeframe. There are no conclusions presented in this report. The report simply lays out the issues for Manitoba Hydro and the Province of Manitoba to consider.

Other than technical and economic considerations, there are few absolutes in the east vs. west debate. There are uncertainties associated with most aspects of the project, including:

- *Will the line impact a bid for a World Heritage Site?* The answer is possibly, but not necessarily.

- *Is there support from the First Nations on the east side of Lake Winnipeg?* Government meetings in 2004 concluded that there was none. However, recent statements made by First Nations to the media and east side planning documents suggest that there is now some support.

- *Will there be international opposition from environmental groups to an east side route even if there were First Nations agreement to proceed?* Very likely, but the tenor of the debate may change, as environmental groups could no longer point to a lack of First Nations support for the east side route as part of their opposition, and it could potentially place them in conflict with First Nations communities, with whom they have previously partnered.

- *Could continued or further conflict with individual First Nations impact power sales to Minnesota in the future?* Potentially yes.

- Manitoba has a business relationship with First Nations more or less from Conawapa to Snow Lake. West and south of Snow Lake the position of First Nations on the west side is unknown.

- Environmental opposition to a route on the west side of the province is likely much less than opposition to an east side route. However, it is still uncertain and unpredictable.

- Issues of ecological integrity and Protected Areas are better-studied and advanced on the east side. There is significantly less clarity and knowledge as well as profile regarding these issues on the west side.

- For woodland caribou, a west side routing would be a better option, but would not be without potential impacts.

- In built up areas there are preliminary indications from municipalities that they equate a transmission line with development and prosperity, and feel some responsibility to facilitate route location. However, there will be site-specific opposition from property owners. There will likely be strong opposition where the line circumnavigates the south and east sides of Winnipeg.

- The public has not understood the need for the Bipole III Line, nor the complexity of the trade-offs required for a routing decision. Recent licensing processes have become increasingly acrimonious and lengthy, which has further impeded communication and knowledgeable debate.

- Routing on the west side will be neither easy nor guaranteed.

The issues are rife with contradictions, such as:

- Hydro provides grid service to east side communities yet the Corporation is regarded with apprehension and distrust in some circles, even where the only involvement with Manitoba Hydro has provided benefits.

- In some communities, an all-weather road is acceptable on the east side (and even desirable) but a Bipole III Line is not.

The terms of reference provided for this assignment are attached as Appendix I.

2.0 Need for Bipole III Line

2.1 Present Situation

There is an immediate need to increase the security of Manitoba's HVdc transmission system that presently transmits 70% of the peak power requirements of the province over two ± 500kV HVdc transmission lines (Bipole I and Bipole II Lines). These two lines run along a single right of way (ROW) through the Interlake area from large generator stations on the Nelson River system in northern Manitoba to the major load centres in the southern part of the province.

The original transmission system design provided for the output of both Bipole I and Bipole II converters to be temporarily connected together in parallel on either of the two ± 500kV HVdc lines. In the event of the loss of one of the lines, this enabled most of the output of the northern converters to be transmitted to the south, albeit with increased line losses, on the remaining transmission line.

The southern Manitoba load centre, however, remains vulnerable to the simultaneous loss of both lines. This would leave southern Manitoba dependent on power from Winnipeg River generation, northern generation connected to the southern ac system, and available import from adjacent interties. In addition, the southern Manitoba electrical system is vulnerable to the loss of Dorsey Converter station through which all the HVdc transmitted from the north passes and where it is converted from direct current to alternating current for use on the southern distribution system. Dorsey station is also the Manitoba termination of the 500kVac interconnection with the United States.

The vulnerability of the existing system to a single destructive event was starkly demonstrated when 19 towers of the two existing HVdc lines on the same row were simultaneously toppled due to a wind shear downburst event on September 5, 1996. Fortunately, this did not cause widespread supply problems, as it occurred during the night at a time of low demand, with little requirement for heating or air conditioning. Had it occurred at a time of peak demand, it could have had a much more severe effect.

The severity of the effect of the complete loss of access to northern generation in the future, at or near peak load times, could lead to southern Manitoba experiencing a severe disruption to commercial and domestic activity, a strain on emergency services, and a risk to the health and safety of the population in general.

2.2 Options to Improve Security of the Present System.

Recently, several studies have been undertaken to assess alternative options to improve the security of the existing HVdc transmission system. All of the alternatives involve building an additional ± 500kV HVdc north/south transmission line (Bipole III Line). To minimize the risk of the loss of all three ±500kV HVdc lines (the two existing lines on the same ROW and the proposed additional Bipole III Line), it was recognized that the new line must be located on a ROW corridor remote from the existing lines.

The geography of Manitoba, includes some significantly large lakes that lead to a natural separation of possible transmission line routes into the following three north/south corridors:

- The "East" corridor, between Lake Winnipeg to the west and the Ontario border to the east.
- The "Interlake" corridor, between Lake Manitoba, Lake Winnipegosis and Cedar Lake to the west, and Lake Winnipeg to the east.
- The "Far West" corridor, between the Saskatchewan border to the west, and Lake Manitoba, Lake Winnipegosis and Cedar Lake to the east.

Studies of these corridors have been undertaken by Manitoba Hydro to determine the best technical and economic option for the location of the Bipole III Line.

2.2.1 The "East" Corridor

Routing the Bipole III Line along the East Corridor offers the most attractive technical solution for improvement to the security of the existing HVdc north/south transmission system. It is the shortest route, consequently minimizing exposure to line failure and making it the most economical to build.

The operation of the transmission system with the completed Bipole III Line along the eastern route, as well as providing the required additional system security, would enable the cost of building and operating the Bipole III Line to be recovered through the increase of export sales due to the savings through the decrease in line losses.

It is intended that the new Bipole III Line from Henday would terminate at the planned Riel Station, which is to be located close to the east side of the Red River Floodway, next to the existing Deacon Reservoir.

A paralleling line would connect the Riel Station to the Dorsey Converter station to enable the existing Bipole II converters at Dorsey and at Henday to be connected to the Bipole III Line. The two existing lines (Bipole I & Bipole II Lines) would then be connected in parallel to the Bipole I converters at Dorsey and at Radisson.

This configuration would provide for the needed emergency parallel connection of existing converters, enabling transmission of almost all of the output from existing converters in the event of the complete loss of transmission on any one of the corridors.

Consideration should also be given to advancing the installation of converters on the east route to provide for significant HVdc transmission in the event of a catastrophic loss of Dorsey station.

2.2.2 The "Interlake" Corridor

Presently, all of the HVdc power from northern generation is transmitted along the existing Bipole I and Bipole II Lines, which are sited on the same ROW along the Interlake corridor. To provide for a new ROW along this corridor while maintaining an adequate separation distance to prevent a single event affecting both ROWs has proved to be challenging.

Previous studies have determined that a separation distance between ROWs should be at least 40km to reduce the chance of a single event affecting all three lines, with a return period in excess of 800 years. The only option for a marginally suitable ROW would involve building artificial islands that allow island hopping of the transmission line across Cedar Lake.

The consensus is that an additional route through the Interlake would not provide adequate security for the total north/south HVdc transmission system, but it may be considered for future north/south transmission once the security issue is resolved.

2.2.3 The "West" Corridor

Routing the Bipole III Line along the West Corridor would provide the greatest separation between the existing lines and the proposed new line, but it would also be the longest, most expensive and least useful for emergency operation in the event of the loss of one of the transmission corridors.

Unfortunately, due its long length, its characteristics make it unsuitable to operate with either of the existing Bipole I or Bipole II converters, requiring it to have its own converters designed to operate with the longer line. The Bipole III Line and converters would not be able to operate connected in parallel with the existing Bipole I and Bipole II converters.

If the Bipole III Line (West) were lost, the existing Bipole I and Bipole II lines would be able to carry the full existing output from northern converters. However, if the Bipole I and II Lines (Interlake) were lost, the new Bipole III (West) would only be able to carry its rated load (about 50% of the available output). Together with imports from tielines, this may be sufficient to meet current peak load requirements for southern Manitoba but would require the advancement of a fourth HVdc Line and converters (Bipole IV) to meet load growth expectations.

2.3 Intermediate Future Development

Intermediate future system development calls for the building of further northern generation, which would require the provision of additional north/south transmission capacity.

If the Bipole III Line were built along the East Corridor, additional capacity could be provided by installing the Bipole III converters. (If Bipole III converters were installed

earlier, to provide security in the event of a catastrophic loss of Dorsey, no new converter capacity would be required.) This would provide for at least two-thirds of northern capacity to be transmitted south in the event of loss of either corridor.

If the Bipole III Line, together with converters, is built along the West Corridor, only about one-third of northern capacity could be transmitted to the south in the event of total loss of transmission on the Interlake corridor. If the transmission on the west were lost, the Interlake corridor would be able to carry about two-thirds of northern capacity.

2.4 Ultimate Development

In the event that full development of northern generation were to occur, it would approach 90% of the province's total generation capacity. This would require the construction of Bipole IV and Bipole V. For reliability purposes this would require a third corridor.

The ultimate requirement for Bipoles IV and V should not be construed as lessening the technical arguments for an east side location for Bipole III.

3.0 The Environmental Landscape of Alternative Routes

Either option for routing of the Bipole III Line will traverse both forested and rural areas of Manitoba. In very broad terms, a west side routing will traverse very roughly 580 km of forest from Henday to approximately The Pas, then approximately 760 km of rural landscape from The Pas to Riel. An eastern routing would traverse 800 km of forest from Henday to about the Winnipeg River and 85 km from there to Riel. The forested areas of the west route are much more intensively developed than on the east side, with roads, rail lines, geotechnical survey lines, and transmission lines, as well as forestry and mining operations. Both east and west side routings contain traditional land use areas and Treaty Land Entitlement areas of various First Nations, as well as Resource Management Areas. A larger, wide-spread population is affected by a west side routing, which also impacts more of the densely populated region in proximity to Winnipeg.

3.1 Differences among Potential Biophysical Impacts

Generally, different types and magnitudes of potential biophysical impacts could occur in the two landscapes of forested and rural areas. Potential impacts are associated with the construction phase and the presence of and maintenance of the transmission line and ROW, and will vary with line length and specific sites. In the boreal forest areas of northern Manitoba, key potential impacts are:

- Loss of ecological integrity
- Changes to ecologically sensitive and protected areas
- Declines in populations of rare, threatened and endangered wildlife, habitats and flora
- Disturbance to fur-bearing and other wildlife populations important to local communities, as well as alteration to habitat and changes in ease of human access
- Stream crossings that could alter water quality, aquatic habitats and fish species

In the more southern rural and rural residential areas, biophysical impacts tend to be more site-specific and could include some of the same issues, but often to a lesser degree. Ecological integrity is generally not of concern in this landscape, which tends to already have significant existing infrastructure, such as roads and other transmission lines.

Opinions on the significance of residual biophysical impacts after mitigation range from minimal to unacceptable impact. However, in the past decade, several significant transmission line projects have undergone provincial and federal environmental assessment and licensing. Consequently, Manitoba Hydro has developed extensive experience in mitigating transmission line biophysical impacts through:

- Extensive consultation processes to understand local concerns and gain information to assist in routing and mitigation
- Routing selection studies to avoid sensitive areas, and to reduce aesthetic and other impacts

- Environmental protection plans that are monitored by several regulatory agencies and include stream crossing guidelines and improved vegetation management practices

The following sections provide a high-level overview of an eastern vs. western routing for each of the key biophysical issues and has not benefited from information from local communities.

3.1.1 Ecological Integrity

Ecological integrity is a broad term often used by environmental groups, the scientific community and federal government, yet it is not necessarily consistently defined. To date, it has not figured significantly, if at all, in Manitoba Hydro reports; the focus is usually on habitat, sustainable development and cumulative impacts. The Clean Environment Commission recommended that periodic reports on ecological integrity (as well as enduring features, biodiversity and sustainability) be part of the Environmental Protection Plan for the Wuskwatim Project. Ecological integrity is sporadically but increasingly cited as the reason to "save the boreal forest," which is discussed in more detail below. A high level review of ecological integrity issues indicates that this is a complex subject. Neither the east nor the west side would be particularly favoured.

Ecological integrity seems to often mean "intactness," ensuring continuity of systems and processes, unfragmented and distant from human infrastructure. Global Forest Watch Canada defines intact forest as 50,000 ha (500 sq. km) and at least 10 km wide, while the World Resources Institute defines intact forest as areas of 200 sq. km or more that is mostly undivided by roads or other access routes, although they recognize that smaller tracts of forest may still contain high conservation values.

Clearly, the east side has greater existing ecological integrity than the west side. The west side has a 90 year history of mining, forestry, hydroelectric development and associated infrastructure of roads, rail lines and cut lines for geophysical exploration. The Flin Flon/ Snow Lake greenstone belt and the Thompson Nickel belt are two of the most prolific mining districts in the world. Forestry operations extend throughout most of the northern area to be traversed by a western corridor save for the Split Lake Resource Management Area. While the east side is also traversed to some extent by transmission lines (for example, north to Poplar River, east to Little Grand Rapids, and in the North-Central Project region) and by winter roads, with plans for all weather road development to Bloodvein and potentially further north it is of a different scope and intensity. The existence of extensive development in the west however, does not mean that biophysical impacts in that region would be less nor that it would necessarily be easier to find a route. Several other observations relevant to this debate include:

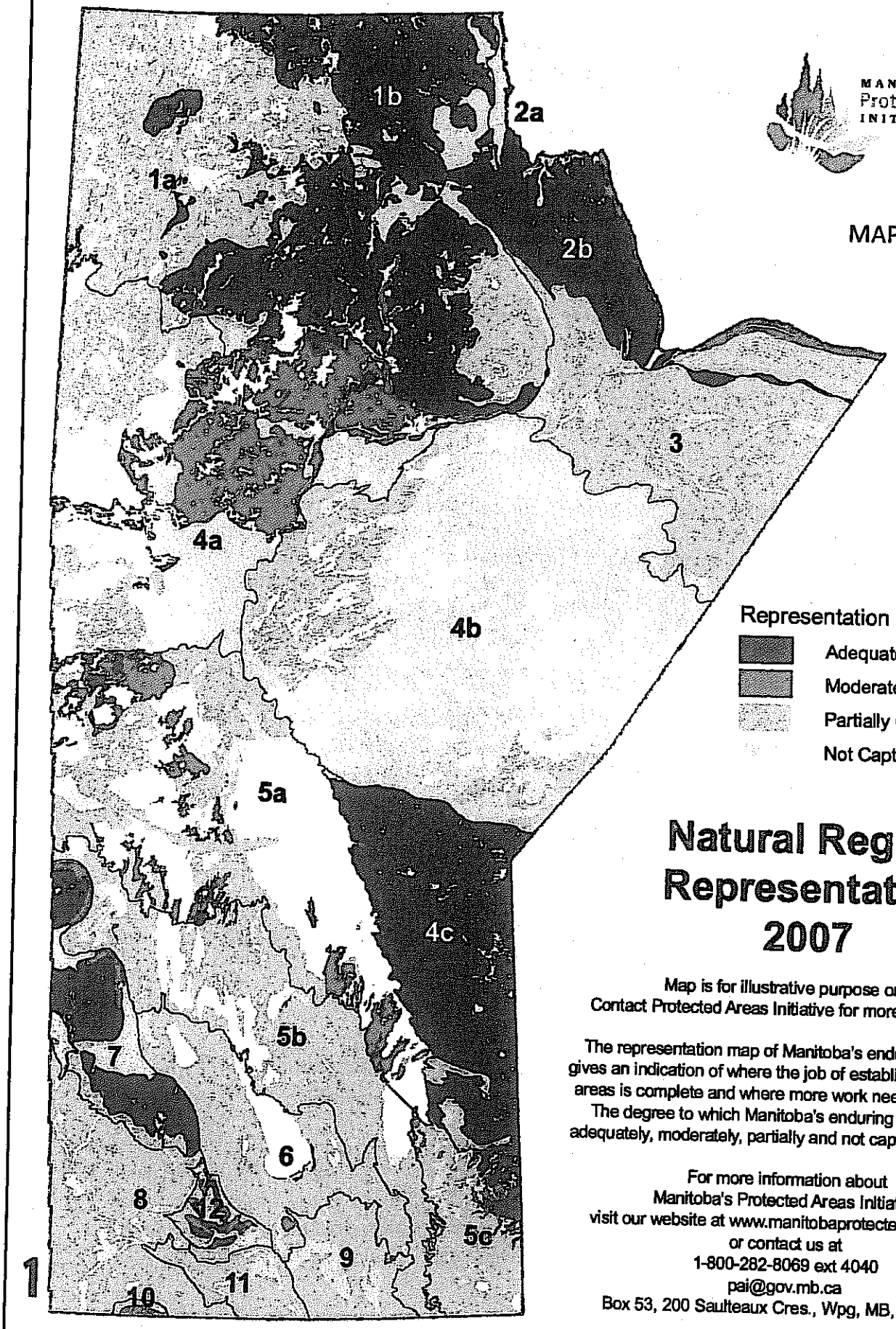
- The section of boreal forest between Poplar River and Oxford House, representing roughly 25% of an east side route, is largely free of linear infrastructure. It is also free from forestry resource allocation – a key criterion in preserving ecological integrity. This is the area where the greatest impact on ecological integrity would occur, particularly if the

Poplar/Nanowin Rivers Park Reserve is to be avoided through a more easterly routing. From Berens River south, a routing close to Lake Winnipeg and adjacent to the existing transmission line ROW would have minimal impacts on ecological integrity.

- The east side is virtually entirely in the boreal shield ecozone. Given that this forest does not recognize provincial boundaries, even with an east side Bipole III Line, tracts of intact boreal shield forest greater than the definitions above would remain in this region of Manitoba and Ontario.
- A west side routing will cross not only boreal shield but also boreal plains ecozones (from roughly Ponton to Red Deer Lake). This latter ecozone is considered to be highly impacted and at greater risk – according to Global Forest Watch, less than 15% remains in large, intact areas. This includes the same ecozone that was identified for protection as part of the proposed Manitoba Lowlands National Park. Although there are potential routing options through this ecozone that could parallel existing developments, an argument could be made that this region has greater urgency for protection of ecological integrity than the vaster boreal shield forest of the east side. However, this forest does not have the same profile and emotional appeal as the east side.
- A July 2007 map prepared by Manitoba's Protected Areas Initiative illustrates at a high level where the Province considers that adequate protection exists for the Natural Regions (or ecoregions) of Manitoba (Map 1). Both an east and a west side routing would pass through ecoregions that are not considered to have the enduring features adequately captured, including ecoregions where no protection yet exists. This is most significant for the east side, where the large Natural Region 4b Hayes River Upland would have to be traversed, but a west side routing may pass through several natural regions that do not have enduring features captured. However, the map also indicates that an east side routing would pass through a significant area that is considered adequately represented – Natural Region 4c Lac Seul Upland.
- A more detailed discussion of the potential UNESCO World Heritage Site is provided below, but some references suggest that if 50% or more of a region's land is given protected status, then integrity is protected. As noted above, the Province already considers this natural region to be adequately represented in terms of enduring features. This means that, provided that the Bipole III Line does not alter the potential UNESCO status, a routing scenario for the east side could be developed if it were coupled with real, and perhaps additional, protected status.

3.1.2 Ecologically Sensitive Areas and Protected Areas

Manitoba's Protected Areas Initiative is in the process of assembling a network of lands that protect representative samples of the province's 18 natural regions. This has been identified as a priority for the provincial government. Candidate sites move through a hierarchy of designation, beginning with Area of Special Interest (ASI) to Protected Area



MANITOBA'S
Protected Areas
INITIATIVE

MAP 1

Representation Legend

- Adequately Captured
- Moderately Captured
- Partially Captured
- Not Captured

Natural Region Representation 2007

Map is for illustrative purpose only.
Contact Protected Areas Initiative for more information.

The representation map of Manitoba's enduring features gives an indication of where the job of establishing protected areas is complete and where more work needs to be done. The degree to which Manitoba's enduring features are adequately, moderately, partially and not captured is shown.

For more information about
Manitoba's Protected Areas Initiative
visit our website at www.manitobaprotectedareas.com
or contact us at
1-800-282-8069 ext 4040
pai@gov.mb.ca
Box 53, 200 Saulteaux Cres., Wpg, MB, R3J 3W3

July 2007

Manitoba

Proposal to Park Reserve to Protected Area. Once established, a Protected Area would likely not be able to be traversed by a new transmission line.

Existing and potential Protected Areas exist along both the east and the west sides of the province, rendering this topic largely neutral in terms of deciding on an east vs. a west preference. Potential impacts on ecologically sensitive areas and protected areas can largely be avoided through routing selection that avoids them – recognizing that avoidance adds to costs through longer line length and the need for more expensive angle towers. Other factors to consider:

- On the east side, the existing or potential Protected Areas are large, but generally better identified and further along in the designation process. There are several ASIs between Poplar/Nanowin Rivers Park Reserve and Henday area, but they are large blocks and routing may be possible through them. In other words, there is more knowledge and certainty in dealing appropriately with Protected Areas on the east side.

- There is less knowledge and certainty regarding potential and existing Protected Areas on the west side. The greatest challenge will be finding a route through the area known as the Saskatchewan River Forest Reserve and south, roughly from Cormorant and down to Swan River. Although lacking the profile of the east side, sites such as the Saskatchewan River Delta may be important. Large swaths of this area are covered by ASIs. In most cases, ASI boundaries are flexible and can be changed to respond to new information. However, single or restricted occurrence enduring features have limited flexibility for boundary changes. Significantly, during the Wuskwatim Transmission Line Project, essentially only one alternative route could be identified for evaluation in the section from Herblet Lake to Rall's Island Station near The Pas. The timing to gather appropriate information and work through consultative processes on potential protected areas on the west side would be significant.

- An east side routing will cross two Canadian Heritage Rivers, the Hayes and the Bloodvein, both of which are already crossed by either 66 kV or 138 kV transmission lines. A west side routing will cross one Canadian Heritage River, the Red, which is presently crossed by a 500 kVac line north of Winnipeg. Although CHRS status does not preclude additional transmission lines, there will be an aesthetic impact on the recreational experience and an impact on the values for which the rivers were nominated, particularly for the two northern rivers.

3.1.3 Rare, Threatened and Endangered Wildlife, Habitats and Flora

In the absence of routing studies for either the east or west side, it is impossible to know the extent and magnitude of rare, threatened and endangered wildlife, habitat and flora. Detailed route selection typically identifies such sites for avoidance. The major exception

is woodland caribou, and the following section compares the two potential routings in terms of potential impact on this iconic species.

Woodland Caribou

Of all the wildlife in the boreal forest the woodland caribou is often singled out special attention. Canadian coins feature the queen on one side and symbols of our identity on the other. On the quarter it's a caribou. A prominent symbol of wilderness values.

All boreal populations of woodland caribou are listed as Threatened both provincially and nationally. There is a provincial conservation and recovery strategy in place in Manitoba and a draft national recovery strategy nearing completion federally. Both strategies recognize the primary objectives in caribou conservation as retaining existing populations and maintaining the integrity of their ranges. The common history of woodland caribou decline is for individual populations to have their ranges disturbed by human activity, which (i) isolates populations, (ii) removes habitat, (iii) upsets the natural balance between caribou and other species, and (iv) provides opportunity for increased kill by human hunters. Caribou commonly occur in small herds (tens to perhaps a few hundred animals) and have a low reproductive rate compared to moose and white-tailed deer. Consequently, caribou populations lack the ability to recover from even a few additional deaths each year. Disturbed populations typically dwindle and then disappear. The disappearance can take as long as a few decades, but the end is predictable. Over the past century, numerous boreal woodland caribou populations have disappeared across Canada and there is no record of any population ever re-establishing itself after it has become locally extinct.

There are several points of general consensus in the wildlife research and management communities regarding boreal woodland caribou:

(1) The critical aspects of habitat are that it occurs in a very large range (hundreds or thousands of square kilometres), and that it be mature coniferous forest (including bogs and fens if present);
(2) Caribou populations will decline if they are sharing their range with moose or white-tailed deer and their parasites or predators;
(3) Caribou populations will decline with even small increases in the number of individuals killed by humans; and
(4) The negative effects of range disturbance may not become evident for 20 years or more owing to a time lag before changes in wildlife and human uses of a range occur.

Potential impacts to caribou from transmission lines may occur from the noise and activity during transmission line construction, which could displace any caribou in its vicinity, likely by several kilometres. Effects of construction activities are unlikely to yield long-term consequences to caribou populations if the disturbance is of short duration and it is planned to avoid key seasons.

In isolation, the direct effects of a transmission line ROW, once operating, are not likely to disrupt an established population and should not put caribou populations at risk – it is

the access facilitated by a transmission line ROW that leads to greater risk. Specifically, human access for hunting and access by other forms of wildlife, which presents risk of disease transmission from moose and white-tailed deer as well as changes in predator populations. Accordingly, the ability to isolate a transmission line ROW from other activities will dictate its impact upon caribou.

In comparing the east side to the west side from a transmission line planning point of view, all caribou ranges encountered are High Risk, regardless of an eastern or western routing.

East Side: Any transmission line constructed on the east side of Lake Winnipeg would intersect the range of the Atikaki-Berens population, one of three populations already in the High Risk category. The Manitoba Conservation and Recovery Strategy shows a blank space north of the Atikaki-Berens range. It is known that this area contains one or more caribou populations but there is not sufficient information to determine the extent of their range(s). It would be prudent to consider the area between the Atikaki-Berens range and Oxford House as being occupied by caribou. Lake Winnipeg is a natural barrier to woodland caribou populations. Should a transmission line be constructed on the east side of Lake Winnipeg, placing the corridor close to the lake would, at worst, remove the westernmost margin of population ranges and cause minimal loss of caribou range.

West side: The western corridor options provide opportunities to follow existing transmission lines, rail lines or highways for most of its length. The Wabowden population's range is already bisected by both roads and rail lines. From the Wabowden area, a route north of Moose Lake then south past the Pas and Swan River appears able to avoid introducing any new linear features into caribou ranges.

Eastern vs. western routing: Considering the points of consensus on boreal woodland caribou noted above and the knowledge of woodland caribou in Manitoba, the west side presents the best options for woodland caribou in Manitoba. It would not need to fragment additional caribou ranges and would leave a large contiguous block of caribou habitat on the east side of Lake Winnipeg. Widening an existing transmission line corridor would reduce impacts relative to creating a new corridor. As noted above, the direct effects of a transmission line are much less than the effects related to associated access. Parallel transmission lines in the same corridor would provide a minimal increase in access compared with the establishment of a transmission line in a new area. Potential mitigation measures could be applied regardless of the selected routing, although their effectiveness are speculative. Route selection is the most important consideration; within any selected route, mitigation measures should focus on access along the ROW. It is also important to note that though the ranges and dynamics of all woodland caribou populations in Manitoba are not known and might benefit from study, funding additional research will not provide new information for many years and is unlikely to be able to inform the planning process.

3.1.4 Disturbance to Fur-bearing and Other Wildlife Populations

While important, especially for Aboriginal communities, at this high level of comparison, no significant difference between an eastern vs. western routing is identifiable, with the exception that an east side routing passes through a greater length of boreal forest, while the west side routing passes through more ecozones and potentially a greater diversity of wildlife populations.

3.1.5 Aquatic Habitats and Stream Crossings

While important, at this high level of comparison, no significant difference between an eastern vs. western routing is identifiable. Both routing options would cross major rivers and a myriad of smaller rivers and streams, as well as a variety of wetlands. The longer western route might cross more water bodies, but this is speculation. Existing mitigation measures would reduce potential impacts regardless of the routing choice.

3.1.6 Impacts on Carbon Stocks

The Wuskwatim Transmission Line Project includes an assessment of potential impacts on carbon stocks. Global warming is of increasing concern and attention. Right now it is difficult to make any meaningful comparison for an east vs. west Bipole III Line. Very generally, it appears that potential release of carbon would be greatest in forested areas, meaning that the east side may have a higher impact without mitigation or offsets. This issue cannot be used in making routing decisions at present due to insufficient information, but Manitoba Hydro will be increasingly cognizant of this topic.

3.2 Differences among Potential Socio-economic Impacts

In general, as with biophysical impacts, routing selection processes plus environmental assessment and mitigation measures result in few residual socio-economic impacts with new transmission lines. However, the mitigation required may be difficult, expensive and sometimes extremely disruptive and upsetting for the individuals involved. Public perception, especially near Winnipeg and other built-up areas, will view the construction and presence of the Bipole III Line negatively (see Section 4.1).

The west side option is significantly longer through rural and built-up areas and will require more avoidance routing and mitigation to minimize impacts on:

- Farming operations
- Visual impacts
- Noise
- Heritage resources
- Health concerns, especially linked to EMF (regardless of current scientific literature or Manitoba Hydro's position)
- Negative impact on property values

It will be virtually impossible to avoid homes in routing the Bipole III Line. The risk for the associated significant dislocation is greater with the longer western option, particularly in the vicinity of Winnipeg.

Socio-economic impacts will require avoidance routing and mitigation in the northern sections for either an eastern or western potential routing including: communities, Registered Trap Lines, access by non-members into traditional land use or Resource Management Areas of First Nations, etc. Neither routing would be more or less challenging in this regard. However, the west side has a long history of mining, forestry, hydroelectric development, settlements and related infrastructures that are not found in the core parts of the east side. While at times this may provide opportunity to parallel existing infrastructure and reduce impacts, intense human development conversely presents more obstacles.

4.0 Considerations Associated with Different Routing Options

This section raises a number of considerations that are linked to biophysical and socio-economic impacts, but deal with specific issues. For example, one consideration is the nature of opposition in built-up areas and why a western route might be perceived as benign while an eastern route is troubling. And while the issues raised here are eclectic, they are useful considerations associated with different route options and important from a general planning perspective. One notable feature in all of these topics is the degree of uncertainty, as each involves a degree of speculation and ultimately requires substantial judgment.

4.1 Opposition in Built-Up Areas

A west side routing would pass through significantly greater rural areas and pass in proximity to more built-up areas, particularly near Winnipeg.

Limited discussion with elected municipal officials in rural municipalities and planning districts suggest a surprising absence of strong views that would preclude a new HVdc line in built-up areas. Opinions have been expressed to the effect that:

- The municipal relationship with Manitoba Hydro has always been positive. There will be no outright opposition to a line by municipal governments. The municipal position might be cautious but certainly open to discussion and a willingness to find solutions.
- There were offers from Planning Boards to facilitate discussion and meetings
- There is a notion that transmission lines are necessary for the public good. Civic duty requires cooperation in building this infrastructure.
- Some people associate transmission lines with economic development and prosperity and see them in a positive light
- Financial incentives to landowners have created a very positive relationship with the Corporation. Municipal concerns would relate to use of municipal lands and impacts to future development opportunities.

There will be site-specific opposition to new transmission in built-up areas of the province. It is inconceivable that new transmission could be built without coming close to some rural or ex-urban residences. Based on Hydro's experience to date, opposition from individuals affected by the line can be expected to be ardent, vociferous and litigious. Depending on the magnitude of opposition, elected officials may become less accepting of the HVdc line. In addition to the cost of acquiring easements and rights-of-way, Hydro should expect to be faced with expropriations, buyouts, and settlements for damage to property values.

To terminate at Riel, a west side routing will need to circumnavigate Winnipeg to a significantly greater degree than an east side routing. Ex-urban development has increased the extent and density of houses and developments outside the city's perimeter since the previous Bipoles were built and since the 500 kv line was built in and out of Riel. Opposition will be more vocal and organized in these areas, and mitigation

measures such as financial incentives to landowners will be less appealing and successful than in rural farmland. No one will want the HVdc line in their back yard.

4.2 The Evolving Nature of Resources Management Areas

In northern Manitoba, the provincial government is party to the development of Resource Management Areas (RMA) and the recognition of Traditional Use Areas. RMAs exist or are in development on both the east and west sides of the province. These initiatives are in collaboration with First Nations and recognize that Aboriginal rights extend beyond reserve boundaries into unoccupied Crown lands. They have proven to be an effective forum to facilitate discussion and to coordinate planning. The whole notion of co-management has been evolving, in part due to Supreme Court rulings, and in part simply due to an interest in better community relations.

However, the evolution of Traditional Areas and Resource Management Areas is beginning to show there are limits at which they can become counterproductive. While a Resource Management Area should provide a forum for consultation and improved decision-making, if the RMA begins to take on attributes of real property, it can become an impediment to development and cause conflict among First Nations by allowing one party to effectively veto projects of interest to the majority of Aboriginal people in any one region. Rather than reducing conflict, these arrangements can create tensions whereby the government states that the relationship is one of consultation but in effect grants a right of consent to each First Nation in a region prior to any resource allocation.

These areas are a direct provincial responsibility, however, Manitoba Hydro is often drawn into these discussions because of First Nation concerns about mitigating or offsetting impacts of transmission lines. First Nations on both the east and west side have clearly indicated a desire to be consulted regarding future hydro-electric development, including transmission lines, and the RMA agreements will be a factor in these discussions.

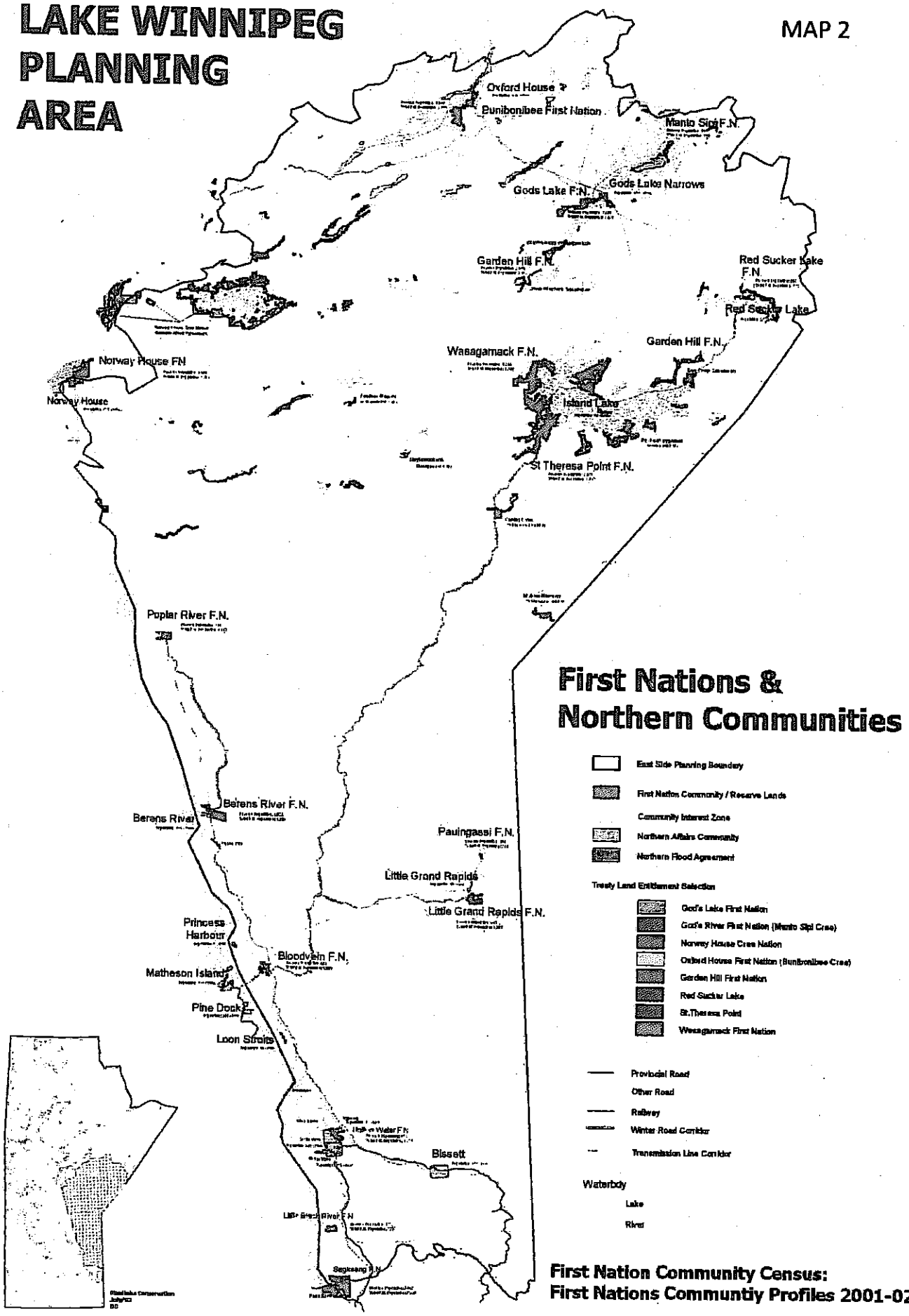
4.3 Current Partnerships

Manitoba Hydro has two major business partnerships with First Nations related to the development of new generation:

- There is an agreement with Nisichawayasihk Cree Nation (NCN) to jointly develop the Wuskwatim Generating Station. This is a 200 MW plant estimated to cost some 1 billion dollars. Associated transmission will see a new corridor from Thompson to the Wuskwatim site and to The Pas.
- In October 2000, Manitoba Hydro and Tataskweyak Cree First Nation (TCN) entered into an agreement in principle to explore the business opportunity to develop the Keeyask Generating Station. This is a 620 MW site that will cost upwards of 3 billion dollars. While transmission has not been discussed, TCN has understood that it will have to facilitate a transmission corridor as well as agreement to an infringement of Aboriginal rights at the site of the station. However, discussions about a Bipole III Line to date has been in the context of a

EAST SIDE LAKE WINNIPEG PLANNING AREA

MAP 2



First Nations & Northern Communities

- East Side Planning Boundary
- First Nation Community / Reserve Lands
- Community Interest Zone
- Northern Affairs Community
- Northern Flood Agreement

Treaty Land Entitlement Selection

- God's Lake First Nation
- God's River First Nation (Manto Sipi Cree)
- Norway House Cree Nation
- Oxford House First Nation (Bunibonibee Cree)
- Garden Hill First Nation
- Red Sucker Lake
- St.Theresa Point
- Wasagamack First Nation

- Provincial Road
- Other Road
- Railway
- Winter Road Corridor
- Transmission Line Corridor

Waterbody

- Lake
- River

First Nation Community Census:
First Nations Communtiy Profiles 2001-02)

Northern Community Census:
Northern Community Profiles 1996 Census

north/south orientation away from the TCN Resource Management Area. The notion of an east/west line would be something new and would potentially traverse a significantly longer section of the RMA.

The TCN Resource Management Area covers as much as 7% of the province. It stretches from the proposed Conawapa converter site to the LGD of Mystery Lake (Thompson) and is contiguous with the NCN RMA.

These relationships suggest there is a reasonable opportunity to achieve agreement with both TCN and NCN on a west side transmission corridor. This report has not involved any technical studies but a map review of the integrated transmission system at least suggests the opportunity to widen existing and proposed transmission corridors through these Resource Management Areas to The Pas.

4.4 The East Side "Address"

Regardless of potential impacts and opposition to a west side routing, the east side has gained an upscale "address". It has garnered international attention and has become symbolic of efforts to "save the boreal forest". The east side has been formally recognized by Parks Canada as a place of "***outstanding universal value***" when it added this area to Canada's Tentative List of World Heritage Sites. Details regarding this initiative and the profile of the east side among environmental groups are discussed in later sections.

A Manitoba news release of February 2007 notes "The project has already ***generated considerable international interest*** since the site would fill an identified gap in the World Heritage Site system of protected areas, and because it proposes an innovative approach to land management that combines natural and cultural features. It has exceptional ecological values with extensive undisturbed forests, lakes and wetlands that reflect unique geological processes and represent critical habitat for several threatened or endangered species including woodland caribou, bald eagles and wolverines. The site also represents an outstanding example of traditional Aboriginal life based on a close and enduring relationship to the land"

It is notable that similar claims are not made for the west side of the province, even though there are ecological units on the west route that are arguably of equal value to anything to be found on the east.

This notion of an east side address is important in understanding why an east side route would likely attract fire while a west side route may move through the environmental licensing process somewhat easier.

4.5 The East Side Planning Initiative/ WNO

The East Side Planning Initiative or Wabanong Nakaygum Okimawin (WNO) virtually encompasses the entire area required for an east side Bipole III corridor save for the extreme northern end (Map 2). Launched in 2000, WNO has a mandate to develop

"traditional land-use plans and a broad area plan for the east side." There are 16 First Nations in the planning area with Norway House/Gods Lake and the Island Lake communities on the northern boundary and Sagkeeng on the south.

The EPI/WNO has gone through several evolutions. Most recently, on April 3, 2007, the Province of Manitoba and the Signatory First Nations signed the Wabanong Nakaygum Okimawin (WNO) Council of Chiefs Accord. The Accord "confirms the government to government relationship between WNO First Nation Governments and the Government of Manitoba ...reinforcing the most comprehensive traditional land use planning in this country."

Clause 3.10 states that until the "First Nations land use plans are developed and adopted or resource management agreements are in place, the Province, before deciding on a proposal for an allocation or disposition of Manitoba Crown land or resources for an activity in the Planning area, will consult meaningfully with any First Nation Government whose aboriginal or treaty rights may be adversely affected by the proposal." Late drafts of the Accord went beyond consultation to grant the right of consent over resources dispositions on the east side. References to consent have all been removed from the final document.

4.6 WNO and the Transmission Line

The "Promises to Keep..."[1] document states: "The vision of the East Side Planning Initiative is based on the fundamental principal that the land is and must continue to be protected and. Further, it is a vision which:

- Equates the importance of human development with the requirement for a wise and sustainable stewardship of the land."

The document goes on to say that this vision includes opportunities for economic development of local resources. It is intended to balance economic, social and environmental issues. It is not prescriptive of excluding any type of development and is not prescriptive of excluding a transmission line.

There is a disconnect between the Province's and WNO's position on the Bipole III Line. The "Promises to Keep..." document notes that in its own community consultations the "reaction to the corporation and the proposed transmission line corridor on the east side of Lake Winnipeg was either uniformly negative, or contained significant overtones of mistrust and suspicion" (section 6.6). However, the report did not recommend that the line not be built. The report actually included 10 recommendations providing guidance on major issues that would have to be dealt with through negotiation, consultation and planning. Further, there is a perception that some east side communities are willing to discuss an east side route in the context of economic opportunities. A recent example was found in the printed media ("East side is the right side", Letter to the Editor, *Winnipeg Free Press*, July 28, 2007).

[1] Promises to keep - towards a Broad Area Plan for the East Side of Lake Winnipeg, East side Planning Initiative, September 2004

This issue is complicated by statements from the provincial government ruling out an east side location, in part, because of opposition from First Nations. In a ministerial tour of east side communities in 2004, First Nation communities voiced consistent and uniform opposition to an east side route. In early 2007, statements were made by government ministers to the effect that an east side location was being protected from Hydro development.

WNO may be a potential forum to continue discussion of an east side location. As an organization with a mandate to develop a plan for the east side, the Province would be looking to the WNO for advice. However, while the Secretariat is managing the planning process through the WNO Council of Chiefs structure, the WNO does not have a mandate to make significant decisions on behalf of participating First Nations.

There is uncertainty and risk regarding support or opposition by First Nations for potential routings on either side, although the debate has been more specific and longer term on the east side. It is clear that there is some First Nation support for an east side route but that the support is not unanimous. Also, the support that exists is conditional on financial incentives/opportunities that are beyond what Hydro has proposed for its transmission development fund. For a west side routing, there is opportunity from existing partnerships with NCN and TCN, and recent transmission lines have been successfully routed, but this does not guarantee that opposition will not occur and nor be significant and demand the same financial incentives/opportunities. First Nations have not been directly contacted for this report.

4.7 The Government Role in Planning

Planning for a new transmission line includes elements that are beyond Manitoba Hydro's mandate. Amongst those interviewed there is a common opinion that the Province should take a lead role in the initial planning and decision-making. The rationale for this includes:

- The expense involved. The cost for the Bipole III Line down either corridor will run into the hundreds of millions of dollars, with a west side routing costing significantly more. The choice of east vs. west will affect the provincial debt and the ability of Manitoba Hydro to pay a future dividend.
- The reputation of the Crown is at stake.
- The Crown has a duty to consult. Over time, Supreme Court decisions have refined and provided guidance about the Crown's duty to consult with respect to Aboriginal and treaty rights. The Crown has an obligation to respect and honour the Aboriginal and treaty rights of communities and communities have a right to be appropriately consulted and accommodated if activities adversely affect their rights. Some aspects of this duty to consult may be delegated to Manitoba Hydro but ultimately the Crown has the responsibility to meet this obligation.

There is a wide range of interests that are also the mandate of the Province of Manitoba. These include:

- The impact of land-use decisions and shared decision making on non-First Nation communities and industry, and the potential conflicts with other public policy objectives;
- Public well-being in terms of health and safety linked to reliability;
- Commitment to address climate change and protect and improve the environment;
- Potentially competing values; and
- Community and economic development responsibilities.

5.0 Impact on Other Initiatives in the Area

There is forestry and mineral exploration on the east side of Lake Winnipeg. There are also plans to start extending all weather roads into the region. None of these initiatives would be impacted by or benefit from an east side transmission corridor.

The sole issue that has received attention in this respect is the potential for a large part of the east side to be inscribed as an UNESCO World Heritage Site. Most of this section deals with UNESCO issues.

5.1 UNESCO World Heritage Site

UNESCO (The United Nations Educational, Scientific and Cultural Organization) through its **World Heritage Committee** has inscribed 851 properties worldwide to its **World Heritage List**. These properties are recognized by the World Heritage Committee as having **Outstanding Universal Value.** The properties may be listed as cultural, natural or mixed locations. Inscription of sites on the World Heritage List serves as a catalyst for heritage preservation and provides access to the World Heritage Fund. Sites inscribed on the World Heritage List benefit from the development and implementation of a comprehensive management plan that sets out preservation measures and monitoring mechanisms. Inscription of a site can bring an increase in tourist activities at the site. This can bring funding to the site and local economy provided that the tourism activities are well planned and within sustainable tourism principles.

Just as projects may be inscribed, they may also be removed from the World Heritage List if they do not maintain their cultural and/or natural values. A number of sites are listed as being in danger of removal. These include a site in China where UNESCO has serious concern over a controversial proposal to build dams and water power infrastructure near the site. China has been asked to provide a report within the next year on the environmental consequences of the project.

Parks Canada is the lead federal agency for the implementation of the World Heritage Convention in Canada. Sites considered for nomination by a State Party are placed on a **Tentative List**. Canada last updated its Tentative List in 2005. At that time, over 150 sites were identified as potential candidates with 10 being placed on the list. One of these was a large site located in the boreal forest of eastern Manitoba and northwestern Ontario known as Pimachiowin Aki, which was advanced as a combined natural and cultural site.

The proponents of Pimachiowin Aki are:

- Pikangikum First Nation (Ontario)
- Poplar River First Nation
- Pauingassi First Nation
- Little Grand Rapids
- Governments of Manitoba and Ontario

The east side generally and Pimachiowin Aki specifically has received significant provincial, national and international attention and support.

Nomination of a site requires a wide range of management plans and documents cataloguing the "cultural and natural" heritage values. Pimachiowin Aki will take four to six years before the nomination is ready to be put forward to UNESCO for consideration. The Bipole III Line routing and assessment studies could conceivably be occurring in advance of or concurrent with this process, which may generate greater opposition unless Manitoba Hydro is seen as actively and meaningfully supporting the UNESCO process, as well as working on a routing that avoids the study area completely.

The precise boundaries of the site are not known and will not be known for some time. But while the boundaries of the site are not well defined, Parks Canada believes there is a high potential for conflict with a transmission line. Furthermore, First Nations territories extend all the way to Lake Winnipeg, meaning there is no place where the line can be built without impacting to some degree the cultural values of the Aboriginal population.

The impact of the Bipole III Line on any future UNESCO application is uncertain. In large part it depends on the level of cooperation between Manitoba Hydro and all of the UNESCO proponents. There are numerous World Heritage Sites that have fully developed modern infrastructure systems. Most of these were in place before inscription. A transmission line within the site would certainly weaken the case for inscription based on "natural values".

The worst case scenario would be constructing the Bipole III Line in the face of First Nation opposition. Under the UNESCO convention, the proponents and especially the State Party are obligated to protect an area of **"outstanding universal value"**. This includes protection for both natural and cultural values. Building a line within the site in the face of opposition would be taken as a lack of commitment to UNESCO values and poor stewardship. It is not clear how the UNESCO process would deal with conflicting First Nation support and opposition to a transmission line.

The best case scenario would:

- Achieve full cooperation with First Nations and other proponents
- Develop agreements between Manitoba Hydro and First Nations that go beyond a simple financial relationship to demonstrate mutual respect, recognizes stewardship for the land and honours First Nations cultural ties to the land. This could be shown through meaningful support of Pimachiowin Aki.
- Clarify and align the Province's and Manitoba Hydro's positions and priorities. The Bipole III Line project will only move forward if the two entities share a common vision and objectives on both transmission and UNESCO issues.

If First Nations are on-side, the Bipole III Line routing studies could commence and begin to consider the broad and site-specific biophysical and socio-economic impacts. If all or some First Nations oppose the line, it could become a serious complication involving the Province's honour with respect to previous commitments, its reputation and its commitment to "stewardship". Regardless, it will be a long and difficult process.

5.2 Roads and Other Initiatives

The Province has committed to a road up to Bloodvein First Nation by rebuilding the Rice River Road and bridging the Bloodvein River. This is a five-year program with an annual commitment of $8 million and a total project cost of $41 million. This has been discussed as the first step in establishing all-weather road access further north into Berens River.

Manitoba Infrastructure and Transportation is about to commission a "System Planning Study" that would consider the options for more northern communities. This will likely involve an east/west route from the Island Lake communities to Norway House.

First Nation support for roads but opposition to the Bipole III Line is not necessarily inconsistent when viewed from a community context. While the roads have been identified by the communities as something they need and want, the need for the Bipole III Line is external and potentially of no community benefit. In Aboriginal communities, Manitoba Hydro developments come with an image of environmental degradation and an atmosphere of distrust.

The proposed roads will avoid the proposed UNESCO site. Persons involved with the UNESCO process seem willing to take the application forward with notions of a road but are apprehensive about the Bipole III Line unless there is clear First Nation acceptance. For those who see transmission lines as benign, this position might be difficult to accept. It should be noted, however, that the current road proposal for the northern part of the region does not involve a north/south link. That alignment apparently, at least in part, reflects a concern to maintain the wilderness values of the region. This road would traverse the area (Natural Region 4b Hayes River Upland) with the greatest need and opportunity to preserve ecological integrity on the east side.

5.3 Manitoba Model Forest

The east side is home to Manitoba's only Model Forest, a non-profit organization dedicated to finding new and innovative approaches to sustainable forestry practices in the boreal forest. An east side routing for the Bipole III Line would traverse the Manitoba Model Forest research area but would not affect their designation as a model forest.

5.4 Minnesota Legislation

During the 2007 Minnesota Legislative session an Omnibus and Energy Policy Bill was passed requesting Manitoba Hydro to provide information annually with regard to First Nations that are a signatory to the Northern Flood Agreement.

The Bill reads as follows:

> Sec. 9. Minnesota Statutes 2006, section 216C.052, is amended by adding a subdivision to read:
>
> Subd. 8a. **Manitoba Hydro Information.** By January 1. 2008 and each year thereafter, the task force shall request the Manitoba Hydro-Electric Board to

provide the following information for each community that is a signatory to the Northern Flood Agreement, including South Indian Lake:

(1) median household income and number of residents employed full-time and part-time
(2) the number of outstanding claims filed against Manitoba Hydro by individuals and communities, and the number of claims settled by Manitoba Hydro; and
(3) the amount of shoreline damaged by flooding and erosion, and the amount of shoreline restored and cleaned.

For purposes of this subdivision, "Northern Flood agreement" means the agreement entered into by the Northern flood Committee, Incorporated, the Manitoba Hydro-Electric Board, the province of Manitoba and the government of Canada on December 16, 1977.

This legislation was a result of lobbying by Fresh Energy and Minnesotans for Energy Efficient Economy (ME3). ME3 initiated the Just Energy campaign in December 2001, which focuses on educating consumers about the impacts Manitoba Hydro's large dams are allegedly having on people and the environment.

Fresh Energy claims that Manitoba Hydro is able to sell power to Excel Energy at a low rate because the external environmental and socio-economic costs are not included. This, they claim, hurts Minnesota's own renewable energy development.

Their purpose is to block future sales to Minnesota in order to develop the market for wind energy in that state. They support the development of energy that is locally generated and appear to be using the claims of a Manitoba First Nation to further their interests.

Fresh Energy and ME3 appear to have a strong presence in Minnesota, and will continue to attempt to negatively influence purchases of Manitoba hydro-electric power. A lengthy dispute with First Nations over the selection of a route for the Bipole III Line will likely add 'fuel to the fire' regarding opposition to the purchase of power from Manitoba.

6.0 Scope of Interest of Environmental Organizations

This section considers a number of factors involving local, national and international environmental organisations. Like other aspects of the routing options (other than technical considerations) there is uncertainty.

There is no credible **Theory of Action** to guide decision-making in this area. While having unanimous support from First Nations along either routing option is clearly beneficial, it is far from certain that any course of action will produce a predictable overall result and change the magnitude and nature of potential opposition by environmental organizations to either an eastern or western route. A firm decision and pushing ahead without consensus could produce a range of results. For example:

- It could be found, after the fact, that some of the concerns and issues raised by either side prove to be bogeymen.
- Alternatively, environmental groups could coalesce around this issue and make it into an international *cause celebre*, damaging the reputation of the Crown, causing a local political crisis and threatening energy exports to the United States.
- Since the outcome is unpredictable, it argues for taking extraordinary measures for achieving consensus before moving ahead. At some point, however, the economic price of avoiding conflict might simply be too great and the Corporation and the Province will have to risk a conflict situation. There are significant economic concerns that have to be balanced against uncertain outcomes in the environmental arena.

6.1 Nature of the Debate

The debate can be characterized as being one of technical/economic/public good arguments vs. less quantifiable environmental concepts, concerns and a different public good, as well as impacts on Aboriginal culture and interests. To some First Nation and environmental groups, the transmission line is a symbol of environmental destruction and specifically the loss of something unusual and of great value. While the arguments may not always be completely logical and the "facts" put forward may be inaccurate at times, the opposition is very real and should not be underestimated.

To a certain extent the debate has been sloganized: "Save the Boreal Forest"/protect "Pristine Wilderness Values". These slogans make a strong appeal to emotion, but what does saving the boreal forest mean in practical terms?

There are perceptions that we need at least one place preserved from development – protection for our one last wild place. These are very deeply held opinions. Increasingly, the scientific community is weighing in on the debate, raising ecological integrity as a more measurable and definable objective. More data is becoming available about the boreal forest in terms of its role as the "lungs of the planet" and as a carbon sink, as well as the 'free' services it provides, such as purifying water sources. Nonetheless, the debate will be one of values – caribou vs. economics. This argument cannot be won on the basis of duelling environmental impact reports. Hints from both sides of the debate that disaster will happen if their side does not prevail do not assist in arriving at the best decision. The

debate has to be engaged at the community as well as the provincial and international level.

To date, the debate has largely focused on the east side, and the implications of a west side routing have not been fully discussed. There is much that is unknown about this potential routing, including potential opposition environmental groups.

6.2 Commitments

Commitments have been made to the public, First Nations, local environmental groups and international environmental groups that there will not be a transmission line on the east side of Lake Winnipeg. Specifically, a minister of the provincial government apparently had a meeting with the Natural Resources Defense Council (NRDC) and made a commitment to the NRDC that there would not be a transmission line down the east side of Lake Winnipeg.

The context of these commitments is important, i.e. they were made in the context of apparent unanimous opposition to the line by First Nation communities on the east side. If that position has now changed there may be good reason to re-evaluate government decision-making (e.g. a letter to the editor published in the *Winnipeg Free Press* on July 28, 2007 by the Chief of Berens River indicated a desire for an east side routing).

The discussion has been complicated by public statements committing the government to protection for the east side, a debate in the media, and advocacy for creation of a UNESCO World Heritage Site. The proposed Pimachiowin Aki World Heritage Site has the potential of being used by opponents of the transmission line as a powerful weapon in the debate, regardless of whether actual boundaries of the site would exclude an HVdc transmission line next to the existing 66 kV line. As a proponent of the site, the Province is required to demonstrate stewardship and to offer protection for the natural and cultural characteristics of the site, which the government has promoted as being of "outstanding value to humanity". An east side routing creates the opportunity to attack the Province's commitment to stewardship with the argument being that the government's actions are contrary to the UNESCO Convention and would endanger the potential for inscription.

6.3 The Risk of Creating a Cause Celebre

An east side transmission corridor could develop into a "cause celebre". How would that happen and what is the significance? Does it matter? How can the risks of these events be balanced against the direct cost of the longer and technically inferior west side Bipole III Line?

If an east side route location develops into a confrontation – First Nations and environmental groups vs. Hydro – it will draw in national and likely international environmental groups. This creates a risk to the Province's reputation. Decision-making and licensing processes will become more onerous and lengthy. A cause celebre also potentially creates an economic risk related to export energy markets.

The risk of creating a cause celebre derives in part from the fact that the east side has achieved national and international recognition. This was reinforced by the UNESCO

proposal by way of which Parks Canada has recognized the east side as a place of "outstanding universal value." Being added to Canada's Tentative List for World Heritage Sites is a "prestigious place to be."

The east side has a prominent place on the web sites of major national and international environmental associations and a prestigious environment award was recently made to Sophia Rabliauskas of Poplar River First Nation:

> "Working on behalf of the Poplar River First Nation, Rabliauskas succeeded in securing interim protection for the boreal forest of Manitoba, effectively preventing destructive logging and hydro-power development while the government and international agencies deliberate on the future of the region. The Goldman Prize **amplifies the voices of these grassroots leaders** [emphasis added] and provides them with: **international recognition** [emphasis added] that enhances their credibility and **worldwide visibility** [emphasis added] for the issues they champion."[2]

NRDC has also identified the east side of Manitoba through its BioGems campaign, which prominently features the east side boreal forest.

> "The Natural Resources Defense Council (NRDC) is an environmental action group supported by 1.2 million members and activists. Our mission is to safeguard the earth: its people, its plants and animals, and the natural systems on which all life depends. By fighting in court, working through Congress, and mobilizing millions of people worldwide, NRDC has stopped powerful corporate interests from destroying our clean air and water, public lands and wildlife habitats."[3]

The NRDC has aligned itself with high profile individuals that attract media attention. In the case of the boreal forest, Robert F. Kennedy Jr. has taken an active role in protecting the boreal forests of eastern Manitoba.

The NRDC has been cited in the media as one of the United States most powerful and effective environmental groups. The NRDC web site offers specific commentary on the Manitoba commitment to protect the east side:

> "Until recently the wildest stretch of the forest along the border of Manitoba and Ontario was in danger of losing these nesting grounds to new hydropower development. *But in May 2005, the Manitoba government announced that it will seek alternative routes for proposed hydro transmission lines that would have cut through the forest* [emphasis added]."

If the east side became a high profile issue, it is expected that other international groups will also participate.

---

[2] Web Site (www.goldmanprize.org): The Goldman Environmental Prize
[3] NRDC Web Site: www.savebiogems.org

How would Manitobans react to this? While many Manitobans wish to be perceived as environmentally sensitive, there may be a public backlash against international interveners, particularly Americans, weighing in on what is seen as a local issue.

Could a cause celebre involve more than public tension? Is there a risk to energy exports to the United States? Potentially this could come by way of legislation in U.S. markets where the wind energy and/or coal lobby coupled with environmental groups could manage to successfully block energy imports from Manitoba. The U.S. has a reputation for protective trade actions and recent legislation in Minnesota already obliges the state to consider the environmental effects of electrical generation in Manitoba. The notion of impaired energy exports is highly speculative but is part of the overall consideration in balancing a much more expensive western route against a potential confrontation on the east side.

The potential cause celebre is strengthened by the collaboration of environmental groups with First Nations, and a linking of their joint concerns. Conversely, if all or some First Nations begin to support the Bipole III Line, environmental groups could no longer point to a lack of First Nations support for the east side route as part of their opposition, and it could potentially place them in conflict with First Nations communities, with whom they have often previously partnered.

6.4 Environmental Organizations

A detailed but not exhaustive list of environmental organizations that may have an interest in participating in the debate about routing Bipole III can be found in Appendix II. It is drawn from interveners in the Wuskwatim licensing process and organizations that have identified interest in the boreal forest and/or specifically the east side on their websites. Since the debate to date has focused on the east side, it is not known which, if any, local groups may oppose a west side routing.

6.4.1 Local Environmental Groups

Local environmental groups will actively participate in the licensing process of major projects such as Bipole III Line. They are familiar with the Manitoba environment and can provide useful input by identifying environmental impacts that may have been underestimated or overlooked and suggesting mitigation measures.

Local environmental organizations are generally small and under funded. As such, they have limited ability to influence public policy. Their primary strength is their strong connection to national and international organizations, and their ability to draw these organizations into the debate.

6.4.2 National Environmental Groups

National environmental organizations are much larger than local groups and have substantially more funding. Thus, they have some ability to retain experts and to proactively place advertisements outlining their position in the media.

6.4.3 International Environmental Groups

International environmental organizations tend to be very large, well financed and influential. They operate by stopping projects they consider destructive to the environment. Local and national environmental organizations rely extensively on the media to carry the issue into the public forum as a matter of public interest. The defining distinction between these organization and international organizations is the financial ability of the international organizations to pay for media messaging, to lobby and to litigate. With the resources and experience to involve the courts in a meaningful way, international organizations do not need to rely on political pressure generated by free media coverage to force favourable decisions.

The following table compares local, national and international environmental organizations and outlines their relative strengths.

TABLE 1: LOCAL, NATIONAL, INTERNATIONAL ENVIRONMENTAL ORGANIZATIONS

	Local	**National**	**International**
Structure	Volunteer Small or informal memberships	Local chapters National membership/ less than 25 000 Some paid staff but mostly volunteer at the chapter level Focus on programs	High paid technical staff including in-house legal counsel Well organised fund raising structure Membership ^ 500 000
Financial Resources	none to modest	< $5 M annual budget	> $50 M annual budget
Capabilities	Local newspaper articles/ letter writing Contacts to national and international environmental organizations Present at environmental hearings	Media stories Organize local demonstrations	Litigation High level lobbying Paid media messaging Media savvy with extensive media contacts National member and public mobilization Celebrity spokesperson
Potential Impact	Raise local concern about government/ Hydro environmental policies	National attention Impact guidelines for the environmental licensing process	Legal injunctions Adverse legal judgments International trade threats/ action

The Way Forward

Elements of a go-forward strategy:

- A connection has to be made between the proposed transmission line and the public good. Without public support a decision will never be made for either corridor.
    - This report assumes that a new bipole is essential to improving the reliability of the integrated transmission system and that the public is at significant risk from energy outages due to potential failure of the existing HVdc lines. Contradictory messages in the public forum include the notions of new generation "merchant plants" and economic opportunities associated with the "Manitoba Advantage". Clarity is required as to the rationale for this project.
- An east side route requires near unanimous First Nation approval. There is little public will to act contrary to firm First Nation opposition.
    - Testing First Nation reaction to renewed discussions on an east side corridor will require that tacit approval of the province. This is a sensitive area that will require the province to acknowledge that it is prepared to re-evaluate its position on an east side route on the basis of new information.
- There is an opportunity to turn this project from one where there is reluctant approval to proceed with any corridor to pride in having developed a "best in class" facility.
    - Manitoba Hydro has become arguably a leader in innovation when it comes to community relations and environmental commitments. Rather than proceeding on the basis that a new HVdc line is something really awful that has to be done in spite of effects, the project should be presented as an opportunity to highlight Manitoba skills and commitment to environmental issues.
    - There is a win-win solution that needs to be explored. This holds true for either an east or west side corridor.
    - The focus on innovation, commitment to minimizing biophysical and socio-economic impacts and enhancing aboriginal culture will not likely win over people with deeply held environmental convictions but it will take energy out of a "stop the line" campaign.
- The way forward, for either corridor, must include a strategy to protect the cultural identity of First Nations as well as offering economic development opportunities for them. It's got to be both and cannot be simply a financial pay-off.
    - Protection of culture should be addressed firstly;

- The notion of economic opportunities should come second. It is as complex, however, as protecting and enhancing aboriginal culture:
    - There are few direct community benefits available in either the construction or operation of the line
    - There are rising expectations about the magnitude of cash benefits that will be available through funding arrangements that might come with the line. These expectations will be difficult to meet.

- In either the eastern case or the western case the province should be directly involved in corridor selection. There are provincial interests and responsibilities that are beyond Hydro's mandate.

Appendix I

Terms of Reference
Bipole III Transmission Route Study

Review of Socio-Economic and Environmental Considerations and Potential Roles and Impacts of Environmental Organizations

Manitoba Hydro is in need of a major north-south transmission line in order to enhance the reliability of the existing power system to deliver power generated in northern Manitoba to the southern load centres.

Numerous technical reviews have been undertaken of routing options, including East of Lake Winnipeg, the Interlake and West of Lake Manitoba. These studies have determined technical benefits associated with an East Side routing.

Manitoba Hydro is interested in obtaining additional information with respect to the environmental and community considerations of different routing options. As well as regarding the potential roles and impacts of environmental organizations that play an active role vis a vis hydroelectric transmission in Manitoba.

Accordingly, Manitoba Hydro are interested in contracting consulting services to evaluate:

- The environmental landscape of alternative routes, including an assessment of environmental significance;
- Considerations associated with different routing options, including community preferences, potential community partnerships;
- Considerations associated with the impact of a transmission line on other initiatives, in the area, in particular, the potential UNESCO World Heritage Site designation and related community partnerships;
- The scope of interest of environmental organizations in Manitoba transmission routing, including membership, local interest and support and potential influence;
- Relative risks from an environmental perspective

Appendix II

The following is a list of local, national and international organizations that may be expected to participate in a Bipole III Line licensing process.

Local Organizations

Boreal Forest Network
The Boreal Forest Network identifies itself as an environmental justice organization of environmentalists, indigenous peoples and scientists concerned with the protection and sustainable use of the boreal forest, one of the three great forest systems of the world. Their website states that the boreal is also home to almost a million indigenous people, many of whom retain a strong connection with their cultures and traditions and value their traditional economies.

The Boreal Forest Network is strongly opposed to the eastern route and has published papers expressing a preference for the western route. It is expected that they will be very active in any licensing process for Bipole III Line.

Centre for Indigenous Environmental Resources (CIER)
CIER is a national, First Nation-directed environmental non-profit organization with charitable status and is based in Winnipeg, Manitoba. CIER was founded in 1994 by a small group of First Nation leaders from across Canada who recognized the need for Aboriginal peoples to have the capacity to solve environmental problems affecting their lands and resources. CIER received federal non-profit corporate status in 1995 and became a registered charity in 2000. CIER develops and implements sustainable solutions to proactively address environmental issues affecting First Nations lands and resources.

CIER appeared at the Wuskwatim hearings and can be expected to participate in a Bipole III Line licensing process.

Consumers Association of Canada – MB Chapter/Manitoba Society of Seniors
The Consumers' Association of Canada describes itself as an independent, non-profit, volunteer organization dedicated to educating and informing consumers and to representing the best interests of consumers to all levels of government and to all sectors of society. The Manitoba Society of Seniors represents Manitobans 50 plus by promoting their needs and concerns.

These two organizations are usually represented by common legal counsel and usually provide a common presentation at hearings such as the Wuskwatim licensing process and rate applications before the Public Utilities Board. They focus on both environmental and economic issues.

Manitoba Industrial Power Users Group (MIPUG)
MIPUG represents the large industrial power users in the Province. They have the financial capability to hire experts in various areas of expertise as deemed advisable. While not an environmental organization, MIPUG appeared at the Wuskwatim hearing and can be expected to appear at a Bipole III Line hearing focusing on security of supply and economics. The greater cost of a western route will be of concern to them.

Manitoba Wildlands
Manitoba Wildlands identifies itself as a Manitoba based non-profit environmental organization that continues the protected areas work of WWF Canada and Nature Canada in the province. According to its website, it works with Manitoba communities, industry sectors and other environmental organizations. Fulfillment of public policy to establish protected areas, which represent our lands and waters, is the focus of Manitoba Wildlands. The organization also provides international, national and regional information about climate change, water, energy, species, biodiversity, and forests.

Manitoba Wildlands participated in the Wuskwatim hearing process and can be expected to be participate at future hearings regarding Manitoba Hydro facilities. They currently are working for and providing advice to the Poplar River First Nation.

Provincial Council of Women of Manitoba
The mission of the Provincial Council of Women of Manitoba is to empower women to improve the quality of life for themselves, their families and society. PCWM acts as an advocacy body at the provincial level on behalf of various women's groups and organizations concerning a wide range of issues relating generally to the improvement of social conditions for the community and family.

It is possible that the PCWM could appear at a hearing regarding Bipole III Line approval focusing primarily on social issues.

Resource Conservation Manitoba (RCM)
RCM is a non-profit, non-governmental organization directed by an elected community board. RCM's mission is to promote ecological sustainability through environmental education and to develop alternatives to current practices. Their programs focus on sustainable transportation, waste reduction, climate change, and sustainable living. In addition, RCM's elected community board makes formal presentations on issues such as utility rates, extended producer responsibility, ecological fiscal reform, and urban planning.

RCM promotes applied, ecological sustainability through environmental education and the development of alternatives to current unsustainable practices.

RCM did not participate in the Wuskwatim hearings and may or may not become involved in a Bipole III licencing process.

Time To Respect Earth's Ecosystems (TREE)
TREE describes itself as committed to the advancement of a more sustainable society in which the planet's natural endowments of living and nonliving systems and resources are valued, respected and conserved. Recognizing that this natural legacy is finite and subject to degradation and depletion, TREE promotes eco-efficiency, improving the ratio of social benefits to environmental harms as essential pillars of a sustainable society.

TREE participated in the Wuskwatim hearing and can be expected to participate in future hearings focusing primarily on issues of sustainability, particularly energy conservation, alternatives to northern generation, and the socio-economic consequences of alternatives.

National Organizations

Canadian Boreal Initiative
The Canadian Boreal Initiative (CBI) describes itself as "working with a wide range of conservation organizations, First Nations, industry and other interested parties to link science, policy and conservation activities in Canada's boreal forest." Located in Ottawa, CBI also partners with non-governmental organizations, First Nations and others across the country in on-the-ground boreal conservation work. The Canadian Boreal Initiative is supported financially by the Pew Charitable Trusts.

While CBI is unlikely to participate directly in the Bipole III licensing process, they will be involved through their partners doing on-the-ground conservation work.

Canadian Parks and Wilderness Society (CPAWS)
CPAWS is a national organization with 13 chapters across the country, including a Manitoba chapter. It has a membership of 20,000 and a staff of 50 with an annual budget of almost $5,000,000. One of the organization's primary objectives is protection of the boreal forest. As a signatory to the Boreal Forest Conservation Framework released by the Canadian Boreal Initiative, the goal of CPAWS is to protect at least 50% of Canada's boreal forest in areas off-limits to development.

CPAWS has issued a public warning regarding the proposed transmission of power between Manitoba and Ontario, which would bisect Ontario's northern boreal region. CPAWS urges governments to proceed with caution subject to the following conditions:

- The project must demonstrate that it is better than alternatives
- Routes for the project should proceed through already fragmented landscapes before intact areas are disturbed
- If fragmenting the intact landscape is necessary, then it should proceed only after conservation-based land use planning determines how to protect the region's ecological integrity
- Carbon implications must be fully accounted for
- Aboriginal peoples have constitutionally protected rights that require governments to fully consult and accommodate these rights

CPAWS holds the position that for hydro-electric facilities to be truly "green," they must be located close to the end user to eliminate the impacts of long transmission lines.

Given their focus on the boreal forest at both the national and Manitoba chapter level, CPAWS is likely to choose to participate in the Bipole III Line licensing process.

David Suzuki Foundation
The David Suzuki Foundation is a large environmental foundation funded largely by individual donations and with substantial media presence and experience. Global conservation is one of the Foundation's primary objectives. That prominently includes protecting the boreal forest. They could well participate in the Bipole III Line licensing process.

Nature Canada (formerly Canadian Nature Federation)
Nature Canada is a member-based, non-profit conservation organization. Their network includes 40,000 supporters and more than 350 naturalist organizations across Canada.

Their mission is to protect nature, its diversity, and the processes that sustain it. The focus of Nature Canada is on effecting change on issues of national significance, including bird conservation, wilderness protection, endangered species and national parks.

Nature Canada may well participate in the Bipole III Line licensing process, as it would involve routing through the boreal forest, the nesting grounds of many species of migratory birds.

Sierra Club of Canada
The mission of the Sierra Club of Canada is to develop a diverse, well-trained grassroots network working to protect the integrity of our global ecosystems. The Sierra Club of Canada's mission focuses on five overriding threats:

- loss of animal and plant species;
- deterioration of the planet's oceans and atmosphere;
- the ever-growing presence of toxic chemicals in all living things;
- destruction of our remaining wilderness; and
- spiralling population growth and over consumption.

While not participating in the Wuskwatim process, given their dedication to maintaining the ecological integrity of the remaining wilderness, the Sierra Club could choose to participate in the Bipole III licencing process.

International Organizations

Natural Resources Defense Council
NRDC is a large, vocal and influential organization with 1.2 million members and has partnered previously with Canadian and Manitoban environmental organizations. Their

mission is to safeguard the earth – its people, plants and animals – and the natural systems on which all life depends. The NRDC often aligns itself with high profile individuals that attract media attention. In the case of the boreal forest, Robert F. Kennedy Jr. has taken an active role in protecting the forest of eastern Manitoba.

The New York Times and The Wall Street Journal, among others, have identified NRDC as one of America's most powerful and effective environmental groups. By fighting in court, working through Government, and mobilizing millions of people worldwide, NRDC has stopped powerful corporate interests from implementing projects that the NRDC believed threatened air and water quality, public lands and wildlife habitats.

The NRDC BioGems campaign [which prominently includes the east side boreal forest] empowers citizens to take effective online action in defence of our planet's most endangered wild places"[4]

The NRDC website offers specific commentary on the Manitoba commitment to protect the east side as follows:

> "Until recently the wildest stretch of the forest along the border of Manitoba and Ontario was in danger of losing these nesting grounds to new hydropower development. **But in May 2005, the Manitoba government announced that it will seek alternative routes for proposed hydro transmission lines that would have cut through the forest** [emphasis added]. Yet until the government grants permanent protection to the region, the threat of transmission lines, roads, mining and logging remains. Indeed, Manitoba Hydro's president has said that the recent decision concerning transmission lines does not mean that the company is ruling out development in the region, only that it is looking at other options."

The NRDC is a vocal supporter of the proposed United Nations World Heritage Site and is working with the Poplar River First Nation to assist them in achieving their goals.

NRDC is almost certain to participate in the licensing of Bipole III Line, particularly if an east side route is selected. Given their history and resources available to them that participation could include both intervention at a hearing and legal action in an attempt to prevent or delayconstruction. It is unknown, but possible that they could oppose a west side routing as well.

In addition to NRDC, there may be other American or European organizations that national and local environmental groups could align themselves with, if they feel international intervention would assist them in achieving their objectives.

[4] NRDC Web Site: www.savebiogems.org

Tab 41

Appendix 8.10

Community Reports: "What We Heard" By Community

East Side Planning Initiative Community Visits

September 2003 to January 2004

What We Heard

Final Report By Community

Response to East Side Planning Initiative Community Visits

September 2003 to January 2004

Communities Visited and Groups Invited to Participate:

Groups:
FN – First Nations
MMF – Manitoba Metis Federation
NACC – Northern Association of Community Councils
ESPI – East Side Planning Initiative
ESRT or Round Table – East Side Round Table

Communities **Page**

Berens River FN, NACC, MMF 1
Bissett NACC 3
Bloodvein FN 5
Bunibonibee Cree Nation 6
Garden Hill FN, MMF 9
God's Lake FN, NACC 12
Hollow Water FN 14
Island Lake NACC 15
Little Black River FN 16
Little Grand Rapids FN 18
Little Grand Rapids NACC 20
Manigotagan NACC, MMF 20
Manto Sipi Cree Nation 21
Matheson Island / Loon Straits / Princess Harbour NACC 22
Norway House Cree Nation 23
Norway House NACC 24
Pauingassi FN 26
Pine Dock NACC 27
Powerview and local MMF 28
Red Sucker Lake FN, NACC, MMF 30
Sagkeeng FN (North Shore) 31
Sagkeeng FN (South Shore) 35
Seymourville / Aghaming NACC. 37
St. Theresa Point FN 38
Wasagamack FN 42

What We Heard

Berens River First Nation - NACC, MMF

- We would like to see the agendas of the advisory groups and East Round Table meetings of upcoming events and presentations, especially with respect to the areas of concern. We want to be notified and informed. We want the minutes of the meetings to be circulated to the community.

- Protected areas need to be revisited. The Poplar River Protected Area includes some lands, which are part of Berens River traditional territory. Because Berens River was never consulted on this, its territory should be removed from the protected area.

- We as a community are concerned with Lake Winnipeg water quality. The algae, smell and water levels are all concerns for us.

- River quality is threatened by activities that are still occurring in Ontario. What happens in Ontario will ultimately affect the Watershed here in Manitoba. We need to know what is happening in Ontario.

- We need to know what Manitoba Hydro has in store for us. We cannot create an effective community plan without knowing where the hydro-line is going to be placed.

- Hydro maintains its transmission lines by using chemicals to kill plants. Imagine what that will do to our trees and animals. We would like to know what type of chemical they will be using and have any existing studies forwarded to us.

- Hydro lines and roads will destroy our traditional way of life. How are the young people going to survive?

- Are they going to put the lines in the north, but distribute the electricity to the south?

- The cost of hydro in the north shows we are not getting our share of the resources sold.

- We will not be able to tap into the hydro lines.

- Are there any studies of the effects of transmission lines on humans and the environment? If so, we would like to see them.

- The literature provided does not address how this process might affect treaty rights. Should speak

- more about constitutional treaty rights, protected areas.

- How will this plan affect outstanding Treaty Land Entitlements? What has been happening with respect to the TLE process? How much Crown Land should we be granted?

- We do not condemn the ESPI process; we just do not have a position in place as yet.

- There is no protocol to consult with First Nations.

- Are there any studies being done on the effects of dams and the associated lake quality and lake level changes? These factors affect our livelihoods. What about studies on the rivers, river levels and river water quality? Also we need to know the effects of control structures on our water systems. Our water has gone down 4 feet and it is affecting our fishermen.

- Hydro should consult if they have a plan in place.

- Do you come out and help us with an action plan to stop it development if we do not want a hydro line here?

- If the Trappers Association make a presentation, will you hear it?

- Trapline boundaries should be the boundaries for planning.

- An all-weather road would effect Treaty #5. Right now there is no money coming this way for road development and maintenance of existing network. Available dollars are not reaching into the northern areas.

- If a road goes through we need to get our lands back for ecotourism. We are not getting our share.

- We have 3rd world roads here.

- We need economic development; government is stalling development.

- Safety on Lake Winnipeg is an issue as people have died crossing the lake.

- Do not want more consultations – takes too long.

- Need to make recommendations immediately - be preventive.

- Berens River recommended the ESRT advise the government that it would like to see Rupertsland Constituency cut in half.

- Our children's education service is below provincial teaching standards.

- Our business is presently going to Pine Dock, then Gimli and Selkirk. They value our business.

Bissett – NACC

- Include all East Side communities in one meeting.

- Caribou habitat protection important.

- Economic development and environmental protection processes need to work together in a balanced way.

- Wanipigow River Protected Area has allowed mature trees to fall into River and is destroying the river quality. If trees are allowed to be cut, the economic gain is met and the river is managed. Protectionism measures applied by Parks Manitoba may do more harm than good to the river and river areas.

- Land allocation methods for specific purposes by the province are not an acceptable practice.

- Why should we be interested in mining activity when the broad area plan is going to prevent such?

- Land regulations contravene Mining Act.

- Bissett is a mining town and residents believe there is mining potential for the area.

- Mining is the lifeblood of Bissett. Exploration needs to continue.

- Government bureaucracy is causing problems with respect to mining activity. To keep a claim valid, one has to show some kind of development or be in violation of the Mining Act and loose the claim. In many cases, people have been refused permits to travel forestry roads to their claim.

- Government must allow claims in the area. The government supports the community, however not in the way the community wants them to.

- Nopiming and Atikaki Parks restrict mining development.

- First Nation Communities are getting all the traplines and pulp potential. They have a federal voice, larger than ours.

- It appears that the message that Manitoba is not open for business is getting outside to the industry. American mining investors are going elsewhere when they learn the Hayes River will be set aside as a heritage river. How will this affect future mining exploration activity?

- Residents want to benefit from mining and want to stop restrictions imposed by park regulations and legislation.

- Nopiming Park was originally a multi-use park. Now you cannot consider it a multipurpose park due to restrictions. Recreation activities and development are causing problems.

- The province should sell Crown lands for development by local land developers. I am specifically referring to a piece of land, which is not pristine, but on which other activities used to take place but no longer do. All that remains now is a bunch of run down buildings. To allow local residents to make use of such lands is sustainable development in my opinion.

- Trust issues are non-existent with government initiatives (i.e. lodges and cabin development). Government did not follow the recommendations of the community in the past, why should we trust them now?

- Access to existing education and training programs needed to help secure future for the community.

- Tourism does not benefit Bissett. The road through Nopiming bypasses Bissett.

- Government has negatively impacted Caribou when they developed the road through Nopiming. Road development has affected the Owl Lake Caribou herd (Black Lake calving grounds).

- A Canadian Heritage River designation impedes mining exploration.

- Who is going to replace the vacated mining representative position on the ESRT.

- The Prospectors and Developers Association should be represented on the East Side Advisory Committee.

- Pave road from Manigotagan and finish straightening road to Bissett.

- What is happening with the Cat Lake to Red Lake Road?
- Jobs are needed in Bissett. Some have to leave by spring for work.

Bloodvein First Nation

- Safety is a concern.
- Can we access information on the Internet?
- We have to fight for our land. I see that in process for East Side area.
- Community is all for economic development.
- The planning process should be with First Nation's people directly because it impacts First Nations directly.
- We need to know who the stakeholders are and what their plans are in all of this.
- We need to do more as a community to protect treaty lands.
- We need to develop our own plan.
- Elders and youth must be involved to voice concerns in our community.
- We need protected area for our traditional lands.
- We want total control of the management of forestry and mining here.
- We do not think the people on the ESRT represent us. I strongly recommend considering one of the communities like Poplar River or Hollow Water to represent us. They live on the East Side.
- What are the hidden agendas on economic development?
- If we tell you what we want, what guarantees are there that we will get what we want?
- We are working on several proposals that involve our traditional land and we are asking for total control.

- Does the area that Tembec is planning to cut involve Bloodvein, or is it part of the planning area? We want to do the cutting ourselves, not Tembec. We are in a process of looking at deals like the one Pikangikum has with their Whitefeather Initiative and co-management model.

- Are they going to hurt the rivers if the road comes?

- How much space will the Native people have?

- We are preparing for the all weather road by training our people how to use the heavy equipment needed too build.

- We are not a stand-still community; we are looking forward to young people gaining employment.

- Most often people out there come here to tell us what's best for us, but we live here, not them. They come in and take over and say it is in our best interest. They have not walked in our moccasins so to speak. The time frame is too long, it take too much time and in the mean time the government have their way to control it till they get what they want.

Bunibonibee Cree Nation

- We need to do something for our young people. We need to look in the long term.

- We need to plan what we are doing in an orderly fashion.

- Concerned that corporations come in and ruin a First Nation community and the First Nation doesn't get anything from it. For example, First Nations currently do not benefit from harvest of timber resources. Communities must benefit if there is development, not the individual but the whole community.

- An all-weather road would cut through many traplines and trappers would not get anything from it.

- Must plan right with traditional knowledge. Must carefully consider how development takes place. Have to consider how we are part of the land.

- Trapline regulations pretty strict - size of a cabin etc, cost of permits to build etc. Regulations quite an issue here. Too many regulations and why are there regulations on our land?

- Not happy with 100-foot set back from water bodies.

- A 200' x 200' area for trapper's cabins is not realistic. There should be more flexibility for types of traps to be used.

- Government regulations prohibit using trapline/cabins for rental purposes. Regulations should support trappers.

- One of the questions I have, one thing promised to us, First Nations have access to live off the land so how come there are regulations e.g. hunting? After all is done what is going to become of the process and plan?

- Trapping is an issue of sharing resources again. This should be part of the issue for the Round Table – so we can maintain our lifestyle. Trapping and its regulations need to be addressed in the plan

- Gain must be distributed to the community as a whole, not to individuals.

- Teach youth how to grow trees and about renewing the forest and fishery resource. Learn how to develop and operate businesses to create a good living for residents.

- Happy to see things moving ahead through the process.

- Must share resources and FN must benefit from them.

- Thankful that people are focusing on our concerns. Often people call on us for work and we do most of the hard work. In the end however, we are thrown aside. It is good to have people who are concerned about us.

- Why can someone own our traditional land? I worked for long time in fisheries and for 5 months could make a living fishing. Prices of fish not viable now. We need a subsidy program for fishing.

- Concerns were expressed about a burial ground threatened by development. There are 3 graves and it should be marked on a map.

- People who come up here like mining companies, need to bring more money into the community and share the wealth.

- Land use is very important.

- Timber is the most important resource to retain for the community. Mining activity is expensive to pursue.

- Trapping regulations not meeting our needs and don’t make sense.

- More meetings are needed.

- Were there studies done for resource assessments, land analysis, community development, economic development and traditional history?

- Hydro promised money ($8000.00 per trapper) to trappers who were hit by the development but they did not follow through. I get the same impression about the round table.

- Concerns about hunting. When an area becomes developed there is a boundary placed around it and you can't hunt there. Can we go hunting and hunt where we want? The plan has to allow us to be able to go in and hunt where we want, even if the area is developed.

- Concerns about third parties coming in and using our traditional areas and then we have a problem negotiating with them on land use. Negotiating can take a very long time.

- We are encouraged by the chief and council having this evening.

- Interesting idea – teaching our young people to grow trees so they can re-grow what is taken out, same with fish – need to target the young people.

- An all-weather road has all sorts of advantages including training for heavy equipment operators.

- Oxford Lake was closed for fishing due to high transportation costs to market. We were throwing away our catch because there was no transportation to market. It is a waste of time, energy and fish. Pickerel is the only viable species now and it is three times the work. Need to build a road to transport fish out. Advantage of road – transportation the fish, shopping trip, etc, - all weather road is the answer. On the other side more influences coming in and not all good influences. We need to be aware of that.

- Important that FN gets the first chance to get employment.

- There was mention of stakeholders. Northern Stores, MTS, MB Hydro are stakeholders. Are they trying to maximize benefits for the communities – what are they doing for the communities?

- If a trapper looses a cabin in a fire is there a way that he can be reimbursed for it?

- This information should go to the schools for study and response.

- Need to look at funding for informing the community of the process.

- It is important to get a community person hired soon because election is coming in November.

Garden Hill First Nation – MMF

- Youth are not aware of the Treaties, their cultural traditions, the old way of life and survival on the land. Government should provide funding to train youth to learn about Aboriginal tradition and culture.

- Loss of traditional way of life and children being taught to follow dominant way of life.

- Fish are being depleted from the lakes and information is not being shared on fish management strategies, if any are planned or exist.

- Health is a major issue, particularly diabetes. Government should work more closely with northern communities in the area to address health concerns.

- High price of goods and services makes it difficult if not impossible to purchase healthy foods such as fresh fruit and vegetables.

- Government needs to respect hunting and other rights, if parks, which include traditional hunting areas, are deemed to be set aside as protected areas.

- In the past, the province did not consult with trappers regarding government actions impacting on traditional trapping/hunting grounds.

- Concern raised because of the lack of community members at the meeting. Another community meeting recommended allowing for more involvement from the rest of the community.

- Do not talk about a hydro line before a commitment to an all-weather road as the community cannot continue to be at an economic disadvantage due to an absence of all-weather road access.

- We see the pros and cons of roads to communities. The social impact has to be addressed when we see a road coming into Garden Hill. A lot of elders have expressed they do not want a road because of the destruction of life from alcohol and drugs.

- It is critical to understand and be aware of the many sites of historical and cultural significance before proceeding with roads or hydro.

- We have heard from Hydro before. They came to us, but did not give us enough time to respond. You have to give us more time. There is a lack of information provided by Hydro for the community to adequately respond or participate. We do not want a poor consultation process. We do not want this to be like the Hydro process.

- Development has to be shared with the people of Garden Hill.

- There is a need for more information on the ESPI process.

- Concern about mining at Twin Lake and if the community could get government to involve them in meaningful consultation before permitting mining in their traditional territory.

- Possibility of constructing a larger airport on a cost shared basis.

- Government can promise anything but not deliver because in the end government will do what they want.

- There is a lack of trust between communities and government.

- There is concern about a proposed road which can be built from North of God's Narrows connecting Northern Ontario.

- Pros' and cons of an all weather road discussed - would lower the price of goods and transportation.

- Communities will need an analysis on what impacts an all-weather road will have on them. Elders have expressed some negative thoughts a road would bring to the community, such as alcohol, drugs and gang related problems. Government in the end will go the cheapest route.

- Manitoba Hydro held a consultation process on its hydro Bipole lll transmission line but shared only what they wanted and expected the community to learn everything on that day. Time will be needed for the community to absorb the information and get it out to all the members in order to fully participate in this process.

- A suggestion was made to include all East Side communities in one meeting.

- Maps don't show territorial lines due to lack of funding and shortage of technical people. Need for technical people to assist the community in this process.

- Lack of telephone lines is a real problem. People are not able to use the phone between 5:00 pm to midnight. This causes further problems regarding emergencies.

- If the community does not become involved in the process, they will be losing an excellent opportunity to participate in planning and development activities.

- Community is concerned of the short timeline.

- Where is the funding coming from.

- What are the next steps to this process?

- Economic development and environmental protection processes need to work together in a balanced way.

- We are not fully aware of the Treaty anymore. The younger generations have not been educated about the Treaty and the significance of our Treaty at the time it was signed.

- Years ago the white man put up a sawmill here and took all the best trees, we did not care for sustaining them then. Then he came for the fish. There are still trees and fish, but the best are now gone.

- The younger generation is not learning the traditional ways. Our youth only correspond with what they learn from a white dominant society. Our sickness is worse today (diabetes) because we have lost some of our traditional ways. If we dropped a young person off in the bush today he would not know how to survive, to make a fire, to make a bed. We need funding to retain our traditional ways and livelihood. We have to retain our traditional ways to heal ourselves.

- Prices are too high to afford the goods that we once could afford.

- Years ago the Island Lake Tribal Council talked about co-management of resources.

- You must be aware that there is a park being proposed in the area of the Wasagamack First Nation. The local trappers do not want this. There also is mining at Twin Lake. The trappers at Red Sucker Lake did not agree to this. They also are planning a road. Can the people at Red Sucker stop this legally. The people there have not been consulted. Is this the way it should be? Does the province have a responsibility to consult?

- There was a process with Treaty land selections where we identified our traditional lands, and sacred and cultural spots. The round table does not

have this information. This must be integrated, but we never had the money like you have to record all of this and create fancy maps. We need money to identify and map where the important sites and lands are. We are short of technical skills. Your community coordinators cannot do this alone.

- The community must have a general Board meeting to discuss this East Side plan.

- In 1972 a report by the community on all-weather roads was sent to the government.

- The people of Garden Hill need to hear from other communities. Why not get a few people from the 16 communities to get together to see if there are shared values. We need to understand one another. Recommend two or three from each community.

- In the past, government projects (i.e. MTS) have not included extra funding to First Nations. You have a few people, but need more people involved in the planning process. You have to understand another reality. There is no money here, there are no jobs. Up north we have vast resources, but the money and the jobs benefit the south (Winnipeg).

- Do you know how hard it is to get a telephone line between Garden Hill and Winnipeg from 5-11 at night because all the lines are jammed (internet users). Think about this from a medical perspective. There are ten thousand people up here.

- There are two TV stations here. You have to broadcast on both to touch all the people. It was only broadcast on one so you have missed many of our people.

- We want an all-weather road because we see things will be cheaper for us to but, but we are also concerned for our youth because this road will make it easier to bring in booze and drugs.

God's Lake First Nation - NACC

- The East Side Planning Initiative is entirely new to us and more information is needed. Who are the 22 people on the round table? Where are they from? How were they appointed? Is there a timeline for this process?

- Our rights are treaty driven. How can the process affirm treat rights when the Natural Resources Transfer Agreement is a contradiction to them? We have to educate mainstream society about our treaties.

- Government has a hidden agenda. When we ask the province to address our needs they say that they are not responsible. First Nation people should not be considered a federal responsibility.

- We have to consider the human factor in this process. Our regional needs have to be considered; health and education. For example, we need a regional hospital that is central to communities such as in God's Lake narrows.

- We have concerns about the environment and have been fighting with the province about cleaning up the old transmission line to an old mine on Elk Island. There is about 50 miles of wire just left on site. The government tells me they have no funds so how can they make this process work if they can't even undertake one little mine clean-up project. I don't know who else to talk to.

- When traditional areas are referred to by governments they think it is a trapline. Our ancestors come from Ontario and our traditional area is also in Ontario. It is not only ours but belongs to other First Nations.

- We are not opposed to an all-weather road as it would help alleviate the high cost-of-living for First Nation people. We would like to see road access to communities before hydro lines go through. What are other communities saying about this?

- Governments don't want to listen and probably won't listen to this plan either. For example, cottagers – governments would soon listen to them.

- We would like our road and human issues dealt with before Hydro.

- I can't see that there is anything wrong with an all-weather road. We would have benefits such as forestry and tourism.

- The community would want an east-west road connection. Use the winter road alignment so as not to disturb any more landscape.

- The timber company in The Pas has a license for cutting in our area.

- Governments do not consult with us about mining and claims until after the fact.

- We have to have training for our youth to prepare them for future opportunities such as resource development that may result from the East Side plan.

- Community contact positions should be full-time.

- Provincial government is holding up our treaty land entitlement – they should move a little faster.

Hollow Water First Nation

- Does the government or industry consult with the people or just Chief & Council?

- Do the Chief and Council have to be present for there to be consultation?

- What would happen if the recommendations conflict with the community plans?

- Does anyone in the round table membership oppose development?

- Who makes the final decision on the recommendations?

- What is community participation?

- There is a need to have something in place besides just community forum and working group. There is a need to go house to house.

- Is this consultation or an information session?

- Information should be provided beforehand to facilitate preparation and discussion. Provide information by all available means.

- Is there already a plan?

- Development already exists. What is left to be decided?

- We need a map to indicate traditional uses at Hollow Water and include Black Island.

- Hollow Water could provide a land use plan to round table.

- How can the province come in and provide permits on the Hollow Water River for cottages?

- Is Black Island included in the planning area?

- When did this process start? Was there nothing before that? Shouldn't the community have been involved in 1999? Why did it take so long to get to the communities? This should have begun with the communities.

- What about traditional territories beyond treaty (reserve) lands?

- Traditional lands are being taken away. All this is predetermined. There is a lot of skepticism about this process.

- What type of agreements can the community get from this process?

- Will government put community interests before Hydro?

- Will there be funding and technical support for community participation at the same level as the RT?

- Will there be a set amount of funding?

- What is the completion date?

- A presentation was made on the need to create a local advisory board. It was emphasized that this is an opportunity that the community must seize now because if it does nothing it would lose an opportunity. We want to be involved in benefits, partner and training for anything happening in our region. We will block any developments done without consultation.

- Traditional areas need to be extended and users need to have a say on what happens there. It all comes down to the land you control. Give us the control to see how serious you are.

- When will round table be back?

- There should be regular contact between the Community and the Round Table.

Island Lake – NACC

- How long after the deadline will the plan actually take place?

- Once the recommendations have been made, when will they be given to government?

- Who is pushing for the all weather road? Government or communities?

- Government needs to hear from communities other than Island Lake in regards to an all weather road.

- Local people need to be hired if an all-weather road is to be built.

- Forestry is not offering much employment because of changing modern technology.

- Is there any one community that can stop the process? There may not be consensus at the end of this process because different groups have different interests and views.

- Will there be a possibility to meet as a community to discuss this process to include all members.

Little Black River First Nation

- Timber is being cut within our trap lines without our input.

- The ESPI ties in with some of our community initiatives.

- The maps on the wall need to be blank so that we can identify what we want to protect as ours.

- Economic benefit and jobs are not going back to local communities.

- Expansion at Nopiming will mean that pollution will come down through our river system.

- The chief and council should be here, as we need to have direction and input from our leadership.

- Any additional travel going north will create additional opportunities for us such as a gas bar for example. A gas bar location on highway #304 might be accomplished through Little Black River reserve land being “swapped”.

- Let’s put our minds together to make our reserve a better place. We have people come to our community, let’s work together with them to plan for our community.

- We will be working to develop ideas and plans and will invite the Round Table back then.

- We need economic development, tourist development; there are lots of alcohol problems.

- We have visions of ecotourism and general tourism development.

- We need to create employment and learn how to use resources. The Round Table is here to help us, we have a small reserve and there have been too many changes of leadership. Let's work together.

- Relations must improve, not just with government but people in general. We do not want to be in a position where we have to beg for our own future. Give us our resources back.

- Billions have been spent on gun control. Money could have been better spent on assistance.

- Our infrastructure needs to be upgraded. We have a beach but lack the funding to improve the road to it. We need gravel and crushed rock for the road.

- If there is forestry development we want to do it. We disagree with the Forest Management License.

- One time wild rice was open for use by anyone but harvesting was taken away from us. Today we need a permit to harvest. We want it back and be able to share with everyone. We want to get back to that way of life. We were here before the boundaries.

- Cottage developments and expansions are occurring. Water treatment plants etc. are issues that are happening on our traditional lands and we are not being informed. We need to be made aware of these developments and our concerns listened too.

- We are scared of partnerships that are formed without the First Nations Council.

- Lets do the planning so we can help our community develop and prosper.

- We are a small community with a lack of support. Changes in leadership lead to minimal positive activity/development. We need to develop our plan to aid our community. We need to get as much from our resources as we can.

- Our land use will supercede any other plans.

- Our trapline is smaller than others in the area and should be made larger. Our population has grown.

- We have concerns with hydro and Bipole III.

- We have concerns with sustainable development. What happened to our buffalo?

- We are hindered in what we can do in our territory because of our circumstances.

- I am glad that governments seek knowledge from our scientists (Elders). Does the government already have a plan? Everything we need is contained in Treaty # 5. Why do you have to come back for reaffirmation?

- Why are there no muskrats and fish anymore? Is it because of hydro?

- Non-Aboriginal people have to work with us; relations between us have to improve.

- Maybe we don't need your help; we just need the resources you took from us.

- When is the road into the community of Loon Straits going to be improved?

- Little Black River is very interested in cottage development in the area and we should have exclusive rights to such.

Little Grand Rapids First Nation

- How do we ensure outsiders don't come in and over exploit the resources?

- How can the community stop lodges from taking in hundreds of fish?

- Commercial fishing is being opposed by local lodge owners and therefore sport fishing is the only game in the area.

- Water quality is becoming an issue as the water color is changing and affecting fish quality.

- There was mention of the world heritage site being proposed by three First Nations in the area. What will happen to the committee formed for an accord with Pikangikum, Pauingassi, Poplar and Bloodvein to address the issue of sustaining the environment? Will it be disbanded because of the round table and this process? It is recommended that the committee be included in this process.

- There has been vandalism of trap lines. There is no compensation with respect to loss of revenue by local trappers.

- The First Nation needs employment and has identified employment opportunities with Manitoba Conservation as a part solution to local unemployment issues.

- Need to improve relations and communications with Manitoba Conservation, particularly with the NRO's.

- It is a historical moment that the government is sharing information with First Nations people.

- First Nation identified future resource sharing as a means of financing resource management.

- Government hasn't shared much so what is being planned?

- Is government stopping all development on the east side? Will the winter road be built this year?

- There are no recycling opportunities in the community and as a result, landfill sites are pressured to take recyclable materials thereby using necessary space.

- Atikaki Park closed all doors and no economic development opportunities.

- Cottage and lodge developments are a concern. It appears only white outsiders are approved for lodge and other licenses.

- Trappers indicate that wildlife is moving away from traditional spawning and calving areas.

- The community would like co-management opportunities.

- There is a need for their own conservation officers to police their own community.

- Non-Aboriginals will force us out of our own lands.

- People want to maintain traditional lifestyles.

- Lodge owners are using airplanes to hunt.

- Hunting only for sport.

- Community would like another set of maps.

Little Grand Rapids NACC

- If the forests are not cut and used it will burn and no one will benefit.
- Winter roads are built too late in the season. There is a need to ensure the winter road is built earlier by the band. There is lack of capacity and experience for neighboring communities to do the job they need to do.
- Have more RCMP/policing for the surrounding communities.
- There are child welfare issues in the communities.
- What is government's strategy to deal with alcoholism and rampant drug abuse by adults and youth? This is the future of the communities and more priority should be given on these life and death issues.

Manigotagan – NACC, MMF

- There are trust issues between community members and government in general. The community finds it difficult to trust the objectives of the initiative and whether or not their suggestions/comments will be taken into consideration when it is time to make decisions.
- An elder from each community should sit on the round table to represent communities and present traditional knowledge on resources and medicines. Elders should attend all meetings.
- Everything should be recorded at these meetings.
- A community radio station could broadcast these meetings.
- Decisions will be difficult given all the competing issues.
- Money should be spent on existing roads before a new one is planned for the east side.
- Local people must benefit from resource use activities.
- The community requires jobs and road improvement projects could provide them.

- Whenever industry moves into the area, people from outside the community benefit more than local people.

- There is a lot of mistrust due to past actions of government. For example, at Wanipigow, cottage owners erected a water control structure drastically reducing the flow of water downstream. This is the source of drinking water for the Hollow Water First Nation.

- It is unrealistic to expect communities to develop positions by June 2004. This date makes the process seem like it is being fast-tracked. Communities need time and resources (money, facilitators, etc.) to identify issues and formulate positions on them.

- The Manigotagan River Park Reserve is being pushed on the people. The community of Manigotagan is planning to expand their boundary up the Manigotagan River to the second falls. Because our community is situated on the river, we would like to continue our community on the river. The park reserve is willing to start at the second falls but once the BI-Pole lll line comes down, will they take the land back from the community for this line? This is something that the community does not want to see happen.

- A person can get an outfitter license but no moose or deer tags. The resource allocation process needs to be reviewed.

- How can the City of Winnipeg dump raw sewage that affects Lake Winnipeg and not be held responsible? Fisheries are affected by water quality in the lake. Algae blooms are increasing and affecting fishers' livelihood.

- Manigotagan will share its community plan with the round table when it is ready.

- Manigotagan want more training and education opportunities in the community.

- Manigotagan does not want the Manitoba Hydro BI- Pole line running trough their community.

Manto Sipi Cree Nation

- A concern was raised that cyanide from a mine on Elk Island was polluting a river that runs into God's Lake, and whether or not it could be stopped before it was too late. The water quality should be checked.

- An all-weather road is important; it would be good for groceries. Concerns raised around all-weather access to the community included a negative impact on the lodge, on young people (access to drugs) and possible abuse of traditional areas. Highway would have to be kept clean by R.C.M.P. It is not going to be easy.

- Any routing of an all-weather road should connect God's River with Thompson.

- Manto Sipi Cree Nation needs early fire notification and professional fire fighters.

Matheson Island – Loon Straits, Princess Harbour – NACC

- At what stage is Manitoba Hydro at in getting their line in?

- Can the north-south hydro line be done in collaboration with the winter roads, ie. make 1 instead of 2 corridors?

- Why not put the roads and lines together so they do not have to use so much forest?

- Is there an issue with stopping the road in the East Side?

- I can feel the effects of the damage that Hydro has done, the water levels are low.

- It would be a blessing to have a road for those communities.

- Who is to tell us how to make these decisions and who will help us develop a plan?

- There will be anglers, hunters and trappers up here and they will use up the lands too quickly.

- Loon Straits is forgotten people here, in what way can we benefit from outsiders?

- Jobs and economic development are important.

- What advantages does the west side have when the East Side opens up?

- What are other communities saying about their issues? They might have said things we won't think about and vice-versa.

- Why does Manitoba Hydro get to say “no” to the road?
- They should take the road if they want their line to go through it?
- Make them pay for the road too, instead of a fee.
- There has been destruction from Hydro in the past with little compensation.
- Is there compensation for impacting trapline areas of First Nations if hydro lines go through?

Norway House Cree Nation

- Only a small part of original Manitoba left; it is fearful what is happening.
- How can we make our living here in a deteriorating environment?
- How can we protect our mother earth because this land is all ripped up?
- Norway House was a happy place but not anymore.
- We are beginning to return to traditional medicine.
- Fish movement in and out of the land is important
- What are the government’s plans regarding the development of the East Side?
- The Norway House Cree Nation is not accountable to the Government of Manitoba and an MOU should be in place before we participate in any planning process dealing with resource management.
- The local trappers association wants to know what will happen to the trap lines when development occurs.
- There is high unemployment in our communities, because when any development opportunities arise, proponents bring their own people to work on local projects. We have a lot of traditional people here that are qualified to work.
- We want government to consult trappers about their plans because we want to keep the land in its original state.

- Norway House considers itself a sovereign nation and the fact that the province established a First Nation Council does not mean it represents Norway House First Nation. We consider this a provincial entity.

- Land planning is important to the trappers. The trappers believe they are losing access to traditional trapping areas.

- Fur market prices are low and trapping operations are more expensive today than in the past.

- The Norway House First Nation members have a hard time locating maps for use in trapping.

- There is mining activity in the Red Sucker Lake vicinity, however, we believe this to be Norway House traditional territory.

- Since the construction of the highways, the three types of Caribou who used to be here, no longer inhabit this area.

Norway House NACC

- Information that was to be provided to communities is not being received.

- Information is not going to the community in a timely fashion.

- What is the plan? Government must have a plan in place already.

- Are any communities suggesting leaving some areas as they are?

- Is this process a spin off from the Manitoba round table? No this process is the East Side Planning Initiative and separate from the Manitoba round table.

- Does this process overlap the other round table? Yes everything overlaps.

- Request for a list of the round table and First Nations Council membership list.

- How many people attended the Norway House Cree Nation community visit?

- Concern about mining.

- Should be able to revisit the plan and have a renewal within 5 years and have the ability to revisit because changes will continue to change in the area.

- Treaty Rights must be honoured and accessibility to the lands be available for First Nations.

- Change in the water, it's dirtier with more algae.

- Swampland has an ecological process and function and is not to be viewed as wasteland.

- Aware that progress can't be stopped, it will happen.

- Each new venture should be step by step and ensure to plan stage by stage and not everything coming at once.

- Norway House NACC is currently in the process of creating a community plan. Northern Affairs has been dealing with Northern Flood issues and this has pushed their planning back.

- Concern that once the road is built people will follow with their developments. Outside influences coming into the community could be a concern.

- Community involvement needs to be done before any decisions can be made.

- Current road into the community is in terrible condition and needs repair.

- Tourism would be a plus for the community.

- Is there any info that shows possible routes for an all weather road?

- Individual councilors are building cottages and are pushing for a road.

- Cost of food and supplies higher in some communities.

- Government won't build a road unless it is for there own needs. It won't be built because the community wants it. It will be built because of the resources the government wants and needs.

- Economic development over the next 10-15 years is a major priority for the community.

- Development of a fish processing planting is currently being discussed. Fish is currently being sent to Freshwater Fish Marketing Board.

- Need to develop eco-tourism.

- Fishing Lake, cabins and opportunities not available to everyone in the community.

- Community is not made aware of activities from the resource board. They have recently been provided a spot on the board.

- Growing cranberries could be a viable opportunity for the area.

- Each community has to be consulted and they decide what should be done along the east side.

- Have to ensure it is a process that is revisited and changed as needed.

- Radio stations can be used as a means of getting the information out to the community.

- Trappers and elders communicate in Cree so there is a need to make the information available in Cree.

- Hydro development along the east side is a concern for the community.

Pauingassi First Nation

- When people are given permits to trap in the Pauingassi traditional area, the First Nation wants to be consulted so that the First Nation members can be apprised of who has been given permits and develop working relations with permitees.

- Wild rice harvesting is an opportunity the First Nation can develop and maintain.

- The construction and maintenance of a local airport would bring much-needed jobs in the area as well as bring the costs of goods and services down to acceptable levels. Currently, the price of a four-litre milk is $13.99 in Pauingassi, which is four times the price of milk in the south. Alcohol, however, is the same price.

- The construction of a local airport would also improve medi-vac programs for those individuals who require medical emergency assistance.

- The First Nation has indicated our priorities should be reviewed to accommodate our young people who require milk to develop their minds and bodies.

- Hydro rates are a serious concern to local residents. The current rate for an average sized bungalow is approximately $200.00 per month while rates in the south for a similar size home is approximately $75.00.

- While Manitoba Hydro has introduced an insulation program to help defray hydro costs, communication between Hydro and the First Nation administration has not been the best. The First Nation wants to see rates lowered through any means.

- Unemployment rates range in the 80-90 percent. A commercial fishery in the area would improve job creation, however, transporting fish would remain a high cost to the industry.

- There is opposition to outpost hunting in the area. This opportunity is done without any consultation with the local people.

- The First Nation wants to work closer with the Natural Resource Officers who frequent the area. They want their people hired to work alongside the NRO's.

- The province has sided with local lodge owners and favour these owners when developing pollicies on lodges in the north. People who live in the north should be given priority when policies are developed.

- The First Nation requested a land status report on their existing reserve lands. They indicated a misunderstanding exists between the parent First Nation and Pauingassi.

- The First Nation will advise the ESPI if they require a community meeting.

Pine Dock

- Why is Pine Dock included in the discussions of the East Side Planning exercise?

- A proposed road on the East Side of Lake Winnipeg would impact inhabitants, wildlife, eco-system, etc.

- The community wants to be consulted on land transactions and allocations in the area.

- The cost-efficiency or feasibility to build an all-weather road up the east side of Lake Winnipeg is questionable.

- The community expressed concerns about not being notified well about East Side meetings and requested that information be sent to them in a timely manner so that they would be ale to comment effectively.

Powerview and Local MMF

- Have additional timber leases been increased?
- How will the Hydro projects on the East Side impact the ESPI Process?
- Is the extension of 304-highway north talked about in connection with hydro development?
- Are we here to talk about the development on the east side?
- Send future information to Powerview Metis Local through the Manitoba Model Forest
- Is there objection to the development and construction of an all-weather road?
- There should no more Federal and provincial parks established without consent of the community.
- All communities in the southern portion of the study area have been developed around logging. We need logging and mining on the east side. Logging is much more environmentally sensitive today.
- We are concerned about the environment. Hunting, fishing and trapping are an important part of our life.
- These meetings are important.
- People in the community are educated and must be listened to.
- Parks would be OK if the tourists didn't make such a mess.
- The only thing allowed on the Bloodvein River is a canoeing and people are making decisions about the area without knowing anything about it.
- There is support for the construction of an all-weather road, to reduce freight and hauling costs and to create employment, but not more Parks.
- Costs in the north are directly related to the freight costs.

- An all-weather road would not only be helpful to the community, but also to taxpayers.

- Health problems are greater in the north; a road would help alleviate much of the problem.

- You cannot find nurses to go north because they have to fly.

- Education in health and diet, as well as nursing, ambulance and police services, would all improve with a new road.

- If a road goes into a remote area, concerns about culture are what that area makes of it. People from remote areas must leave their community on medical trips and have no one to escort them, visit them, or aid in their recovery, because others can't get to and from the hospital by road.

- There are a lot of untapped Federal dollars that could be put to training programs for local people to develop an all-weather road. This would create local employment.

- People are in favor of development but we also care about the environment. We live here and do not want to see the environment destroyed. The mill at Pine falls is very environmentally concerned and responsible. We helped reforest areas while Abitibi was here. That was never done down East.

- What ill effects will an all weather road do or have? Has the road through the Interlake affected the environment?

- If our First Nations brothers want a road we should support them.

- Environmental impact studies must take place.

- It is startling on how the wealthy all over the world try to tell us what to do we are being watched by the world. There was a person from Germany in Hollow Water begging the people of Hollow Water to stop this process (ESPI).

- Influential environmental groups are negatively impacting local communities.

- How much time is being spent in schools? It is their future and they need to be involved. We must get information to the schools, to teach the children to protect the environment but still have progress and development

- You don't need to protect the trees to the degree that a protected area demands. There are enough protected areas.

- We in the community have to have a say in what is going on. We need to have a strong understanding of what has to be done not some millionaire in Florida.

- Will there be no forestry licence expansions until the ESPI is complete?

- It is not easy to reforest a mature forest; it is much easier to reforest an area after has been cut.

- Communities must be advised of the park issues, so that they understand the impact.

- Tourist come from the city to our area and leave so much garbage behind that it costs our communities to clean up the mess. They also bring their own food and drink with them so what will they be doing for communities up the east side when they don't spend money here?

- Is it odd that chronic wasting disease is rampant in Manitoba's major national park, Riding Mountain, where logging and hunting are prohibited?

- The environmental people should come to talk to our community so that we can tell them how we feel.

Red Sucker Lake First Nation – NACC, MMF

- There is a need to find a way to get community members more informed about the East Side Planning Initiative. Radio and TV could be used and information is required in the local dialect.

- The community needs someone to point out the potential for development and how to develop resources.

- There is a need for more discussions between government and the community.

- There is a need to be involved in the designation of protected areas. A community member had received a map from Energy & Mines that showed an area south of Red Sucker Lake that he was told was protected. If that were true, mining in the area would not be available to the community, nor would jobs. There is also good timber around Red Sucker Lake and there was a concern that a protected areas designation would prevent one individual from developing a sawmill to replace a number of tents with buildings.

- For this reason as well, the community must also be consulted about mining activity. Community members have observed the comings-and-goings of mining equipment, personnel, etc., all of which, it knows nothing about.

- One trapper raised a concern about people coming onto his trapline and staking a claim and then him being asked to leave his trapline.

- There is a need to have more Elders involved in this process.

- Youth must have a role in this process as they are excluded most times.

- Everyone needs to work together in this process.

- Several people noted the hardship in living up north. Gas is $1.99 per litre. The cost of a helicopter to go there (33 miles) is $4,000.00 for a one-way trip. Everything is expensive. The round table is needed.

- Jobs are needed.

- A concern was raised about mining companies abandoning mines and just leaving the environment destroyed. An example was noted in which 197,000 gallons of diesel fuel were left in tanks within one trapline after a mine closed. The site is in Ontario, 30 miles from Red Sucker Lake. The tanks are now leaking.

- One Elder noted that boundaries were set up and regulations passed that interfered with the peoples' livelihood.

- There is a need for a community map focussing on activities that might affect the planning.

- The East Side Planning Initiative requires more time to discuss issues focussing on aboriginal interests.

Sagkeeng First Nation (North Shore)

- There should be more Elders and youth involved in the process.

- There should be an office established for our students to discuss this and other issues.

- We are happy that the province is finally listening to us

- If an all-weather road is built, funds should not be deducted from our INAC funds.

- What is meant by annual allowable timber cut?

- A concern was expressed about opening up the north to mining and its ecological impacts. How does mining development fit I with sustainable development?

- What is happening with the impacts on the environment as a result of abandoned mines, ie tailings, heavy metal pollution, etc.?

- Why wasn't Manitoba Tourism in the video? We should be looking at the potential of this sector instead of forestry ad mining.

- There needs to be environmental impact studies done before development takes place.

- If we take fish and timber away - we take away lives.

- Give dollars for road development to communities to lower their costs for consumption.

- An all-weather road must not impact our treaty rights.

- Lumber companies erect fences and gates on roads after they clear-cut and claim that area. We have no access anymore. In one company area, we went hunting by going through an unlocked gate, however, conservation charged our people with trespassing and hunting and seized our guns. By doing this, our treaties rights and land entitlement are taken away.

- Who is studying and monitoring water and air pollution?

- There needs to be more support from Tourism Canada, not just from the Province of Manitoba.

- The video should show Elders, woman and children expressing their view.

- We should earn some money from this initiative.

- What damage does the pulp mill do to our water?

- We have to phone the mill for permission to hunt. If we do not hunt within those times, we are charged.

- What benefits will First Nations get out of an all-weather road and will we be compensated for its impact?

- While the province talks about shared resources, we haven't had anything shared with us through treaty rights or land entitlement.

- If the First Nations claimed the beaches on the east side of Lake Winnipeg, they could get millions of dollars in return.

- Our rights have been trampled on for many years and the pulp mill took our traditional livelihood away.

- Development on the East Side has to do with resource harvesters, not First Nation's people. Forestry harvesters and cottage developers will benefit from development.

- What benefits do we get from Forest development? We were promised jobs by past forest operations, it did not happen.

- How are court case decisions concerning Treaty Rights, such as the Supreme Court decision concerning Sparrow, going to be looked at by the round table?

- Treaties need to be interpreted to know what they imply before land use decisions for the east side can be made.

- Protected areas are being established without consultation with affected First Nations.

- The maps you have arrived with have no Anishnabe input.

- How do you protect the environment if a road goes through?

- Treaty Rights have not been defined by Anishnabe people within our communities. We need to understand some of these things before we get involve with east side planning. Our land has been taken over, we are now beggars in our own land.

- When I was young, we lived off the land and didn't need help. We had an abundance of resources. Then change came in a form of a document called The Indian Act. In 1942 a person pushed for the Indian Act, from British Columbia. Our chief went against it, he knew enfranchisement was coming. In 1948, chiefs were called in to revise the Indian Act. It was rejected but passed through in 1951. Our Chief John Thompson was disregarded, and the Federal government declared elections. Sagkeeng had been in a downward spiral ever since. We were self-sufficient until 1951; money wasn't needed, goods were traded.

- If we put resources to use in communities today, we would teach people to be like before 1951

- The province had a lot of gall to ask Anishinabe to support changes to the Fisheries Act.

- Let Anishinabe map out their protected areas and territory areas on the maps.

- Lumber companies are clear cutting in parks.

- Mining is bad for environment.

- Roads construction will affect plants and animals and therefore how can treaty rights to hunt not be impacted?

- Why is Tembec involved in this process and what percentage of the east side will they be allowed in the future?

- We should be developing promotional materials for our culture? We could do this through tourism.

- Ecotourism should be seen as an alternative to forestry and mining. Bring in German tourists who want to learn about our culture.

- The Royal Proclamation state rights will be protected. How will this road impact these rights?

- First Nations are not allowed to hunt in parks yet lumber companies can go in and harvest. This is an infringement on Treaty Rights.

- Many of us have criminal records and cannot use firearms, we might as well go back to bow and arrows.

- The mill has caused great damage to the community, nobody wants to takes responsibility for this.

- Lumber companies and hydro do not care about damage. They care about profit.

- Understanding Treaty Rights is also responsibility of Manitoba government and not just First Nations.

- Promote students in each First Nation. Students have role to play and need to work closely with your office. Set up a sub-office in Sagkeeng to help students gather information and advocate on behalf of their First Nation.

- Can you guarantee our treaty rights to be honored when new road is built?
- What are other communities saying about an all-weather road?
- Visiting communities only once is not fair as it does not solicit all the issues and concerns of the communities.

Sagkeeng First Nation (South Shore)

- There seem to be two entities: the province and Tembec. How do we separate them?
- 75 years ago we promised them and they promised us. Today, they have not delivered. We had a deal with one company and we are still waiting.
- There is no information on economics.
- We are interested in your opinion, but you do not live in the community. How can you suggest change?
- How can 20 people digest all this information, for example, things I hear about mining?
- We may say something but it is going to happen anyway.
- Why wasn't there more information on the video about ecotourism?
- How is sharing information going to help me?
- There should be no mining in the planning area at all. There is too much poison from the mining industry.
- We are concerned about changes in government and direction jeopardizing the plan.
- Treaties were signed and recognized as nothing but promissory notes
- We are here to share information and the powers that be will use that information to do their projects
- Is this initiative related to an all-weather road?
- Should we put a dollar figure to life?

- A road will open up the drug trade and communities will lose their language. Look at Cross Lake and hydro and the negative consequences it caused.

- We will become the 51st state of the U.S. the way things are going.

- We are losing our rights now, ie dental.

- Used to see large trees but as a result of forestry, they do not exist anymore. Logging companies are hauling toothpicks. They over cut and don't reforest. I see positive change in selective cutting and applying traditional knowledge.

- What kinds of life will our children will have? Youth look forward to being 18 to receive welfare.

- There is nothing left in our traditional area because of mining, forestry, etc. All the game and furbeares are gone. There is nowhere to trap.

- Tembec and First Nations have to work together to develop a committee to define Traditional Ecological Knowledge projects and surveys. Is Tembec committed to funding TEK mapping?

- Want to see more emphasis on watershed management. Look at how many mills, cottages, towns, etc. are dumping into the river as far away as Thunder Bay.

- Concerned about water pollution and its impact on the health of our people and children. Monitor our water intake - not like Waterton. We need money to get our domestic water supply treated. Our Elders are telling us that there is something wrong with our water.

- Mining raises red flag; companies create pollution. They provide jobs, but what about safety?

- Should have First Nation people looking after natural resources.

- Mines declare bankruptcy and the clean up is left to others.

- Three different metals were found in the water of Lake Winnipeg.

- Treaties were signed with the Federal government. Where does Province fit in?

- Communities have to be educated on the all-weather road and its impact.

- Who will benefit from tourism?

- Should have woman and men working on the development?

- This initiative is important and our leadership should be sitting here.

- Tried for years to get water testing but the paper company says the water is safe to drink. Doctors say do not swim in it because it's contaminated.

- They talk about mining and forest in the video. These activities can cause great damage.

- There is nothing in our trapping area now and our medicine is being destroyed. We hope that you are in a position to help.

- Doctors say that if you drink chlorine over time you get cancer and diabetes.

Seymourville/Aghaming – NACC

- A concern was raised regarding the composition of the Round Table: how many Aboriginal people were on it and how many lived in the planning area.

- Tourism must be made more accessible in the area. One person had a proposal to purchase additional land to expand his tourism facility refused due to competing interest of protected areas and Tembec's right of first refusal in the area. Operations like Pelican Harbour however, got land development privileges and were supposed to provide jobs in return, which they did not.

- Concerns were raised on the impacts of opening up the East Side on traditional lifestyle of hunting, trapping and fishing.

- Metis and NACC communities need to have an equal say with First Nations.

- There needs to be profit-sharing between large corporations and communities.

- Concerns were expressed about how NACC communities would receive fair representation and what they could do to ensure their recommendations are honoured.

- A concern was expressed that a proposed sawmill partnership excluded Seymourville.

- Seymourville needs to develop its own plan as well as look at a larger geographical area and work with surrounding communities. It will need funds to accomplish this.

- A question was asked where BI-Pole lll was going to be erected and how close it will come to the community.

- Internal road conditions pose health and safety concerns that have to deal with on a constant basis. Can the round table help the community lobby for better roads?

- How often does the Round Table and First Nation Council meet?

- The deadline to complete the plan by June 2004 is unrealistic. It is unrealistic to expect communities to develop positions before then.

- The community of Manigotagan is planning to expand their boundary up the Manigotagan River to the second falls. Because the community is situated on the river, they wish to continue growth along the river. While the Manigotagan River Park Reserve is willing to start at the second falls, there is a concern that once the BI-Pole II comes down, the Province will take the land back from the community for this line. This is something that the community does not want to see happen.

St. Theresa Point First Nation

- I heard someone welcomed the shift in government policy to include First Nation people in planning processes. He indicated government has been exploiting resources since 1933 and deliberately excluded First Nations in resource management.

- He suggested negotiations between First Nations and the province include resource ownership, resource management and revenue sharing schemes.

- Traditional territory belongs to community members.

- Depletion of resources, medicinal plants, fish and animals are being destroyed by outsiders.

- An elder expressed concerns regarding the ability of wildlife populations to sustain them.

- He asked what the province is doing regarding the protection of drinking water on Lake Winnipeg and fisheries.

- Local artifacts belong to First Nation people in the area and should be returned.

- Terms and conditions of treaty should be resolved first before commencing with planning activities on the East Side.

- First nation education should be a requirement of the public school systems including universities.

- Trappers and fishers should be treated the same as farmers down south.

- Road access into traditional lands would impact on wildlife and traplines.

- Development would upset natural process. Any development should be properly planned and proceed with caution.

- Environment is changing and land ruined and disrespected by non-Aboriginal people.

- Trespassers should be charged for trespassing and destruction on traditional land and affecting the livelihood of local trappers.

- Planting and harvesting of wild rice on traditional land by non-Aboriginal people is affecting livelihood of local people.

- There has been building of damns to irrigate water for wild rice, without asking for permission to build them. The province should also do something about the waste material along our shorelines.

- Need to consult with community before any activity happens in the planning area.

- Secretariat provided information about the role of the recently established Aboriginal Relations Branch within the department.

- Secretariat to follow up with Aboriginal Relations Branch regarding trespassers harvesting wild rice without permission from the community.

- Activities from Hydro, logging, mining adversely affect the community and the land.

- What plans exist regarding the construction an airport and a road from St. Theresa Point to Wasagamack First Nation?

- The province should negotiate ownership since development would be on their land.

- There are concerns respecting the proposed Manitoba Hydro BI-Pole lll transmission line and how it will impact employment opportunities for the communities.

- Revenue sharing between the province and the communities should include Hydro, mining, pulp, logging, forestry and commercial fishing.

- Health conditions and lack of proper nutrition is an issue because of restrictions on hunting rights that are an infringement on Treaty and inherent rights.

- All resource issues need to be looked at to preserve First Nation culture and way of life.

- Need to conserve and preserve all resources for future generations.

- The general public and public school systems need to include Aboriginal history life styles and way of life in order that we eliminate cultural differences.

- Media needs to be kept in check and lines of communication need to be clear.

- Local trappers and fishermen need to be represented on the round table.

- There is a need for funding for community cleanup to help attract and develop tourism opportunities for the communities.

- Development of resources needs to be clear and transparent.

- Conduct clear and open surveys.

- Communities require traditional territory maps.

- There is a rapidly growing population in the communities and financial resources cannot keep up with demand.

- Natural law of nature is being altered and changed.

- Hudwin Lake is recognized as a traditional area.

- Is Hudwin Lake a protected area and do they have the right to hunt or trap or will restrictions be implemented? Can a community member go into the area and build on it as his inherent right?

- Natural Resources Transfer Agreement should be reviewed to ensure all people understand it.

- Province should negotiate with all First Nations and not just one.

- The province needs to ensure the information flows into the communities.

- The traditional territory is where the older people were born. It is only recently that people have lived in communities like St. Theresa Point. He notices that the environment has changed, the land has been spoiled by white people. The fish and animals are not the same.

- How can I charge a trespasser on my land? The issue is a wild rice harvester who also put a dam up to raise water levels and impacted his livelihood.

- First Nation people are keepers of the land. The new activities like hydro, forestry and mining are an exploitation of our resources.

- The North-West Hydro project that brought power to seven local communities was funded 75% by INAC, 15% by Manitoba and 10% by Hydro. Now Hydro owns an infrastructure that was paid for by Treaty (INAC) dollars. The First Nations should have ended up owning the lines and hired Hydro to manage them. The First Nations should also own the roads and airports that will be built on reserve land in this area. Bi-Pole III is a moneymaking scheme for Manitoba. The revenues should be shared with us. The same can be said for mining, forestry and commercial fishing.

- Our rights to hunt and fish are being restricted. We should not require any permits (gun registration, fishing permits) as this is an infringement on our rights. The legislation has to be looked at.

- We need to keep the land clean – we depend on the land for food and medicine. The land is what keeps us alive. Any kind of development must preserve and conserve. I hear Lake Winnipeg is polluted. If they (Whites) are going to come are they going to do the same with their technology.

- We do not want secret surveys of our resources. We hear of helicopters flying people around to look at the land. Developers must come to the community first.

- There should also be a trapper representative and a fishing representative on your round table.

- Farmers get compensated for loss of income. So do East Coast fishermen. Trappers have lost income because of markets. Trappers should be treated the same as farmers with respect to loss of income.

- We need a road to promote tourism

- There should be dollars for community clean up.

- There should be a process for 10-year reviews of development in the north.

- People in the south need to be educated about our ways in the north – they get a slanted view of our ways. The South has no understanding of the hardships here.

- The Province, not only the Federal Government, must respect the treaties.

- I have expressed my concerns many times. The creator gave us the resources – all the things on Earth. These are what define us as First Nations. My concerns over government are decisions that affect our identity. As an example, First Nations had their own way of child rearing. We believe that it is important to discipline a child. Now there are laws against this and it results in delinquency. Also, the government has wanted to assimilate us and change us to white people.

- It is my wish to leave our resources as they once were. The way this should be – the goose knows when to go south. This is how nature works. We cannot disrupt this. Our climate changing is upsetting the natural process. This is what so-called development has done to our country.

- Is Hudwin Lake a true protected area? If you do your research you should find past agreements on this area. Can First Nations hunt, fish and trap in these protected areas. My son wants to put a cabin up at Hudwin Lake. This has been a traditional area since 1953. Some elders used to live there.

- You must deal with the northern bands seven collectively as well as individually.

Wasagamack First Nation

- Wasagamack First Nation has begun to explore and research the development of a forest management plan, a resource management plan, a community development plan and a long-term sustainable development plan.

- There is a concern regarding the future of the young people in the area. This process must enable their ability to practice traditions and culture in order that they can survive on the land.

- A concern was expressed about outsiders coming into the community, collecting and recording data, leaving and not returning any information or results.

- The community must benefit from the ESPI process.

- Intruders onto existing trap line areas affect wildlife populations due to poor mining practices and lack of environmental and wildlife considerations. These same people also trap in the community's traditional trapping area which results in declining revenues for trappers and less wildlife for sustenance use by local people.

- Due to the language barrier and infrequency of communication between the two cultures, it is difficult to communicate and resolve local issues and concerns. There is a need to work closer together and translate all literature to Oji-Cree for elders and other community members to understand and participate fully in this process.

- Traditional hunting grounds are being invaded and communities have been told there is nothing community members can do about it. There is a need to respect and protect wildlife and hunting grounds. Sport hunting should not be allowed. We have video footage of hunters killing for sport.

- The community is thankful for the opportunity for Elders to speak and share their knowledge.

- There is a need for the community to be given time to absorb the information provided and return views and comments at a later date.

- There is a need for maps to show burial sites so they are not desecrated in any future land developments.

- It is preferable to have a united voice representing the Island Lake First Nations. For that reason, the round table members need to sit down with the Island Lake Tribal Council to discuss concerns, ideas and views about their communities and development in the area.

- Fish caught locally do not taste the same and now we have to go to traditional fishing areas to be able to eat fish.

- Once the report is completed will the committees be consulted and will Hydro work only with the round table?

- Compensation concerns from Manitoba Hydro to the First Nation were raised.

- There was a time you could drink water straight from the lake. Due to water quality concerns, the community must now rely on the water treatment plant for its water.

- We hear of (southern) people flying around in helicopters to shoot moose. We do not appreciate these sport hunters who only take the antlers. This is disrespect. We have to use every part of the animals we hunt. We also find intruders on our trap lines. This happened as far back as 1933 when I came upon a driller while out shooting for rabbits. My mother told me there was a lot of exploration and mining in the early days.

- There are times today when you hear that outsiders are invading our hunting territories. A man has been told that he cannot hunt or fish in his area for the area is set aside for sport fishing now. The (Canadian) government said they would take care of the Indian People and allow us to hunt in our traditional ways. They are taking this away slowly, just look at the gun registration. This East Side plan must protect hunting, fishing and trapping rights and respect the traditional hunting grounds.

- Outfitters planted wild rice in my trap line. Over time we have noticed the fish disappearing from this area. I met this person and told him he should not have done this in the first place. No one talked to us about this development.

- There was talk some years ago about planning for the land in our area. The Island Lake Tribal Council has begun to look at how the land should be cared for.

- The community needs to define traditional boundaries. We need to map traditional sites, summer camps and burial grounds. This will take a lot of resources, but these things have to be respected. We need this information before Bi-Pole III and roads come through.

- You need to change a few things with this new process. People often come from the outside to speak and get our input, but they never come back. Very few people get involved this way. You need to come back to Wasagamack.

- Your brochures should be translated into syllabics for some people can not read English.

- The people of Wasagamack need to work together with the southerners. We have to focus on what is going to happen in our lands. We also need to capitalize on our fishing and hunting skills.

- A representative of MKO spoke about areas that the Community needs opportunity to explore. These are a (1) community development plan; (2) forest management plan; (3) resource management plan; and (4) sustainable development plan.

- There was a story from an elder who witnessed his father becoming the first chief for Wasagamack. At this time an Indian agent signed an agreement and wrapped the chief in a Canadian flag as a symbol that Canada would protect our people and protect the land. This was a show of respect for Indian leaders. Now the chiefs do not get respect. Today all we have is broken promises on Treaty. There was a tree beside the Band Office that symbolized our first chief. This is where he went when it was time for him to pass on. Today there is a monument outside the Band Office that symbolizes our first chief.

- As First Nation people we have a lot of disadvantages in these communities. I fished and trapped when I was 14. This was the education provided by my parents. Your time here is too short for me to tell my tale. What I will tell you is that the four communities of Island Lake are close knit. As individual First Nations we are not strong enough to deal with the issues. The four must stand together.

- If we knew before hand that the government was coming we could have come better prepared. For some reasons we take it for granted that our council will give us the information. This does not happen. You see only a few people here – it embarrasses me. Because of such short notice we can not put our ideas in writing. We have to follow-up though. It is important to maintain contact.

- People down south do not know what it is like around here. They do not know our youth enjoy the forest and to go hunting. We are not in the bush enough though. The decline of traditional knowledge (i.e. curing of trees for medicine) has resulted in a decline in our health (i.e. diabetes). We have to obtain knowledge of our environment again and how to use the forest wisely. The Elders are passing on and the knowledge is being lost. The school system has to recognize this. There has to be a balance to allow people to go on the land.

- The next time you come up should be in the winter when the roads are in. Then you can have a meeting with all four communities together.

- We have to keep government honest with respect to Treaty rights. The government wants to amend various acts to get out of its commitments. An example is federal changes to the Indian Act. It says it has consulted us - via the Internet. This is not adequate consultation.

Appendix 8.11

Community Reports: "What We Heard" By Issue

East Side Planning Initiative Community Visits

September 2003 to January 2004

What We Heard

Final Report By Issue

Response to East Side Planning Initiative Community Visits

September 2003 to January 2004

What We Heard

Groups invited to participate:

FN – First Nations
MMF – Manitoba Metis Federation
NACC – Northern Association of Community Councils
ESPI – East Side Planning Initiative
ESRT or Round Table – East Side Round Table

Communities Visited:

Berens River FN, NACC, MMF
Bissett NACC
Bloodvein FN
Bunibonibee Cree Nation
Garden Hill FN, MMF
God's Lake FN, NACC
Hollow Water FN
Island Lake NACC
Little Black River FN
Little Grand Rapids FN
Little Grand Rapids NACC
Manigotagan NACC, MMF
Manto Sipi Cree Nation
Matheson Island / Loon Straits / Princess Harbour NACC
Norway House Cree Nation
Norway House NACC
Pauingassi FN
Pine Dock NACC
Powerview and local MMF
Red Sucker Lake FN, NACC, MMF
Sagkeeng FN (North Shore)
Sagkeeng FN (South Shore)
Seymourville / Aghaming NACC
St. Theresa Point FN
Wasagamack FN

What We Heard regarding:

Treaty Rights and Tradition..... 1
Environment, Protected Areas..... 9
Economic Development, Forestry, Mining..... 14
Roads..... 25
Hydro..... 29
Other Issues and Concerns..... 31

Note:

Some of the messages heard are presented as one concern shared by more than two people. Some are phrased as general topics of concern. Others are individual concerns paraphrased in short form.

Treaty Rights and Tradition

- People down south do not know what it is like around here. They do not know our youth enjoy the forest and to go hunting. We are not in the bush enough though. The decline of traditional knowledge (i.e. curing of trees for medicine) has resulted in a decline in our health (i.e. diabetes). We have to obtain knowledge of our environment again and how to use the forest wisely. The Elders are passing on and the knowledge is being lost. The school system has to recognize this. There has to be a balance to allow people to go on the land.

- We have to keep government honest with respect to Treaty rights. The government wants to amend various acts to get out of its commitments. An example is federal changes to the Indian Act. It says it has consulted us - via the Internet. This is not adequate consultation.

- Concerned that corporations come in and ruin a First Nation community and the First Nation doesn't get anything from it. For example, First Nations currently do not benefit from harvest of timber resources. Communities must benefit if there is development, not the individual but the whole community.

- Government regulations prohibit using trapline/cabins for rental purposes. Regulations should support trappers.

- One of the questions I have, one thing promised to us, First Nations have access to live off the land so how come there are regulations e.g. hunting? After all is done what is going to become of the process and plan?

- Trapping is an issue of sharing resources again. This should be part of the issue for the Round Table – so we can maintain our lifestyle. Trapping and its regulations need to be addressed in the plan

- Concerns were expressed about a burial ground threatened by development. There are 3 graves and it should be marked on a map.

- Trapping regulations not meeting our needs and don't make sense.

- The literature provided does not address how this process might affect treaty rights. Should speak

- We need to know more about constitutional treaty rights, protected areas.

- How will this plan affect outstanding Treaty Land Entitlements? What has been happening with respect to the TLE process? How much Crown Land should we be granted?

- There is no protocol to consult with First Nations.
- If the Trappers Association make a presentation, will you hear it?
- Trapline boundaries should be the boundaries for planning.
- First Nation Communities are getting all the traplines and pulp potential. They have a federal voice, larger than ours.
- The planning process should be with First Nation's people directly because it impacts First Nations directly.
- We need to do more as a community to protect treaty lands.
- Elders and youth must be involved to voice concerns in our community.
- We need protected area for our traditional lands.
- We want total control of the management of forestry and mining here.
- How much space will the Native people have?
- Concerns about hunting. When an area becomes developed there is a boundary placed around it and you can't hunt there. Can we go hunting and hunt where we want? The plan has to allow us to be able to go in and hunt where we want, even if the area is developed.
- Concerns about third parties coming in and using our traditional areas and then we have a problem negotiating with them on land use. Negotiating can take a very long time.
- Youth are not aware of the Treaties, their cultural traditions, the old way of life and survival on the land. Government should provide funding to train youth to learn about Aboriginal tradition and culture.
- Loss of traditional way of life and children being taught to follow dominant way of life.
- Health is a major issue, particularly diabetes. Government should work more closely with northern communities in the area to address health concerns.
- Government needs to respect hunting and other rights, if parks, which include traditional hunting areas, are deemed to be set aside as protected areas.
- In the past, the province did not consult with trappers regarding government actions impacting on traditional trapping/hunting grounds.

- We are not fully aware of the Treaty anymore. The younger generations have not been educated about the Treaty and the significance of our Treaty at the time it was signed.

- The younger generation is not learning the traditional ways. Our youth only correspond with what they learn from a white dominant society. Our sickness is worse today (diabetes) because we have lost some of our traditional ways. If we dropped a young person off in the bush today he would not know how to survive, to make a fire, to make a bed. We need funding to retain our traditional ways and livelihood. We have to retain our traditional ways to heal ourselves.

- We are not fully aware of the Treaty anymore. The younger generations have not been educated about the Treaty and the significance of our Treaty at the time it was signed.

- The younger generation is not learning the traditional ways. Our youth only correspond with what they learn from a white dominant society. Our sickness is worse today (diabetes) because we have lost some of our traditional ways. If we dropped a young person off in the bush today he would not know how to survive, to make a fire, to make a bed. We need funding to retain our traditional ways and livelihood. We have to retain our traditional ways to heal ourselves.

- You must be aware that there is a park being proposed in the area of the Wasagamack First Nation. The local trappers do not want this. There also is mining at Twin Lake. The trappers at Red Sucker Lake did not agree to this. They also are planning a road. Can the people at Red Sucker stop this legally. The people there have not been consulted. Is this the way it should be? Does the province have a responsibility to consult?

- There was a process with Treaty land selections where we identified our traditional lands, and sacred and cultural spots. The round table does not have this information. This must be integrated, but we never had the money like you have to record all of this and create fancy maps. We need money to identify and map where the important sites and lands are. We are short of technical skills. Your community coordinators cannot do this alone.

- Our rights are treaty driven. How can the process affirm treat rights when the Natural Resources Transfer Agreement is a contradiction to them? We have to educate mainstream society about our treaties.

- Government has a hidden agenda. When we ask the province to address our needs they say that they are not responsible. First Nation people should not be considered a federal responsibility.

- When traditional areas are referred to by governments they think it is a trapline. Our ancestors come from Ontario and our traditional area is also in Ontario. It is not only ours but belongs to other First Nations.

- Provincial government is holding up our treaty land entitlement – they should move a little faster.

- The chief and council should be here, as we need to have direction and input from our leadership

- Let's put our minds together to make our reserve a better place. We have people come to our community, let's work together with them to plan for our community.

- Relations must improve, not just with government but people in general. We do not want to be in a position where we have to beg for our own future. Give us our resources back.

- We are scared of partnerships that are formed without the First Nations Council.

- I am glad that governments seek knowledge from our scientists (Elders). Does the government already have a plan? Everything we need is contained in Treaty # 5. Why do you have to come back for reaffirmation?

- Maybe we don't need your help; we just need the resources you took from us.

- There are trust issues between community members and government in general. The community finds it difficult to trust the objectives of the initiative and whether or not their suggestions/comments will be taken into consideration when it is time to make decisions.

- An elder from each community should sit on the round table to represent communities and present traditional knowledge on resources and medicines. Elders should attend all meetings.

- We are beginning to return to traditional medicine.

- The Norway House Cree Nation is not accountable to the Government of Manitoba and an MOU should be in place before we participate in any planning process dealing with resource management

- Norway House considers itself a sovereign nation and the fact that the province established a First Nation Council does not mean it represents Norway House First Nation. We consider this a provincial entity.

- Land planning is important to the trappers. The trappers believe they are losing access to traditional trapping areas.

- One Elder noted that boundaries were set up and regulations passed that interfered with the peoples' livelihood.

- Concerns were raised on the impacts of opening up the East Side on traditional lifestyle of hunting, trapping and fishing.

- Metis and NACC communities need to have an equal say with First Nations.

- I heard someone welcomed the shift in government policy to include First Nation people in planning processes. He indicated government has been exploiting resources since 1933 and deliberately excluded First Nations in resource management

- Traditional territory belongs to community members.

- Terms and conditions of treaty should be resolved first before commencing with planning activities on the East Side.

- Trappers and fishers should be treated the same as farmers down south.

- Health conditions and lack of proper nutrition is an issue because of restrictions on hunting rights that are an infringement on Treaty and inherent rights.

- All resource issues need to be looked at to preserve First Nation culture and way of life.

- The general public and public school systems need to include Aboriginal history life styles and way of life in order that we eliminate cultural differences.

- Hudwin Lake is recognized as a traditional area.

- Is Hudwin Lake a protected area and do they have the right to hunt or trap or will restrictions be implemented? Can a community member go into the area and build on it as his inherent right?

- Our rights to hunt and fish are being restricted. We should not require any permits (gun registration, fishing permits) as this is an infringement on our rights. The legislation has to be looked at.

- The Province, not only the Federal Government, must respect the treaties.

- It is my wish to leave our resources as they once were. The way this should be – the goose knows when to go south. This is how nature works. We

cannot disrupt this. Our climate changing is upsetting the natural process. This is what so-called development has done to our country.

- There is a concern regarding the future of the young people in the area. This process must enable their ability to practice traditions and culture in order that they can survive on the land.

- Traditional hunting grounds are being invaded and communities have been told there is nothing community members can do about it. There is a need to respect and protect wildlife and hunting grounds. Sport hunting should not be allowed. We have video footage of hunters killing for sport.

- The community is thankful for the opportunity for Elders to speak and share their knowledge.

- There are times today when you hear that outsiders are invading our hunting territories. A man has been told that he cannot hunt or fish in his area for the area is set aside for sport fishing now. The (Canadian) government said they would take care of the Indian People and allow us to hunt in our traditional ways. They are taking this away slowly, just look at the gun registration. This East Side plan must protect hunting, fishing and trapping rights and respect the traditional hunting grounds.

- The community needs to define traditional boundaries. We need to map traditional sites, summer camps and burial grounds. This will take a lot of resources, but these things have to be respected. We need this information before Bi-Pole III and roads come through.

- There was a story from an elder who witnessed his father becoming the first chief for Wasagamack. At this time an Indian agent signed an agreement and wrapped the chief in a Canadian flag as a symbol that Canada would protect our people and protect the land. This was a show of respect for Indian leaders. Now the chiefs do not get respect. Today all we have is broken promises on Treaty. There was a tree beside the Band Office that symbolized our first chief. This is where he went when it was time for him to pass on. Today there is a monument outside the Band Office that symbolizes our first chief.

- As First Nation people we have a lot of disadvantages in these communities. I fished and trapped when I was 14. This was the education provided by my parents. Your time here is too short for me to tell my tale. What I will tell you is that the four communities of Island Lake are close knit. As individual First Nations we are not strong enough to deal with the issues. The four must stand together.

- If we knew before hand that the government was coming we could have come better prepared. For some reasons we take it for granted that our council will

give us the information. This does not happen. You see only a few people here – it embarrasses me. Because of such short notice we can not put our ideas in writing. We have to follow-up though. It is important to maintain contact.

- Does the government or industry consult with the people or just Chief & Council?
- Do the Chief and Council have to be present for there to be consultation?
- What would happen if the recommendations conflict with the community plans?
- Is this consultation or an information session?
- We need a map to indicate traditional uses at Hollow Water and include Black Island.
- Hollow Water could provide a land use plan to RT.
- How can the province come in and provide permits on the Hollow Water river for cottages?
- Is Black Island included in the planning area?
- What about traditional territories beyond treaty (reserve) lands?
- Traditional lands are being taken away. All this is predetermined. There is a lot of skepticism about this process.
- There has been experience with vandalism of trap lines. There is no compensation with respect to loss of revenue by local trappers.
- What type of agreements can the community get from this process?
- We want to be involved in benefits, partner and training for anything happening in our region.
- Traditional areas need to be extended and users need to have a say on what happens there. It all comes down to the land you control. Give us the control to see how serious you are.
- How do we ensure outsiders don't come in and over exploit the resources.
- Cottage and lodge developments are a concern. It appears only white outsiders are approved for lodge and other licenses.

- Non-Aboriginals will force us out of our own lands.

- The Norway House Cree Nation is not accountable to the Government of Manitoba and an MOU should be in place before we participate in any planning process dealing with resource management.

- Land planning is important to the trappers. The trappers believe they are losing access to traditional trapping areas.

- Treaty Rights must be honoured and accessibility to the lands be available for First Nations.

- When people are given permits to trap in the Pauingassi traditional area, the First Nation wants to be consulted so that the First Nation members can be apprised of who has been given permits and develop working relations with permitees.

- The First Nation remains opposed to Outpost hunting in the area. This was done without consultation with the local people.

- The First Nation requested a land status report on their existing reserve lands.

- Tembec erects fences and gates on roads after they clear-cut and claim that area. We have no access anymore. In one Tembec area, we went hunting by going through an unlocked gate, however, conservation charged our people with trespassing and hunting and seized our guns. By doing this, our treaties rights and land entitlement are taken away.

- While the province talks about shared resources, we haven't had anything shared with us through treaty rights or land entitlement.

- If the First Nations claimed the beaches on the east side of Lake Winnipeg, they could get millions of dollars in return.

- How are court case decisions concerning Treaty Rights, such as the Supreme Court decision concerning Sparrow, going to be looked at by the Round Table?

- Treaties need to be interpreted to know what they imply before land use decisions for the east side can be made.

- Treaty Rights have not been defined by Anishnabe people within our communities. We need to understand some of these things before we get involve with East Side Planning. Our land has been taken over, we are now beggars in our own land.

- Roads construction will affect plants and animals and therefore how can treaty rights to hunt not be impacted?

- First Nations are not allowed to hunt in parks yet Tembec can go in and harvest. This is an infringement on Treaty Rights.

- Understanding Treaty Rights is also responsibility of Manitoba Government and not just First Nations.

- Treaties were signed and recognized as nothing but promissory notes.

- There is nothing left in our traditional area because of mining, forestry, etc. All the game and furbeares are gone. There is nowhere to trap.

- Treaties were signed with the Federal government. Where does Province fit in?

- There is nothing in our trapping area now and our medicine is being destroyed. We hope that you are in a position to help

Environment, Protected Areas

- We have concerns about the environment and have been fighting with the province about cleaning up the old transmission line to an old mine on Elk Island. There is about 50 miles of wire just left on site. The government tells me they have no funds so how can they make this process work if they can't even undertake one little mine clean-up project. I don't know who else to talk to.

- Fish are being depleted from the lakes and information is not being shared on fish management strategies, if any are planned or exist.

- Is Hudwin Lake a true protected area? If you do your research you should find past agreements on this area. Can First Nations hunt, fish and trap in these protected areas. My son wants to put a cabin up at Hudwin Lake. This has been a traditional area since 1953. Some elders used to live there.

- The traditional territory is where the older people were born. It is only recently that people have lived in communities like St. Theresa Point. The environment has changed, the land has been spoiled by white people. The fish and animals are not the same.

- How can the City of Winnipeg dump raw sewage that affects Lake Winnipeg and not be held responsible? Fisheries are affected by water quality in the lake. Algae blooms are increasing and affecting fishers' livelihood.

- Protected areas need to be revisited. The Poplar River Protected Area includes some lands, which are part of Berens River traditional territory. Because Berens River was never consulted on this, its territory should be removed from the protected areas.

- Wanipigow River Protected Area has allowed mature trees to fall into River and is destroying the river quality. If trees are allowed to be cut, the economic gain is met and the river is managed. Protectionism measures applied by Parks Manitoba may do more harm than good to the river and river areas.

- Land allocation methods for specific purposes by the province are not an acceptable practice.

- Nopiming Park was originally a multi-use park. Now you cannot consider it a multipurpose park due to restrictions. Recreation activities and development are causing problems.
- We as a community are concerned with Lake Winnipeg water quality. The algae, smell and water levels are all concerns for us.

- River quality is threatened by activities that are still occurring in Ontario. What happens in Ontario will ultimately affect the Watershed here in Manitoba. We need to know what is happening in Ontario.

- Caribou habitat protection important.

- Economic development and environmental protection processes need to work together in a balanced way.

- What are the hidden agendas on economic development?

- Not happy with 100-foot set back from water bodies.

- A 200' x 200' area for trapper's cabins is not realistic. There should be more flexibility for types of traps to be used.

- Expansion at Nopiming will mean that pollution will come down through our river system.
- A concern was raised that cyanide from a mine on Elk Island was polluting a river that runs into God's Lake, and whether or not it could be stopped before it was too late. The water quality should be checked.

- How can we make our living here in a deteriorating environment?

- How can we protect our mother earth because this land is all ripped up?

- A concern was raised about mining companies abandoning mines and just leaving the environment destroyed. An example was noted in which 197,000 gallons of diesel fuel were left in tanks within one trapline after a mine closed. The site is in Ontario, 30 miles from Red Sucker Lake. The tanks are now leaking.

- Depletion of resources, medicinal plants, fish and animals are being destroyed by outsiders.

- An elder expressed concerns regarding the ability of wildlife populations to sustain them. He asked what the province is doing regarding the protection of drinking water on Lake Winnipeg and fisheries.

- Environment is changing and land ruined and disrespected by non-Aboriginal people.

- Natural law of nature is being altered and changed.

- We need to keep the land clean – we depend on the land for food and medicine. The land is what keeps us alive. Any kind of development must preserve and conserve. I hear Lake Winnipeg is polluted. If they (Whites) are going to come are they going to do the same with their technology.

- Fish caught locally do not taste the same and now we have to go to traditional fishing areas to be able to eat fish.

- There was a time you could drink water straight from the lake. Due to water quality concerns, the community must now rely on the water treatment plant for its water.

- How do we ensure outsiders don't come in and over exploit the resources.

- Concern of lodges taking in hundreds of fish, how can the community stop this from happening. Commercial fishing is being opposed by local lodge owners and therefore sport fishing is the only game in the area. Water quality is becoming an issue as the water color is changing and affecting fish quality.

- There was mention of the World Heritage site being proposed by three First Nations in the area. What will happen to the committee formed for Accord with Pikangikum, Pauingassi, Poplar, and Bloodvein to address the issue of sustaining the environment. Will it be disbanded because of the Round Table and this process?

- No recycling opportunities in the community as a result landfill sites are pressured to take recyclable materials thereby using necessary space.

- Traditional areas indicate that wildlife is moving away from traditional spawning and calving areas.

- Trappers notice change in animals moving away from spawning areas.

- Lodge owners are using airplanes to hunt.

- Only a small part of original Manitoba left; it is fearful what is happening. How can we make our living here in a deteriorating environment? How can we protect our mother earth because this land is all ripped up? -

- Change in the water, it's dirtier with more algae. Swampland has an ecological process and function and is not to be viewed as wasteland.

- The First Nation is part of an alliance with three other First Nations to identify and request a world heritage site be establish identifying their traditional territories.

- There should no more Federal and Provincial parks established without consent of the community.

- We are concerned about the environment. Hunting, fishing and trapping are an important part of our life.

- Parks would be OK if the tourists didn't make such a mess.

- The only thing allowed on the Bloodvein River is a canoeing and people are making decisions about the area without knowing anything about it.

- There is support for the construction of an and all-weather road, but not more Parks.

- People are in favor of development but we also care about the environment. We live here and do not want to see the environment destroyed. The mill at Pine falls is very environmentally concerned and responsible. We helped reforest areas while Abitibi was here. That was never done down East.

- Environmental impact studies must take place.

- You don't need to protect the trees to the degree that a protected area demands. There are enough protected areas.

- Tourist come from the city to our area and leave so much garbage behind that it costs our communities to clean up the mess. They also bring their own food and drinks with them so what will they be doing for communities up the east side when they don't spend money here?

- A concern was expressed about opening up the north to mining and its ecological impacts. How does mining development fit I with sustainable development?

- What is happening with the impacts on the environment as a result of abandoned mines, ie tailings, heavy metal pollution, etc.?

- There needs to be environmental impact studies done before development takes place.

- Who is studying and monitoring water and air pollution?

- What damage does the pulp mill do to our water?

- Protected areas are being established without consultation with affected First Nations.

- How do you protect the environment if a road goes through?

- Ecotourism should be seen as an alternative to forestry and mining. Bring in German tourists who want to learn about our culture.

- There is too much poison from the mining industry.

- There is nothing left in our traditional area because of mining, forestry, etc. All the game and furbeares are gone. There is nowhere to trap and our medicines are being destroyed..

- Tembec and First Nations have to work together to develop a committee to define Traditional Ecological Knowledge projects and surveys. Is TEMBEC committed to funding TEK mapping?

- Want to see more emphasis on watershed management. Look at how many mills, cottages, towns, etc. are dumping into the river as far away as Thunder bay.

- Concerned about water pollution and its impact on the health of our people and children. Monitor our water intake - not like Waterton. We need money to get our domestic water supply treated. Our Elders are telling us that there is something wrong with our water.

- Mines declare bankruptcy and the clean-up is left to others.

Economic Development, Forestry and Mining

- We need to do something for our young people. We need to look in the long term.

- Must plan right with traditional knowledge. Must carefully consider how development takes place. Have to consider how we are part of the land.

- Trapline regulations pretty strict - size of a cabin etc, cost of permits to build etc. Regulations quite an issue here. Too many regulations and why are there regulations on our land?

- Teach youth how to grow trees and about renewing the forest and fishery resource. Learn how to develop and operate businesses to create a good living for residents

- Thankful that people are focusing on our concerns. Often people call on us for work and we do most of the hard work. In the end however, we are thrown aside. It is good to have people who are concerned about us.

- Why can someone own our traditional land? I worked for long time in fisheries and for 5 months could make a living fishing. Prices of fish not viable now. We need a subsidy program for fishing.

- People who come up here like mining companies, need to bring more money into the community and share the wealth.

- Were there studies done for resource assessments, land analysis, community development, economic development and traditional history?

- Interesting idea – teaching our young people to grow trees so they can re-grow what is taken out, same with fish – need to target the young people.

- Important that First Nations gets the first chance to get employment.

- There was mention of stakeholders. Northern Stores, MTS, MB Hydro are stakeholders. Are they trying to maximize benefits for the communities – what are they doing for the communities?

- High price of goods and services makes it difficult if not impossible to purchase healthy foods such as fresh fruit and vegetables

- Concern about mining at Twin Lake and if the community could get government to involve them in meaningful consultation before permitting mining in their traditional territory.

- Possibility of constructing a larger airport on a cost shared basis.

- Lack of telephone lines is a real problem. People are not able to use the phone between 5:00 pm to midnight. This causes further problems regarding emergencies.

- Economic development and environmental protection processes need to work together in a balanced way.

- Years ago the white man put up a sawmill here and took all the best trees. Then he came for the fish. There are still trees and fish, but the best are now gone

- Prices are too high to afford the goods that we once could afford.

- Years ago the Island Lake Tribal Council talked about co-management of resources.

- In the past, government projects (i.e. MTS) have not included extra funding to First Nations. You have a few people, but need more people involved in the planning process. You have to understand another reality. There is no money here, there are no jobs. Up north we have vast resources, but the money and the jobs benefit the south (Winnipeg).

- Do you know how hard it is to get a telephone line between Garden Hill and Winnipeg from 5-11 at night because all the lines are jammed (internet users). Think about this from a medical perspective. There are ten thousand people up here.

- We have to consider the human factor in this process. Our regional needs have to be considered; health and education. For example, we need a regional hospital that is central to communities such as in God's Lake narrows.

- Governments don't want to listen and probably won't listen to this plan either. For example, cottagers – governments would soon listen to them.
- The timber company in The Pas has a license for cutting in our area.

- Governments do not consult with us about mining and claims until after the fact.

- We have to have training for our youth to prepare them for future opportunities such as resource development that may result from the East Side plan.

- Timber is being cut within our trap lines without our input.

- Economic benefit and jobs are not going back to local communities

- Any additional travel going north will create additional opportunities for us such as a gas bar for example. A gas bar location on highway #304 might be accomplished through Little Black River reserve land being “swapped”.

- We need economic development, tourist development; there are lots of alcohol problems.

- We have visions of ecotourism and general tourism development.

- We need to create employment and learn how to use resources. The Round Table is here to help us, we have a small reserve and there have been too many changes of leadership. Let’s work together.

- Our infrastructure needs to be upgraded. We have a beach but lack the funding to improve the road to it. We need gravel and crushed rock for the road.

- If there is forestry development we want to do it. We disagree with the Forest Management License.

- One time wild rice was open for use by anyone but harvesting was taken away from us. Today we need a permit to harvest. We want it back and be able to share with everyone. We want to get back to that way of life. We were here before the boundaries.

- Cottage developments and expansions are occurring. Water treatment plants etc. are issues that are happening on our traditional lands and we are not being informed. We need to be made aware of these developments and our concerns listened too.

- Lets do the planning so we can help our community develop and prosper.

- We are a small community with a lack of support. Changes in leadership lead to minimal positive activity/development. We need to develop our plan to aid our community. We need to get as much from our resources as we can.

- We have concerns with sustainable development. What happened to our buffalo?

- We are hindered in what we can do in our territory because of our circumstances

- Little Black River is very interested in cottage development in the area and we should have exclusive rights to such

- Local people must benefit from resource use activities.

- The community requires jobs and road improvement projects could provide them.

- Whenever industry moves into the area, people from outside the community benefit more than local people.

- There is a lot of mistrust due to past actions of government. For example, at Wanipigow, cottage owners erected a water control structure drastically reducing the flow of water downstream. This is the source of drinking water for the Hollow Water First Nation.

- The Manigotagan River Park Reserve is being pushed on the people. The community of Manigotagan is planning to expand their boundary up the Manigotagan River to the second falls. Because our community is situated on the river, we would like to continue our community on the river. The park reserve is willing to start at the second falls but once the BI-Pole lll line comes down, will they take the land back from the community for this line? This is something that the community does not want to see happen.

- Manigotagan will share its community plan with the round table when it is ready.

- Jobs and economic development are important.

- Fish movement in and out of the land is important

- The local trappers association wants to know what will happen to the trap lines when development occurs.

- There is high unemployment in our communities, because when any development opportunities arise, proponents bring their own people to work on local projects. We have a lot of traditional people here that are qualified to work.

- We want government to consult trappers about their plans because we want to keep the land in its original state.

- There is mining activity in the Red Sucker Lake vicinity, however, we believe this to be Norway House traditional territory.

- The community needs someone to point out the potential for development and how to develop resources.

- There is a need to be involved in the designation of protected areas. A community member had received a map from Energy & Mines that showed an area south of Red Sucker Lake that he was told was protected. If that were true, mining in the area would not be available to the community, nor would jobs. There is also good timber around Red Sucker Lake and there was a concern that a protected areas designation would prevent one individual from developing a sawmill to replace a number of tents with buildings.

- For this reason as well, the community must also be consulted about mining activity. Community members have observed the comings-and-goings of mining equipment, personnel, etc., all of which, it knows nothing about.

- One trapper raised a concern about people coming onto his trapline and staking a claim and then him being asked to leave his trapline.

- Several people noted the hardship in living up north. Gas is $1.99 per litre. The cost of a helicopter to go there (33 miles) is $4,000.00 for a one-way trip. Everything is expensive. The round table is needed.

- Tourism must be made more accessible in the area. One person had a proposal to purchase additional land to expand his tourism facility refused due to competing interest of protected areas and Tembec's right of first refusal in the area. Operations like Pelican Harbour however, got land development privileges and were supposed to provide jobs in return, which they did not.

- There needs to be profit-sharing between large corporations and communities.

- A concern was expressed that a proposed sawmill partnership excluded Seymourville.

- Seymourville needs to develop its own plan as well as look at a larger geographical area and work with surrounding communities. It will need funds to accomplish this.

- It has been suggested negotiations between First Nations and the province include resource ownership, resource management and revenue sharing.

- First nation education should be a requirement of the public school systems including universities schemes.

- Development would upset natural process. Any development should be properly planned and proceed with caution.

- Trespassers should be charged for trespassing and destruction on traditional land and affecting the livelihood of local trappers.

- Planting and harvesting of wild rice on traditional land by non-Aboriginal people is affecting livelihood of local people.

- Need to consult with community before any activity happens in the planning area.

- Activities from Hydro, logging, mining adversely affect the community and the land.

- What plans exist regarding the construction an airport and a road from St. Theresa Point to Wasagamack First Nation?

- The province should negotiate ownership since development would be on their land.

- There are concerns respecting the proposed Manitoba Hydro BI-Pole lll transmission line and how it will impact employment opportunities for the communities.

- Need to conserve and preserve all resources for future generations.

- There is a need for funding for community cleanup to help attract and develop tourism opportunities for the communities.

- Development of resources needs to be clear and transparent.

- Conduct clear and open surveys.

- How can I charge a trespasser on my land? The issue is a wild rice harvester who also put a dam up to raise water levels and impacted his livelihood.

- First Nation people are keepers of the land. The new activities like hydro, forestry and mining are an exploitation of our resources.

- The North-West Hydro project that brought power to seven local communities was funded 75% by INAC, 15% by Manitoba and 10% by Hydro. Now Hydro owns an infrastructure that was paid for by Treaty (INAC) dollars. The First Nations should have ended up owning the lines and hired Hydro to manage them. The First Nations should also own the roads and airports that will be built on reserve land in this area. Bi-Pole III is a moneymaking scheme for

Manitoba. The revenues should be shared with us. The same can be said for mining, forestry and commercial fishing.

- We do not want secret surveys of our resources. We hear of helicopters flying people around to look at the land. Developers must come to the community first.

- There should be a process for 10-year reviews of development in the north.

- Wasagamack First Nation has begun to explore and research the development of a forest management plan, a resource management plan, a community development plan and a long-term sustainable development plan. There should be a process for 10-year reviews of development in the north.

- A concern was expressed about outsiders coming into the community, collecting and recording data, leaving and not returning any information or results.

- Intruders onto existing trap line areas affect wildlife populations due to poor mining practices and lack of environmental and wildlife considerations. These same people also trap in the community's traditional trapping area which results in declining revenues for trappers and less wildlife for sustenance use by local people.

- There is a need for maps to show burial sites so they are not desecrated in any future land developments

- We hear of (southern) people flying around in helicopters to shoot moose. We do not appreciate these sport hunters who only take the antlers. This is disrespect. We have to use every part of the animals we hunt. We also find intruders on our trap lines. This happened as far back as 1933 when I came upon a driller while out shooting for rabbits. My mother told me there was a lot of exploration and mining in the early days.

- Outfitters planted wild rice in my trap line. Over time we have noticed the fish disappearing from this area. I met this person and told him he should not have done this in the first place. No one talked to us about this development.

- There was talk some years ago about planning for the land in our area. The Island Lake Tribal Council has begun to look at how the land should be cared for.

- The people of Wasagamack need to work together with the southerners. We have to focus on what is going to happen in our lands. We also need to capitalize on our fishing and hunting skills.

- A representative of MKO spoke about areas that the Community needs opportunity to explore. These are a (1) community development plan; (2) forest management plan; (3) resource management plan; and (4) sustainable development plan.

- Forestry is not offering much employment because of changing modern technology.

- We need economic development; government is stalling development.

- Our children's education service is below provincial teaching standards.

- Our business is presently going to Pine Dock, then Gimli and Selkirk. They value our business

- The province should sell Crown lands for development by local land developers. I am specifically referring to a piece of land, which is not pristine, but on which other activities used to take place but no longer do. All that remains now is a bunch of run down buildings. To allow local residents to make use of such lands is sustainable development in my opinion.

- Trust issues are non-existent with government initiatives (i.e. lodges and cabin development). Government did not follow the recommendations of the community in the past, why should we trust them now?

- The Prospectors and Developers Association should be represented on the East Side Advisory Committee.

- Community is all for economic development.

- We need to develop our own plan.

- If we tell you what we want, what guarantees are there that we will get what we want?

- We are working on several proposals that involve our traditional land and we are asking for total control.

- Does the area that Tembec is planning to cut involve Bloodvein, or is it part of the planning area? We want to do the cutting ourselves, not Tembec. We are in a process of looking at deals like the one Pikangikum has with their Whitefeather Initiative and co-management model.

- We are not a stand-still community; we are looking forward to young people gaining employment.

- Why should we be interested in mining activity when the broad area plan is going to prevent such?

- Land regulations contravene Mining Act.

- Bissett is a mining town and residents believe there is mining potential for the area.

- Mining is the lifeblood of Bissett. Exploration needs to continue.

- Government bureaucracy is causing problems with respect to mining activity. To keep a claim valid, one has to show some kind of development or be in violation of the Mining Act and loose the claim. In many cases, people have been refused permits to travel forestry roads to their claim.

- Government must allow claims in the area. The government supports the community, however not in the way the community wants them to.

- Nopiming and Atikaki Parks restrict mining development.

- It appears that the message that Manitoba is not open for business is getting outside to the industry. American mining investors are going elsewhere when they learn the Hayes River will be set aside as a heritage river. How will this affect future mining exploration activity?

- Residents want to benefit from mining and want to stop restrictions imposed by park regulations and legislation.

- A Canadian Heritage River designation impedes mining exploration.

- Who is going to replace the vacated mining representative position on the ESRT.

- There is a need to create a local advisory board. This initiative is an opportunity that the community must seize now because if it does nothing it would lose an opportunity. We want to be involved in benefits, partner and training for anything happening in our region. We will block any developments done without consultation.

- The First Nation needs employment and has identified employment opportunities with Manitoba Conservation as a part solution to local unemployment issues.

- First Nation identified future resource sharing as a means of financing resource management.

- Atikaki Park closed all doors and no economic development opportunities.

- Members expressed the concern that if the forests are not cut and used it will burn and no-one will benefit.

- There is high unemployment in our communities, because when there are any development opportunities arise, proponents bring their own people to work on local projects. We have a lot of traditional people here that are qualified to work.

- Tourism would be a plus for the community.

- Economic development over the next 10-1 5 years is a major priority for the community.

- Development of a fish processing plant is currently being discussed. Fish is currently being sent to Freshwater Fish Marketing Board.

- Need to develop eco-tourism.

- Growing cranberries could be a viable opportunity for the area.

- First Nation identified wild rice harvesting as an opportunity they can develop and maintain.

- The construction and maintenance of a local airport would bring much needed jobs in the area as well as bring the costs of goods and services down to acceptable levels.

- The construction of a local airport would improve medi-vac programs for those individuals who require medical emergency assistance.

- Job creation is a major concern for the First Nation. Current unemployment rates range in the 80-90 percent. The council indicated commercial fisheries in the area would improve job creation, however, transporting fish would remain a high cost to the industry.

- The First Nation remains opposed to Outpost hunting in the area. This was done without consultation with the local people. The First Nation wants to work closer with the Natural Resource Officers who frequent the area. They want their people hired to work alongside the NRO's and believe the province has sided with local lodge owners and favour these owners when developing policy on lodges in the north. People who live in these areas (north) should be given priority when policies are developed.

- All communities in the southern portion of the study area have been developed around logging. We need logging and mining on the east side. Logging is much more environmentally sensitive today.

- It is not easy to reforest a mature forest; it is much easier to reforest an area after has been cut.

- Why wasn't Manitoba Tourism in the video? We should be looking at the potential of this sector instead of forestry and mining.

- There needs to be more support from Tourism Canada, not just from the Province of Manitoba.

- If the First Nations claimed the beaches on the east side of Lake Winnipeg, they could get millions of dollars in return.

- Development on the East Side has to do with resource harvesters, not First Nation's people. Forestry harvesters and cottage developers will benefit from development.

- What benefits do we get from Forest development? We were promised jobs by past forest operations, it did not happen.

- Ecotourism should be seen as an alternative to forestry and mining. Bring in German tourists who want to learn about our culture.

- Mining raises red flag; companies create pollution. They provide jobs, but what about safety?

- Should have First Nation people looking after natural resources.

Roads

- An all-weather road would cut through many traplines and trappers would not get anything from it.

- An all-weather road has all sorts of advantages including training for heavy equipment operators.

- Oxford Lake was closed for fishing due to high transportation costs to market. We were throwing away our catch because there was no transportation to market. It is a waste of time, energy and fish. Pickerel is the only viable species now and it is three times the work. Need to build a road to transport fish out. Advantage of road – transportation the fish, shopping trip, etc, - all weather road is the answer. On the other side more influences coming in and not all good influences. We need to be aware of that.

- Do not talk about a hydro line before a commitment to an all-weather road as the community cannot continue to be at an economic disadvantage due to an absence of all-weather road access.

- We see the pros and cons of roads to communities. The social impact has to be addressed when we see a road coming into Garden Hill. A lot of elders have expressed they do not want a road because of the destruction of life from alcohol and drugs.

- There is concern about a proposed road which can be built from North of God's Narrows connecting Northern Ontario.

- An all-weather road would effect Treaty #5. Right now there is no money coming this way for road development and maintenance of existing network. Available dollars are not reaching into the northern areas.

- If a road goes through we need to get our lands back for ecotourism. We are not getting our share.

- We have 3rd world roads here.

- Tourism does not benefit Bissett. The road through Nopiming bypasses Bissett.

- Government has negatively impacted Caribou when they developed the road through Nopiming. Road development has affected the Owl Lake Caribou herd (Black Lake calving grounds).

- Pave road from Manigotagan and finish straightening road to Bissett.

- What is happening with the Cat Lake to Red Lake Road?

- Jobs are needed in Bissett. Some have to leave by spring for work.

- Are they going to hurt the rivers if the road comes?

- A proposed road on the East Side of Lake Winnipeg would impact inhabitants, wildlife, eco-system, etc.

- We are preparing for the all weather road by training our people how to use the heavy equipment needed too build.

- Pros' and cons of an all weather road discussed - would lower the price of goods and transportation.

- Communities will need an analysis on what impacts an all-weather road will have on them. Elders have expressed some negative thoughts a road would

bring to the community, such as alcohol, drugs and gang related problems. Government in the end will go the cheapest route.

- The cost-efficiency or feasibility to build an all-weather road up the east side of Lake Winnipeg is questionable.

- We want an all-weather road because we see things will be cheaper for us to but, but we are also concerned for our youth because this road will make it easier to bring in booze and drugs.

- We are not opposed to an all-weather road as it would help alleviate the high cost-of-living for First Nation people. We would like to see road access to communities before hydro lines go through. What are other communities saying about this?

- We would like our road and human issues dealt with before Hydro.

- I can't see that there is anything wrong with an all-weather road. We would have benefits such as forestry and tourism.

- The community would want an east-west road connection. Use the winter road alignment so as not to disturb any more landscape.

- Who is pushing for the all weather road? Government or communities?

- Government needs to hear from communities other than Island Lake in regards to an all weather road.

- Local people need to be hired if an all-weather road is to be built.

- Money should be spent on existing roads before a new one is planned for the east side.

- An all-weather road is important; it would be good for groceries. Concerns raised around all-weather access to the community included a negative impact on the lodge, on young people (access to drugs) and possible abuse of traditional areas. Highway would have to be kept clean by R.C.M.P. It is not going to be easy.

- Any routing of an all-weather road should connect God's River with Thompson.

- Is there an issue with stopping the road in the East Side?

- It would be a blessing to have a road for those communities.

- Why does Manitoba Hydro get to say "no" to the road?

- Since the construction of the highways, the three types of Caribou who used to be here, no longer inhabit this area.

- Internal road conditions pose health and safety concerns that have to deal with on a constant basis. Can the round table help the community lobby for better roads?

- Road access into traditional lands would impact on wildlife and traplines.

- The annual practice of building winter roads is that they are built too late in the season. There is a need to ensure the winter road is built earlier by the band. There is lack of capacity and experience for neighboring communities to do the job they need to do.

- Since the construction of the highways, the three types of Caribou who used to herd here, no longer inhabit this area.

- Concern that once the road is built people will follow with their developments. Outside influences coming into the community could be a concern.

- Current road into the community is in terrible condition and needs repair.

- Government won't build a road unless it is for there own needs. It won't be built because the community wants it. It will be built because of the resources the government wants and needs.

- There is support for the construction of an and all-weather road, but not more Parks.

- Costs in the north are directly related to the freight costs.

- An all-weather road would not only be helpful to the community, but also to taxpayers.

- Health problems are greater in the north; a road would help alleviate much of the problem.

- You cannot find nurses to go north because they have to fly.

- Education in health and diet, as well as nursing, ambulance and police services, would all improve with a new road.

- If a road goes into a remote area, concerns about culture are what that area makes of it. People from remote areas must leave their community on medical trips and have no one to escort them, visit them, or aid in their recovery, because others can't get to and from the hospital by road.

- There are a lot of untapped Federal dollars that could be put to training programs for local people to develop an all-weather road. This would create local employment.

- What ill effects will an all weather road do or have? Has the road through the Interlake affected the environment?

- If our First Nations brothers want a road we should support them.

- If an all-weather road is built, funds should not be deducted from our INAC funds.

- Give dollars for road development to communities to lower their costs for consumption.

- What benefits will First Nations get out of an all-weather road and will we be compensated for its impact?

- How do you protect the environment if a road goes through?

- Roads construction will affect plants and animals and therefore how can treaty rights to hunt not be impacted?

- What are other communities saying about an all-weather road?

- A road will open up the drug trade and communities will lose their language. Look at Cross Lake and Hydro and the negative consequences it caused.

- Communities have to be educated on the all-weather road and its impact.

Hydro

- Hydro promised money ($8000.00 per trapper) to trappers who were hit by the development but they did not follow through. I get the same impression about the round table.

- It is critical to understand and be aware of the many sites of historical and cultural significance before proceeding with roads or hydro.

- We have heard from Hydro before. They came to us, but did not give us enough time to respond. You have to give us more time. There is a lack of information provided by Hydro for the community to adequately respond or participate. We do not want a poor consultation process. We do not want this to be like the Hydro process.

- Manitoba Hydro held a consultation process on its hydro Bipole lll transmission line but shared only what they wanted and expected the community to learn everything on that day. Time will be needed for the community to absorb the information and get it out to all the members in order to fully participate in this process.

- We have concerns with hydro and Bipole III.

- Why are there no muskrats and fish anymore? Is it because of hydro?

- Manigotagan does not want the Manitoba Hydro BI- Pole line running trough their community.

- At what stage is Manitoba Hydro at in getting their line in?

- Can the north-south hydro line be done in collaboration with the winter roads, ie. make 1 instead of 2 corridors?

- Why not put the roads and lines together so they do not have to use so much forest?

- I can feel the effects of the damage that Hydro has done, the water levels are low.

- There has been destruction from Hydro in the past with little compensation.

- Is there compensation for impacting trapline areas of First Nations if hydro lines go through?

- A question was asked where BI-Pole lll was going to be erected and how close it will come to the community.

- The community of Manigotagan is planning to expand their boundary up the Manigotagan River to the second falls. Because the community is situated on the river, they wish to continue growth along the river. While the Manigotagan River Park Reserve is willing to start at the second falls, there is a concern that once the BI-Pole II comes down, the Province will take the land back from the community for this line. This is something that the community does not want to see happen.

- There are concerns respecting the proposed Manitoba Hydro BI-Pole lll transmission line and how it will impact employment opportunities for the communities.

- Once the report is completed will the committees be consulted and will Hydro work only with the round table?

- Compensation concerns from Manitoba Hydro to the First Nation were raised.

- We need to know what Manitoba Hydro has in store for us. We cannot create an effective community plan without knowing where the hydro-line is going to be placed.

- Hydro maintains its transmission lines by using chemicals to kill plants. Imagine what that will do to our trees and animals. We would like to know what type of chemical they will be using and have any existing studies forwarded to us.

- Hydro lines and roads will destroy our traditional way of life. How are the young people going to survive?

- Are they going to put the lines in the north, but distribute the electricity to the south?

- The cost of hydro in the north shows we are not getting our share of the resources sold.

- We will not be able to tap into the hydro lines.

- Are there any studies of the effects of transmission lines on humans and the environment? If so, we would like to see them.

- Are there any studies being done on the effects of dams and the associated lake quality and lake level changes? These factors affect our livelihoods. What about studies on the rivers, river levels and river water quality? Also we need to know the effects of control structures on our water systems. Our water has gone down 4 feet and it is affecting our fishermen.

- Hydro should consult if they have a plan in place.

- Do you come out and help us with an action plan to stop it development if we do not want a hydro line here?

- Hydro development along the east side is a concern for the community.

- Hydro rates are a serious concern to local residents. They provide examples of current rates for an average sized bungalow is approximately $200.00 while rates in the south for similar size home is approximately $75.00 per month. Manitoba Hydro has introduced an insulation program to help defray hydro costs, however, liaison and communication between Hydro and the

First Nation administration has not been the best. The First Nation wants to see rates lowered through any means.

- How will the Hydro projects on the East Side impact the ESPI Process?
- Is the extension of 304 highway north talked about in connection with hydro development?
- Tembec and hydro do not care about damage, they care about profit.

Other Issues and Concerns

- We need to plan what we are doing in an orderly fashion.
- Gain must be distributed to the community as a whole, not to individuals.
- More meetings are needed.
- If a trapper looses a cabin in a fire is there a way that he can be reimbursed for it?
- This information should go to the schools for study and response.
- Need to look at funding for informing the community of the process.
- Concern raised because of the lack of community members at the meeting. Another community meeting recommended allowing for more involvement from the rest of the community.
- There is a need for more information on the ESPI process.
- Government can promise anything but not deliver because in the end government will do what they want.
- There is a lack of trust between communities and government.
- A suggestion was made to include all East Side communities in one meeting.
- Maps don't show territorial lines due to lack of funding and shortage of technical people. Need for technical people to assist the community in this process.
- If the community does not become involved in the process, they will be losing an excellent opportunity to participate in planning and development activities.

- Community is concerned of the short timeline.

- Where is the funding coming from.

- What are the next steps to this process?

- The people of Garden Hill need to hear from other communities. Why not get a few people from the 16 communities to get together to see if there are shared values. We need to understand one another. Recommend two or three from each community.

- The East Side Planning Initiative is entirely new to us and more information is needed. Who are the 22 people on the round table? Where are they from? How were they appointed? Is there a timeline for this process?

- Once the recommendations have been made, when will they be given to government?

- Is there any one community that can stop the process? There may not be consensus at the end of this process because different groups have different interests and views.

- Will there be a possibility to meet as a community to discuss this process to include all members.

- Is there any one community that can stop the process? There may not be consensus at the end of this process because different groups have different interests and views.

- Will there be a possibility to meet as a community to discuss this process to include all members.

- The ESPI ties in with some of our community initiatives.

- The maps on the wall need to be blank so that we can identify what we want to protect as ours

- We are hindered in what we can do in our territory because of our circumstances.

- Non-Aboriginal people have to work with us; relations between us have to improve.

- Decisions will be difficult given all the competing issues.

- It is unrealistic to expect communities to develop positions by June 2004. This date makes the process seem like it is being fast-tracked. Communities need time and resources (money, facilitators, etc.) to identify issues and formulate positions on them.

- Manigotagan will share its community plan with the round table when it is ready.

- Who is to tell us how to make these decisions and who will help us develop a plan?

- What advantages does the west side have when the East Side opens up?

- What are other communities saying about their issues? They might have said things we won't think about and vice-versa.

- Only a small part of original Manitoba left; it is fearful what is happening.

- What are the government's plans regarding the development of the East Side?

- There is a need to find a way to get community members more informed about the East Side Planning Initiative. Radio and TV could be used and information is required in the local dialect.

- There is a need for more discussions between government and the community.

- There is a need to have more Elders involved in this process.

- Youth must have a role in this process as they are excluded most times.

- Everyone needs to work together in this process.

- The East Side Planning Initiative requires more time to discuss issues focussing on aboriginal interests.

- A concern was raised regarding the composition of the Round Table: how many Aboriginal people were on it and how many lived in the planning area.

- Concerns were expressed about how NACC communities would receive fair representation and what they could do to ensure their recommendations are honoured.

- The deadline to complete the plan by June 2004 is unrealistic. It is unrealistic to expect communities to develop positions before then.

- Media needs to be kept in check and lines of communication need to be clear.

- Local trappers and fishermen need to be represented on the round table.

- There should also be a trapper representative and a fishing representative on your round table.

- Farmers get compensated for loss of income. So do East Coast fishermen. Trappers have lost income because of markets. Trappers should be treated the same as farmers with respect to loss of income.

- People in the south need to be educated about our ways in the north – they get a slanted view of our ways. The South has no understanding of the hardships here.

- I have expressed my concerns many times. The creator gave us the resources – all the things on Earth. These are what define us as First Nations. My concerns over government are decisions that affect our identity. As an example, First Nations had their own way of child rearing. We believe that it is important to discipline a child. Now there are laws against this and it results in delinquency. Also, the government has wanted to assimilate us and change us to white people.

- Due to the language barrier and infrequency of communication between the two cultures, it is difficult to communicate and resolve local issues and concerns. There is a need to work closer together and translate all literature to Oji-Cree for elders and other community members to understand and participate fully in this process.

- It is preferable to have a united voice representing the Island Lake First Nations. For that reason, the round table members need to sit down with the Island Lake Tribal Council to discuss concerns, ideas and views about their communities and development in the area.

- There is a need for the community to be given time to absorb the information provided and return views and comments at a later date.

- You need to change a few things with this new process. People often come from the outside to speak and get our input, but they never come back. Very few people get involved this way. You need to come back to Wasagamack.

- The next time you come up should be in the winter when the roads are in. Then you can have a meeting with all four communities together.

- Most often people out there come here to tell us what's best for us, but we live here, not them. They come in and take over and say it is in our best interest. They have not walked in our moccasins so to speak. The time

frame is too long, it take too much time and in the mean time the government have their way to control it till they get what they want.

- Safety on Lake Winnipeg is an issue as people have died crossing the lake.

- Need to make recommendations immediately - be preventive.

- Berens River recommended the ESRT advise the government that it would like to see Rupertsland Constituency cut in half.

- We do not condemn the ESPI process; we just do not have a position in place as yet

- We do not think the people on the ESRT represent us. I strongly recommend considering one of the communities like Poplar River or Hollow Water to represent us. They live on the East Side.

- There is a need to have something in place besides just a community forum and working group. There is a need to go house to house.

- Information should be provided beforehand to facilitate preparation and discussion. Provide information by all available means.

- When did this process start? Was there nothing before that? Shouldn't the community have been involved in 1999? Why did it take so long to get to the communities? This should have begun with the communities.

- Need to improve relations and communications with Manitoba conservation, particularly with the NRO'S.

- Chair discussed the INAC funding and use of it for this process. Historical moment for government to open the doors to share information with First Nations people.

- Need for their own conservation officers to police their own community.

- Have more RCMP/policing for the surrounding communities.

- Concern was raised regarding child welfare issues in the communities. What is government's strategy to deal with alcoholism and rampant drug abuse by adults and youth? This is the future of the communities and more priority should be given on these life and death issues.

- We are beginning to return to traditional medicine.

- Should be able to revisit the plan and have a renewal within 5 years and have the ability to revisit because changes will continue to change in the area.

- Norway House NACC is currently in the process of creating a community plan. Northern Affairs has been dealing with Northern Flood issues and this has pushed their planning back.

- Current road into the community is in terrible condition and needs repair.

- Trappers and elders communicate in Cree so there is a need to make the information available in Cree.

- Tembec open houses are being held for the public. Tembec is not a proponent on the all-weather road.

- Is the extension of 304 highway north talked about in connection with hydro development?

- Send future information to Powerview Metis Local through the Manitoba Model Forest.

- People in the community are educated and must be listened to.

- What ill effects will an all weather road do or have? Has the road through the Interlake affected the environment?

- It is startling on how the wealthy all over the world try to tell us what to do we are being watched by the world. There was a person from Germany in Hollow Water begging the people of Hollow Water to stop this process (ESPI).

- How much time is being spent in schools? It is their future and they need to be involved. We must get information to the schools, to teach the children to protect the environment but still have progress and development

- We in the community have to have a say in what is going on. We need to have a strong understanding of what has to be done, not some millionaire in Florida.

- The community of Pine Dock expressed concerns about not being notified well about East Side meetings and requested that information be sent to them in a timely manner so that they would be ale to comment effectively.

- Communities must be advised of the park issues, so that they understand the impact.

- Is it odd that chronic wasting disease is rampant in Manitoba's major National Park, Riding Mountain, where logging and hunting are prohibited?

- The environmental people should come to talk to our community so that we can tell them how we feel.

- There should be more Elders and youth involved in the process.

- Promote students in each First Nation. Students have role to play and need to work closely with your office. Set up a sub-office in Sagkeeng to help students gather information and advocate on behalf of their First Nation.

- Pine Dock wants to be consulted on land transactions and allocations in the area.

- The maps you have arrived with have no Anishinabe input.

- When I was young, we lived off the land and didn't need help. We had an abundance of resources. Then change came in a form of a document called The Indian Act. In 1942 a person pushed for the Indian Act, from British Columbia. Our chief went against it, he knew enfranchisement was coming. In 1948, chiefs were called in to revised the Indian Act. It was rejected but passed through in 1951. Our Chief John Thompson was disregarded, and the Federal government declared elections. Sagkeeng had been in a downward spiral ever since. We were self-sufficient until 1951; money wasn't needed, goods were traded.

- If we put resources too use in comminutes today, we would teach people to be like before 1951.

- Tembec and First Nations have to work together to develop a committee to define Traditional Ecological Knowledge projects and surveys. Is TEMBEC committed to funding TEK mapping?

Tab 42

"Promises to Keep..."

Towards a Broad Area Plan *for the East Side of Lake Winnipeg*

Executive Summary



Manitoba

4507



"Promises to Keep..."

Towards a Broad Area Plan *for the East Side of Lake Winnipeg*

Legal Impact of the Status Report

The contents of this Status Report – the narrative, analysis, observations, and recommendations are presented to the Government of Manitoba in the spirit of good will and good faith. The Government of Manitoba is committed to improve the relationship between the people of the province and First Nation/Aboriginal peoples based on principles of mutual recognition, mutual respect, and mutual responsibility. Nothing in this Status Report shall be construed to restrict, compromise or fetter the ability of First Nations and Aboriginal communities and their members to fully enjoy the Aboriginal and Treaty Rights recognized and affirmed by the Canadian Constitution and the evolution of Canadian case law. The Government of Manitoba, in creating the East Side Planning Initiative, has affirmed that the content of this Status Report shall not be construed to alter, replace, or fetter the legal responsibility and obligation of the provincial government to engage in meaningful consultation and accommodation with respect to any and all issues identified in this report.

Manitoba

4509

"Promises to Keep[1]..."

Towards a Broad Area Plan *for the East Side of Lake Winnipeg*

Dedicated to:

The future of the people
of the east side of Lake Winnipeg
and to the land which will continue to sustain them.

[1] The title of the status report is taken from the final stanza of the Robert Frost poem ***Stopping By Woods On A Snowy Evening***

> The woods are lovely, dark and deep.
> But I have promises to keep,
> And miles to go before I sleep,
> And miles to go before I sleep.

Letter of Transmittal



Broad Area Planning

East Side Planning Initiative

Room 405 - 326 Broadway
Winnipeg, Manitoba R3C 0S5
204-945-8114 or 1-800-214-6497
204-948-2948 Fax
espi@gov.mb.ca

September 2004

The Honourable Stan Struthers
Minister of Conservation
Government of Manitoba
Room 330 Legislative Building
450 Broadway
Winnipeg, MB R3C 0V8

Dear Minister Struthers:

On behalf of the East Side Round Table and the First Nations Council, it gives us great pleasure to submit to you our status report on the development of a Broad Area Plan for the east side of Lake Winnipeg entitled *Promises to Keep*. For your convenience and reference, as well as for broader distribution, we are also pleased to provide you with a separate executive summary of the status report.

In presenting this report to you and your government, we wish to assure you that we have laboured long and hard to both gain the confidence and understand the preferences of the residents of the east side of Lake Winnipeg concerning the current and future land use of this magnificent area.

As our report will outline, there have been numerous meetings and discussions with interest groups and stakeholders, Northern Affairs and Métis communities and the leadership and residents of First Nations communities, the latter comprising over 96 per cent of the population of the east side of Lake Winnipeg. As the first prototype and flagship initiative emanating from the recommendations of the Consultation on Sustainable Development Implementation, this status report will affirm that the Government of Manitoba has embarked on a unique and promising venture – a venture that seeks to empower the residents of the east side of Lake Winnipeg and engage them in a process that increases their access and control over decisions that will affect the quality of their lives. On their behalf, we commend your government for initiating this most important dialogue.

The development of the Broad Area Plan has not been completed. Yet much has been accomplished in defining a sustainable land use plan for an area equivalent to one-eighth of the land mass of Manitoba. While this status report provides you with a measure of our progress, much remains to be done in our quest to protect the environment, assure sustainable development in the area and achieve certainty for investment and economic development ventures.

We believe that our preliminary observations and recommendations chart a precise and measurable course on the path to completing the Broad Area Plan and we strongly recommend that the Government of Manitoba stay the course through to its completion. The *Memorandum of Understanding* with First Nations communities and the promise of one with the Métis Nation residents on the east side of Lake Winnipeg, the extensive consultations with Northern Affairs communities, and the pending comprehensive dialogues with Manitoba's First Nations communities on the east side of Lake Winnipeg, will shape a Broad Area Plan based on thorough consultations and a sensitivity to the environment that is unparalleled in recent Manitoba history.

The recommendations contained in this report are based on extensive preliminary consultations with communities on the east side and the dedicated work of our colleagues on the East Side Round Table, the First Nations Council and the Advisory Committee. We are convinced that this East Side Planning Initiative will produce a Broad Area Plan that will not only serve the residents of the area and the interests of all Manitobans, but will also define the future of Broad Area Planning and sustainable development in Canada.

We commend this work to your attention and respectfully request that it be permitted to reach its natural and positive conclusion.

Respectfully yours,



Chief Phil Fontaine
Chair
East Side Planning Initiative



Elder Ed Wood
Associate Chair
East Side Planning Initiative

Acknowledgements

September 2004

The Honourable Stan Struthers
Minister of Conservation
Government of Manitoba
Room 330 Legislative Building
450 Broadway
Winnipeg, MB R3C 0V8

Dear Minister Struthers:

The preparation and submission of this status report, *Promises to Keep,* and the separate executive summary which accompanies it, is premised on the assumption that it is but an important waypoint on a path that will lead to Manitoba's first Broad Area Plan based on the sustainability principles identified in the *Consultation on Sustainable Development Implementation,* which your government has adopted as policy. The East Side Planning Initiative (ESPI) has begun a comprehensive and inclusive process of information sharing and gathering. The complexities of the many issues at hand require no less.

This status report, the contextual observations and many recommendations it contains, owes its genesis, first and foremost, to the many people resident on the east side of Lake Winnipeg who took the time to attend community meetings and express their concerns and ideas. This report, in thanks for their participation, is dedicated to them and their fellow citizens.

The East Side Round Table and the First Nations Council, as duly constituted and in working groups, have spent countless hours hearing of people's concerns, listening to presentations, sifting through forests of documents, reports and expert opinion, debating the issues and, finally, crafting this status report. That they were able to do so while respecting the diverse views and disparate interests of those around each table, is a testament to their dedication and commitment to this process. Thanks are also extended to the members of the East Side Advisory Committee who took the time to attend meetings, and furthermore, took advantage of the opportunity to submit observations and recommendations to the ESPI.

Appreciation is also extended to Phil Fontaine who retained his role as chair of the East Side Round Table and First Nations Council even after assuming the onerous role of National Chief of the Assembly of First Nations. A particular vote of thanks is given to associate chair Ed Wood who so often went above and beyond the call of duty in encouraging participation, supporting the goals of the process and providing his expertise, influence and credibility in developing a common agenda.

Our appreciation is also extended to community leaders, elders, and co-coordinators who facilitated and took an active part in assisting the ESPI process; to community residents who attended meetings, prepared thoughtful interventions and attended ESPI Open Houses; to the many presenters who appeared before the Round Table and the First Nations Council; to the numerous organizations and individuals who supported the preparation of the East Side Youth Conference, which we hope will materialize in the fall of this year.

Thanks are also offered to the minister and officials of Manitoba Conservation, as well as those departments and agencies of the provincial government that facilitated and supported the work of ESPI.

And finally, I would like to thank each member of the secretariat and the consultants who have supported our work. Their tireless pursuit of excellence and the professionalism and respectably demonstrated in supporting both the East Side Round Table and the First Nations Council in their pursuit of an independent course in crafting this report, have been very much appreciated. I know that I speak for both the Round Table and the First Nations Council in expressing appreciation for the efforts in preparing the numerous drafts and re-drafts of this report.

Without these contributions, the Round Table and the First Nations Council would not have achieved its impressive list of accomplishments in preparing *Promises to Keep.* As the title suggests, this status report is but a stop along the pathway that we must continue to walk to fully complete the Broad Area Plan for the east side of Lake Winnipeg and its accompanying protocols. In starting this important initiative, it is hoped that the Government of Manitoba will see it through to its fruition.

Peter André Globensky
Executive Coordinator
East Side Planning Initiative

"Promises to Keep..."

Towards a Broad Area Plan *for the East Side of Lake Winnipeg*



1. Table of Contents

Letter of Transmittal 5

Acknowledgements 7

1. **Table of Contents** 9
2. **Introduction to the Report** 11
3. **The Broad Area Plan: A Statement of Vision & Values** 15
4. **The East Side of Lake Winnipeg Broad Area Plan** 17
5. **Overarching Themes & Recommendations of General Application**
   - 5.1 Solidifying an On-Going Process: Continuing the Creation of a Broad Area Plan & Possible Options – An Interim Planning Authority 23
   - 5.2 Building Positive Relationships with Aboriginal Peoples: *Protocols of Agreement* 29
   - 5.3 Initiatives to Protect the Integrity of the Boreal Environment 31
6. **Priority Issues & Recommendations**
   - 6.1 Working Groups: Constructing the Observations & Recommendations .. 37
   - 6.2 Aboriginal and Community Development 38
   - 6.3 Forest Resources Issues 40
   - 6.4 Transportation Issues 43
   - 6.5 Tourism and Recreation Issues 46
   - 6.6 Hydro Transmission Corridor Issues 48
   - 6.7 Mining Issues 51
   - 6.8 Additional Significant Issues 53
7. **Conclusion**
   The Path Forward: Challenges & Opportunities 55

1. Table of Contents *(cont'd)*

8. Appendices

8.1 East Side Planning Initiative: East Side Round Table, First Nations Council, East Side Advisory Committee, Government Review Panel (Phase I), East Side Planning Initiative Secretariat and Government Liaison Committee 57

8.2 List of All Appendices & Locations of Availability 59

Glossary 61

List of Maps and Figures

First Nations & Northern Communities Map 13

Public Participation Process 21





2. Introduction

The East Side Planning Initiative was born out of the Consultation on Sustainable Development Implementation (COSDI) that was undertaken between the fall of 1997 and the spring of 1999. The multi-stakeholder, consensus-based process produced a report that was adopted by government in October 2000. The report recommended that the implementation of sustainable development include the creation of broad area plans (BAPs) across the province. Broad area planning is defined as *integrated and coordinated planning that is based on the sustainability of the ecosystem.* Such a planning process ensures that future land, resource and development decisions address the environmental, social, health, cultural and economic needs of the public, local communities, First Nations and various stakeholders and interest groups.

The COSDI report outlines the basic framework for such a planning process. Advocating that all planning must be based on principles of sustainability, the report made recommendations regarding openness and transparency in the process, the need for relevant information to be readily available on a timely basis, the use of traditional ecological knowledge (TEK), the development of protocols to guide consultation with Aboriginal peoples and the development and use of capacity-building mechanisms to enable meaningful public participation.

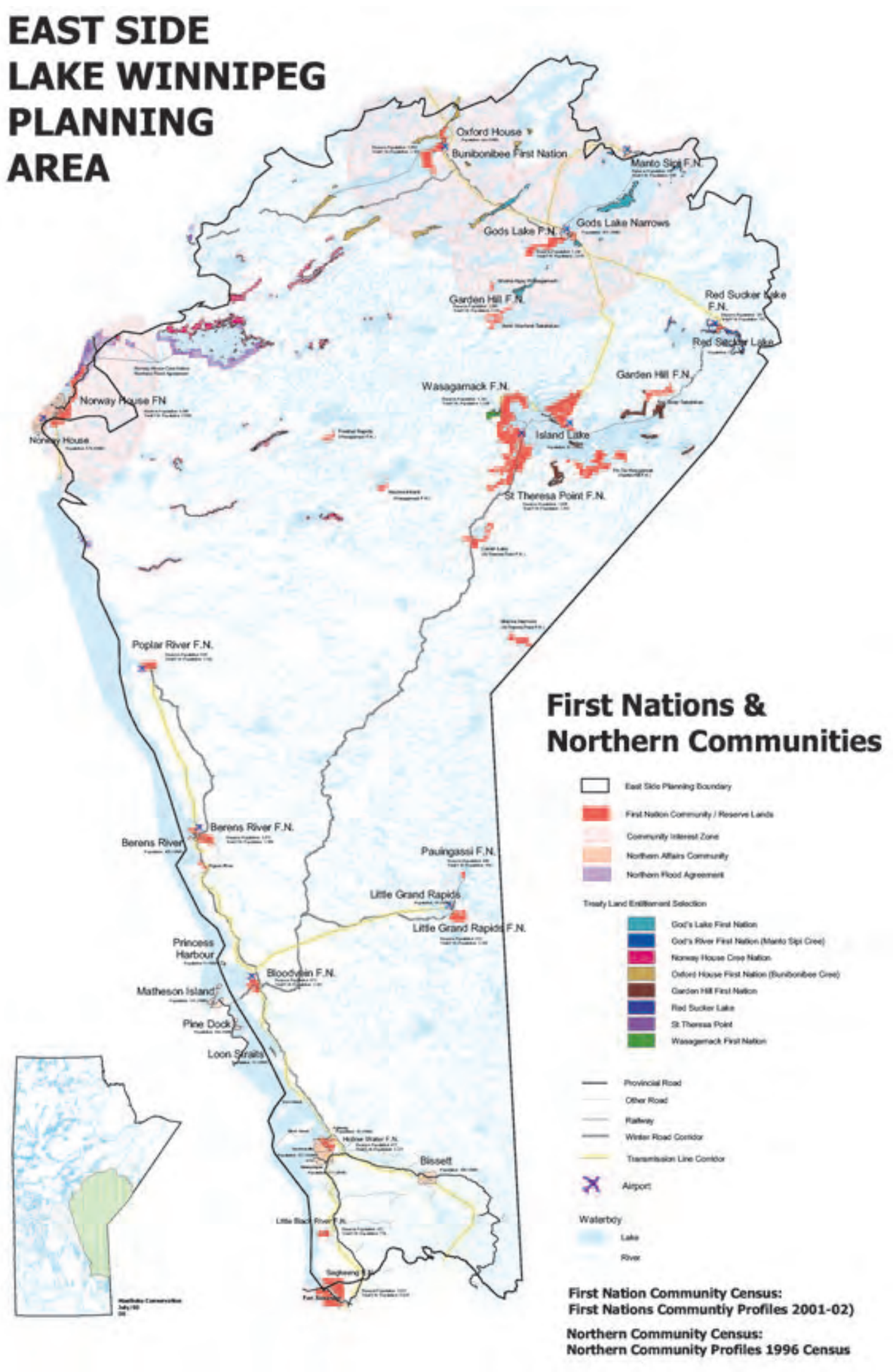
The East Side Planning Initiative (ESPI) is the first large-area planning exercise since the adoption of the COSDI report. It is a complex area, requiring a complex process. It covers a large geographic area – approximately 82,000 square kilometres – housing many diverse and disparate interests. Although its population is largely situated in 16 First Nations communities, each with its own aspirations, there is a significant interest in the area by other Manitobans because it represents to some an area of pristine beauty and to others, exciting economic development potential.

East Side
Planning Initiative

To address this mix of aspirations, and remain consistent with the COSDI philosophy, the ESPI has undertaken the task of involving local residents in the details of the planning for the future of their area.

This is a status report on the progress being made by the ESPI process in the development of a Broad Area Plan for the east side of Lake Winnipeg. By July 2004, the deadline set by government for submission of a draft plan, the process of plan development is incomplete. The East Side Round Table has engaged in the most rigorous public consultation process in the history of the province, and in the course of doing so, has developed a proposed vision for the plan area and some preliminary recommendations, as listed below. However, the process is not yet finished. More discussions with communities and First Nations are necessary in building a broad consensus for the direction to take in the emerging plan. This direction is forming, but has not yet fully formed.

This executive summary provides a detailed synopsis of the contents of the main "Promises to Keep" Status Report. A lengthy list of references used or received is also included in the master document, copies of which will be made available to east side communities. The executive summary and the main report will be available to the public in both print, electronic and CD versions and will be posted on the ESPI website. Copies of the extensive references will be available at all Manitoba Public Registry offices.


EAST SIDE
LAKE WINNIPEG
PLANNING
AREA
Oxford House
Bunibonibee First Nation
Manto Sipi F.N.
Gods Lake F.N.
Gods Lake Narrows
Garden Hill F.N.
Red Sucker Lake F.N.
Red Sucker Lake
Garden Hill F.N.
Wasagamack F.N.
Norway House FN
Norway House
Island Lake
St Theresa Point F.N.
Poplar River F.N.
Berens River F.N.
Berens River
Pauingassi F.N.
Little Grand Rapids
Little Grand Rapids F.N.
Princess Harbour
Bloodvein F.N.
Matheson Island
Pine Dock
Loon Straits
Hollow Water F.N.
Bissett
Little Black River F.N.
Sagkeeng F.N.
First Nations &
Northern Communities
East Side Planning Boundary
First Nation Community / Reserve Lands
Community Interest Zone
Northern Affairs Community
Northern Flood Agreement
Treaty Land Entitlement Selection
God's Lake First Nation
God's River First Nation (Manto Sipi Cree)
Norway House Cree Nation
Oxford House First Nation (Bunibonibee Cree)
Garden Hill First Nation
Red Sucker Lake
St Theresa Point
Wasagamack First Nation
Provincial Road
Other Road
Railway
Winter Road Corridor
Transmission Line Corridor
Airport
Waterbody
Lake
River
First Nation Community Census:
First Nations Communtiy Profiles 2001-02)
Northern Community Census:
Northern Community Profiles 1996 Census



3. The Broad Area Plan: A Statement of Vision and Values

The area of eastern Manitoba contained within the boundaries of the East Side of Lake Winnipeg Broad Area Plan is one of unparalleled beauty and rugged fragility. It is some 82,000 square kilometres in area. Thirty-six thousand residents living in 34 communities inhabit the east side, and over 96 per cent of that population is First Nations peoples. The geography is part of the largest ecozone in Canada (Boreal Shield) and contains the fourth largest, contiguous boreal forest in the world. As any of its residents who live there will tell you, it is a special place, deserving of special measures to ensure that the environment is protected and all development is sustainable.

The East Side Planning Initiative (ESPI) seeks to put into practice the vision articulated in COSDI. This was "To develop an integrated framework for large area and municipal planning, significant resource allocations and environmental management decisions to ensure sustainable development in Manitoba."

The vision for ESPI is based on the fundamental principle that the land is and must continue to be protected.

Further, it is a vision which:

- equates the importance of human development with the requirement for a wise and sustainable stewardship of the land, thereby recognizing the rights of the inhabitants who live there to have access to services and necessities that will improve the quality of their lives;
- regards the East Side as a protected landscape within which economic development activities are permitted if it is agreed that they are sustainable and benefit local communities;
- believes human development must be grounded on integrated and coordinated planning that honours the social integrity of communities and the natural integrity of the environment;

East Side Planning Initiative

- commits to planning for the sustainability of the ecosystem, where our human interactions with it must maintain or restore ecological integrity and not cause it to deteriorate;
- invites Manitobans to steward and value all the resources that may be found there. These resources include the cultural uniqueness of those who live there and the natural resources that have defined and contributed so significantly to our economy; and
- embraces the immeasurable value to our spiritual and psychological well-being that is provided by a landscape of animals, forests, water, air, soil and rock all of which comprise the natural capital of the area. This landscape has contributed to the definition of our character and identity as Aboriginal peoples, Manitobans and Canadians.

There are a number of fundamental values that surround the broad area plan and give it integrity. It is critical that the interests and desires of those who live on the east side of Lake Winnipeg be incorporated into the fabric of the plan. As well, it must incorporate an ongoing mechanism that will provide for meaningful public participation in the further development and governance of the plan. The broad area plan must recognize the enormous influence of the area's cultural landscape. As such, it will honour the significant historical relationship that continues to exist between the land and its first inhabitants, and will recognize, affirm and be in compliance with Aboriginal rights and treaty obligations. It will incorporate inclusive *Protocols of Agreement,* recognizing the importance of the consultative process and the nature of the government-to-government relationship.

The Broad Area Plan places an exceptional value on the importance of traditional ecological knowledge and sound science in the development of a comprehensive land-use planning information database. In the temporary absence of such, the "precautionary principle" will become the automatic default mechanism. In other words, in the absence of adequate information about natural resources or threshold limits, decision-making will be on the side of caution. Planning precedes development; therefore, planning must be based on verifiable and comprehensive knowledge. Without data available to support human activity or development, it is not in our best interests, nor that of the environment, to proceed.

Once completed, the East Side of Lake Winnipeg Broad Area Plan will provide strategic advice and direction to east side communities, government departments and agencies, and everyone engaged, or thinking of engaging, in commercial and recreational activities in the area.

It is with this comprehensive and collective vision, and upon these values, that the Broad Area Plan for the east side of Lake Winnipeg will be developed.





4. The East Side of Lake Winnipeg Broad Area Plan

Following the announcement of the Broad Area Planning Initiative for the east side of Lake Winnipeg in 2000, a three-member government review panel was established to discuss elements of the initiative with First Nations, local communities, the public, industry, non-government organizations and others interested in the future of the area. These elements included the boundaries for the planning area; the steps and timing for the planning process; major issues within and options for the area; and appropriate mechanisms to guide the input and formulate the plan. A final report was released to the public through Manitoba Conservation's Public Registry Network. The report was also placed on the East Side Planning Initiative website at ***www.gov.mb.ca/conservation/eastsideplan***. Subsequently, an East Side Round Table, an East Side First Nations Council and an Advisory Committee were struck to respectively direct and advise the process, all of which were served by a Secretariat.

Following numerous orientation and issue–presentation sessions, the Round Table and First Nations Council moved to establish an extensive round of community information sessions for residents of the east side of Lake Winnipeg.

The objectives of the community visits were to present information on ESPI; to elicit community feedback representative of community sectors that included women, youth and Elders regarding conservation, environmental issues, etc. and to exchange information to create greater awareness regarding the east side plan. The purpose and objectives of ESPI were produced on video and in print form in English, Cree, Ojibway and Oji-Cree to assist in communicating consistent information to communities and organizations.

In November 2003, members of the Round Table and the First Nations Council, with the assistance of members of the Secretariat, began a process that would engage all 34 east side First Nations, Northern Affairs and Métis communities in over 80 initial meetings. Comments from the community visits were

East Side Planning Initiative

carefully recorded and presented in a document entitled *What We Heard* (see full report appendices, Public Registry and ESPI website).

Using working groups derived from the membership of the Round Table, the First Nations Council and Advisory committees, the process then focused on preparing preliminary recommendations for the BAP. With the knowledge that a final plan was not possible to achieve within the time frame specified by government, the Round Table and First Nations Council decided to compile a status report based on the observations, submissions and recommendations gathered to date. As a result of this, the need for an ongoing mechanism was seen as critical.

The majority of recommendations in this report are drawn from the issues identified during the community visits and summarized in the "What We Heard" documents. It must be emphasized that the initial community visits were strictly introductory, and should not be viewed as consultative. In fact, a commitment was made to provide resources for engaging in community planning to provide more deliberate input to the process. This is one of the "promises to keep." It also means that the specific recommendations in the report must be considered provisional until further discussion and consultation opportunities are completed and the East Side First Nations Council has had the opportunity to formulate additional community-based recommendations.

Parallel to this process, the First Nations Council initiated negotiations with the Government of Manitoba to strike a *Memorandum of Understanding* committing First Nations governments on the east side of Lake Winnipeg and the Government of Manitoba to negotiate *Protocols of Agreement* that would become a central component of the Broad Area Plan. The Manitoba government committed to a similar process for the Métis Nation resident on the east side of Lake Winnipeg.

Mandate Summary

The mandate provided by the Minister of Conservation to the East Side Round Table (ESRT) and the First Nations Council (FNC) was identified in the *Phase I Final Report.* It called for recommendations for the development of a broad area plan that would take the following topics into consideration. Chapters 5 and 6 elaborate each of the mandate issues:

Treaty and Aboriginal Rights; Aboriginal and Community Development; Traditional Activities; Protected Areas; Consultations on Land and Resource Allocations; Existing Land Uses and New Development Proposals; Forest Resources; Transportation Issues; Tourism and Recreation; Hydro Issues; Mining Issues; and Other Issues such as research and data needs.

As well, the mandate identified the minimum components of the plan as:

"A vision for the planning area; goals and objectives based on the needs of the area; ecosystem, land use and resource management principles and/or

codes of practice; a land use zone map with policies and/or guidelines for each zone; procedures for the regular review and amendment of the approved plan; and a glossary of significant resource allocations, licenses, permits and other allocations and the issuing body."

While many components have been incorporated into the status report, the analysis and recommendations are but preliminary and the development of the Broad Area Plan remains very much a work-in-progress.

The Public Participation Process

In launching the East Side Planning Initiative, the government committed to a public participation process to gather the views of residents of the east side of Lake Winnipeg, stakeholders and all Manitobans. The future of this important and delicate ecosystem will be determined by the principles of wise stewardship and sustainable resource management that are established within the Broad Area Plan. It is why the government called for comprehensive public engagement in charting a future for this resource-rich and ecologically significant environment.

It is a cornerstone of our democratic heritage that people have an inherent right to be engaged in decision-making processes that affect the quality of their lives. While much remains to be completed in this process, it is clearly evident that all participants have committed themselves to as rigorous and thorough a public process as resources will permit.

In the preparation of preliminary recommendations for the Government of Manitoba on the general content of the Broad Area Plan, and some of the more important processes that must now be pursued (the *Protocols of Agreement*), the East Side Round Table and the First Nations Council committed themselves to an extensive and comprehensive public consultation process. Some of the many activities are summarized below:

- Substantial documentation and information including public comments received during the preliminary discussions phase of the planning initiative and Round Table & First Nation Council minutes and presentations, have been placed on the Manitoba Public Registry (Registry File # 4718.00) and on the East Side Lake Winnipeg Planning Initiative website. ***http://www.gov.mb.ca/conservation/eastsideplan/***
- A multilingual information kit (English, Cree, Ojibway, Oji-Cree & Syllabics) consisting of a video presentation, CD, core summary documents, detailed maps and a community questionnaire, has been prepared for public review.
- A first round of community, information-sharing visits engaging the 34 First Nations, Northern Affairs and Métis communities on the east side of Lake Winnipeg has been completed. To date, over 80 community visits and meetings have been held on the Broad Area Plan.
- The East Side Round Table published and distributed *What We Heard,* a compendium of observations, recommendations and concerns expressed by

"There are communities like ourselves all over the country who have long looked after lands not as owners, but as caretakers of this great land. This is how we were taught as Native people; land is not something you own, land is a gift that you use, to live on it, to protect it and look after it. That principle was used by our people and continues to be used today."

(Poplar River community member
Poplar River – Website)

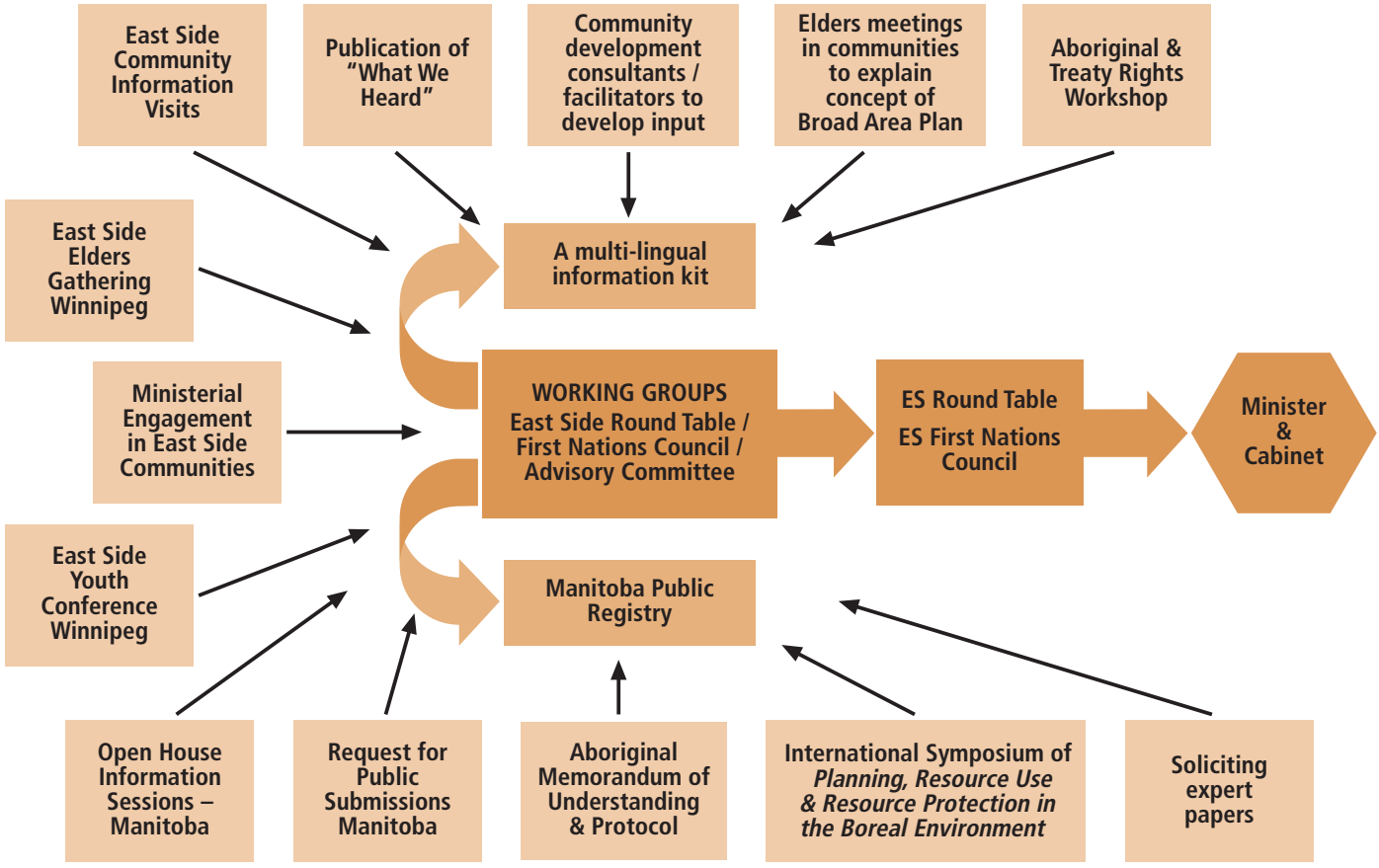


community residents gathered during the first round of community visits. The document is cross-referenced by community and by issues.

- Resources will be made available through the engagement of community development consultants to assist the east side communities in further developing their positions and inputs to the Broad Area Plan through the second stage of community visits.
- As 96 per cent of the population of the east side of Lake Winnipeg consists of First Nations peoples, the Round Table and the First Nations Council organized an Elders gathering to begin receiving their recommendations and concerns about the Broad Area Plan. Elders are invited to all Round Table and First Nations Council meetings.
- The Round Table and the First Nations Council organized a workshop on "Recent Case Law and Aboriginal & Treaty Rights and Entitlements" to consider the impact of such on the east side of Lake Winnipeg.
- There were three Open House information sessions in Manitoba where documentation was made available and the scope and intent of the Broad Area Plan was explained to interested Manitobans. Submissions, recommendations, concerns and observations were solicited through questionnaires.
- The First Nations on the east side of Lake Winnipeg and the Government of Manitoba have signed a *Memorandum of Understanding,* the first step in negotiating *Protocols of Agreement* that will be incorporated into the Broad Area Plan. A similar process has been recommended to the Government of Manitoba regarding the Métis Nation resident on the east side of Lake Winnipeg.

The public participation process is an integral and vital part of the development of the Broad Area Plan for the east side of Lake Winnipeg.

Public Participation Process





5. Overarching Themes & Recommendations of General Application

5.1 Solidifying an Ongoing Process: Continuing the Creation of a Broad Area Plan & Possible Options – An Interim Planning Authority

As has been indicated above, it is clear that much has been done, and much remains to be done. The submission of this preliminary report can be but a bridge to the ongoing work required to complete this complex and important process. This unique initiative has both raised expectations and provided all parties with an opportunity to chart new, more constructive relationships.

Indeed, few jurisdictions in Canada have undertaken an initiative of such breadth, scope and vision. With patience and perseverance, it has the potential to significantly contribute to broad area planning in Canada. The essence of this broad area plan will be the significant breadth of community support that it will enjoy because of the engagement of communities, residents and stakeholders who have an abiding interest in the future of the east side.

It is, therefore, essential that the government not break faith with this process and that the development of the Broad Area Plan proceed, unimpeded. The East Side Round Table and the First Nations Council have been told repeatedly that this is one of the most comprehensive public participation processes that the Government of Manitoba has undertaken. If it continues to be done with care and patience, the end product will be well worth the effort expended.

The East Side Round Table and First Nations Council remain convinced that an ongoing structure and mechanism external to, but reliant upon, government and partner resources is essential to the completion of the Broad Area Plan for the east side of Lake Winnipeg and its accompanying protocols. This ongoing mechanism, which we characterize as an *East Side First Nations Council*

East Side
Planning Initiative

(ESFNC), would be an interim structure with specific responsibilities and authorities. The ESFNC would continue until such time as the Broad Area Plan is formally adopted and replaced with an appropriate, permanent collaborative governance mechanism. Options for the establishment of the ESFNC are considered below. Because this is an interim arrangement, the establishment of the ESFNC must be simple to accomplish. There will be no time for lengthy administrative or legislative processes to establish and empower the ESFNC. As well, the system under which the ESFNC makes decisions and recommendations must be straightforward and efficient.

The short-term nature of this arrangement also means that the current legislative and regulatory decision-making processes, such as environmental assessment and licensing, natural resources permitting and forest management practices, will remain in place. The challenge is to provide the ESFNC with the ability to make decisions where legislation allows and have extraordinary influence in areas where it has no explicit legislative support.

There are a number of ways such a body can be established and a number of factors to consider regarding the options for establishing and empowering the ESFNC. Current legislation and negotiated agreements provide authority and precedent for the establishment of the ESFNC with appropriate powers for an interim regime on the east side.

The Planning Act provides two options for establishing and empowering the ESFNC on the east side of Lake Winnipeg. Section 10 of the act allows Cabinet, following consultation with the councils of nearby communities, to designate an area of special regional or provincial significance as a "special planning area." The designation enables, among other things, the protection and conservation of the environment and of natural resources. The designation includes conditions attached to the area during the planning process, including the temporary suspension of existing development plans and a moratorium on new development except with the written permission of the minister.

Another designation option exists under *The Planning Act* (Section 99). The act deems the Minister of Northern Affairs to be the council for areas that are not incorporated communities and allows the minister to delegate some of his/her powers to a local committee or community council – to enact a development plan bylaw and a zoning bylaw for the area.

Under either of these designations, and based on the principles and recommendations articulated in this status report, the ESFNC could work co-operatively with First Nations governments, the Métis Nation government and the councils of the incorporated communities to develop some interim principles and criteria for development. Proposed developments would be vetted by the ESFNC to ensure they were consistent with these principles and criteria.

As a third option, *The Northern Affairs Act* provides the Minister of Northern Affairs with the authority needed to ensure orderly governance in the northern parts of the province. To this end, the minister acts as a municipality (except in incorporated communities). The minister can designate an area as a community and appoint a local committee to provide local services and act in an advisory/consultative capacity to him/her. The minister can delegate planning and management services to the local committee.

In a similar fashion to the options under *The Planning Act,* the Minister of Northern Affairs could establish the ESFNC as a local committee under *The Northern Affairs Act* and provide it with bylaw-making powers with respect to interim planning and management services.

As a possible supplement to the above options, there is opportunity under *The Wildlife Act* to strengthen the wildlife management capability of the ESFNC. The act provides for the minister to enter into agreements with any group or individual for the joint management of wildlife, which includes the development and implementation of joint informational, educational or training programs; the conduct of joint biological or ecological investigations; and the joint management of wildlife habitats. A fourth option involves the *Northern Flood Agreement (NFA),* negotiated in response to the adverse environmental and social impacts caused by hydroelectric development in northern Manitoba. It led to the development of share-management agreements with the First Nations that were signature to the NFA. Other First Nations communities have also negotiated share-management agreements.

The use of a share-management agreement with the ESFNC, as representative of the area outside the incorporated communities, is a possible approach to providing the ESFNC with the authority it needs to undertake its interim responsibilities. A problem is that the development of a share-management agreement is generally a negotiated process that takes considerable time to complete. Given the wide representation on the ESFNC, there could be quite diverse opinions about the terms of the agreement. As well, the *Protocols of Agreement,* which are to be a fundamental part of the final Broad Area Plan, are likely to focus extensively on share-management agreements.

The proposed arrangement raises the question of the relationship between the larger area and the local communities. ESFNC should develop principles for decision-making during the interim period vis-à-vis the relationship between the ESFNC and individual communities.

However it is accomplished, it is critical that through whatever means are available, the ESFNC should be given sufficient status to influence the legislated government decision-making processes currently in place.

"After some 500 years of a relationship that has swung from partnership to domination, from mutual respect and co-operation to paternalism and attempted assimilation, Canada must now work out fair and lasting terms of coexistence with Aboriginal people."

(RCAP)

5.1 Recommendations

5.1.1
The Government of Manitoba commit to continuing a comprehensive process of dialogue, negotiations and consultations with the inhabitants of the east side of Lake Winnipeg, and stakeholders to ensure the development of all components of the Broad Area Plan for the east side of Lake Winnipeg including a *Protocol of Agreement* with East Side First Nations Governments which must respect, recognize and protect Aboriginal and Treaty Rights.

5.1.2
The Government of Manitoba also commit to negotiating, as part of the Broad Area Plan for the east side of Lake Winnipeg a *Protocol of Agreemen*t with the Métis government representing the Métis Nation resident on the east side of Lake Winnipeg, which must respect, recognize and protect Aboriginal Rights.



5.1.3
The Government of Manitoba acting solely or in concert with other partners provide adequate human and financial resources to permit the comprehensive on-going process to complete all components of the Broad Area Plan including the *Protocols of Agreement.*

5.1.4
The Minister of Conservation actively explore the possibility of creating a resources and financial partnership with other provincial departments, the federal government, east side First Nations, the private sector, public agencies and environmental non-governmental organizations in order to generate a pool of funds and other resources to permit the on-going development of a comprehensive Broad Area Plan.

5.1.5
The Government of Manitoba re-organizes the structural and operational support mechanisms for the on-going process by continuing with the East Side First Nations Council, which would receive advice from an advisory body, and would serve until such time as the Broad Area Plan and the *Protocols of Agreement* are completed and adopted by the Government of Manitoba, First Nations and Métis governments.

5.1.6
The East Side First Nations Council be provided with a renewed mandate:

- To continue to facilitate and support negotiations and consultations on Protocols of Agreement with the First Nations governments;
- To continue to facilitate and support negotiations and consultations on a Protocol of Agreement with the Métis government representing the Métis Nation resident on the east side of Lake Winnipeg;
- To continue to provide and collect information, consider and analyze community and individual submissions, engage in discussions and prepare

the final recommendations for the Broad Area Plan for the East Side of Lake Winnipeg pursuant to the mandate initially provided by the Minister; and

- To assume planning authority for land use and development within the territory of the broad area plan in providing the Government of Manitoba with direction and advice on major, large-scale land use developments or initiatives.

Until such time as the Broad Area Plan and the Protocols of Agreement have been concluded, the East Side First Nations Council shall assume planning authority for lands in the planning area at the earliest possible opportunity.

5.1.7
The Government of Manitoba consider the options identified in 5.1 in establishing and defining the planning authority for the East Side First Nation Council.

5.1.8
The Government of Manitoba shall consult with the East Side First Nations Council and seek its direction and recommendations on all major new land use developments, including cottage lot developments, or initiatives, such as those described in Phase 1 – Final Report, occurring within the planning boundaries of the east side of Lake Winnipeg. As such, the East Side First Nations Council will exercise regional planning powers to the maximum extent allowable under existing legislation or case law, until such time as the Government of Manitoba is in receipt of the final recommendations constituting the draft Broad Area Plan for the east side of Lake Winnipeg. It is understood that this authority extends only to those lands outside of reserve lands or Treaty Land Entitlements within the planning region, and in which First Nation and Métis Nation Governments, and the Government of Manitoba assert sole or joint interest and jurisdiction.

5.1.9
With respect to the composition of the East Side First Nations Council (ESFNC),

- The ESFNC be presided over by an independent Chair whose appointment is subject to the mutual agreement of the ESFNC and the Government of Manitoba;
- The ESFNC will consist of the twenty-one (21) members – sixteen (16) East Side First Nation Chiefs or their designates, one (1) representative from the Métis Nation government, or their designate, and four (4) representatives nominated by the East Side Round Table, with a preference for the inclusion of current members; and
- The ESFNC will be assisted by an East Side Advisory Committee, the members of which shall be agreed upon by the ESFNC and the Government of Manitoba.

5.1.10
All decisions of the ESFNC be subject to the principle of a "double majority", that being the majority of the ESFNC members and the authorized representative to the ESFNC of the First Nation governments within whose traditional lands, the land use activity is proposed to take place. It is understood by this principle, that no major developments may proceed without the expressed consent of the First Nation so affected. Conversely, should the ESFNC not approve a First Nations land-use initiative, it is incumbent upon the applicant First Nation, as part of a mediation process, to indicate how the initiative is consistent with the values and principles of the Broad Area Plan.

5.1.11
The ESFNC be supported by a sufficiently resourced and independent Secretariat, the head of which is appointed following the joint concurrence of ESFNC and the Government of Manitoba.

5.1.12
The ESFNC be assisted in the process of finalizing the Broad Area Plan recommendations for the east side of Lake Winnipeg by the East Side Advisory Committee recognizing that membership in this committee may have to be re-constituted so as to remain current. The ESFNC may wish to continue to use existing Broad Area Plan Working Groups or create other such support mechanisms.

5.1.13
It is understood that all such developments or initiatives identified in recommendation 5.1.8 above be subjected to a comprehensive *Aboriginal and Treaty Rights and Traditional Lands Impact Assessment as part of any Environmental Impact Assessments* that may be required. It is further recommended that the ESFNC, early in its mandate, commission research in order to establish an acceptable methodology for conducting such an assessment.

5.1.14
Consistent with the approach identified in 5.3 *Initiatives to Protect the Integrity of the Boreal Environment*, that all of the lands within the boundaries of the Broad Area Plan for the east side of Lake Winnipeg, external to human settlements are considered as "Protected" as further elaborated in Chapter 5.3, and pursuant to the processes defined above, it is understood that in this context, the ESFNC will assume planning authority for land use and development within the territory of the Broad Area Plan in providing the Government of Manitoba with direction and advice on major, large-scale land use developments or initiatives.

5.2 Building Positive Relationships with Aboriginal Peoples: *Protocols of Agreement*

Mandate

"The east side plan recognize, affirm and be in compliance with treaty obligations and Aboriginal rights and be consistent with the consultation/ protocol guideline recommendations of the COSDI Report respecting First Nations and Aboriginal peoples."

The majority of the residents living on the east side of Lake Winnipeg are Aboriginal peoples, the greater numbers of which are First Nations. Sixteen First Nations communities make up nearly 96 per cent of the total population resident on the east side. Members of the Métis Nation are comparatively smaller in number and most live within communities under the jurisdiction of Aboriginal and Northern Affairs.

Developing a Broad Area Plan for the east side of Lake Winnipeg is the objective of the ESPI. Because First Nations peoples represent the majority population and because of their historical and cultural relationship to the land First Nations people are a key component to this process. The Métis Nation also has this special relationship to the land. For that reason, their views and concerns must be an important component to the planning process.

Within the past eight months, ESPI teams made approximately 80 visits to communities throughout the east side of Lake Winnipeg to provide information and listen to concerns of residents. The message from many communities was the hope that the ESPI process could give them a forum to convey views and opinions on the pressing issues, respecting their traditional territories and the environment. Among the concerns heard in many communities was that resource development and economic activity often happened in and around their areas without local input or benefit.

As noted in this report, because of Treaty and Aboriginal rights and a unique relationship with the land, First Nations governments and the Métis Nation government on the east side of Lake Winnipeg must be not only participants, but also partners, in future planning on the east side. To help ensure this partnership, a *Memorandum of Understanding* (MOU) was signed in April, 2004, between the Province of Manitoba and 13 First Nations on the east side of Lake Winnipeg. The MOU represents a commitment by both parties to work together in protecting the environment and boreal forest on the east side and ensuring a safe and secure future for all who live there.

The next stage of this process is to resolve issues and build consensus on initiatives respecting a Broad Area Plan for the east side of Lake Winnipeg. It is believed this will best be achieved through *Protocols of Agreement* between First Nations on the east side of Lake Winnipeg and the Province of Manitoba. This agreement would contain a set of rules for working towards negotiation

"Manitoba work in partnership with Aboriginal peoples to develop a cooperative protocol to address the involvement of Aboriginal peoples where their land and resource use planning, significant resource allocation, development assessment and review and regulatory mechanisms, including effects assessment tools and documents are affected."

(Consultation on Sustainable Development Implementation – 1999)

and consensus. There will also be a need for a separate protocol negotiation process between the province and Métis Nation resident on the east side of Lake Winnipeg.



5.2 Recommendations:

5.2.1
A Protocol of Agreement be developed between the Government of Manitoba and First Nation governments on the east side of Lake Winnipeg and that the agreement will become an integral part of the Broad Area Plan and serve to guide its implementation.

5.2.2
A Protocol of Agreement be developed between the Government of Manitoba and the Métis Nation government representing the Métis Nation resident on the east side of Lake Winnipeg and that the agreement will become an integral part of the Broad Area Plan and serve to guide its implementation.

5.2.3
The Government of Manitoba should finalize outstanding Treaty Land Entitlement issues with First Nation governments on the east side of Lake Winnipeg.

5.2.4
The Government of Manitoba must develop a resource-sharing framework for the east side of Lake Winnipeg within the context of the Protocols. The framework may require two levels: an umbrella agreement between Governments of Manitoba, First Nations and the Métis Nation to serve as guiding principles for the area. Second level agreements will be required between Governments of Manitoba, First Nations and the Métis Nation Governments on specific land use. Agreements for specific land use decisions would include but would not be limited to access, revenue sharing, procurement, capacity building, shared stewardship, and environmental management.

5.2.5
Such agreements should be concluded on all resource uses within Aboriginal traditional territories prior to implementation of recommendations of the Broad Area Plan. For example, these agreements could include share-management arrangements for various natural resources within the planning area, including but not limited to provisions for royalty and/or revenue sharing and other benefits with First Nations Governments and the Métis government representing the Métis Nation resident on the east side of Lake Winnipeg for resources removed from traditional lands.

5.2.6
The Government of Manitoba, crown corporations and other public agencies, and the private sector must recognize, respect, and honour local agreements between east side First Nations Governments and the Métis Nation resident on the east side of Lake Winnipeg respecting development within traditional, cultural, and resource territories, as this is instrumental in creating greater control and participation for local communities.

5.2.7
Community-based land use planning, consistent with the values and principles of the Broad Area Plan, should be initiated or completed prior to any development activities within their traditional lands. It should guide the identification and development of resource-based opportunities, including protected areas and infrastructure development in the east side planning area. As has been indicated elsewhere in this report it is of paramount importance that adequate resources be made available to assist First Nation and Métis Governments and Northern Affairs communities in land use planning. Community-based land use planning must be given priority attention by all governments engaged or impacted by this process.

5.2.8
All future discussions, consultations and negotiations between the public and private sectors, and First Nations and Métis Governments and Northern Affairs communities on the east side of Lake Winnipeg be subject to the protocols defined for such activities in the on-going governance mechanism adopted to oversee the implementation of and adherence to the Broad Area Plan for the East Side of Lake Winnipeg.

5.2.9
Whatever on-going mechanism is established to oversee the implementation of and adherence to the east side of Lake Winnipeg Broad Area Plan, it include monitoring and compliance powers to ensure that both public and private sector resource users comply with all components of the Protocols with First Nations and Métis governments respecting the Broad Area Plan for the east side of Lake Winnipeg.

5.3 Initiatives to Protect the Integrity of the Boreal Environment

One of the three fundamental principles guiding the advice the East Side Round Table provides to government on the Broad Area Plan is: "Maintaining the ecological integrity and biological functions of the boreal forest within the planning area."

Based on this principle, maintaining the integrity of the boreal environment on the east side has been a core consideration in the development of the plan. Generally, this means the free operation of natural ecological processes that

bring about ecosystem self-organization, diversity, resilience, long-term change and renewal. Ecological integrity is an ecosystem state of being, and needs to be seen as something to be maintained over time. It results in a landscape in which there is a full complement of species, natural populations, interdependent relationships, diverse habitats and multiple pathways for energy flow through the ecosystem. On the east side, we are also speaking of a landscape that continues to support Aboriginal people who occupy and use the land.

The boreal environment in the east side planning area is unique in several ways. It is inhabited by 16 First Nations that have occupied it for millenniums, and it is large – approximately 82,000 square kilometres. It is a mostly undisturbed (by human activity) and contiguous forest and wetlands complex representing one of the few remaining, mainly untouched, broad area landscapes in mid-Canada. As well, there has been relatively little economic development within it, although it is widely recognized that the economic development potential on the east side is high and virtually unexploited. This makes sound planning a necessity.

Potential threats to ecological integrity on the east side take the form of unsustainable levels of economic activity, or allowing it to occur in sensitive locations. There are also concerns over the gradual inhabitation of shorelines by cottage owners and their subsequent demand for services, and the suppression of wildfire, which gradually threatens the whole forest with major conflagration. The challenge is to achieve a consensus on how to use and protect this landscape in a sustainable manner and to do so using current scientific data and traditional ecological knowledge.

There have already been several initiatives aimed at achieving long-term protection for portions of the east side. The protected area network is intended to contain adequate representation of significant enduring features in each of the 18 natural regions and sub-regions in Manitoba. On the east side, 14 per cent of the land area is already under formal protection within parks and includes the Poplar/Nanowin Rivers Park Reserve. This reserve comprises approximately 7,400 square kilometres of the traditional lands of the Poplar River First Nation. The First Nation is presently engaged in a community-based, land-use planning project to determine what land uses and further protections will be applied within the Park Reserve area.

In *Manitoba's Action Plan for a Network of Protected Areas,* the province has committed to a public process for reaching decisions on designating protected areas under the act. The 1998 *Memorandum of Understanding* between Manitoba and the Assembly of Manitoba Chiefs and the Manitoba Keewatinowi Okimakinak (MKO) outlines a process of identifying, establishing and managing a network of protected areas. These decision-making processes should be developed as a component of the Broad Area Plan.

In 2002, Poplar River, Pauingassi, Little Grand Rapids and Bloodvein First Nations, along with Pikangikum in Ontario, agreed in a signed accord, to join

their traditional territories together, as one large protected area under their stewardship. This huge area includes the traditional territory of the Pikangikum First Nation on the Ontario side. Together, the five First Nations have agreed to co-operate in the protection and care of these lands as a sacred trust. Further, the five First Nations in the accord have requested that their initiative be given international recognition by being considered as a UNESCO World Natural and Cultural Heritage Site.

A related activity stems from the Canadian Boreal Initiative. The initiative has advanced a framework for boreal forest conservation that seeks to give the highest level of protection to at least 50 per cent of the forest, and support sustainable communities in the remainder, through development based on state-of-the-art stewardship and management practices. The vision of the initiative is to safeguard ecological integrity in the forest, apply sustainable development practices, and ensure local and First Nations engagement in land management decisions.

To accomplish this, the framework calls for an interconnected network of large protected areas across the boreal band of forest. It should be stressed that the Canadian Boreal Initiative envisions protection and sustainable communities on the same landscape. The initiative does not conflict with the goals of protection as advanced by First Nations in their 2002 accord.

It is clear that the meaning of the term "protection," as used in the First Nations Accord, although not specifically defined, is different from its meaning in the Manitoba Parks Act or other acts and regulations. The difference seems to be two-fold. First, protection in legislation involves the prohibition of certain land uses such as mining and logging. If managed within the framework of traditional values and knowledge and under the guidance of Elders, it is apparent that the First Nations' concept of "protected" does not necessarily prohibit these land uses, and could include local stewardship of forest resources and other developments.

With these differences in mind, there are two notions of what we mean by "protected". To some, "protected" means lands on which some land uses, such as resource extraction, are prohibited by law. To others, "protected" means lands that are cared for and used according to traditional approaches and the land is passed undamaged to subsequent generations. Both notions need to apply within the plan area.

It is important, therefore, to conceive of the whole planning area as protected, and that within it, there are sub-areas with different levels of protection. The highest level of protection could be the parks and other areas that are protected through legislation. These could continue to be land areas where certain uses are prohibited by law. Other levels of protection can be applied to other land uses within the plan area. These require the stipulations that land use decisions need to be based on adequate knowledge of effects and thresholds, as well as on the clear preferences of the communities affected, based on a thorough process for consultation.

"The northern boreal ecoregion accounts for about one third of this planet's total forest area. It is comprised of a broad circumpolar band which runs through most of Canada, Russia, Scandinavia and parts of Northern Scotland. Compared to much of the world, this ecoregion enjoys a sparse population and thus one would think, few threats to its immense and majestic beauty. However the reality is quite different."

- Sierra Club

5.3 Recommendations

5.3.1
The entire planning area is envisioned as "protected", in the sense that First Nations use the term, as described above. In practice, decisions on new economic developments (forestry, mining, tourism, etc.), or on the limitations imposed pending completion of the Broad Area Plan, would require the concurrence of the East Side First Nations Council (ESFNC). All resource development decisions that are made for the area would be assessed on the basis of whether they affect protection, in addition to the usual considerations. Existing licenses and developments would continue. This approach is similar to and mirrors the intent of the protection afforded the territorial lands of the five First Nations that signed the Protected Area Accord.

5.3.2
The Government of Manitoba play an active role with the federal government in establishing a UNESCO (U.N.) World Natural & Cultural Heritage Site on the east side. The site should include the land area encompassed in the application by the five First Nations signatory to the protected areas Accord, and Atikaki[1] and Woodland Caribou Provincial Parks.

5.3.3
The Government of Manitoba request the East Side First Nations Council to identify specific levels of protection within the planning area, including protection conferred by Order-in-Council, and other forms of protection, as determined by the ESFNC. In so doing, the guidance and principles given by the Boreal Forest Conservation Framework should be considered. This would result in a portion of the planning area receiving the highest level of protection, consistent with the principles of the Canadian Boreal Initiative, and other areas identified to support sustainable communities and resource stewardship activities.

5.3.4
First Nations and the Métis Nation resident on the east side who have been denied traditional uses of designated protected areas within established parks, such as Atikaki, should be advised that they have these rights.

5.3.5
The process for evaluating and recommending areas to be formally protected by Order-in-Council should be accelerated and improved to ensure that First Nations, the Métis Nation resident on the east side, local communities and affected stakeholders are brought together and strive for a consensus, and that east side communities have a higher standing in the process.

5.3.6
The improved and accelerated review process should be followed for the eight large ASIs in Natural Region 4b, in order to ensure that these enduring

[2] Atikaki – From the Ojibway words "Atik" meaning "caribou" and "Aki" meaning "land".

features are properly recognized and captured within the protected areas network. In addition, the improved review process should be used to evaluate and recommend the three smaller protected area proposals in Natural Region 4c.

5.3.7
The Government of Manitoba provides the necessary resources to complete these evaluations for ASIs in Natural Regions in 4b and 4c within the next two years, and updates its Action Plan for a Network of Protected Areas, including goals objectives and timelines, by the end of the current fiscal year.

5.3.8
The 1998 Memorandum of Understanding signed between the Manitoba Government and First Nations on how they will cooperate on protected areas should be extended and followed.

5.3.9
Two new land use categories are needed for designating protected areas under appropriate provincial legislation. One is needed to protect First Nations' and Métis Nation's sacred, historical and burial sites without disclosing the exact location. This is to protect the sites from damage and impacts. These do not need to be parks or ecological reserves. The other is recognition of First Nation Traditional Lands. These lands could be situated inside or outside of parks. This recognition would mean lands protected and cared for utilizing traditional First Nation and Métis Nation values, approaches and ecological knowledge, and with activities prescribed by local decision-making and control. Where there are shared traditional territories, First Nations would be invited to develop a common approach which would satisfy their mutual interests in the territory.

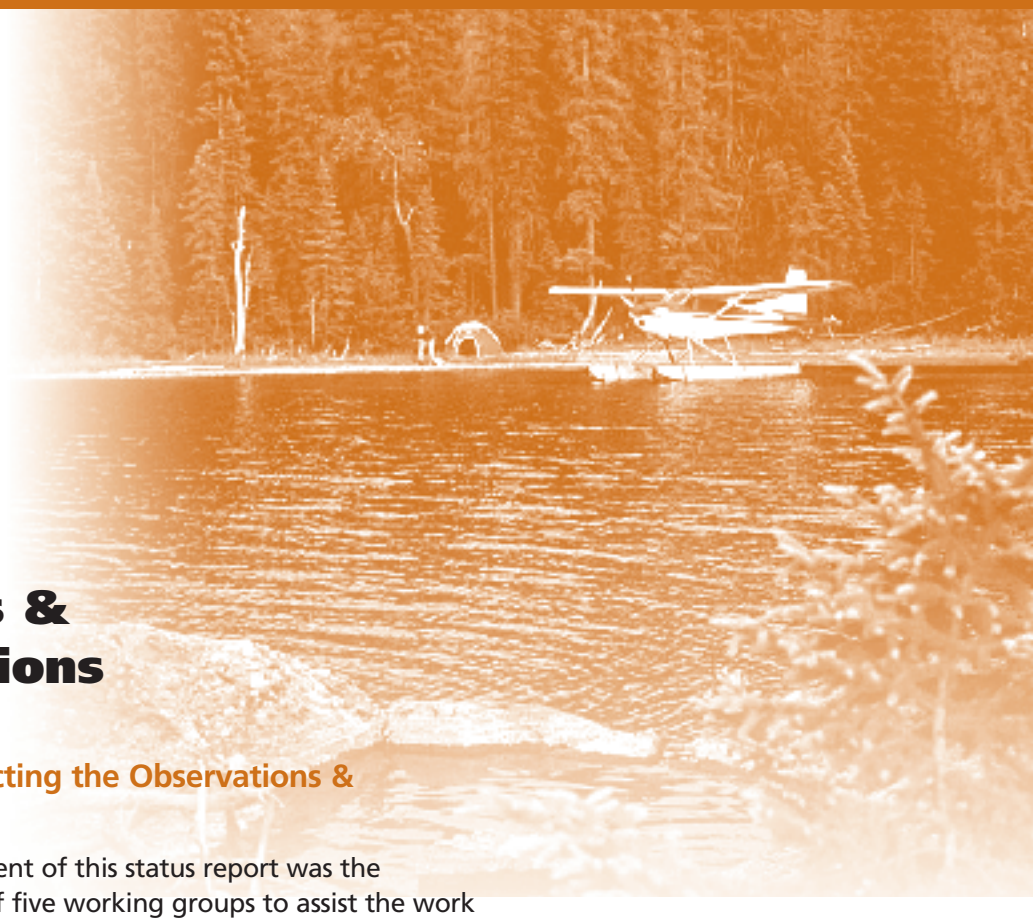
5.3.10
Individual protected areas in parks without management plans should have them developed, and a plan review process established within 2 years. Protected areas without management plans, outside of parks, should have them developed and a plan review process be established within two years. All protected areas should be reviewed against the potential impacts of climate change, fire, insects and disease, maintenance of ecological processes, surrounding incompatible land uses in the area, and appropriate strategies developed (e.g., Fire Smart Program in Jasper National Park). This formal periodic review should be supported by continued monitoring efforts that involve and employ local people.

5.3.11
The Government of Manitoba develop and utilize adaptive ecosystem based management standards and practices. As an example, measures are needed to protect water ways and bank (riparian) features.

5.3.12
The Government of Manitoba secure sufficient financial and human resources, including contributions from other partners (federal government, public & private sector, environmental non-government organizations) to permit east side First Nations to undertake and/or complete *Traditional Ecological Mapping* of their traditional territories.

5.3.13
With the fundamental recognition that accurate and proficient land use planning can only proceed with timely and topical information, and mindful of the equally fundamental application of the precautionary principle, the Government of Manitoba move with all possible dispatch to ensure that all necessary environmental data concerning the east side of Lake Winnipeg is both acquired or updated at the earliest possible opportunity.





6. Priority Issues & Recommendations

6.1 Working Groups: Constructing the Observations & Recommendations

A significant step in the development of this status report was the establishment in January 2004 of five working groups to assist the work of the East Side Round Table (ESRT), discuss specific issues and get down to identifying specific recommendations.

An Aboriginal Protocol Working Group was established to consider the development of a *Memorandum of Understanding* leading to a protocol that would be followed throughout the ESPI process and the implementation of recommendations arising out of the final report.

Three Regional Working Groups (a northern, central and southern) were established to consider a minimum of three of the main planning issues associated with their geographic areas. (These issues are defined on pages 4 and 5 in the *Executive Summary of the East Side of Lake Winnipeg – Broad Area Planning Initiative: Phase 1 Final Report).* Each RWG was chaired by a member of the ESRT or FNC and limited to 12 members from the membership of the ESRT, FNC and ESAC. In this arrangement, participation in the detailed planning discussions was as broad as possible. A key objective of each RWG was to make sure it considered Aboriginal and treaty rights and traditional ecological and local knowledge in its discussions.

A fifth working group, the Plan Co-ordination & Implementation Working Group, was also established. Its role was to develop a 'Vision and Values' statement to guide the work of the working groups, consider and propose plan governance and implementation mechanisms for the Broad Area Plan, and integrate the observations and recommendations of the three geographic working groups into a series of recommendations.

East Side Planning Initiative

An extremely important factor in the development of the vision and recommendations contained in this status report is the high degree of participation in the discussions by Round Table and First Nations Council members, members of the ESAC and others.

6.2 Aboriginal and Community Development

Mandate

"The east side round table review the status of community planning in the planning area and provide advice on ways and means to meet the needs for community plans".

"The east side round table provide advice on the relationship that should be established between the broad area plan and local community plans and how they may be integrated into the large area plan for the east side of Lake Winnipeg."

Poplar River, Black River and Hollow Water First Nations are in the process of developing land use plans for their traditional areas. Berens River First Nation and the Island Lake Tribal Council have indicated their intentions of doing the same. The communities of Manigotagan and Wasagamack are in the process of developing community plans. In spite of these initiatives, the majority of communities in the study area have not undertaken any form of planning, community or otherwise, even though they desire to do so.

There are community development issues on the east side that are broader than those captured by the mandate. These include:

- the increasing population of First Nations Peoples in the area and the lack of economic opportunities, due to the lack of opportunity;
- non-local ownership of businesses and cash outflows, possibly due to policy and regulatory roadblocks preventing access to financing and an inability to acquire licenses for various activities;
- difficulty in starting and running small businesses, because of too many regulations (Trapline regulations, for example, are too costly and restrictive);
- too few training and local employment opportunities; and
- a seeming lack of interest and support from government in pursuing potential local partnerships, in spite of possible new opportunities for economic development on the east side.

The *Memorandum of Understanding* and resulting *Protocols of Agreement* between First Nations and Métis Nation on the east side of Lake Winnipeg and the Government of Manitoba will serve as the foundation for meaningful involvement in economic development and land use decisions affecting their communities and traditional territories.

6.2 Recommendations

6.2.1
All First Nation governments, the Métis Nation government representing Métis residents on the east side of Lake Winnipeg, and Northern Affairs communities in the east side planning area be provided the necessary financial and other resources to develop and produce plans for both their community and surrounding areas of interest, including Traditional Ecological Knowledge, before significant development expansion, new developments, or new licenses are issued in any potentially affected area.

6.2.2
Future development must be contingent on the establishment of processes and policies that ensure community involvement, training and employment and that resource allocation decisions involve local communities.

6.2.3
The Government of Manitoba provide capacity building initiatives and programs for people to participate more fully in resource activities in their traditional territories. Effective skills training programs must be developed to maximize local input in community economic development initiatives.

6.2.4
A formal assessment be done that would identify current and anticipated economic opportunities and skill sets that will be required to take advantage of these opportunities. Training programs such as business management skills must then be designed and delivered to meet these needs. Other programs could include emergency fire fighting, first aid, dangerous goods, presentation skills, emergency readiness, ecotourism, life skills, and proposal preparation.

6.2.5
Certification training programs be established for those occupations where certification is currently not required – e.g. tourism industry, timber harvesting, mining and commercial fishing.

6.2.6
The development of local enterprise and ownership be encouraged in addition to ensuring that there is local benefit, training and employment when the public or private sector is operating in the planning area.

6.2.7
The Government of Manitoba must support joint ventures / partnerships / local ownership creating the means for communities to gain benefits from resource initiatives and economic activities within communities and traditional territories. All economic development initiatives undertaken by the public or private sector within the planning area should ensure training and employment opportunities for local residents where possible.



6.2.8
First Nations, Métis and local community governments be given representation on Manitoba government boards, agencies, commissions and committees in order to gain more information and participate more actively with respect to planning and development issues that impact their traditional territories.

6.2.9
The Government of Manitoba commit to working with the ESFNC and First Nation governments to establish a natural resources management authority that would be operational within three years. The authority must be grounded on the principles of the seven generations and the structure and authorities of the Great Lakes Indian Fish and Wildlife Commission is offered as a desired model.

6.2.10
The Government of Manitoba actively engage the Métis Nation resident on the east side of Lake Winnipeg and local communities in developing and enhancing their own conservation capacity and engagement in formal conservation practices and activities in the planning area.

6.3 Forest Resources

Mandate

"The east side round table provide advice on protecting the values of the boreal forest, its sustainability, and sustainable use including, but not limited to:

- *maintaining biological diversity and ecological functions;*
- *role in carbon storage;*
- *non-timber forest products;*
- *ecotourism; and*
- *sustainable forest harvesting activities.*

The province not permit any major new timber allocation beyond the annual allowable cut, as determined by Manitoba Conservation within Forest Management License #1 and historical allocation levels in Integrated Wood Supply Area #1, subject to annual public review and pending completion of the broad area plan."

Forest resources on the east side are valuable. Commercial logging and processing operations constitute an important economic activity. The forest provides much more than wood; it is a habitat for hundreds of species and provides valuable ecological services (see Chapter 5.3). It is also the focus of interest for First Nations and the Métis Nation on the east side, because of their ancestral habitation of the area, their use of the forest for food, furs, medicines, spiritual and ceremonial purposes, and economic interests. The

priority for the future will be on the sustainability of these values and services, and where there are commercial operations, on making the economic benefits available to local communities.

Tembec Industries Inc. is the principal private sector interest in forestry operations in the area. Its Evergreen Forest Management License Agreement operates on a 20-year term, and is renewed every 10 years for an additional 10-year term. This provides a minimum of 10 and a maximum of 20 years to the agreement.

The agreement assigns management and reforestation responsibility for Forest Management License #1 (FML#1) to Tembec, while the Government of Manitoba retains these responsibilities for timber sales in the Integrated Wood Supply Areas east and west (1 & 2) of Lake Winnipeg. Forest management operations in FML #1 are authorized through Environment Act licenses awarded to 10-year forest management plans. Expansion of the license area would require the renegotiation of the Forest Management License Agreement.

In the northern portion of the planning area, north of approximately the 53rd parallel, the forest inventory is over 30 years old. Absence of current data on timber species, volumes and operability limits commercial forest management and planning in this large area. Also, absence of a transportation infrastructure in the northern half of the planning area severely limits commercial forestry activities.

Because there are multiple users of the forest, and multiple interests competing to have their interests met, finding the right balance is an ongoing challenge. Forestry operations, local benefits, community growth and development, and the transportation network, are all linked. The development of an all-weather road north of Hollow Water First Nation to Bloodvein First Nation and beyond is seen by some as the key to expanding forestry operations further north.

Ascertaining forest values is fundamental to finding the appropriate balance. Various techniques, such as those developed by the Forest Stewardship Council or The World Wildlife Fund–Canada, can be used to provide assessments of high value forests and forest attributes. Subsequent management decisions would require the maintenance or enhancement of the defined attribute and a monitoring program would have to be established to assess the effectiveness of the measures employed.

A long-term threat to forest resources is an increased risk of large forest fires as the climate changes and the predicted drier summer conditions occur. This threat could escalate with increased recreation access in the future.

Comments from communities indicate good support for forestry development that is sustainable, as long as there is local input to the process, and as long as benefits accrue to communities directly.

"All communities in the southern portion of the study area have been developed around logging. We need logging and mining on the east side. Logging is much more environmentally sensitive today."

(East Side Resident)

6.3 Recommendations:

6.3.1
To ensure sustainable forestry practices are maintained on the east side of Lake Winnipeg, all commercial forestry activities are encouraged to operate according to standards and procedures established or recommended by management and forest certification systems.

6.3.2
When Manitoba renegotiates the FML #1, it does so through the East Side First Nations Council ensuring more timely opportunities for input. When stakeholders operate outside FML-1, such as within the Integrated Wood Supply Area #1, First Nations governments and the Métis Nation resident on the east side of Lake Winnipeg must be consulted and accommodated.

6.3.3
Provisions are needed for royalty, revenue sharing or other benefits for First Nation and Métis governments on the east side of Lake Winnipeg for timber removed from the planning area.

6.3.4
A comprehensive Forest Resource Inventory (FRI) should be completed for the entire planning area to guide the review of commercial forestry expansion, new developments, or new licenses proposed within the planning area.

6.3.5
Using assessment tools such as the High Conservation Value Forest method, identify and quantify the values contained within the forests in the planning area. Such an assessment could address environmental, social, health, Aboriginal and treaty rights, cultural, and economic factors. Models such as the Whitefeather example in Ontario could be used in developing forest plans for each First Nation, commercial forest interest, and local community.

6.3.6
The development of local enterprise and ownership should be encouraged, in addition to ensuring that there is local benefit, training and employment when companies based outside the planning area are operating within the planning area. There may be alternatives to selling timber within a local market, such as bartering, trading, etc., that should be explored.

6.3.7
Alternatives to conventional forest uses be explored and developed, such as using the forest for carbon storage, non-timber forest products, biodiversity services, and other non-forestry uses. For example, there may be economic value in the carbon storage capacity of the forest for emissions trading purposes.

6.3.8
Genetically modified or otherwise “improved” trees should not be used in the planning area, as there is a concern over the eventual decrease in genetic diversity that can result.

6.3.9
Affected First Nations, Métis and local governments and affected stakeholders should be consulted and accommodated prior to the planning or decommissioning of forest roads within the plan area.

6.3.10
Any permitted or licensed forestry development or activity must investigate, identify and mitigate impacts on other licensed or permitted activities such as trapping, wild rice propagation, lodges and outfitters, and others. The Government of Manitoba shall work with the East Side First Nations Council to establish a process to ensure sufficient communications between license holders and provide a mechanism to resolve any conflict or disputes that may arise due to competing licensed interests. Conflict resolution by a third party mediator could be a consideration.

6.4 Transportation

Mandate

"The east side round table provide advice on the proposed transportation assessment work plan of Manitoba Transportation and Government Services which will include the planning, consultation, upgrading and construction of the road to the Bloodvein community."

In August 1999, Manitoba Transportation retained Dillon Consulting Limited to undertake a study to look at the feasibility of developing an all-weather road system to improve access to remote communities on the east side of Lake Winnipeg. The study was to be a preliminary, cost-benefit assessment to determine if more comprehensive considerations of an all-weather road development in the study area were justified.

In a report prepared by Dillon Consulting entitled *East Side of Lake Winnipeg All Weather Road Justification and Scoping Study (August, 2000),* two all-weather road route scenarios, with different points of origin, were evaluated. In one scenario, all east side communities would be connected from the south via Manigotagan. In the other, the northern communities would be connected from the west via Norway House/Cross Lake with a separate connection from Manigotagan serving only the southern communities.

The report's general conclusion was that an all-weather road in the east side of Lake Winnipeg could be justified for many communities on the basis of long-term transportation cost savings alone.

In February 2001, Paskanake Project Management provided a review of the findings in the Dillon report for Whelan Enns Associates Inc. It questioned the report's overall justification levels for the all-weather road scenarios and suggested the level and degree of community support presented for an all-

"The construction and maintenance of a local airport would bring much needed jobs in the area as well as bring the costs of goods and services down to acceptable levels."

(East Side Resident)



weather road, with respect to the majority of affected communities, was overstated.

In 2001, Dillon Consulting prepared a second report for Manitoba Transportation entitled *Work Plan to Develop an All-Weather Road Network for the East Side of Lake Winnipeg – Final Report (Dillon Consulting Limited and N.D. Lea, October, 2001).* It presented a planning approach and overall work plan to design and service east side of Lake Winnipeg communities with an all-weather road network.

While roads can have both positive and negative implications relative to economic, social and environmental considerations, it can generally be concluded that there is support for upgrading the existing Rice River Road and its extension to the community of Bloodvein. As well, there is support from most communities for a regional all-weather road network beyond Bloodvein. With respect to Berens River First Nation, a letter dated July 30, 2002, to Mr. Phil Fontaine, Chair of the East Side Round Table, on behalf of the Berens River Chief and Council, stated that the construction of an all-weather road is the highest priority in terms of developing the east side of Lake Winnipeg.

6.4 Recommendations

6.4.1
Manitoba Transportation proceed with its proposed planning process to undertake the Rice River Road upgrade and its extension to the community of Bloodvein on the following conditions:

- Manitoba Transportation conduct a thorough review of routes in collaboration with directly affected First Nation, Métis Nation resident on the east side of Lake Winnipeg, NACC and non-Aboriginal communities;
- The final route selection follow from results of an independent environmental assessment of alternatives;
- The environmental impact assessment to include: as proposed in 5.1, an Aboriginal and Treaty Rights Impact Assessment, and a multiplier effect projection; and
- Locating the Bloodvein crossing so as to avoid Longbody Creek and locating a road corridor as close as possible to the lakeshore to minimize environmental impacts.

6.4.2
Manitoba Transportation provide the UMA engineering study to the ESPI secretariat for distribution to and consideration by the East Side First Nations Council and ESAC.

6.4.3
Manitoba Transportation amend its proposed planning process to upgrade the Rice River Road, by extending it to the community of Berens River.

6.4.4
Manitoba Transportation apply for an environmental license for the upgrade of the Rice River road presenting the final road alternative to the Manitoba Clean Environment Commission.

The following recommendations concern Component 2 of *Manitoba Transportation's Work Plan to Develop an All-Weather Road Network for the East Side of Lake Winnipeg – Final Report (Dillon, 2001):*

6.4.5
Manitoba Transportation undertake an amended Regional Transportation Network Study to consider other means of access, such as rail, bridges, dirigibles, hovercraft and ferries, to communities on the east side of Lake Winnipeg in addition to an all-weather road option.

6.4.6
Consider existing case studies on the impact of road access on remote communities and through wilderness areas in order to better understand both positive and negative environmental and social impacts, and to prepare mitigation measures where needed.

6.4.7
Manitoba Transportation facilitate independent research leading to a comprehensive understanding of all social, environmental, economic and cumulative affects consequences of an all-weather road system on the east side. As identified in recommendation 5.1.13, the required Environmental Impact Assessment must include a comprehensive Aboriginal and Treaty Rights and Traditional Lands Impact Assessment. This research should also include an examination of alternative transportation routes and methods and must proceed in advance of all-weather road development proposals beyond the Rice River road.

6.4.8
The East Side First Nation Council be involved in the review of road corridor alternatives and prior to final route selection, Manitoba Transportation apply for an environmental license and present the final road alternative to the Clean Environmental Commission.

6.4.9
Prior to any construction, regardless of road standard, Manitoba Transportation and other road developers develop road management plans for all roads. These plans would include standard options, location options, environmental impact mitigation plans, decommissioning plans and access restriction plans. The process of road management planning should also have a thorough public consultation process built in.

6.4.10
An environmental impact assessment address the cumulative impact of rights-of-way for both an all-weather road and Hydro Bi-Pole III.

6.4.11
Ferry and barge services to east side communities remain commissioned and unchanged until alternatives are in place, at which time, private ownership could be encouraged as an option to services not publicly owned.

6.4.12
An economic assessment be undertaken to evaluate potential impacts that might occur as a result of the loss of existing business relationships between east Lake Winnipeg and west Lake Winnipeg businesses through the decommissioning of ferry/barge services.

6.4.13
The on-going maintenance and upgrading of airports, or the development of new airports, will remain a government responsibility and priority and not be at the expense of any work on an all-weather road.

6.4.14
Prior to the establishment of new all-weather road developments, and with local community involvement, comprehensive plans should be developed to protect wildlife (e.g., refuge corridors) that could be impacted by increasing road access.

6.4.15
Any transportation development or activity with a permit or license to proceed or operate must investigate, identify and mitigate impacts on other licensed or permitted activities such as trapping, wild rice propagation, lodges and outfitters, and others. The Government of Manitoba must work with the East Side First Nations Council to establish a process to ensure sufficient communications between license holders and provide a mechanism to resolve any conflict or disputes that may arise due to competing licensed interests. Conflict resolution by a third party mediator could be a consideration.

6.5 Tourism and Recreation

Mandate

"The east side round table consider and address the opportunities and acceptability of ecotourism and tourist development in the planning area."

It is generally agreed that there is a high potential for tourism and recreation in the planning area. Recreational opportunities are especially high for wilderness and ecotourism, cultural tourism and backcountry camping and canoeing. There are dozens of locations of campgrounds, outfitter camps and caches, and numerous commercial lodges throughout the southern portion of the planning area. There are fewer facilities north of the Poplar/Nanowin Rivers Park Reserve. Licenses to lodges and outfitter camps are issued by the Licensing Advisory Committee, a committee internal to government, formed

under the *Resource Tourism Operator's Act.* There is a local perception that this committee is biased against new license applicants from within the planning area.

The opportunities for further development of tourism and recreation in the planning area have not yet been considered in detail by the Round Table. This is an area for further elaboration in the development of the Broad Area Plan. To date, indications are that further development of this potential is wanted and needed, and that the focus should be on creating improved local capacity and benefits. More tourism development in the area is strongly linked to the transportation network. More local benefits in this sector would flow from the development of all-weather roads. However, there is a great concern over the creation of new cottage developments, because these tend to be followed by incremental demands for improvements in services and access.

6.5 Recommendations

6.5.1
Decisions on development of tourism facilities should be tied into other decisions on infrastructure, such as roads and other services. Better coordination of these decisions is needed in the placement of tourism developments. This is particularly important if tourism developments are spurred by the Aboriginal Tourism Strategy being developed by the province.

6.5.2
A local decision-making mechanism for approval of new or expanded tourism facilities is needed, and must be based on joint governance arrangements between First Nations, local communities and the province. The Licensing Advisory Committee should seek advice from a local decision-making mechanism. The criteria for making these judgments need to be clear and complete explanations given to applicants when permits and licenses are turned down. A process for resolving disputes and appealing decisions is also required.

6.5.3
The expansion of opportunities for non-consumptive forms of recreation, such as outdoor education and ecotourism, in addition to the existing hunting and fishing opportunities, is encouraged. Provision should be made for the hiring and training of significant numbers of local residents for advancement in the industry.

6.5.4
Provision for hiring and training people for advancement in the industry from the local community must be a condition of licenses and permits in future tourism facilities. Training programs should provide accreditation to recognized standards and certification.

6.5.5
Provide First Nation, Métis and local communities with better access to information and training in tourism development, marketing and entrepreneurship.

6.5.6
Because of potentially significant environmental impacts, new cottage developments must be subject to rigorous environmental impact assessments. New road locations to cottage developments should not negatively affect ecotourism and entrepreneurship opportunities.

6.5.7
The Government of Manitoba support a comprehensive Aboriginal tourism strategy and provide resources for its implementation.

6.5.8
The Government of Manitoba support the creation of a Manitoba First Nations Tourism Group with financial and technical assistance to, in part, facilitate their participation in the areas of ownership in lodges, outposts, camps, etc., and in training and advocacy. Provision for hiring and training of members of First Nations communities for advancement in the industry should be a condition of licenses and permits in future tourism facilities.

6.5.9
Any tourism and recreation development or activity with a permit or license to operate must investigate, identify and mitigate impacts on licensed or permitted activities such as trapping, wild rice propagation, lodges and outfitters, and others. The Government of Manitoba shall work with the East Side First Nations Council to establish a process to ensure sufficient communications between license holders and provide a mechanism to resolve any conflict or disputes that may arise due to competing licensed interests. Conflict resolution by a third party mediator could be a consideration.

6.5.10
The East Side First Nations Council develop a clear consultation process regarding the allocation of non-resident big game licenses as the current process appears to be unfair to local entrepreneurs.

6.6 Hydro Transmission Corridor Issues

Mandate

"As part of the planning process, Manitoba Hydro co-ordinate any future transmission line communications and public consultation activities with the east side round table. The east side round table provide regional guidance relative to Manitoba Hydro in regards to future electrical transmission facilities within the planning area. Manitoba Hydro work with the east side planning

secretariat and directly with the east side round table to ensure the effective and efficient co-ordination of planning and communication activities in the planning area."

The purpose of the initial east side community visits initiated by Manitoba Hydro was to gauge public interest and reaction to the possible location of a hydroelectric transmission corridor down the length of the east side of Lake Winnipeg. Manitoba Hydro had not completed its full round of community visits when, by mutual agreement between Manitoba Hydro and ESPI, the former agreed to suspend all community information sessions/consultations until ESPI had completed its first round of community visits.

A wide range of issues and concerns were broached in submissions to ESPI from east side communities and residents, numerous stakeholders and Manitoba citizens on the subject of hydroelectric transmission. They ranged from what ESPI has termed "legacy issues" – expressions of distrust and resentment over past relationships between First Nations and Métis nation peoples and Manitoba Hydro to practical concerns about the absence, adequacy and cost of electrical energy in many communities, to more macro-level policy considerations of the vital importance of hydroelectricity in reducing greenhouse gas emissions and mitigating the onslaught of climate change.

East Side Round Table members were impressed with the breadth and depth of concerns expressed by residents of the east side of Lake Winnipeg respecting past relationships with Manitoba Hydro. Many compelling statements and arguments were put before Round Table and First Nations Council members asking for assurances that local communities would benefit economically from the installation of transmission lines on the east side. Equally, concerns were expressed about the impact that such installations might have on the natural environment – from the introduction and leaching of pesticides into water tables and courses, to the disruption of traditional activities such as hunting and trapping. There were few communities visited by Round Table and First Nations Council members that did not have strong opinions and concerns about the possible future location of a hydro transmission corridor on the east side of Lake Winnipeg.

Manitoba Hydro has a legacy issue with which it has to contend. When the topic of Manitoba Hydro or the issue of the possible east side location of BiPole III was raised in communities through the ESPI process, reaction to the corporation and the proposed transmission line corridor on the east side of Lake Winnipeg was either uniformly negative, or contained significant overtones of mistrust and suspicion.

East Side Working Group members who considered this issue were consensual in their opinion that the transmission corridor not proceed unless and until Manitoba Hydro can clearly indicate that there are clear and permanent economic benefits to be accrued by communities on the East Side.

"We have heard from Hydro before. They came to us, but did not give us enough time to respond. You have to give us more time. There is a lack of information provided by Hydro for the community to adequately respond or participate. We do not want a poor consultation process."

(East Side Resident)

6.6 Recommendations:

6.6.1
All future discussions, consultations and negotiations between Manitoba Hydro and First Nations and Aboriginal communities on the east side of Lake Winnipeg be subject to, as and when they are developed, the *Protocols of Agreement* with First Nations and the Métis Nation resident on the east side of Lake Winnipeg respecting the Broad Area Plan for the east side of Lake Winnipeg between the Government of Manitoba and First Nations governments and Aboriginal communities located on the east side of Lake Winnipeg.

6.6.2
A comprehensive *Aboriginal Treaty Rights and Traditional Lands Impact Assessment* be completed as part of the Environmental Impact Assessments that must be undertaken as part of the possible location of the BiPole III line on the east side of Lake Winnipeg. Should such an assessment indicate that impacts are anticipated, and compensation or revenue – sharing is required, it is further recommended that Manitoba Hydro reach an agreement-in-principle on compensation, or such revenue – sharing as a component of, and prior to, the conclusion of the Environmental Impact Assessments.



6.6.3
Manitoba Hydro identify the location of all potential corridor routes for transmission lines, including those external to the east side of Lake Winnipeg Planning Area.

6.6.4
Should the location of a BiPole III hydro transmission corridor on the east side of Lake Winnipeg continue to be considered as a viable option by Manitoba Hydro that it expend the resources necessary, including the provision of resources to the communities themselves to ensure that communities on the east side of Lake Winnipeg are fully informed, involved and consulted on all components of the intended proposal, including the likely impact of the corridor on the nominated UNESCO World Heritage site.

6.6.5
With respect to the possible location of a BiPole III hydro transmission corridor on the east side of Lake Winnipeg, that should it proceed, Manitoba Hydro provide assurances that, wherever possible, the corridor be adjacent to other vehicle transportation corridors, unless an environment impact assessment determines this is not advisable. Where hydro and transportation corridors diverge, there will be no road access to the hydro transmission corridor.

6.6.6
With respect to the possible location of a BiPole III hydro transmission corridor on the east of Lake Winnipeg, that should it proceed, Manitoba Hydro provide assurances to local communities that employment opportunities will be provided and local resources utilized on a priority basis.

6.6.7
With respect to the possible location of a BiPole III hydro transmission corridor on the east of Lake Winnipeg, should it proceed, Manitoba Hydro provide assurances that where the transmission lines cross recreation or navigable rivers that transmission line support pylons will be located so as to be hidden from normal sight lines on or adjacent to the river, and, should environmental assessments prove such is feasible, that the transmission lines corridors be buried at key river crossings.

6.6.8
As concerns have been expressed about the potential negative impact on human and animal health caused by the possible creation of magnetic fields in the area of transmission corridors with operating hydro transmission lines, any HVDC transmission lines must maintain a minimum five hundred metre distance from settlements and residences. Manitoba Hydro should make available to the public all current research on this issue. Should such research indicate that there are possible negative effects upon human health, Manitoba Hydro must inform residents potentially exposed to these corridors of what steps the agency plans to take to eliminate the possible health hazard.

6.6.9
Any hydro transmission development or activity with a permit or license to operate must investigate, identify and mitigate impacts on licensed or permitted activities such as trapping, wild rice propagation, lodges and outfitters, and others. The Government of Manitoba shall work with the East Side First Nations Council to establish a process to ensure sufficient communications between license holders and provide a mechanism to resolve any conflict or disputes that may arise due to competing licensed interests. Conflict resolution by a third party mediator could be a consideration.

6.6.10
The Government of Manitoba encourage and mandate Manitoba Hydro to fully and publicly explore the viability of locating alternative energy source infrastructure (wind and solar) on the east side of Lake Winnipeg and create opportunities for east side residents and all Manitobans to benefit from these low-impact energy sources.

6.7 Mining Issues

Mandate

"The east side Round Table consider the potential for mineral development and its acceptability within the various land use zones that may be designated in the planning area.

Mining exploration and development in the planning area continue as per existing established public consultation requirements, environmental review and licensing requirements and other required reviews and permitting processes and procedures."

Mineral exploration and development within the planning area is manageable within established procedures and approval mechanisms, but requires more attention to local communications and co-operation. Exploration is ongoing to a limited extent, and the mineralized belts are generally well identified. Information sources, maps and reports are available online through the Manitoba government website.

Although the mineral potential and the geology of the southern area are relatively well known and developed, this is not the case with the central and northern areas. Mineral exploration within these areas has been sporadic, due to the relative remoteness and poor access to these areas, and because the geology of these areas has only been mapped on a reconnaissance level. The mineral potential of the northern part of the planning area remains poorly understood.

A process has been developed between the government and the minerals sector through which new protected area proposals are screened. Where no conflicts arise, there is a green light from the sector. Where conflicts arise, a resolution is negotiated, which sometimes requires more detailed information about the mineral potential and the Area of Special Interest (ASI). This process has successfully screened the ASI within the planning area.

The ESPI planning process has not advanced far enough to enable identification of specific land use zones, other than existing protected areas, where mineral exploration and development would potentially be excluded.

In March 2000, the mineral sector, Manitoba government, First Nations groups and other stakeholders developed a Manitoba Minerals Guideline containing the principles that should be followed for building relationships and creating opportunities during the mineral development process. This guide set a standard for how the mining industry and communities on the east side should be co-operating.

Active mineral claims give certain land access and occupation rights to the holder. People in local communities may not realize that these rights of occupation of land by mineral exploration companies are included when mineral claims are staked. Sudden unannounced or unexpected activity by an exploration company near a small community can surprise the local residents. These surprises can and should be avoided through the use of the Manitoba Minerals Guideline.

6.7 Recommendations

6.7.1
The East Side First Nations Council develop a consultation process regarding potentially affected peoples and licensees prior to the approval of mineral exploration programs, permits and staking activity.

6.7.2
Mineral exploration and development is an acceptable activity within the planning area, provided that the proposed East Side First Nations Council plays an oversight role in consultation and approval mechanisms, decisions are taken on a case by case basis, and there is local benefit from the activity.

6.7.3
The Manitoba Minerals Guideline (2000) principles for community consultation, information sharing, protecting environmental integrity, policy review and development and creating opportunities be accepted as the starting point for guiding relationships between the minerals industry and communities on the east side of Lake Winnipeg.

6.7.4
The onus for using the Guidelines falls on both the mining companies and the communities. Even with best efforts, not everyone in a community may be satisfied with the information they receive about exploration or mining activities. As much effort needs to be made within the community to share this information, as is made by the industry to make it available.

6.7.5
Any mining development or mining exploration activity with a permit or license to operate must investigate, identify and mitigate impacts on licensed or permitted activities such as trapping, wild rice propagation, lodges and outfitters, and others. The Government of Manitoba shall work with the East Side First Nations Council to establish a process to ensure sufficient communications between license holders and provide a mechanism to resolve any conflict or disputes that may arise due to competing licensed interests. Conflict resolution by a third party mediator could be a consideration.

6.8 Additional Significant Issues

Mandate

"The government should seek the advice of the round table on any significant issue which might arise during the course of the planning process."

Research Needs

In the course of this planning activity, it has become evident that several areas of ongoing research are needed to further support Broad Area Planning, and refine management approaches and techniques. One prominent concern is

the lack of natural resource data available for the planning area north of the 53rd parallel. There, species inventories, lake surveys, forest inventory, mineral exploration, and historic and archeological investigations are all needed to develop better information to support land use decisions. More information is also needed on threatened or sensitive species such as woodland caribou.

A more complete assessment of the research needs in the planning area will be part of the ongoing development of the Broad Area Plan. At this stage, the need for further research is noted.

6.8 Recommendations

6.8.1
To assist in developing a better understanding of research needs on the east side, it is recommended that a group of advisors be assembled from various Manitoba research and other institutions. This group could advise government on research needs and priorities. Membership of this group could be drawn from the universities, the Centre for Indigenous Environmental Resources, the Natural Resources Institute, Freshwater Institute, etc.



Other Recommendations

6.8.2
The Government of Manitoba be consistent in fulfilling its public policy commitments by not issuing licenses and permits for new development within the planning area that would violate standards, regulations or policies for water quality protection.

6.8.3
The Government of Manitoba continues to fulfil its obligation to protect species when reviewing development expansion, new developments or new license proposals within the planning area.

6.8.4
To provide an additional level of protection to the boreal environment when undertaking business developments, that all new business ventures, with 25 or more employees, are encouraged to secure and maintain registration with an independent organization which is designed to address the potential environmental effects of the operation. At a minimum, such systems will identify potential environmental impacts, develop and implement controls to mitigate negative environmental impacts and require an independent assessment by a registered auditor. Existing business (with 25 or more employees) developments will be required to comply with this requirement within 5 years. As all existing systems are voluntary, the Government of

Manitoba would have to establish the necessary policy framework to support the recommendation.

6.8.5
Impact benefit agreements with standardized criteria should be mandatory for development initiatives impacting land use within the Broad Area Plan for the east side of Lake Winnipeg.

7.0 Conclusion
The Path Forward: Challenges & Opportunities

Negotiations and discussions on many of the planning, protection and development issues identified in the original mandate for the Broad Area Plan have not been completed, nor has there been adequate opportunity for east side residents to prepare their input to this planning process. It is to the credit of the Government of Manitoba and its commitment to this exercise that it will likely extend the period for community input.

The signed *Memorandum of Understanding* between East Side First Nations governments and the Government of Manitoba commits both parties to a process of negotiations and consultations which may lead to *Protocols of Agreement.* Consistent with the recommendations in COSDI, the Government of Manitoba is strongly encouraged to commit to a separate process of protocol negotiations with the Métis Nation Government of the east side of Lake Winnipeg. It is essential to the overall success of the East Side Planning Initiative to recall that the broad area planning and protocol processes are inextricably intertwined. One cannot proceed without the other.

Another facet of the Broad Area Plan is a governance mechanism that will ensure adhesion to the Broad Area Plan and *Protocols of Agreement.* The necessary authority will have to be vested in such a mechanism to guarantee local community input while adhering to the principles of sustainable development and protection of the environment, which are the foundations of the Broad Area Plan.

An ambitious undertaking, if done with respect for the necessary complexity of the process, the Broad Area Plan for the east side of Lake Winnipeg will represent a watershed in the evolving relationship between government and Aboriginal communities in Canada. It will alter the social and economic relationships between the Government of Manitoba and First Nations governments on the east side of Lake Winnipeg.

There are numerous and daunting challenges to this enterprise: The constant challenge of ensuring that information and data is adequately shared with the population of the east side; the need for vigilance and persistence in "following through" with all components of the planning exercise; the

essential requirement for improved horizontal communications among provincial government departments, thereby reducing "stovepipe bureaucracy."

The Government of Manitoba can enjoy a measure of pride in undertaking this risk-filled venture and committing itself to staying the course. The successful completion of both the protocols and the Broad Area Plan will contribute immeasurably to redefining relationships that have been marked historically by mistrust and bitterness. Should this venture succeed and allow Aboriginal communities to play the predominant role in charting their own futures with the access to the resources to do so, all Manitobans will benefit.

Another opportunity realized with the adoption of the Broad Area Plan for the east side of Lake Winnipeg is an unprecedented measure of protection for a significant and contiguous boreal environment.

This status report is but a benchmark along the way, and the path ahead does finally offer a glimpse of what a fully functional Broad Area Plan may look like. The fragile coalition of interests which have contributed to the preparation of this report and support its objectives must now rely on the good faith and good will of the government which commissioned this initiative. Let us hope that this faith and this will has not been misplaced so that *"Promises to Keep"* will become promises kept.



Appendix 8.1

East Side Planning Initiative



East Side Planning Initiative

Round Table, First Nations Council, Advisory Committee, Government Review Panel (Phase I), Secretariat and Government Liaison Committee

National Chief Phil Fontaine – Chair

Mr. Ed Wood – Associate Chair

East Side Round Table

The Right Honourable Edward Schreyer – Special Advisor

Mr. Al Benoit
Mr. Dan Benoit (Alternate)

Mr. Paul Chief

Mr. Don Courchene

Ms. Sherry Dangerfield

Mr. Helgi Einarsson

Mr. Ken Ellison

Mr. Wesley Harper

Mr. Ed Huebert

Mr. Peter Kinew

Mr. Gilbert Knott

Mr. Mike Martel

Dr. Peter Miller

Chief Vera Mitchell

Mr. Tom Nepetaypo

Dr. David Punter

Mr. Don Sullivan

Mr. Jim Ticknor

Ms. Cherry White

Chief Nancy Whiteway

East Side First Nations Council

Hilda Flett	Berens River First Nation
Frank Young Dwayne Bushie (Alternate)	Bloodvein First Nation
Chief Bailey Colon	Bunibonibee Cree Nation
Jack Fiddler	Garden Hill First Nation
Chief Gilbert Andrews	God's Lake First Nation
Larry Barker succeeded by Chief Ian Bushie Ferlon Barker (Alternate) Rene Barker (Alternate)	Hollow Water First Nation
Jonas Peebles	Little Black River First Nation
Nelson Keeper	Little Grand Rapids First Nation
Chief Roger Ross, succeeded by Chief Moses Okimaw	Manto Sipi Cree Nation
Jim Cromarty	Norway House Cree Nation
Albert Pascal, succeeded by Sheldon Kent	Pauingassi First Nation
Eddy Hudson	Poplar River First Nation
Lawrence Harper, succeeded by Chief Fred Harper	Red Sucker Lake First Nation
Joe Daniels	Sagkeeng First Nation
Roy A. Mason	St. Theresa Point First Nation
Chief Cornelius Wood	Wasagamack First Nation
Simon Fobister Joe Kuhn	Grand Council Treaty #3

East Side Advisory Committee

Note: While other groups were contacted by the East Side Secretariat for membership on the East Side Advisory Committee, no other names were forwarded.

Aboriginal Resource Council	Richard Gaywish
Aghaming Community Council	Bob Bull

Berens River Community Council	Henry McKay & Brian Whiteway
Bissett Community Council	Patti Grapetine
Gods Lake Narrows Community Council	Mayor Leslie Anderson Sr.
Island Lake Community Council	Jerry Bilewitch
Little Grand Rapids Community Council	George Quantrill
Loon Straits	Edgar Bruce
Manigotagan Community Council	Dale Boulette & Greg Wood
Matheson Island Community Council	Harold Bennett & Terry Bennett
Norway House Community Council	Glen Flett
Oxford House Community Council	Tommy Weenusk
Pine Dock Community Committee	Margaret Johnson
Princess Harbour Community Council	Marlene Monkman & Myrtle Magnusson
Red Sucker Lake Community Council	Heather Disbrowe
Seymourville Community Council	Ted Seymour & Brian Lepott
Eastman Regional Development, Inc.	Ron Funk
St Georges Economic Development Council	Dianne Dube
Winnipeg River Brokenhead Futures	Mary Greber
Anishaabe Turtle Island Protectors	Gary Raven
Canadian Parks and Wilderness Society	Krista Scott
Canadian Nature Federation	Gaile Whelan-Enns Jared Whelan (Alternate)
Manitoba Eco-Network	Anne Lindsey
Manitoba Future Forest Alliance	Sara Peloquin
Manitoba Model Forest	Carl Smith
Manitoba Naturalists Society	Les McCann
Northern Lights Heritage Services	Virginia Petch
Resource Conservation Manitoba, Inc.	Liz Dykman

T.R.E.E.	Dr. John Sinclair
Western Canada Wilderness Committee	Ron Thiessen
Canada Wild Rice Council	Lorne Williams
Manitoba Hydro	Wade Munro
Manitoba Prospectors & Developers Association	Ryan Cooke
Manitoba Trappers Association	Stewart Jansson
Mining Association of Manitoba	David Markham
TEMBEC Pine Falls Operations	Vince Keenan
RM of Alexander	George Harbottle
RM of Lac du Bonnet	Bob Bruneau & Don Halbert
LGD of Pinawa	Leonard Simpson
Village of Powerview	Ted Pichor
Island Lake Tribal Council	Chief Goliath Harper
Manitoba Keewatinowi Okimakanak Inc.	Michael Anderson
Manitoba Metis Federation	Dan Benoit
Manitoba Metis Federation Interlake Region	Bill Flett
Manitoba Metis Federation Thompson Region	Lyle Mulholland
Manitoba Metis Federation Southern Region	Marcella Vezina
Southern Chiefs Organization	Dina Bruyere
Manitoba Wildlife Federation	Roger Venton
Manitoba Aviation Council	Fred Petrie
SnoMan, Incorporated	Duncan Stokes

Phase I (August 2000 to March 2002)

Government Review Panel:

Bill Barto

Bruce Bremner

Blair McTavish

Joe Morisseau

Sandy Thompson

Phase 2

East Side Secretariat (March 2002 to July 2003):

Mike Waldram – Executive Coordinator

Bill Anderson

Paulette Delaquis

Joann Hiebert

Barb Hobson

Moses Okimaw

Jennifer Tavares

East Side Secretariat (July 2003 to September 2004)

Peter Globensky – Executive Coordinator

Bill Anderson

Bruce Bruyere

Barb Hobson

Rick Ratte

Dale Sobkowich

Jennifer Tavares

Pat Williamson

Bernie Wood

Government Liaison Committee:

Serge Scrafield

Blair McTavish

Ron Missyabit

Appendix 8.2

List of All Appendices



List of All Appendices

8.1 Reference Maps – East Side of Lake Winnipeg

8.2 Round Table, First Nations Council, Advisory Committee, Government Review Panel (Phase I), Secretariat and Government Liaison Committee

8.3 Boreal Forest World Heritage Site Map

8.4 Executive Summary of Phase One Report
English / Ojibway / Oji-Cree / Cree

8.5 East Side Planning Process Brochure

8.6 East Side Round Table Terms of Reference

8.7 East Side First Nations Council Terms of Reference

8.8 Public Participation Process

8.9 Community & Stakeholder Submissions Received

- Canada Wild Rice Council
- Manitoba Prospectors & Developers Association, June 4, 2003
- Land of the Spirit/Spirits of the Land, The Anishinaabe Turtle Island Protectors and the Boreal Forest Network, May 2004
- Manitoba Model Forest Inc, March 29, 2004
- Dr. W.O. Pruitt, June 9, 2004
- Manitoba Naturalists Society
- Manitoba Trappers Association, July 2, 2004
- Dave Rannard, June 14, 2004
- Brett Sokoloski, July 1, 2004
- TEMBEC, Pine Falls Operations, May 20, 2004
- Wabanong Anishinaabe Trappers Association, June 17, 2004
- Wasagamack First Nation Youth Concerning the East Side of Lake Winnipeg Planning Initiative, May 6, 2004
- Wilderness Committee, June 14, 2004
- Manitoba Environmental Organizations, July 22, 2004

.

8.10 Community Reports: “What We Heard” – By Community

8.11 Community Reports: “What We Heard” – By Issue

8.12 Community Facilitation Reports – NACC Communities

8.13 Reports of Meetings with Elders

8.14 Memorandum of Understanding

8.15 Summary of Departmental P lanning Activities

8.16 East Side of Lake Winnipeg First Nations Community Profiles

8.17 Report of the Working Groups – Compilation Document

8.18 Report of the Open Houses Process

8.19 UNESCO “Man and Biosphere” Programme FAQs

8.20 Legislation Under Which Areas Are Designated Under Manitoba’s P.A.I.

.

Glossary of Terms

- **Aboriginal Peoples** – The definition of "Aboriginal peoples" being used in this document is the legal definition contained in the Constitution of Canada. This includes Indians (on and off reserve Status Indians, First Nations, non-Status Indians, Treaty and non-Treaty Indians), Métis and Inuit.

- **Aboriginal Treaty Rights and Traditional Lands Impact Assessment** – It is necessary to determine the existence of Aboriginal rights and the implications of proposed resource management or development activities on those rights and on the continued use of traditional lands, and whether the approval of the proposal can co-exist with the Aboriginal rights and the continued use of the traditional lands.

- **Area Of Special Interest (ASI)** – These are areas being studied for possible future designation as "protected areas." The studies, utilizing "enduring features" methodology, identify the combinations of soils, geology, climate and landforms (enduring features) that influence biodiversity. The methodology also assesses the contribution of each protected area or ASIs in representing biological diversity within a natural region, and designs study areas to fill gaps in enduring feature and natural region representation. Areas of Special Interest are used to focus consultations and are not protected in any formal manner. In most cases, ASI boundaries are flexible and can be changed to respond to new information.

  According to a protocol established between the departments of Conservation and Industry, Economic Development and Mines, ASIs that meet predetermined criteria are requested in writing by the director of Parks to be placed in a "withdrawal pending" status, meaning that the Crown mineral rights in these areas are not available for new mineral dispositions, pending final resolution of the area's status and future designation of protected lands.

- **Assessment and Review of Effects** – This refers to an assessment and review of all sustainability factors such as environmental, economic, social, cultural and human health. The terms "assessment and review of effects," "assessment and review process," "assessment process," "assessment and review," and "effects assessment" will be used synonymously. The assessment process is generally guided by legislation (such as the Canadian Environmental Assessment Act or Manitoba's Environment Act) which defines both the substantive and procedural requirements, including the scope of the project/undertaking, information requirements, matters to assess and public participation.

- **Biodiversity** – The variability among living organisms from all sources including, among other things, terrestrial, marine and other aquatic ecosystems, and the ecological complexes of which they are a part. This includes diversity within species, between species and of ecosystems (Convention on Biological Diversity, 1992).

  Biodiversity has been seen as the total (and irreducible) complexity of all life, including not only the great variety of organisms but also their varying behaviour and interactions. One of the more broadly shared and economically defensible values for conserving wholesale biodiversity (rather than just the few components or 'biospecifics' with obvious high use value at present) may be seen to lie in ensuring continued possibilities both for adaptation, and for future use, by people in a changing and uncertain world (Natural History Museum, Biodiversity and Worldmap website).

- **Boreal Forest (contiguous)** – Canada's boreal forest is the largest contiguous, intact forest left on earth, covering 35 per cent of the country's land mass and stretching across the north from Newfoundland to the Yukon. It includes the east side planning area. These northern forests are the breeding grounds for over 60 per cent of Canada's bird population with approximately three billion birds nesting there annually. The boreal is also home to the world's largest caribou herd, the second-highest wolf population, and polar, black and grizzly bears.

  Thousands of species of plants, insects and animals – most of which have not been scientifically described but many of which have long been used by Aboriginal people for food and medicinal purposes – are found in boreal ecosystems.

- **Boreal Forest Conservation Framework** – The Boreal Forest Conservation Framework reflects the collective wisdom of the Boreal Leadership Council and is based on the best information currently available. The framework is based on a shared vision to sustain the ecological and cultural integrity of the Canadian boreal forest region, in perpetuity.

  The framework's goal is to conserve the cultural, sustainable, economic and natural values of the entire Canadian boreal region by employing the principles of conservation biology to:

  – protect at least 50 per cent of the region in a network of large interconnected, protected areas; and

  – support sustainable communities, world-leading ecosystem-based resource management practices and state-of-the-art stewardship practices in the remaining landscape

  The Boreal Forest Conservation Framework represents a national vision and goal for the region as a whole, rather than a formula to be applied on a unit-by-unit basis in a particular part of the boreal. In promoting a conservation approach for the entire boreal, the framework recognizes that conservation challenges and opportunities will vary. (Canadian Boreal Initiative website)

- **Boreal Shield** – At 195 million hectares the Boreal Shield is the largest ecozone in Canada. It is almost 80 per cent forested and much of the ecozone remains in a wilderness condition. Most of this ecozone is covered with an immense coniferous forest, consisting primarily of black spruce, white spruce, jack pine, balsam fir and tamarack. Further south, red pine, jack pine and eastern white pine occur, along with some hardwoods, such as white birch, yellow birch and trembling aspen. Black ash, mountain maple and eastern white-cedar also grow in some places. Characteristic mammals of this ecozone include woodland caribou, moose, white-tailed deer, black bear, wolf, marten, snowshoe hare, fisher, Canadian lynx and bobcat. Common bird species include the common loon, boreal owl, great horned owl, yellow-rumped warbler, blue jay, evening grosbeak and white-throated sparrow. (Natural Resource Canada website)

- **Broad Area Planning (BAP)** – This is an integrated and coordinated planning that is based on the sustainability of the ecosystem, to ensure future land, resource and development decisions address the environmental, social, health, cultural and economic needs of the public, local communities, First Nations and various stakeholders and interest groups.

- **Canadian Boreal Forest Initiative** – The Canadian Boreal Forest Initiative, or the Canadian Boreal Initiative (CBI), is an independent organization working with conservationists, First Nations, industry and others to link science, policy and conservation activities in Canada's boreal region. On December 1, 2003, the CBI released the Boreal Forest Conservation Framework. The framework was developed in concert with leading conservation organizations, resource companies and First Nations. Convened by the CBI, this group forms the Boreal Leadership Council, committed to the conservation and sustainable development of Canada's boreal forest region. (Canadian Boreal Initiative (CBI) website)

- **Co-Management (Share-management)** – Share-management is a tool that helps address resource management issues and opportunities between government and users by negotiating shared roles and responsibilities, such as involvement in decision-making and monitoring. (Manitoba Conservation)

- **Consultation** – As perceived by COSDI, consultation is the provision of meaningful opportunities for the public, other governments and stakeholders to influence government or other decisions about matters of concern to them. The concept of meaningful consultation is being more specifically defined by the courts as it applies to the nature of the opportunities for Aboriginal people.

- **COSDI** – The Consultation on Sustainable Development Implementation (COSDI) was a multi-stakeholder, consensus-based process commissioned in 1997 by the government to "consider and make recommendations… on how Manitoba can best implement Sustainable Development Principles and Guidelines into decision-making, including environmental management, licensing, land-use planning and regulatory processes." An 18-member core group and 60-member advisory committee collaborated on the preparation of a report with recommendations. The COSDI Report was submitted to government in June 1999. After an election, the current government adopted the report as a central component of its Sustainable Development Strategy in 2000.

- **Double Majority** – In the context of the East Side Broad Area Plan, double majority is a method for decision-making that allows communities to have a strong voice in decisions affecting the areas they live in. In a vote about a decision affecting a particular community, the decision would require both the vote of the community and a majority of the East Side First Nations Council.

- **Ecological Integrity** – Ecological integrity refers to the quality of a natural, unmanaged or managed ecosystem in which the natural ecological processes are sustained, with genetic, species, and ecosystem diversity assured for the future. Ecosystems have integrity when they have their native components intact, including: abiotic components (the physical elements, e.g., water, rocks), biodiversity (the composition and abundance of species and communities in an ecosystem, e.g., tundra, rainforest and grasslands represent landscape diversity; black bears, brook trout and black spruce represent species diversity) and ecosystem processes (the engines that make ecosystems work; e.g., fire, flooding, predation) – Parks Canada website

- **Ecosystem** – A community of all plants and animals and their physical environment, functioning together as an interdependent unit. (forestry)

- **Ecozone** – Canada has been divided into 15 terrestrial ecozones. Each represents areas of the country which can be easily identified by their general living (biotic) and non-living (abiotic) characteristics. The east side of Lake Winnipeg falls within the Boreal Shield ecozone.
- **Effect** – This is a neutral term including positive and negative impacts of a plan or project.
- **Endangered Species** – Manitoba's Endangered Species Act provides for the minister to designate species as endangered, extinct, extirpated or threatened, depending on their number and status. The different designations allow for different levels of protection.
- **Environmental Thresholds** – The environment, as an integrated system, is healthy as long as its components and their interactions are maintained in a state where they can continue to perform their natural functions. If significant changes are made to any components of the system, the efficiency of the system is affected and the environment is thrown off balance. The environment has a degree of resiliency built into it, which gives it the ability to cope with, or adapt to, some change without damaging effects. Environmental thresholds define those allowable changes. Used in planning or assessment purposes, they help decision-makers know what change to the environment will be within the threshold and therefore acceptable, and what change should be avoided. A common threshold is the assimilative capacity of a waterway. How much of a specified substance can be added to a river without altering the characteristics of the river to a degree that it will adversely impact biota, fish, people, etc.? The thresholds can be developed in advance of development, as a part of the planning process, or in response to a proposed development, as a part of the environmental assessment process.
- **Forest Stewardship Council** – The Forest Stewardship Council (FSC) is an international, non-profit organization founded in 1993 to support environmentally appropriate, socially beneficial and economically viable management of the world's forests. It supports the development of national and regional standards to be used to evaluate whether a forest is being well-managed.

  It is an association of members consisting of a diverse group of representatives from environmental and social organizations, forest and product industries, Indigenous People's organizations, community forestry groups and certification bodies from around the world. With its head office in Bonn, Germany, FSC is governed by an elected board.
- **Fragmentation** – Fragmentation occurs when a large region of, in this case, forest has been broken down or fragmented into a collection of smaller patches of habitat. Fragmentation typically occurs when land is converted from one type of habitat to another. For example, a forest habitat may become fragmented when a highway is built across the forest. The highway would split a single, large, continuous patch of forest into two smaller patches. The greater the degree of fragmentation, the greater the effect, as the once large, continuous forest habitat becomes a series of small, disconnected habitats. Because the characteristics of small forests differ from those of large ones, the characteristics of habitat and its suitability for the pre-existing species can change as well.

- **Genetic diversity** – Genetic diversity refers to variety within individuals within a species or a population, or more specifically, the variety of DNA within a species or population.
- **Great Lakes Indian Fish and Wildlife Commission (GLIFWC)** – The GLIFWC is an inter-tribal, co-management agency committed to the implementation of off-reservation treaty rights on behalf of its 11 Ojibway member tribes. Formed in 1984, and exercising authority specifically delegated by its member tribes, GLIFWC's mission is to help ensure significant, off-reservation harvests while protecting the resources for generations to come.
- **Guidelines** – They refer to instructions provided to the proponent for the information requirements and the conduct of an effects assessment in Manitoba.
- **Habitat** – 1. Those parts of the environment (aquatic, terrestrial, and atmospheric) often typified by a dominant plant form or physical characteristic, on which an organism depends, directly or indirectly, to carry out its life processes. 2. The specific environmental conditions in which organisms thrive in the wild.
- **High Conservation Value Forest** – All forests contain environmental and social values, such as wildlife habitat, watershed protection or sacred sites. Where these values are considered to be of outstanding significance or critical importance, the forest can be defined as a High Conservation Value Forest (HCVF). The idea of HCVFs was developed by the Forest Stewardship Council (FSC) and first published in 1999. This concept moves the forestry debate away from definitions of particular forest types (e.g., primary, old growth) or methods of timber harvesting (e.g., industrial logging) to focus on the values that make a forest important. By identifying these key values and ensuring that they are maintained or enhanced, it is possible to make rational management decisions that are consistent with the maintenance of important environmental and social values.

  High Conservation Value Forests are those that possess one or more of the following attributes:

  a. forest areas containing globally, regionally or nationally significant :
     i. concentrations of biodiversity values (e.g., endemism, endangered species, refugia);
     ii. large landscape level forests, contained within, or containing the management unit, where viable populations of most (if not all) naturally occurring species exist in natural patterns of distribution and abundance;
  b. forest areas that are in or contain rare, threatened or endangered ecosystems;
  c. forest areas that provide basic services of nature in critical situations (e.g., watershed protection, erosion control); and
  d. forest areas fundamental to meeting basic needs of local communities (e.g., subsistence, health) and/or critical to local communities' traditional cultural identities (areas of cultural, ecological, economic or religious significance identified in co-operation with such local communities).

- **Impact Benefit Agreement** – Often arising out of a consultation process, agreements can be developed between a proponent of a development and the host community/region, often an Aboriginal community. The agreement can address one

issue, or can be an umbrella agreement covering all the issues respecting the proposed development – environmental, social, and economic.

- **Land-Use Planning** – This refers to the systematic assessment of land and water potential, alternative patterns of land and resource use and other physical, social and economic conditions, for the purpose of selecting and adopting land and resource use options that are most beneficial to land users, without degrading the resources or the environment. Land-use planning also helps with the selection of measures most likely to encourage such land uses. Land-use planning may be at international, national, district (project, catchment) or local (village) levels. It includes participation by land users, planners and decision-makers and covers educational, legal, fiscal and financial measures.

- **Manitoba Model Forest** – The Manitoba Model Forest is a non-profit organization representing over 25 diverse forest interests. The Model Forest brings together environmentalists; industry; all levels of government; local communities, including First Nations; economic development groups; unions; universities; and Aboriginal organizations, to share their knowledge and resources in their mutual quest for sustainable forests. The Manitoba Model Forest comprises 1.05 million hectares of boreal forest that stretches eastward from Lake Winnipeg to the Manitoba-Ontario border.

  Activities in the Manitoba Model Forest include research, development, education and communications on a wide range of subjects, such as:

  - migration patterns of woodland caribou with the purpose of designing a harvesting plan that will protect the animal's habitat;
  - improving inventories of forest resources; and
  - building lasting partnerships among diverse stakeholders.

- **Manitoba Minerals Guideline** – In May 1998, a process was initiated by the Province of Manitoba's Energy and Mines department (now Manitoba Industry, Economic Development and Mines) to bring together representatives of First Nations, Métis Nation, Northern communities and the Manitoba minerals industry to begin a relationship-building process. The purpose of this process continues to be to strengthen the links between parties, learn about common aspirations, cultural values and communication needs, and to create a climate for mutually beneficial opportunities in the building of a strong minerals industry within Manitoba. The document is a guide to facilitate relationship-building between those involved in, or affected by, minerals activity within the province.

- **Manitoba Principles and Guidelines of Sustainable Development** – These are the principles and guidelines of sustainable development as adopted by Manitoba and set out in *The Sustainable Development Act.*

- ***Memorandum of Understanding*** **(MOU)** – A *Memorandum of Understanding* is one form of written agreement signed by two or more parties. In the case of ESPI, the MOU is preliminary to the negotiation of a protocol that will guide the future relationship between the First Nations on the east side of Lake Winnipeg and the Government of Manitoba with respect to the matters of the east side.

- **Non-Timber Forest Products** – These are all forest products, except timber, including other materials obtained from trees, such as resins and leaves, as well as any other

plant and animal products produced by the forest. In the boreal forests of Canada, there are many commercial enterprises based on non-timber forest products, such as hunting and fishing lodges, trapping operations, outfitting, remote tourist operations and youth camps

- **Precautionary Principle** – "The Precautionary Principle" is Principle No. 15 of the *1992 Rio Declaration on Environment and Development.* It states, in part: "Where there are threats of serious or irreversible damage, lack of full scientific certainty shall not be used as a reason for postponing cost-effective measures to prevent environmental degradation." Although generally accepted, since that time governments and industry have been striving to understand the implications and fine-tune the meaning and application of the principle.
- **Proponents** – Proponents are any persons, including the government, interested in proposing a plan, a significant resource allocation or a development.
- **Protected Area** – This is a parcel of land that is protected from most industrial or commercial activities to preserve its natural features or diversity. This is usually land that is designated by law, or Order in Council, as protected. In Manitoba, *The Parks Act* and other legislation allows for the creation of protected areas. Usually, only non-consumptive recreation is permitted in protected areas. Treaty and Aboriginal rights can be exercised in protected areas.
- **Protected Area Accord** – The *Protected Areas and First Nation Resource Stewardship: A Cooperative Relationship Accord* is a March 2002 accord between Poplar River, Pauingassi, Little Grand Rapids and Pikangikum to create a network of linked, protected areas on ancestral lands, and apply for its designation as a world heritage site. Since 2002, Bloodvein has also signed the accord.
- **Protected Areas Initiative (PAI)** – Manitoba's Protected Areas Initiative is a government program dedicated to building a network of protected areas that contains the tremendous biological diversity found in Manitoba's varied landscapes. Since the start of the PAI in 1990, the area of protected lands has increased from 350,000 hectares to just over 5.4 million hectares in 2004. Approximately 8.4 per cent of Manitoba's lands are protected.
- **Protected Area Network** – This refers to the total network of places and locations, protected by various means within a forest or an area, including riparian reserves, habitat reserves, parks and all other protected areas.
- **Protocols of Agreement** – The COSDI report recommended: "Manitoba work in partnership with Aboriginal peoples to develop a co-operative protocol to address the involvement of Aboriginal peoples where their land and resource use planning, significant resource allocation, development assessment and review and regulatory mechanisms, including effects assessment tools and documents, are affected." The ESPI has been instrumental in negotiating a *Memorandum of Understanding* to guide the development of a more comprehensive agreement – the *Protocols of Agreement,* specifically for the east side First Nations. The protocols will contain an official procedure or set of rules for working towards negotiation and consensus. It is a guide that parties must adhere to in attempting to establish working relationships and share management arrangements. The protocols would focus both on the process and contents of agreements that will meet the objectives of both parties.

Similarly, efforts will be made to negotiate *Protocols of Agreement* with the members of the Métis Nation resident on the east side of Lake Winnipeg. These protocols will govern the relationship between the parties with respect to resource and environmental decision-making on the east side of Lake Winnipeg, including consultation mechanisms and practices.

- **Public** – "The public," for the purposes of this report, has two uses. For notice provisions and a variety of other matters, "the public" means the entire public. In other cases, especially related to participation in effects assessment or planning, "the public" means all those persons whose interest in involvement is neither frivolous nor meant to cause difficulties.

- **Public Participation Process** – This is a formal process of public involvement as a part of a decision-making process. Public participation processes range from relatively passive opportunities for information sharing and comment, to interactive processes which ordinarily involve a defined membership, established ground rules and expectations, opportunities for interaction among participants and the provision for ongoing involvement.

- **Resources** – For the purposes of this report, resources refer to Manitoba's natural resources, air, water and land, unless otherwise indicated.

- **Stakeholder** – Although the normal legal definition relates to the holder of the "stake" during a bet or wager, the word is used quite differently in the context of public consultation processes, especially relative to government decision-making. In this context, "stakeholder" refers to a party with a "stake" or legitimate interest in the outcome of a decision to be made. The word, stakeholder, generally includes non-government entities, usually the ones that have a desire to influence the decision. Thus, stakeholders in a planning process would include the land-users, property owners, non-governmental associations, interest groups, potential developers and individuals. The parties that are governments or decision-makers are not considered stakeholders.

- **Sustainable Development** – This is defined in *The Manitoba Sustainable Development Act* as "meeting the needs of the present without compromising the ability of future generations to meet their own needs." The definition is supplemented by the inclusion in *The Manitoba Principle and Guidelines of Sustainable Development Act.*

- **Sustainable Development Components** – The use of the phrases "sustainable development components," "sustainable development," "sustainability," and "sustainability factors" in recommendations all include economic, social, environmental, human health, and cultural considerations.

- **Tenure** – Tenure refers to socially defined agreements held by individuals or groups, recognized by legal statutes or customary practice, regarding the "bundle of rights and duties" of ownership, holding, access and/or usage of a particular land unit or the associated resources there within (such as individual trees, plant species, water, minerals, etc.).

- **Terms of Reference** – This refers to instructions provided to hearing panels, such as the Clean Environment Commission, for the conduct of such activities as public hearings.

- **Traditional Ecological Knowledge** – Traditional ecological knowledge (TEK) is the knowledge base acquired by indigenous and local peoples over many hundreds of years through their direct contact with the environment. This knowledge includes an intimate and detailed knowledge of plants, animals and natural phenomena, the development and use of appropriate technologies for hunting, fishing, trapping, agriculture and forestry, and a holistic knowledge, or "world view", which parallels the scientific discipline of ecology. When TEK and western scientific knowledge are used in an appropriate and complementary fashion, the two knowledge systems provide a powerful tool for managing natural resources and achieving sustainable development. (Newsletter – Centre for Traditional Knowledge, Canadian Museum of Nature)

- **Traditional Ecological Mapping** – The use of mapping technology is being expanded to accommodate TEK. Most GIS applications have been traditionally concerned only with scientifically derived data. The spatial analytical capabilities of this technology offer great potential to aid in land-oriented decision-making. The quantifiable nature of GIS output supports First Nations positions within political negotiations and legal contexts.

  The challenges are with respect to the informal nature of traditional knowledge. There are several ways to address this issue. First of all, by its very nature GIS has the potential to be more reflective of a holistic world view than static analogue maps. The ability to layer diverse themes, variables and landscape characteristics can more closely approximate a less reductionist, more encompassing environment. The update capabilities of GIS, moreover, can incorporate dynamic conditions in the real world into the analysis.

- **UNESCO – World Natural and Cultural Heritage Site** – The United Nations Educational, Scientific and Cultural Organization (UNESCO) seeks to encourage the identification, protection and preservation of cultural and natural heritage around the world, considered to be of outstanding value to humanity . This is embodied in an international treaty called the *Convention Concerning the Protection of the World Cultural and Natural Heritage,* adopted by UNESCO in 1972. Cultural heritage refers to monuments, groups of buildings and properties with historical, aesthetic, archaeological, scientific, ethnological or anthropological value. Natural heritage refers to outstanding physical, biological and geological formations, habitats of threatened species of animals and plants, and areas with scientific, conservation or aesthetic value. UNESCO's World Heritage mission, among a lengthy list of objectives, is to encourage countries to sign the 1972 *Convention* and to ensure the protection of their natural and cultural heritage, as well as encourage States Parties to the *Convention* to nominate properties within their national territories for inclusion on the World Heritage List.

- **Watershed** – This is the area that drains to a common waterway, such as a stream, lake, estuary, wetland, or even the ocean. (EPA)

- **Wetlands** – Wetlands are areas where water covers the soil, or is present either at, or near, the surface of the soil all year or for varying periods of time during the year, including during the growing season. Water saturation (hydrology) largely determines how the soil develops and what types of plant and animal communities are living in and on the soil. Wetlands may support both aquatic and terrestrial

(both water and land) species. The prolonged presence of water creates conditions that favour the growth of specially adapted plants (hydrophytes) and promote the development of characteristic wetland (hydric) soils.

Wetlands vary widely because of regional and local differences in soils, topography, climate, hydrology, water chemistry, vegetation and other factors, including human disturbance. Indeed, wetlands are found from the tundra to the tropics and on every continent except Antarctica. (EPA)

Tab 43

December 2014

Capital Expenditure Forecast (CEF14)

2014/15 - 2033/34



Finance & Regulatory

Manitoba Hydro

Manitoba Hydro
Consolidated Capital Expenditure Forecast (CEF14)
For the Years 2014/15 – 2033/34

Table of Contents

1.0 Overview

Capital Expenditure Forecast Summary 1
Comparison to CEF13 1
Capital Expenditure Forecast Summary Table 3

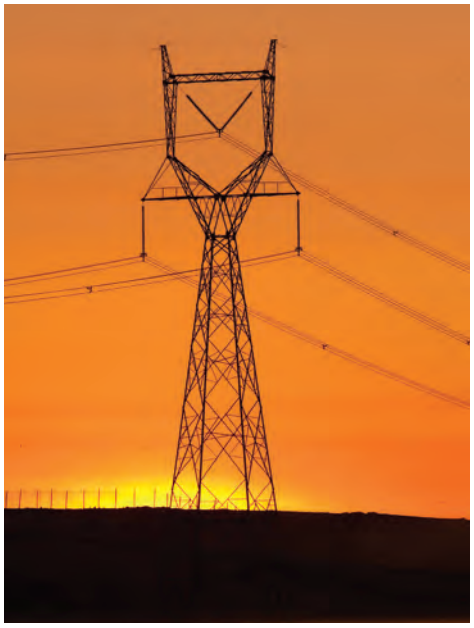
2.0 Project Summaries

ELECTRIC OPERATIONS: 9
MAJOR NEW GENERATION & TRANSMISSION: 9
Wuskwatim - Generation 9
Keeyask - Generation 9
Grand Rapids Hatchery Upgrade and Expansion 10
Conawapa - Generation 10
Kelsey Improvements & Upgrades 11
Kettle Improvements & Upgrades 11
Pointe du Bois Spillway Replacement 12
Pointe du Bois - Transmission 12
Gillam Redevelopment and Expansion Program (GREP) 13
Bipole III - Transmission Line 13
Bipole III - Converter Stations 14
Bipole III - Collector Lines 14
Bipole III - Community Development Initiative 15
Riel 230/500kV Station 15
Manitoba-Minnesota New 500kV Transmission Line 16
Firm Import Upgrades 16
Demand Side Management 17
MAJOR CAPITAL: 18
GENERATION OPERATIONS: 18
Pine Falls Units 1-4 Major Overhauls 18
Jenpeg Overhaul Program 18
Slave Falls Major Overhauls 19
Water Licenses & Renewals 19
Pointe du Bois GS Rehabilitation 20
Great Falls Unit 4 Overhaul 20
Brandon Units 6 & 7 "C" Overhaul Program 21
TRANSMISSION: 22
Rockwood East 230/115kV Station 22
Lake Winnipeg East System Improvements 22
Letellier - St. Vital 230kV Transmission 23
Transmission Line Upgrades for NERC Alert 23
HVDC Dorsey Synchronous Condenser Refurbishment 24
Dorsey 230kV Phase II Zone Building 24
Bipole 2 Thyristor Valve Replacement 25
CUSTOMER SERVICE & DISTRIBUTION: 26
New Madison Station - 115/24kV Station 26
St. Vital Station - 115/24kV Station 26
Dawson Road Station - 115/24kV Station 27
Burrows New 66/12kV Station 27
New Adelaide Station 66/12kV 28

BASE CAPITAL: 29
ELECTRIC OPERATIONS: 29
Generation Operations 29
Transmission 30
Customer Service & Distribution 31
Customer Care & Energy Conservation 32
Human Resources & Corporate Services 32
Finance & Regulatory 33
GAS OPERATIONS: 34
Customer Service & Distribution 34
Customer Care & Energy Conservation 35









Section 1

Overview

Capital Expenditure Forecast Summary
Comparison to CEF13
Capital Expenditure Forecast Summary Table

Manitoba Hydro
Consolidated Capital Expenditure Forecast (CEF14)
For the Years 2014/15 – 2033/34

1.0 Overview

The Capital Expenditure Forecast (CEF14) is a projection of Manitoba Hydro's capital expenditures for new and replacement facilities to meet the electricity and natural gas service requirements in the Province of Manitoba as well as expenditures required to meet firm sale commitments outside the province. Expenditures included in the Capital Expenditure Forecast will provide for an ongoing safe and reliable supply of energy in the most efficient and environmentally sensitive manner.

The Capital Expenditure Forecast is comprised of a number of specifically identified large projects or "major items" as well as numerous unspecified smaller projects referred to as "base items." Major items are normally greater than $50 million in total cost and the construction period on each major item usually extends beyond one year. Base capital expenditure items typically represent sustaining capital requirements to meet electricity and natural gas service replacements and expansions throughout the province. All major and base capital projects are subjected to a rigorous review and approval process before being included in the Capital Expenditure Forecast

The CEF14 includes Major New Generation & Transmission projects which increase capacity and energy or provide increased reliability. In August 2013, the Province of Manitoba issued an Environmental Act licence for the Bipole III Reliability project and construction has commenced with a planned in-service date of 2018/19. In July 2014 the Province of Manitoba issued an Environmental Act licence for the Keeyask Generating Station and construction has commenced with a planned in-service date of 2019/20. Manitoba Hydro continues to develop the Manitoba-Minnesota Transmission Project, a transmission interconnection into the U.S. which supports enhanced export capability, reliability and drought risk mitigation. The Province also endorsed Manitoba Hydro's new, more aggressive demand side management PowerSmart plan which targets a 250% increase in consumption savings.

For CEF14 forecast purposes, it is assumed that the Conawapa Generating Station has been suspended and replaced with a gas turbine required in 2037/38 to meet firm capacity requirements. While the majority of the planning and licensing activities on Conawapa have been suspended, Manitoba Hydro continues to pursue dependable firm export sales based on the earliest possible in-service date of Conawapa in 2029/30 and will re-evaluate the business case (currently anticipated by Fall of 2016).

Base capital targets established for fiscal years 2014/15 through 2020/21 in CEF14 considered increased requirements for aging infrastructure based upon asset condition assessments. Beginning in 2021/22, base capital targets are escalated at a minimum 2% annually.

Capital Expenditure Forecast Summary

The CEF14 totals $25 953 million for the twenty year period to 2033/34. Expenditures for Major New Generation & Transmission (MNG&T) total $12 611 million, with the balance of $13 342 million comprised of expenditures for infrastructure renewal, system safety and security, new and increasing load requirements, and ongoing efficiency improvements.

Comparison to CEF13

The CEF14 for the twenty year period to 2033/34 totals $25 953 million compared to $33 474 million for the same twenty year period included in last year's Capital Expenditure Forecast (CEF13).

Manitoba Hydro
Consolidated Capital Expenditure Forecast (CEF14)
For the Years 2014/15 – 2033/34

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	10 Year Total
CEF13	2 062	2 483	2 543	2 358	2 061	1 878	1 372	1 755	2 319	2 359	21 191
Incr (Decr)	9	73	580	803	52	(408)	(333)	(962)	(1 595)	(1 635)	(3 416)
CEF14	2 071	2 556	3 124	3 161	2 113	1 470	1 039	793	724	724	17 774

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	20 Year Total
CEF13	2 162	2 048	1 838	1 399	1 098	922	828	680	630	679	33 474
Incr (Decr)	(1 384)	(1 264)	(1 054)	(623)	(305)	(151)	(8)	154	245	285	(7 521)
CEF14	778	784	785	776	793	771	820	834	875	963	25 953

The following table provides a summary of the major changes to CEF14.

	Total Projected Cost	10 Year Increase (Decrease)	20 Year Increase (Decrease)
	($ Millions)		
Conawapa - Generation	397	(6 052)	(10 065)
Base Capital Target	NA	422	1 957
Pointe du Bois Powerhouse Rebuild	1 852	(19)	(1 471)
Bipole III - Converter Stations	2 675	881	881
Demand Side Management *	NA	463	802
Additional North South Trasmission	-	(90)	(475)
Bipole III - Transmission Line	1 655	407	407
Keeyask - Generation	6 496	349	349
Gillam Redevelopment and Expansion Program	266	(77)	(100)
Gas Demand Side Management *	NA	50	92
Bipole III - Collector Lines	260	71	71
Dorsey 230KV Zone Building	-	(63)	(63)
New Adelaide Station - 66/12kV	62	62	62
Slave Falls Major Overhauls	126	(63)	-
Other System Upgrades		243	32
		(3 416)	(7 521)

*Assumes that Demand Side Management expenditures will continue to be capitalized upon adoption of IFRS in 2015/16 under the interim standard that continues to permit rate regulated accounting.

Manitoba Hydro
Consolidated Capital Expenditure Forecast (CEF14)
For the Years 2014/15 – 2033/34

CAPITAL EXPENDITURE FORECAST (CEF14)
(in millions of dollars)

	Total Project Cost	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	10 Year Total
Major New Generation & Transmission												
Wuskwatim - Generation	1 448.6	40.5	12.9	14.7	-	-	-	-	-	-	-	68.1
Keeyask - Generation	6 496.1	776.3	676.3	962.2	1 351.3	927.9	616.5	208.6	55.2	4.5	0.1	5 578.8
Grand Rapids Hatchery Upgrade & Expansion	23.5	1.9	4.7	9.3	6.8	-	-	-	-	-	-	22.6
Conawapa - Generation	397.0	43.4	31.4	21.0	-	-	-	-	-	-	-	95.8
Kelsey Improvements & Upgrades	340.4	14.1	9.1	12.9	1.3	-	-	-	-	-	-	37.3
Kettle Improvements & Upgrades	191.6	6.6	23.5	24.6	22.0	31.7	29.5	-	-	-	-	137.9
Pointe du Bois Spillway Replacement	574.8	114.1	51.6	3.8	-	-	-	-	-	-	-	169.5
Pointe du Bois - Transmission	114.3	15.8	17.1	13.8	4.3	-	-	-	-	-	-	50.9
Pointe du Bois Powerhouse Rebuild	1 852.2	-	-	-	-	-	-	-	-	-	-	-
Gillam Redevelopment and Expansion Program (GREP)	266.5	20.0	22.4	22.8	21.8	20.2	18.6	21.3	20.9	19.1	24.6	211.6
Bipole III - Transmission Line	1 655.4	203.5	360.5	381.0	493.8	75.3	-	-	-	-	-	1 514.0
Bipole III - Converter Stations	2 675.1	221.1	580.8	828.7	507.7	195.1	18.4	4.5	-	-	-	2 356.3
Bipole III - Collector Lines	260.2	58.4	75.5	51.7	36.7	4.7	-	-	-	-	-	227.0
Bipole III - Community Development Initiative	62.0	2.3	2.0	1.8	1.6	0.5	-	-	-	-	-	8.1
Riel 230/500kV Station	329.9	36.4	5.6	-	-	-	-	-	-	-	-	42.0
Manitoba-Minnesota Transmission Project	350.3	7.0	32.7	99.6	59.5	65.7	48.1	35.4	-	-	-	348.0
Demand Side Management	NA	51.8	59.2	76.6	83.9	93.7	78.2	72.5	60.8	50.0	49.6	676.2
Generating Station Improvements & Upgrades	NA	-	-	-	-	-	2.8	33.0	33.6	34.3	35.0	138.6
Target Adjustment (Cost Flow)	NA	(161.3)	(51.4)	(61.1)	(12.7)	116.3	71.9	50.9	25.6	8.8	0.7	(12.2)
MAJOR NEW GENERATION & TRANSMISSION TOTAL		**1 451.7**	**1 913.9**	**2 463.5**	**2 577.8**	**1 530.9**	**884.0**	**426.2**	**196.1**	**116.6**	**110.0**	**11 670.7**

Manitoba Hydro
Consolidated Capital Expenditure Forecast (CEF14)
For the Years 2014/15 – 2033/34

CAPITAL EXPENDITURE FORECAST (CEF14)
(in millions of dollars)

	Total Project Cost	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	10 Year Total
Major & Base Capital												
Electric												
Generation Operations												
Pine Falls Units 1-4 Major Overhauls	142.2	7.2	0.7	14.0	26.4	29.6	40.9	-	-	-	-	118.8
Jenpeg Overhaul Program	115.9	-	-	-	-	-	-	-	-	-	2.7	2.7
Slave Falls Major Overhauls	126.1	-	-	-	-	-	2.5	2.4	19.4	18.8	19.9	63.0
Pointe du Bois GS Rehabilitation	182.9	10.1	15.4	47.0	50.0	25.2	9.8	11.2	-	-	-	168.7
Great Falls Unit 4 Overhaul	53.6	15.8	14.2	-	-	-	-	-	-	-	-	30.0
Brandon Units 6 & 7 "C" Overhaul Program	50.4	-	-	-	-	-	6.0	0.4	17.5	7.8	18.8	50.4
Base Capital	NA	98.9	101.6	71.0	55.7	77.2	72.7	118.1	97.8	110.7	98.7	902.4
Total	**NA**	**132.0**	**132.0**	**132.0**	**132.0**	**132.0**	**132.0**	**132.0**	**134.6**	**137.3**	**140.1**	**1 336.1**
Transmission												
Rockwood East 230/115kV Station	53.3	26.6	11.1	-	-	-	-	-	-	-	-	37.7
Lake Winnipeg East System Improvements	64.6	14.2	35.8	8.2	-	-	-	-	-	-	-	58.2
Letellier - St. Vital 230kV Transmission	59.0	1.3	3.7	37.0	13.9	1.6	-	-	-	-	-	57.5
Transmission Line Upgrades for NERC Alert	151.3	1.0	8.6	8.8	8.9	23.3	23.7	24.2	24.7	27.9	-	151.3
HVDC Dorsey Synchronous Condenser Refurbishment	73.3	8.7	8.5	2.7	5.2	2.2	2.3	2.4	2.7	-	-	34.7
Dorsey 230kV Phase II Zone Building	NA	-	-	-	-	-	-	-	-	-	-	-
Bipole 2 Thyristor Valve Replacement	233.7	-	-	-	2.1	13.2	22.9	56.9	57.9	59.0	21.8	233.7
Base Capital	NA	73.2	57.3	68.3	94.8	84.8	76.1	66.5	64.7	63.0	128.2	777.0
Total	**NA**	**125.0**	**125.0**	**125.0**	**125.0**	**125.0**	**125.0**	**150.0**	**150.0**	**150.0**	**150.0**	**1 350.0**

CAPITAL EXPENDITURE FORECAST (CEF14)
(in millions of dollars)

	Total Project Cost	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	10 Year Total
Customer Service & Distribution												
New Madison Station - 115/24kV Station	87.1	32.6	33.6	12.8	-	-	-	-	-	-	-	79.0
St. Vital Station - 115/24kV Station	51.3	0.3	3.0	20.0	20.0	7.9	-	-	-	-	-	51.2
Dawson Road Station - 115/24kV Station	51.8	2.5	0.5	3.0	16.5	20.0	9.3	-	-	-	-	51.8
Burrows New 66/12kV Station	54.7	2.4	-	-	-	-	-	-	-	-	-	2.4
New Adelaide Station - 66/12kV	62.1	0.7	21.2	22.9	8.8	5.0	3.4	-	-	-	-	62.0
Base Capital	NA	197.0	182.6	209.6	160.7	173.0	193.3	206.0	210.1	214.3	218.6	1 965.3
Total	**NA**	**235.5**	**240.9**	**268.3**	**206.0**	**206.0**	**206.0**	**206.0**	**210.1**	**214.3**	**218.6**	**2 211.8**
Customer Care & Energy Conservation	**NA**	**3.2**	**4.0**	**4.1**	**4.1**	**4.2**	**4.3**	**4.4**	**3.6**	**3.7**	**3.7**	**39.2**
Human Resources & Corporate Services	**NA**	**75.0**	**75.0**	**55.0**	**55.0**	**55.0**	**55.0**	**55.0**	**56.1**	**57.2**	**58.4**	**596.7**
Finance & Regulatory	**NA**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**2.2**
		570.9	**577.0**	**584.6**	**522.3**	**522.4**	**522.5**	**547.6**	**554.7**	**562.8**	**571.0**	**5 535.9**
Gas												
Customer Service & Distribution	**NA**	**34.9**	**49.0**	**34.9**	**22.3**	**21.2**	**24.4**	**26.1**	**27.7**	**30.0**	**28.3**	**298.8**
Customer Care & Energy Conservation	**NA**	**3.4**	**5.4**	**4.6**	**4.7**	**4.8**	**4.9**	**5.0**	**5.1**	**5.2**	**5.3**	**48.1**
Gas Demand Side Management	**NA**	**9.6**	**10.4**	**11.0**	**9.4**	**8.7**	**8.9**	**8.9**	**9.3**	**9.5**	**9.9**	**95.5**
		48.0	**64.9**	**50.5**	**36.3**	**34.7**	**38.1**	**39.9**	**42.0**	**44.7**	**43.4**	**442.5**
Major & Base Capital Target Adjustment	NA	-	-	25.0	25.0	25.0	25.0	25.0	-	-	-	125.0
MAJOR & BASE CAPITAL TOTAL		**618.9**	**641.9**	**660.1**	**583.7**	**582.1**	**585.6**	**612.6**	**596.7**	**607.5**	**614.4**	**6 103.4**
CONSOLIDATED CEF14 TOTAL		**2 070.6**	**2 555.8**	**3 123.6**	**3 161.5**	**2 113.0**	**1 469.6**	**1 038.7**	**792.8**	**724.1**	**724.4**	**17 774.1**
ELECTRIC CAPITAL TOTAL		**2 022.6**	**2 490.9**	**3 073.1**	**3 125.2**	**2 078.3**	**1 431.5**	**998.8**	**750.8**	**679.4**	**681.0**	**17 331.7**
GAS CAPITAL TOTAL		**48.0**	**64.9**	**50.5**	**36.3**	**34.7**	**38.1**	**39.9**	**42.0**	**44.7**	**43.4**	**442.5**

Manitoba Hydro
Consolidated Capital Expenditure Forecast (CEF14)
For the Years 2014/15 – 2033/34

CAPITAL EXPENDITURE FORECAST (CEF14)
(in millions of dollars)

	Total Project Cost	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	20 Year Total
Major New Generation & Transmission												
Wuskwatim - Generation	1 448.6	-	-	-	-	-	-	-	-	-	-	68.1
Keeyask - Generation	6 496.1	-	-	-	-	-	-	-	-	-	-	5 578.8
Grand Rapids Hatchery Upgrade & Expansion	23.5	-	-	-	-	-	-	-	-	-	-	22.6
Conawapa - Generation	397.0	-	-	-	-	-	-	-	-	-	-	95.8
Kelsey Improvements & Upgrades	340.4	-	-	-	-	-	-	-	-	-	-	37.3
Kettle Improvements & Upgrades	191.6	-	-	-	-	-	-	-	-	-	-	137.9
Pointe du Bois Spillway Replacement	574.8	-	-	-	-	-	-	-	-	-	-	169.5
Pointe du Bois - Transmission	114.3	-	-	-	-	-	-	-	-	-	-	50.9
Pointe du Bois Powerhouse Rebuild	1 852.2	-	-	-	-	-	-	0.6	2.6	19.1	45.3	67.6
Gillam Redevelopment and Expansion Program (GREP)	266.5	24.4	26.3	4.2	-	-	-	-	-	-	-	266.5
Bipole III - Transmission Line	1 655.4	-	-	-	-	-	-	-	-	-	-	1 514.0
Bipole III - Converter Stations	2 675.1	-	-	-	-	-	-	-	-	-	-	2 356.3
Bipole III - Collector Lines	260.2	-	-	-	-	-	-	-	-	-	-	227.0
Bipole III - Community Development Initiative	62.0	-	-	-	-	-	-	-	-	-	-	8.1
Riel 230/500kV Station	329.9	-	-	-	-	-	-	-	-	-	-	42.0
Manitoba-Minnesota Transmission Project	350.3	-	-	-	-	-	-	-	-	-	-	348.0
Demand Side Management	NA	47.5	48.3	47.2	47.2	48.3	50.2	52.2	54.4	56.6	58.9	1 186.9
Generating Station Improvements & Upgrades	NA	35.7	36.4	45.0	32.2	21.1	9.4	14.4	15.2	25.8	79.3	453.2
Target Adjustment (Cost Flow)	NA	0.2	(0.3)	1.4	1.8	1.2	1.1	(0.6)	(0.6)	(3.0)	(8.5)	(19.4)
MAJOR NEW GENERATION & TRANSMISSION TOTAL		**107.8**	**110.7**	**97.8**	**81.3**	**70.5**	**60.7**	**66.5**	**71.6**	**98.4**	**175.0**	**12 611.1**

Manitoba Hydro
Consolidated Capital Expenditure Forecast (CEF14)
For the Years 2014/15 – 2033/34

CAPITAL EXPENDITURE FORECAST (CEF14)
(in millions of dollars)

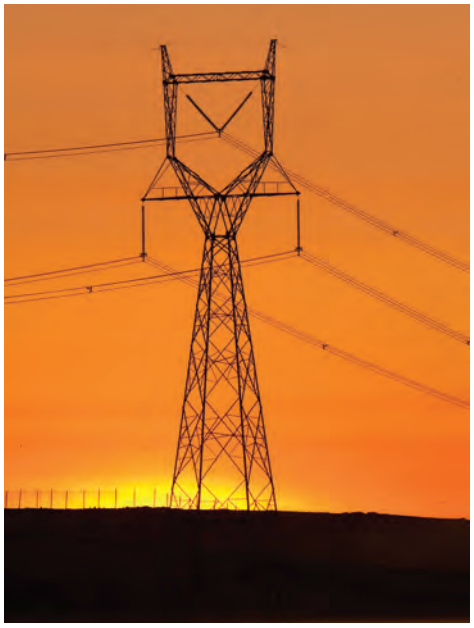
	Total Project Cost	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	20 Year Total
Major & Base Capital												
Electric												
Generation Operations												
Pine Falls Units 1-4 Major Overhauls	142.2	-	-	-	-	-	-	-	-	-	-	118.8
Jenpeg Overhaul Program	115.9	2.9	21.5	21.8	23.3	1.2	45.4	(3.4)	0.6	-	-	115.9
Slave Falls Major Overhauls	126.1	20.1	21.3	20.9	0.9	-	-	-	-	-	-	126.1
Pointe du Bois GS Rehabilitation	182.9	-	-	-	-	-	-	-	-	-	-	168.7
Great Falls Unit 4 Overhaul	53.6	-	-	-	-	-	-	-	-	-	-	30.0
Brandon Units 6 & 7 "C" Overhaul Program	50.4	-	-	-	-	-	-	-	-	-	-	50.4
Base Capital	NA	119.9	103.0	106.0	127.5	153.4	112.3	164.3	163.5	167.4	170.8	2 290.6
Total	**NA**	**142.9**	**145.7**	**148.7**	**151.6**	**154.7**	**157.8**	**160.9**	**164.1**	**167.4**	**170.8**	**2 900.6**
Transmission												
Rockwood East 230/115kV Station	53.3	-	-	-	-	-	-	-	-	-	-	37.7
Lake Winnipeg East System Improvements	64.6	-	-	-	-	-	-	-	-	-	-	58.2
Letellier - St. Vital 230kV Transmission	59.0	-	-	-	-	-	-	-	-	-	-	57.5
Transmission Line Upgrades for NERC Alert	151.3	-	-	-	-	-	-	-	-	-	-	151.3
HVDC Dorsey Synchronous Condenser Refurbishment	73.3	-	-	-	-	-	-	-	-	-	-	34.7
Dorsey 230kV Phase II Zone Building	NA	-	-	-	-	-	-	-	-	-	-	-
Bipole 2 Thyristor Valve Replacement	233.7	-	-	-	-	-	-	-	-	-	-	233.7
Base Capital	NA	153.0	156.1	159.2	162.4	165.6	168.9	172.3	175.7	179.3	182.8	2 452.3
Total	**NA**	**153.0**	**156.1**	**159.2**	**162.4**	**165.6**	**168.9**	**172.3**	**175.7**	**179.3**	**182.8**	**3 025.3**

CAPITAL EXPENDITURE FORECAST (CEF14)
(in millions of dollars)

	Total Project Cost	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	20 Year Total
Customer Service & Distribution												
New Madison Station - 115/24kV Station	87.1	-	-	-	-	-	-	-	-	-	-	79.0
St. Vital Station - 115/24kV Station	51.3	-	-	-	-	-	-	-	-	-	-	51.2
Dawson Road Station - 115/24kV Station	51.8	-	-	-	-	-	-	-	-	-	-	51.8
Burrows New 66/12kV Station	54.7	-	-	-	-	-	-	-	-	-	-	2.4
New Adelaide Station - 66/12kV	62.1	-	-	-	-	-	-	-	-	-	-	62.0
Base Capital	NA	261.6	257.8	263.3	267.2	285.6	268.1	298.7	297.6	302.6	305.3	4 773.2
Total	**NA**	**261.6**	**257.8**	**263.3**	**267.2**	**285.6**	**268.1**	**298.7**	**297.6**	**302.6**	**305.3**	**5 019.6**
Customer Care & Energy Conservation	**NA**	**3.8**	**3.9**	**4.0**	**4.1**	**4.1**	**4.2**	**4.3**	**4.4**	**4.5**	**4.6**	**81.0**
Human Resources & Corporate Services	**NA**	**59.5**	**60.7**	**61.9**	**63.2**	**64.4**	**65.7**	**67.0**	**68.4**	**69.8**	**71.1**	**1 248.6**
Finance & Regulatory	**NA**	**0.2**	**0.2**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**	**4.9**
		621.1	**624.5**	**637.3**	**648.6**	**674.7**	**665.0**	**703.5**	**710.5**	**723.8**	**734.9**	**12 279.9**
Gas												
Customer Service & Distribution	**NA**	**33.7**	**33.5**	**34.0**	**34.7**	**36.6**	**34.1**	**38.2**	**39.3**	**40.2**	**41.0**	**664.1**
Customer Care & Energy Conservation	**NA**	**5.4**	**5.5**	**5.6**	**5.7**	**5.8**	**5.9**	**6.0**	**6.2**	**6.3**	**6.4**	**106.8**
Gas Demand Side Management	**NA**	**9.6**	**9.8**	**10.0**	**5.7**	**5.7**	**5.8**	**5.8**	**5.9**	**6.0**	**6.1**	**165.9**
		48.7	**48.7**	**49.6**	**46.1**	**48.1**	**45.8**	**50.1**	**51.4**	**52.4**	**53.5**	**936.8**
Major & Base Capital Target Adjustment	NA	-	-	-	-	-	-	-	-	-	-	125.0
MAJOR & BASE CAPITAL TOTAL		**669.8**	**673.2**	**686.9**	**694.7**	**722.8**	**710.8**	**753.6**	**761.9**	**776.3**	**788.4**	**13 341.7**
CONSOLIDATED CEF14 TOTAL		**777.6**	**783.9**	**784.7**	**776.0**	**793.3**	**771.5**	**820.1**	**833.5**	**874.7**	**963.4**	**25 952.9**
ELECTRIC CAPITAL TOTAL		**728.9**	**735.1**	**735.1**	**729.9**	**745.3**	**725.7**	**770.0**	**782.2**	**822.2**	**910.0**	**25 016.1**
GAS CAPITAL TOTAL		**48.7**	**48.7**	**49.6**	**46.1**	**48.1**	**45.8**	**50.1**	**51.4**	**52.4**	**53.5**	**936.8**









Section 2

Project Summaries

Electric Operations
Major New Generation & Transmission 9

Major Capital
Generation Operations 18
Transmission 22
Customer Service & Distribution 26

Base Capital
Electric Operations
Generation Operations 29
Transmission 30
Customer Service & Distribution 31
Customer Care & Energy Conservation. . . 32
Human Resources & Corporate Services . 32
Finance & Regulatory 33
Gas Operations
Customer Service & Distribution 34
Customer Care & Energy Conservation. . . 35

Manitoba Hydro
Consolidated Capital Expenditure Forecast (CEF14)
For the Years 2014/15 – 2033/34

ELECTRIC OPERATIONS:

MAJOR NEW GENERATION & TRANSMISSION:

Wuskwatim - Generation

Description:
Design and build the new Wuskwatim generating station with three generators and installed capacity of approximately 200MW on the Burntwood River upstream of Thompson.

Justification:
This project increases generation for both export power purposes and domestic load requirements.

In-Service Date:
First power June 2012

Revision:
Cost flow revision only.

	Total	2015	2016	2017	2018	2019	2020-34
Previously Approved	$ 1 448.6	$ 23.8	$ 12.1	$ -	$ -	$ -	$ -
Increase (Decrease)	-	16.7	0.8	14.7	-	-	-
Revised Forecast	$ 1 448.6	$ 40.5	$ 12.9	$ 14.7	$ -	$ -	$ -

Keeyask - Generation

Description:
Design and build the Keeyask generating station with seven generators and nominal capacity of 695MW on the Nelson River downstream of the Kelsey generating station. Project costs also include activities necessary to obtain approval and community support to proceed with the construction of the future generating station. These costs are comprised of extensive First Nations and other community consultations, pre-project training, joint venture business developments, environmental studies, impact statement preparations, submissions, regulatory review processes, detailed pre-engineering requirements, acquiring all necessary licensing, the design and construction of associated transmission facilities, and improvements to access roadways.

Justification:
This project increases generation for export power purposes and ultimately domestic load requirements.

In-Service Date:
First power November 2019

Revision:
The Keeyask Project control budget was updated in March 2014 as part of the NFAT review of the preferred development plan. The last detailed project estimate was completed in 2009. The control budget includes bid prices from the major contractors including the General Civil Contract, current budget of the Keeyask Infrastructure Project and cost flow revisions.

	Total	2015	2016	2017	2018	2019	2020-34
Previously Approved	$ 6 220.1	$ 471.0	$ 639.3	$ 865.1	$ 1 111.4	$ 942.3	$ 1 201.1
Increase (Decrease)	276.0	305.3	37.1	97.1	239.9	(14.4)	(316.3)
Revised Forecast	$ 6 496.1	$ 776.3	$ 676.3	$ 962.2	$ 1 351.3	$ 927.9	$ 884.8

Manitoba Hydro
Consolidated Capital Expenditure Forecast (CEF14)
For the Years 2014/15 – 2033/34

Grand Rapids Hatchery Upgrade and Expansion

Description:
Expand the capacity of the existing facility through tank replacement/reconfiguration and upgrade of supporting water treatment infrastructure. Modifications to the Research Centre (a separate facility on the GRH site), including well and potable water supply, to serve as a temporary production facility during hatchery upgrade and expansion, and the purchase of portable satellite facilities to allow for fish rearing during hatchery construction. Install electrical service from Grand Rapids Generating Station service to the hatchery.

Justification:
Upgrades to the Grand Rapids hatchery are a requirement of the Keeyask Environment Act licence as well as recently introduced national and provincial regulatory requirements for water quality and biosecurity.

In-Service Date:

March 2018

Revision:
New item.

	Total	2015	2016	2017	2018	2019	2020-34
Previously Approved	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Increase (Decrease)	23.5	1.9	4.7	9.3	6.8	-	-
Revised Forecast	$ 23.5	$ 1.9	$ 4.7	$ 9.3	$ 6.8	$ -	$ -

Conawapa - Generation

Description:
Design and build the Conawapa generating station with ten generators and nominal capacity of 1 485MW on the Nelson River downstream of the Limestone generating station. Project costs also include activities associated with extensive First Nations and other community consultations, pre-project training, environmental studies, impact statement preparations, submissions, regulatory review processes, acquiring all necessary licensing, improvements to access roadways, and detailed pre-engineering required to obtain a license and all necessary approvals to construct the Conawapa generating station.

Justification:
This project increases generation for export power purposes and ultimately domestic load requirements.

In-Service Date:
Under review pending re-evaluation of the business case.

Revision:
Majority of expenditures have been suspended pending re-evaluation of the business case. Remaining expenditures are for the wrap up of preliminary engineering studies and limited environmental and aboriginal studies including capitalized interest on construction in process through August 2016.

	Total	2015	2016	2017	2018	2019	2020-34
Previously Approved	$ 10 491.5	$ 70.1	$ 125.9	$ 99.4	$ 240.6	$ 308.1	$ 9 317.0
Increase (Decrease)	(10 094.5)	(26.7)	(94.5)	(78.4)	(240.6)	(308.1)	(9 317.0)
Revised Forecast	$ 397.0	$ 43.4	$ 31.4	$ 21.0	$ -	$ -	$ -

Manitoba Hydro
Consolidated Capital Expenditure Forecast (CEF14)
For the Years 2014/15 – 2033/34

Kelsey Improvements & Upgrades

Description:
Overhaul and uprate all seven Kelsey generating station units including the replacement of turbine runners, bottom rings, discharge rings or weld overlays, transformers, generator windings and exciters. Perform model testing to refine runner design, perform extensive intake gate rehabilitation, perform draft tube modifications, perform an 8 000 hour inspection, and upgrade rail spur and overhead crane. Upgrade transmission facilities necessary to integrate the additional Kelsey generation into the Manitoba Hydro system network.

Justification:
Rerunnering presents the best economic solution for increasing efficiency at the Kelsey generating station and for adding system capacity without flooding or requiring a new water power license. Overhauling the units will improve the unit output by up to 11MW per unit. The transmission upgrade of a portion of the Kelsey 138 and 230kV buses and the revisions to the Northern AC Cross Trip scheme are required to accommodate the 77MW of additional Kelsey output.

In-Service Date:
October 2016

Revision:
In July 2013, the overhauls on all seven units had been completed and placed back in-service. Significant work remains to fix deficiencies on the head covers of all the units to improve safety and reliability. Wastewater treatment upgrades, required to accommodate the increased workforce during the overhauls, was higher than anticipated due the original design not meeting environmental limits. Final In-service date deferred 26 months from August 2014.

	Total	2015	2016	2017	2018	2019	2020-34
Previously Approved	$ 301.7	$ 2.2	$ -	$ -	$ -	$ -	$ -
Increase (Decrease)	39.0	11.9	9.1	12.9	1.3	-	-
Revised Forecast	$ 340.4	$ 14.1	$ 9.1	$ 12.9	$ 1.3	$ -	$ -

Kettle Improvements & Upgrades

Description:
Rewind stator for units 5-12 and install a new stator frame, core and winding for units 1-4. Perform rotor refurbishment, thrust runner replacement, new excitation transformers, rebabbitting of bearings, excitation upgrade replacements, control and protection system replacements, mechanical systems replacements, and intake gate and wicket gate work for units 1-4.

Justification:
The stator windings at Kettle are polyester bonded mica which is prone to internal degradation as a result of thermal and electrical stresses. There has been a much higher failure rate for stator coils at Kettle than in any of our other generators installed since 1960. Analysis of the internal conditions of the insulation system is ongoing. Re-wedging units at Kettle is an opportunity to repair isolated cases of severe slot discharge, necessary to avoid deterioration. Unit 4 requires repairs due to an incident that occurred in August 2006, where a top clamping finger on the unit broke off and fell into the air gap causing extensive damage to the windings and core.

In-Service Date:
March 2026

Revision:
To reflect final costs for Unit 4, including scope increase for thrust runner replacement, new excitation transformer, re-babbiting of bearings and removal and disposal of the old stator for units 1-4.

	Total	2015	2016	2017	2018	2019	2020-34
Previously Approved	$ 165.7	$ 7.7	$ 23.7	$ 17.3	$ 1.0	$ 31.7	$ 29.5
Increase (Decrease)	25.9	(1.1)	(0.2)	7.3	21.0	-	(0.0)
Revised Forecast	$ 191.6	$ 6.6	$ 23.5	$ 24.6	$ 22.0	$ 31.7	$ 29.5

Manitoba Hydro
Consolidated Capital Expenditure Forecast (CEF14)
For the Years 2014/15 – 2033/34

Pointe du Bois Spillway Replacement

Description:
Design and build a new spillway and new concrete and earth fill dams to replace the existing spillway structures. Includes engineering and environmental studies, community consultation, obtaining regulatory approval, and de-commissioning the existing spillway.

Justification:
Pointe du Bois does not currently meet dam safety guidelines with respect to spillway capacity. A new spillway is required to meet these guidelines.

In-Service Date:
October 2015

Revision:
Deferred spillway in-service due to a late start to concrete placement, lower than planned productivity pushing concrete work into winter months and increased gate installation time. In addition to the delay in the spillway in-service, dam placement activities were suspended due to the late spring melt and higher than average precipitation flows on the Winnipeg River. As a result, final in-service date deferred one year from October 2014.

	Total	2015	2016	2017	2018	2019	2020-34
Previously Approved	$ 559.6	$ 125.3	$ 5.5	$ -	$ -	$ -	$ -
Increase (Decrease)	15.0	(11.2)	46.1	3.8	-	-	-
Revised Forecast	$ 574.8	$ 114.1	$ 51.6	$ 3.8	$ -	$ -	$ -

Pointe du Bois - Transmission

Description:
Redevelop Stafford Terminal station (formerly Scotland station), replace Bank 7 at Pointe du Bois switchyard station, salvage 66kV P lines between Pointe du Bois and Rover stations, install a 115kV transmission line between Pointe du Bois and Whiteshell stations, add Bank 8 to Pointe du Bois switchyard, install a 66kV line between Ridgeway and Rover stations, and upgrade protection at Slave Falls switchyard station.

Justification:
The 66kV lines P1, P2, P3, and P4 between Pointe du Bois and Rover stations have exceeded their expected serviceable life and pose threats to public and employee safety. The reliability of the transmission system in the Winnipeg Central area has been degraded due to the poor physical condition of these lines. In order to successfully operate the power system and continuously deliver high quality power to our customers and protect the public, the P Lines should be removed. The rebuild of Stafford station is required to address due diligence concerns, including Manitoba Hydro grounding and switching standards and public safety, and to increase Winnipeg Central capacity. This work involves converting the 138kV system to 115kV, so work at Pointe du Bois is also required.

In-Service Date:
December 2017

Revision:
Cost flow revision only.

	Total	2015	2016	2017	2018	2019	2020-34
Previously Approved	$ 114.3	$ 8.6	$ 12.3	$ 21.9	$ 7.4	$ -	$ -
Increase (Decrease)	-	7.2	4.8	(8.2)	(3.1)	-	-
Revised Forecast	$ 114.3	$ 15.8	$ 17.1	$ 13.8	$ 4.3	$ -	$ -

Gillam Redevelopment and Expansion Program (GREP)

Description:
Redevelop and expand the Town of Gillam infrastructure in Phases 1B, 2 and 3. Phases 2 & 3 will require further definition based on conceptual design and the requirement of Manitoba Hydro's construction of new facilities in the North.

Justification:
Redevelopment of the Town of Gillam is required to address existing operational needs and to prepare for the growth associated with new generation facilities. The GREP will improve the overall quality of infrastructure in Gillam, which will positively affect attraction and retention for existing and new generation facilities. The GREP supports Corporate initiatives to develop the hydroelectric potential of the Lower Nelson River.

In-Service Date:
March 2027

Revision:
A re-evaluation of the project resulted in cost reductions due to optimization of the project through a redesign of the town centre, residential site development, trailer park and industrial park as well as a re-analysis of customer requirements resulting in a reduction in scope of work.

	Total	2015	2016	2017	2018	2019	2020-34
Previously Approved	$ 366.5	$ 27.0	$ 30.2	$ 30.5	$ 29.5	$ 27.9	$ 221.3
Increase (Decrease)	(100.0)	(7.0)	(7.8)	(7.8)	(7.8)	(7.7)	(62.0)
Revised Forecast	$ 266.5	$ 20.0	$ 22.4	$ 22.8	$ 21.8	$ 20.2	$ 159.3

Bipole III - Transmission Line

Description:
Design and build a +/- 500kV HVdc transmission line of approximately 1 341km (west of Lakes Winnipegosis & Manitoba) from Riel Converter Station to Keewatinohk Converter Station. Conduct environmental impact assessment, acquire property, and obtain licensing necessary for a +/- 500kV DC transmission line and converter stations at Riel and Keewatinohk.

Justification:
Provides increased reliability to the Manitoba Hydro system due to the critical risk to the Province and the Corporation of not mitigating an Interlake (Bipole 1 and 2) corridor outage or a Dorsey station common mode outage. In normal steady state operation, it will also provide an increase in southern power, due to decreased line losses (approximately 76MW under full existing generation). The rating for Bipole III was increased from 2000MW to 2300MW to ensure adequate spare HVdc transmission on the northern collector system. The increased rating ensures future generation can be transmitted via Bipole I, Bipole II and Bipole III in the event of a single valve group outage.

In-Service Date:
July 2018

Revision:
The revised estimate incorporates a more detailed scope based on an issued environment act licence, approved finalized route and right-of-way width, as well as up-to-date market information. The project licence and permits were received later than planned, resulting in 1.5 lost winter seasons of 5 total planned. The estimate is based on the need for at least 4 more winter seasons to construct the transmission line. Project in-service date deferred nine months from October 2017.

	Total	2015	2016	2017	2018	2019	2020-34
Previously Approved	$ 1 259.9	$ 265.9	$ 381.9	$ 263.7	$ 195.2	$ -	$ -
Increase (Decrease)	395.5	(62.4)	(21.5)	117.3	298.6	75.3	-
Revised Forecast	$ 1 655.4	$ 203.5	$ 360.5	$ 381.0	$ 493.8	$ 75.3	$ -

Manitoba Hydro
Consolidated Capital Expenditure Forecast (CEF14)
For the Years 2014/15 – 2033/34

Bipole III - Converter Stations

Description:
Design and build an HVdc converter station with a rating of 2300MW at the proposed Keewatinohk (Keewatinoow) site, including property acquisition costs and the Keewatinohk 230kV AC switch yard. Design and build an HVdc converter station with 2300MW of converters at Riel, including four LCC HVdc synchronous condensers, property acquisition costs and expansion of the Riel 230kV AC switch yard.

Justification:
Provides increased reliability to the Manitoba Hydro system due to the critical risk to the Province and the Corporation of not mitigating an Interlake (Bipole I and II) corridor outage or a Dorsey station common mode outage. The rating for Bipole III was increased from 2000MW to 2300MW to ensure adequate spare HVdc transmission on the northern collector system. The increased rating ensures future generation can be transmitted via Bipole I, Bipole II and Bipole III in the event of a single valve group outage.

In-Service Date:
July 2018

Revision:
The selection of LCC technology has resulted in synchronous condensers being included in the revised estimate. Additionally, the awarded contract prices for the Keewatinohk Camp, Keewatinohk Site Development and the Keewatinohk 230kV AC Switchyard have been incorporated into the revised estimate. The rating for Bipole III was increased from 2000MW to 2300MW to ensure adequate spare HVdc transmission on the northern collector system. Project in-service date deferred nine months from October 2017.

	Total	2015	2016	2017	2018	2019	2020-34
Previously Approved	$ 1 828.5	$ 262.6	$ 493.2	$ 410.2	$ 181.5	$ 127.4	$ -
Increase (Decrease)	846.6	(41.6)	87.6	418.5	326.1	67.7	23.0
Revised Forecast	$ 2 675.1	$ 221.1	$ 580.8	$ 828.7	$ 507.7	$ 195.1	$ 23.0

Bipole III - Collector Lines

Description:
Design and construct three permanent and two temporary 230kV collector lines for the Keewatinohk Converter Station. Construct power substation for the Keewatinohk Converter Station, 138 kV line, microwave tower, and distribution feeders for the Keewatinohk Converter Station. Design and construct the Riel and Keewatinohk electrode lines, sectionalize the 230kV transmission line R49R at Riel. Includes the property acquisition and/or easements for the collector lines and the electrode lines. Design and construct a new bay and modify existing Long Spruce 230 KY AC switchyard for the new collector line to Keewatinohk Converter Station. Design and construction of a new bay and modifications at existing Henday 230 KY AC switchyard for the four new collector lines to Keewatinohk Converter Station. Design and construction of breaker replacements at existing stations (Ridgeway, Rosser, and McPhillips) for Bipole III.

Justification:
Provides increased reliability to the Manitoba Hydro system due to the critical risk to the Province and the Corporation of not mitigating an Interlake (Bipole 1 and 2) corridor outage or a Dorsey station common mode outage.

In-Service Date:
July 2018

Revision:
The revised estimate incorporates a more detailed scope including double circuit for one collector line, increased reliability design for electrode lines, updated assumptions for direct negotiated clearing and construction contracts based on an issued environment act licence and increased scope for Long Spruce and Henday switchyard additions and breaker replacements at existing stations. Project in-service date deferred nine months from October 2017.

	Total	2015	2016	2017	2018	2019	2020-34
Previously Approved	$ 191.4	$ 63.5	$ 46.2	$ 37.7	$ 8.5	$ -	$ -
Increase (Decrease)	69.0	(5.0)	29.4	14.0	28.2	4.7	-
Revised Forecast	$ 260.2	$ 58.4	$ 75.5	$ 51.7	$ 36.7	$ 4.7	$ -

Manitoba Hydro
Consolidated Capital Expenditure Forecast (CEF14)
For the Years 2014/15 – 2033/34

Bipole III - Community Development Initiative

Description:
Establishment of an obligation for a Community Development Initiative to provide benefits to First Nations, Community Councils, rural Municipalities and incorporated Towns and Villages within the vicinity of the Bipole III Project.

Justification:
Manitoba Hydro is responding to community feedback seeking longer term benefits for communities in proximity to high voltage transmission facilities. These funds will be available for community development projects that benefit a broad segment of eligible communities.

In-Service Date:
July 2018

Revision:
Net Present Value calculation increased due to the nine month in-service deferral from October 2017.

	Total	2015	2016	2017	2018	2019	2020-34
Previously Approved	$ 60.8	$ 2.2	$ 2.0	$ 1.8	$ 0.9	$ -	$ -
Increase (Decrease)	1.2	0.1	(0.0)	0.0	0.7	0.5	-
Revised Forecast	$ 62.0	$ 2.3	$ 2.0	$ 1.8	$ 1.6	$ 0.5	$ -

Riel 230/500kV Station

Description:
Conduct environmental impact assessment and obtain licensing necessary for the Riel 230/500kV station. Design and construct a 230/500kV station at the Riel site including the installation of a 230kV bus with a maximum of five Bays, the installation of a 500kV ring bus, the installation of a 230/500kV 1200MVA transformer bank using two 230kV and one 500kV breaker, and the installation of 500kV line reactors with relocating of a reactor phase from Dorsey. Install a second reactor phase from Dorsey as a spare at Riel after the Riel reactors are in-service and salvage the third reactor phase at Dorsey. Sectionalize two 230kV transmission lines R32V and R33V into Riel station using eight 230kV breakers and associated equipment resulting in two Riel-Ridgeway and two Riel-St. Vital transmission lines. Sectionalize 500kV transmission line D602F into Riel station using two 500kV breakers and associated equipment resulting in Dorsey-Riel and Riel-Forbes 500kV circuits.

Justification:
The sectionalization of the 500kV line allows power to be imported during a catastrophic Dorsey outage, as well as an alternate path for power export during a Dorsey transformer outage.

In-Service Date:
October 2014

Revision:
Cost flow revision only.

	Total	2015	2016	2017	2018	2019	2020-34
Previously Approved	$ 329.9	$ 40.8	$ 0.7	$ -	$ -	$ -	$ -
Increase (Decrease)	-	(4.4)	4.9	-	-	-	-
Revised Forecast	$ 329.9	$ 36.4	$ 5.6	$ -	$ -	$ -	$ -

Manitoba-Minnesota New 500kV Transmission Line

Description:
Design, construct and commission a 235km 500kV AC single-circuit transmission line from Dorsey Station to the US border. Design and install one 500kV breaker, one 150MVAr 500kV shunt reactor, one double-wye ungrounded 46kV 73.4MVAr shunt capacitor bank and associated communications and protection at Dorsey. Design and install two 500kV breakers, one 230kV breaker, two double-wye ungrounded 46kV 73.4MVAr shunt capacitor banks, a 1 200MVA 230/500kV autotransformer and associated communications and protection at Riel. Acquire property for right-of-way, conduct environmental impact assessment, conduct community consultations, obtain licensing and perform environmental monitoring for all new facilities. Design, procure and install a new 300MVA phase shifter at Glenboro Station and re-align the transmission lines at the Glenboro Station to accommodate the new transformer.

Justification:
Power sale term sheets have been negotiated with Minnesota Power (250MW) and Wisconsin Public Service (300MW). The existing tie line capacity is insufficient to accommodate the additional sales and therefore a new export line is needed. The proposed transmission facilities will increase the Manitoba to U.S. transfer capability for both export and import purposes.

In-Service Date:
May 2020

Revision:
Cost flow revision and in-service date deferred seven months from October 2019.

	Total	2015	2016	2017	2018	2019	2020-34
Previously Approved	$ 350.3	$ 3.8	$ 29.7	$ 101.1	$ 58.7	$ 63.5	$ 91.8
Increase (Decrease)	-	3.2	3.0	(1.5)	0.7	2.2	(8.3)
Revised Forecast	$ 350.3	$ 7.0	$ 32.7	$ 99.6	$ 59.5	$ 65.7	$ 83.5

Firm Import Upgrades

Description:
Reconductor and resag transmission lines SC25, WT34, and SM26, and replace risers and/or current transformers for stations at Whiteshell, Ridgeway, Transcona, and Parkdale.

Justification:
This project will increase to 100MW Manitoba Hydro's firm import capability from Ontario. Increasing the transmission capability will permit greater volume of energy imports during periods when additional energy may be required.

In-Service Date:
Cancelled.

Revision:
Project cancelled. Since the project was initially approved in 2008 and additional funding approved in 2011, market and corporate conditions have changed, and this import upgrade is no longer a priority considering the capital needs for major projects which must be undertaken. This project is not required for reliability or safety, and its cancellation will not negatively impact financial projections.

	Total	2015	2016	2017	2018	2019	2020-34
Previously Approved	$ 19.9	$ 10.8	$ 8.9	$ -	$ -	$ -	$ -
Increase (Decrease)	(19.9)	(10.8)	(8.9)	-	-	-	-
Revised Forecast	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Demand Side Management

Description:
Design, implement and deliver incentive based PowerSmart conservation programs to reduce electricity consumption in Manitoba.

Justification:
The electric Demand Side Management plan is cost effective as a resource option and is included in Manitoba Hydro's Power Resource Plan (PRP). The DSM plan provides customers with exceptional value through the implementation of cost-effective energy conservation programs that are designed to minimize the total cost of energy services to customers, position the Corporation as a national leader in implementing cost-effective energy conservation and alternative energy programs, protect the environment and promote sustainable energy supply and service.

In-Service Date:
Ongoing.

Revision:
Revisions to energy saving and expenditures for a number of programs to reflect current market information and designed to aggressively pursue cost-effective market-achievable savings. It is assumed that upon adoption of IFRS in 2015/16, the demand side management programs will continue to be capitalized, under the interim standard that continues to permit rate-regulated accounting.

	Total	2015	2016	2017	2018	2019	2020-34
Previously Approved	NA	$ 25.3	$ 24.6	$ 23.9	$ 22.6	$ 21.7	$ 266.9
Increase (Decrease)		26.5	34.6	52.7	61.3	72.0	555.0
Revised Forecast	NA	$ 51.8	$ 59.2	$ 76.6	$ 83.9	$ 93.7	$ 821.9

Manitoba Hydro
Consolidated Capital Expenditure Forecast (CEF14)
For the Years 2014/15 – 2033/34

MAJOR CAPITAL:

GENERATION OPERATIONS:

Pine Falls Units 1-4 Major Overhauls

Description:
Rehabilitation, replacement of and addition to various equipment such as generator re-wind, stator radial keys, breakers, cooling radiators, instrument transformers, unit control & monitoring systems, excitation system upgrades, governor upgrades, meter upgrades, and powerhouse crane refurbishment. Replace unit 1-4 turbine runners with more efficient new design runners, rebuild existing servomotors for increased wicket gate opening allowing more discharge, and rewind the generator stators utilizing modern insulating materials. Conduct a model test and up-rate study.

Justification:
Assessment of the mechanical systems has identified concerns in terms of obsolete equipment, safety, fire risk and adaptability to present day operating conditions and standards. Upgrading is necessary to ensure reliable safe and economical operation. Pine Falls consistently spills more water than the other Winnipeg River plants. Additional generation can be obtained (approximately 17%) with increased discharge capability. Tests have confirmed that the two stator windings are in danger of failure at any time.

In-Service Date:
September 2019

Revision:
Cost flow revision and in-service date deferred five months from April 2019.

	Total	2015	2016	2017	2018	2019	2020-34
Previously Approved	$ 142.2	$ 8.0	$ 5.0	$ 21.9	$ 30.2	$ 27.0	$ 16.0
Increase (Decrease)	-	(0.8)	(4.3)	(7.9)	(3.8)	2.6	24.9
Revised Forecast	$ 142.2	$ 7.2	$ 0.7	$ 14.0	$ 26.4	$ 29.6	$ 40.9

Jenpeg Overhaul Program

Description:
Major overhaul of all six generating units to inspect, repair, modify, and replace components of the turbine/ generator. Areas of concern include journal bearings, thrust bearings, turbine seals, servo motors, wicket gate seals and bushings, waterhead and oil head, stator and rotor, and auxiliary systems.

Justification:
A complete overhaul is required to ensure reliable operation of the units when maximum power requirements on the system are essential.

In-Service Date:
December 2031.

Revision:
None.

	Total	2015	2016	2017	2018	2019	2020-34
Previously Approved	$ 115.9	$ -	$ -	$ -	$ -	$ -	$ 115.9
Increase (Decrease)	-	-	-	-	-	-	-
Revised Forecast	$ 115.9	$ -	$ -	$ -	$ -	$ -	$ 115.9

Slave Falls Major Overhauls

Description:
Perform major overhaul for all eight units at Slave Falls generating station, including spillway improvements/ replacements, excitation upgrades, the addition of a Unit Control and Monitoring System (UCMS) Framework, access road upgrades, and a new walkway across the spillway.

Justification:
Many safety, reliability, environmental, efficiency, operational & dam safety issues have been identified relating to the Slave Falls infrastructure. Extensive repairs, modifications and/or replacements will be required to ensure the serviceability of the plant and spillway infrastructure. Economics of this work may suggest that a new spillway be constructed to replace existing spill infrastructure. Current operating procedures include ice load reduction activites at the spilling structures to ensure structural stability. A dam safety concern has been identified with respect to the minimal remote spilling capability at Slave Falls.

In-Service Date:
September 2027.

Revision:
In-service date deferred six years from September 2021.

	Total	2015	2016	2017	2018	2019	2020-34
Previously Approved	$ 126.1	$ 0.2	$ 0.9	$ 5.3	$ 26.6	$ 30.3	$ 62.9
Increase (Decrease)	-	(0.2)	(0.9)	(5.3)	(26.6)	(30.3)	63.3
Revised Forecast	$ 126.1	$ -	$ -	$ -	$ -	$ -	$ 126.1

Water Licenses & Renewals

Description:
Conduct hydraulic studies, geotechnical assessments, property status and severance line determinations, mapping, license documentation, environmental reviews, and community informational sessions necessary to secure license finalization and/or renewals for the Corporation's hydraulic plants.

Justification:
All hydraulic generating facilities must be authorized under water power licenses and these licenses need to be clearly in force to significantly reduce risk exposure, maintain operating flexibility, maximize export revenues, and contribute to financial strength.

In-Service Date:
Various

Revision:
This item is made up of numerous License Finalizations, Renewals and other programs included to proactively protect the environment and contribute to the corporation's sustainable development principles. It is considered an on-going program cost therefore the budget is now included in Generation Operations Base Target.

	Total	2015	2016	2017	2018	2019	2020-34
Previously Approved	NA	$ 7.0	$ 7.0	$ 6.5	$ 2.4	$ -	$ -
Increase (Decrease)	NA	(7.0)	(7.0)	(6.5)	(2.4)	-	-
Revised Forecast	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Manitoba Hydro
Consolidated Capital Expenditure Forecast (CEF14)
For the Years 2014/15 – 2033/34

Pointe du Bois GS Rehabilitation

Description:
Implement safety upgrades for the Pointe du Bois generating station including fire protection, mechanical hazards, electrical hazards, operational hazards, trips and fall hazards, and various other safety upgrades. Additionally, implement turbine and generator, equipment and civil rehabilitation and upgrades.

Justification:
To provide a high level of health and safety upgrades as well as improved reliability and control, along with a reduction in potential environmental impacts from catastrophic events such as fire or flooding. The plan provides the most economical solution to operate the generating station for an additional twenty years.

In-Service Date:
March 2021

Revision:
Cost flow revision and advanced in-service date five years and four months from July 2026.

	Total	2015	2016	2017	2018	2019	2020-34
Previously Approved	$ 182.9	$ 10.3	$ 15.3	$ 21.7	$ 19.5	$ 20.4	$ 81.5
Increase (Decrease)	-	(0.2)	0.1	25.3	30.5	4.8	(60.5)
Revised Forecast	$ 182.9	$ 10.1	$ 15.4	$ 47.0	$ 50.0	$ 25.2	$ 21.0

Great Falls Unit 4 Overhaul

Description:
Major overhaul to generating Unit 4 including generator rewind, turbine re-runnering, new water passage embedded components, one 3-phase unit transformer, and modernization of components.

Justification:
The re-runnering and major overhaul will provide an opportunity to upgrade/modernize the unit while taking advantage of an already planned outage for the intake gates. The re-runnering will add both capacity and efficiency. The existing transformer is in poor condition and water passage components are starting to fail. The overhaul will increase reliability and extend the asset life by 40 to 50 years.

In-Service Date:
August 2015.

Revision:
Cost flow revision only.

	Total	2015	2016	2017	2018	2019	2020-34
Previously Approved	$ 53.6	$ 16.5	$ 11.9	$ -	$ -	$ -	$ -
Increase (Decrease)	-	(0.8)	2.3	-	-	-	-
Revised Forecast	$ 53.6	$ 15.8	$ 14.2	$ -	$ -	$ -	$ -

Brandon Units 6 & 7 "C" Overhaul Program

Description:
Perform C inspections/overhauls of the Brandon gas turbines Unit 6 & 7 when each of them acquires 24,000 Equivalent Operating Hours (EOH).

Justification:
The reliability of the hot gas path components cannot be predicted after 24,000 EOH. Failure of hot gas path parts could lead to significant collateral damage and an extended forced outage of the units.

In-Service Date:
March 2024.

Revision:
None.

	Total	2015	2016	2017	2018	2019	2020-34
Previously Approved	$ 50.4	$ -	$ -	$ -	$ -	$ -	$ 50.4
Increase (Decrease)	-	-	-	-	-	-	-
Revised Forecast	$ 50.4	$ -	$ -	$ -	$ -	$ -	$ 50.4

Manitoba Hydro
Consolidated Capital Expenditure Forecast (CEF14)
For the Years 2014/15 – 2033/34

TRANSMISSION:

Rockwood East 230/115kV Station

Description:
Design and construct a new 230/115kV Rockwood East Station adjacent to 230kV circuits A3R (Ashern-Rosser) and S65R (Silver-Rosser) including associated equipment, protection, control and communication systems. Sectionalize and extend 230kV and 115kV transmission lines as required and provide communication and protection upgrades.

Justification:
Construction of the Rockwood East Station with three 115kV line terminations would alleviate the overload scenarios for Rosser 230/115kV Banks 2 and 4 and for 115kV circuits CR4 or CR2 between Rosser and Parkdale Stations. It would also increase the 115kV capacity in the Rosser/Parkdale/Selkirk area. The existing Parkdale 115/66kV Station switchyard has very limited opportunity for adding new capacity due to the station's poor condition and limited space.

In-Service Date:
November 2015.

Revision:
Cost flow revision only.

	Total	2015	2016	2017	2018	2019	2020-34
Previously Approved	$ 53.3	$ 29.1	$ 8.6	$ -	$ -	$ -	$ -
Increase (Decrease)	-	(2.5)	2.5	-	-	-	-
Revised Forecast	$ 53.3	$ 26.6	$ 11.1	$ -	$ -	$ -	$ -

Lake Winnipeg East System Improvements

Description:
Build a new 115/66kV Manigotagan Corner Station complete with two 6OMVA transformers, a new 65km, 115kV transmission line from Pine Falls Station to Manigotagan Corner Station and the associated terminations and communications.

Justification:
Pine Falls Station currently operates over firm transformation during winter peak. The absence of firm transformation would cause customer outages in the Lake Winnipeg East area during a Pine Falls transformer outage. The outage would last greater than a week until a spare transformer could be brought in from Winnipeg and connected. A transformer outage would affect more than 1,300 permanent customers and more than 13,000 seasonal (summer) customers. Deferral will place customers at risk of no supply. The new 115/66kV Manigotagan Corner Station and Pine Falls – Manigotagan Corner 115kV Transmission Line will provide firm capacity for area load for the next 20 years, as well as enable the Bloodvein SVC to control effectively the voltage at Bloodvein, Little Grand Rapids, Beren's River and Poplar River for the next 20 years. It also reduces the loading on Pine Falls 115/66kV Station, thereby accommodating load growth in the Victoria Beach, Grand Beach and Bissett areas.

In-Service Date:
October 2016

Revision:
Cost flow revision and in-service date deferred eleven months from November 2015.

	Total	2015	2016	2017	2018	2019	2020-34
Previously Approved	$ 64.6	$ 30.0	$ 17.2	$ 0.0	$ -	$ -	$ -
Increase (Decrease)	-	(15.7)	18.6	8.2	-	-	-
Revised Forecast	$ 64.6	$ 14.2	$ 35.8	$ 8.2	$ -	$ -	$ -

Manitoba Hydro
Consolidated Capital Expenditure Forecast (CEF14)
For the Years 2014/15 – 2033/34

Letellier - St. Vital 230kV Transmission

Description:
Design and construct a new 230kV line from Letellier Station to St. Vital Station including associated terminations and communications. Includes environmental licensing and monitoring, and property rights acquisition.

Justification:
The supply to Letellier Station must be improved in order to overcome the contingency loading and low voltage problems in the south central area of Manitoba caused by load growth, as well as to maintain export levels on the 230kV Tie Line L20D (Letellier to Drayton) at these increased loads.

In-Service Date:
July 2017

Revision:
Cost flow revision and an eleven month deferral from August 2016.

	Total	2015	2016	2017	2018	2019	2020-34
Previously Approved	$ 59.0	$ 3.0	$ 34.9	$ 18.1	$ 1.6	$ -	$ -
Increase (Decrease)	-	(1.7)	(31.2)	18.9	12.3	1.6	-
Revised Forecast	$ 59.0	$ 1.3	$ 3.7	$ 37.0	$ 13.9	$ 1.6	$ -

Transmission Line Upgrades for NERC Alert

Description:
This project consists of a nine year program to upgrade over 1000 transmission line spans to meet CSA Standards for line clearance. A priority listing of the transmission lines and spans requiring mitigation will be developed based on assessment work considering operational and safety risks specific to each line/span.

Justification:
This program addresses discrepancies between the design ratings and actual field ratings of transmission lines thereby ensuring continued reliability and operation of the electrical system as well as mitigating risks to public safety due to insufficient line clearance.

In-Service Date:
March 2023.

Revision:
Cost flow revision only.

	Total	2015	2016	2017	2018	2019	2020-34
Previously Approved	$ 151.3	$ 1.1	$ 8.9	$ 9.0	$ 9.1	$ 23.7	$ 99.5
Increase (Decrease)	-	(0.1)	(0.2)	(0.2)	(0.2)	(0.4)	1.1
Revised Forecast	$ 151.3	$ 1.0	$ 8.6	$ 8.8	$ 8.9	$ 23.3	$ 100.6

HVDC Dorsey Synchronous Condenser Refurbishment

Description:
For all nine (9) Synchronous Condensers at Dorsey, project includes major mechanical refurbishment consisting of re-wedging the stator, refurishment of bearings, rotor, and poles, and replacement of protection and control cubicles, Motor Control Center (MCC), excitation system and cables. Other work includes replacing the H2/CO2 ventilation and detection systems (except SC9Y), vibration monitoring, pony motor brushgear, and liquid mixing valves.

Justification:
Synchronous condensers are required for proper operation of the HVDC system, voltage regulation of the southern AC system and to provide reactive power for power export to the United States. A major inspection and overhaul of each machine is necessary to prevent catastrophic failure, involving the rotors and rotor bolts as indicated by the failures of SC12Y in 1987 and SC11Y in 1988. The cost of repairing a failure when combined with the inability to export power will well exceed the cost of major inspection and overhaul.

In-Service Date:
October 2021.

Revision:
Cost flow revision and in-service date deferred two years from October 2019.

	Total	2015	2016	2017	2018	2019	2020-34
Previously Approved	$ 73.3	$ 7.9	$ 8.9	$ 8.5	$ 5.9	$ 3.4	$ 0.8
Increase (Decrease)	-	0.8	(0.4)	(5.8)	(0.7)	(1.2)	6.6
Revised Forecast	$ 73.3	$ 8.7	$ 8.5	$ 2.7	$ 5.2	$ 2.2	$ 7.3

Dorsey 230kV Phase II Zone Building

Description:
Construction and equipping of two new zone buildings and refurbishing of the existing relay building and equipment. This project also includes installing and replacing various pieces of equipment and modifications to the switchyard.

Justification:
Construction of two new hardened relay buildings plus the hardening and conversion of the existing relay building is the most cost effective and practical option. This approach segregates the 230kV switchyard into three sections, providing for the majority of the 230kV switchyard to remain operational following the loss of a zone building. This meets Manitoba Hydro's system restoration criteria.

In-Service Date:
Cancelled

Revision:
Item cancelled. The Phase I improvements to Dorsey's 230kV Relay Building have significantly reduced the risk of catastrophic failure caused by severe weather and/or fire. The building has been fortified to withstand an F3 category tornado and the implemented fire mitigation measures have reduced the probability of a major fire with the Relay Building by greater than 200 times. These enhancements combined with the future addition of Bipole III have reduced the risks sufficiently to eliminate the need for Phase II.

	Total	2015	2016	2017	2018	2019	2020-34
Previously Approved	NA	$ -	$ -	$ 0.4	$ 16.5	$ 33.2	$ 13.3
Increase (Decrease)	-	-	-	(0.4)	(16.5)	(33.2)	(13.3)
Revised Forecast	NA	$ -	$ -	$ -	$ -	$ -	$ -

Bipole 2 Thyristor Valve Replacement

Description:
Removal of the existing eight (8) thyristor valve groups and their controls, and replace them with eight new de-ionized water cooled HVDC thyristor valve groups and controls.

Justification:
The Bipole 2 thyristor valves and controls are nearing the end of their useful life and require replacement. Replacing the existing thyristor valve groups and controls with new ones will result in reducing the probability of forced outages. This will result in a significant decrease in failures, reduce maintenance requirements, and generally improved reliability for Bipole 2.

In-Service Date:
October 2023

Revision:
Cost flow revision only.

	Total	2015	2016	2017	2018	2019	2020-34
Previously Approved	$ 233.7	$ -	$ -	$ -	$ 2.1	$ 13.3	$ 218.3
Increase (Decrease)	-	-	-	-	-	(0.1)	0.1
Revised Forecast	$ 233.7	$ -	$ -	$ -	$ 2.1	$ 13.2	$ 218.4

Manitoba Hydro
Consolidated Capital Expenditure Forecast (CEF14)
For the Years 2014/15 – 2033/34

CUSTOMER SERVICE & DISTRIBUTION:

New Madison Station - 115/24kV Station

Description:
Build a new 115/24kV St. James Station, new and upgraded feeders, and conversion of St. James, Ness, Berry and King Edward station feeders from 4kV to 24kV. Install 1.5km of new 115kV cable from St. James Station and protection upgrades required at Rosser, Inkster Sherbrook, Mohawk and La Verendrye stations.

Justification:
This project is required to ensure firm supply and a reliable system in the St. James area.

In-Service Date:
March 2017.

Revision:
The installation of 1.5km of 115kV cable from St. James Station to Madison Station is now required because tapping off existing infrastructure in the area is not viable. The contract bid price for the construction of the station and the internal labour to support the contract was higher than previously estimated. The protection upgrades at other stations was not included in previous estimates. The multi in-service date is deferred by twelve months to March 2017 without changing the Madison Station in-service date of March 2016.

	Total	2015	2016	2017	2018	2019	2020-34
Previously Approved	$ 69.6	$ 20.0	$ 25.6	$ 16.1	$ 1.3	$ -	$ -
Increase (Decrease)	17.5	12.6	8.0	(3.3)	(1.3)	-	-
Revised Forecast	$ 87.1	$ 32.6	$ 33.6	$ 12.8	$ -	$ -	$ -

St. Vital Station - 115/24kV Station

Description:
Install a 3-bank 115/24kV station complete with nine feeder positions and protection to replace the existing 24kV distribution at St. Vital Station.

Justification:
The project addresses the equipment rating concerns currently mitigated by station operating restrictions and customer-driven demand for electricity in the area, as well as restoring reliable station contingency plans.

In-Service Date:
December 2018.

Revision:
None.

	Total	2015	2016	2017	2018	2019	2020-34
Previously Approved	$ 51.3	$ 0.3	$ 3.0	$ 20.0	$ 20.0	$ 7.9	$ -
Increase (Decrease)	-	-	-	-	-	-	-
Revised Forecast	$ 51.3	$ 0.3	$ 3.0	$ 20.0	$ 20.0	$ 7.9	$ -

Manitoba Hydro
Consolidated Capital Expenditure Forecast (CEF14)
For the Years 2014/15 – 2033/34

Dawson Road Station - 115/24kV Station

Description:
Install a 2-bank 115kV/24kV station complete with six feeder positions and two capacitor banks to replace existing 24kV distribution equipment at Dawson Road Station.

Justification:
Justification is based on fulfilling customer-driven demand for electricity in the area as well as providing a reliable supply to customers in contingency situations.

In-Service Date:
December 2019.

Revision:
None.

	Total	2015	2016	2017	2018	2019	2020-34
Previously Approved	$ 51.8	$ 2.5	$ 0.5	$ 3.0	$ 16.5	$ 20.0	$ 9.3
Increase (Decrease)	-	-	-	-	-	-	-
Revised Forecast	$ 51.8	$ 2.5	$ 0.5	$ 3.0	$ 16.5	$ 20.0	$ 9.3

Burrows New 66/12kV Station

Description:
Build a new two bank 66kV/12kV indoor station, complete with 12 feeder positions and protection to replace the Alfred and Charles stations.

Justification:
Most of the equipment in this part of Winnipeg has been in service for 77 years. Alfred Station (which supplies Charles Station) lacks access to a satisfactory alternate supply in the event of a 12kV interruption out of Rover Station. Remedial action was recommended for both stations in the Due Diligence Report. It indicated the 4kV switchgear lineups at Alfred and Charles Stations lack arc-resistance and at Alfred Station are sometimes underrated for the available fault current during normal operating conditions. It also had concerns that neither station has an appropriate battery room, all station transformers have patched leaks, they contain asbestos materials, and that spare parts are in short supply.

In-Service Date:
March 2015.

Revision:
Cash flow revision only.

	Total	2015	2016	2017	2018	2019	2020-34
Previously Approved	$ 54.7	$ 5.1	$ -	$ -	$ -	$ -	$ -
Increase (Decrease)	-	(2.7)	-	-	-	-	-
Revised Forecast	$ 54.7	$ 2.4	$ -	$ -	$ -	$ -	$ -

New Adelaide Station 66/12kV

Description:
Construct a new Adelaide Station with 3 x 66-12kV, 30 MVA transformers and three line-ups of switchgear for twenty-three feeder positions. Install a control building for 12kV switchgear, communication, control and protection equipment. Install a 66kV GIS building/equipment for station supply terminations. Install 2 x 3km lengths of 66kV cable through new ductline to extend 66 kV line W6 to terminate at new station. Install new distribution ductline egresses from new station to connect to existing ductline system in downtown area.

Justification:
Constructing the new Adelaide Station will allow for the decommissioning of King Station, addressing all concerns with safety and aging infrastructure at King Station. Adelaide Station also provides sufficient area capacity to allow the proposed William Station project to be deferred. Five feeders from the new Adelaide Station will be expressed through new ductline towards the Health Science Centre (HSC) to aid Sherbrook Station in supplying that area. Sherbrook Station does not have capacity to continue to handle load growth around the HSC Complex by itself.

In-Service Date:
October 2023

Revision:
New item.

	Total	2015	2016	2017	2018	2019	2020-34
Previously Approved	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Increase (Decrease)	62.1	0.7	21.2	22.9	8.8	5.0	3.4
Revised Forecast	$ 62.1	$ 0.7	$ 21.2	$ 22.9	$ 8.8	$ 5.0	$ 3.4

Manitoba Hydro
Consolidated Capital Expenditure Forecast (CEF14)
For the Years 2014/15 – 2033/34

BASE CAPITAL:

ELECTRIC OPERATIONS:

Generation Operations

Description:
These projects are required to provide safe, reliable, efficient supply of power, and to replace plant facilities which are at the end of their useful life. This is comprised of:

GENERATION – Projects relating to upgrading or replacing infrastructure, controls, transformers, breakers, and other equipment at existing generating stations.

GENERATION TOWN SITE SERVICES - Projects required to maintain facilities and provide services to town sites such as Gillam, Grand Rapids and Seven Sisters.

OTHER CAPITAL - Projects relating to upgrading replacing or enhancing domestic water and waste water systems, security systems, office, plant and field equipment replacements; communications; tools and test equipment as well as water licenses & renewals.

Justification:
The generation availability of the older assets has been declining over the last ten years. As Generation Operation's assets age, there is an increase in risk to their availability, which could result in months or years of unit outages and significantly impact the ability to produce power to the transmission system. Enhancements or rehabilitation to the power supply facilities will ensure a safe, reliable and efficient source of energy.

Revision:
Combined Major and Base targets revised through to 2020/21 and escalated at 2% thereafter to consider increased requirements for aging infrastructure replacement based on asset condition assessments.

The tables below show the changes in Base Targets and Major & Base targets.

Generation Operations Base Target

	Total	2015	2016	2017	2018	2019	2020-34
Previously Approved	NA	$ 94.2	$ 87.7	$ 101.8	$ 63.9	$ 59.6	$ 1 186.4
Increase (Decrease)		4.7	13.9	(30.8)	(8.2)	17.6	699.7
Revised Forecast	NA	$ 98.9	$ 101.6	$ 71.0	$ 55.7	$ 77.2	$ 1 886.1

Generation Operations Major & Base Target

	Total	2015	2016	2017	2018	2019	2020-34
Previously Approved	NA	$ 136.3	$ 127.9	$ 157.1	$ 142.5	$ 137.3	$ 1 513.2
Increase (Decrease)		(4.3)	4.1	(25.1)	(10.5)	(5.3)	727.4
Revised Forecast	NA	$ 132.0	$ 132.0	$ 132.0	$ 132.0	$ 132.0	$ 2 240.6

Manitoba Hydro
Consolidated Capital Expenditure Forecast (CEF14)
For the Years 2014/15 – 2033/34

Transmission

Description:
The majority of projects consist of additions, improvements and replacement of transmission lines; replacement, development and upgrades to HVDC facilities; replacement, development and upgrades to communication systems; additions and replacement of field maintenance equipment; and station upgrades. This is comprised of:

SYSTEM RELIABILITY – Projects that address the reliability or capacity of the transmission, or communication systems, including system emergencies and regulatory compliance.

HVDC FACILITIES - Projects relating to upgrading or replacing transformers, breakers, smoothing reactors, protection, controls and other equipment at HVDC facilities.

CUSTOMER SERVICE - Projects that address new or existing service extensions to larger customers.

ENVIRONMENTAL - Projects that enhance or restore the environment, mitigate damage or potential damage to the environment or remove/salvage plant.

SAFETY – Projects that address risk to public or employee safety or emergency preparedness.

OTHER- Projects to acquire tools and equipment that support operation and maintenance of the electric system.

Justification:
This program ensures the reliability of transmission with respect to load, outages, and import/export requirements; as well as addresses safety issues and provides the necessary support for the operation of the HVDC, transmission and communication systems.

Revision:
Combined Major and Base targets revised through to 2020/21 and escalated at 2% thereafter to consider increased requirements for aging infrastructure replacement based on asset condition assessments.

The tables below show the changes in Base Targets and Major & Base targets.

Transmission Base Target

	Total	2015	2016	2017	2018	2019	2020-34
Previously Approved	NA	$ 114.9	$ 126.1	$ 112.0	$ 70.3	$ 65.6	$ 1 305.3
Increase (Decrease)		(41.8)	(68.8)	(43.7)	24.5	19.2	768.6
Revised Forecast	NA	$ 73.2	$ 57.3	$ 68.3	$ 94.8	$ 84.8	$ 2 073.9

Transmission Major & Base Target

	Total	2015	2016	2017	2018	2019	2020-34
Previously Approved	NA	$ 185.9	$ 204.5	$ 148.0	$ 105.5	$ 139.2	$ 1 637.3
Increase (Decrease)		(60.9)	(79.5)	(23.0)	19.5	(14.2)	763.1
Revised Forecast	NA	$ 125.0	$ 125.0	$ 125.0	$ 125.0	$ 125.0	$ 2 400.3

Customer Service & Distribution

Description:
These projects are required to extend sub-transmission, distribution, and transformation facilities to supply service to residential, farm, commercial and industrial customers, and to replace plant facilities whose useful life has been exceeded. Specific types of expenditures include station and line additions, modifications and rebuilds, bank additions, breaker replacements, defective cable replacement, highway changes, field maintenance equipment, woodpole replacements and ice melting requirements. These costs are spread over many facility locations throughout the Province and are comprised of:

SYSTEM IMPROVEMENTS - Projects relating to additions and modifications to the existing electric distribution network to maintain system reliability and standards of safety, as a result of customer load growth, aging infrastructure and operational standards of performance. Assets and facilities include distribution stations, poles, conductors, transformers, streetlights, cables, duct lines and manholes.

CUSTOMER SERVICE - Projects relating to new or existing service extensions to commercial and residential customers.

NEW STATIONS - Projects relating to station development requirements in both Winnipeg and rural Manitoba to address capacity limitations.

OTHER CAPITAL - Projects relating to VHF radio replacements and field maintenance equipment.

Justification:
The residential, farm, commercial and industrial loads are expected to grow at an average rate in excess of 1.5% per annum and will require a program of additions to the system to accommodate these anticipated loads. As the distribution assets are approaching the end of their designated lifespan a four year program has been established to replace critical infrastructure.

Revision:
Combined Major and Base targets revised through to 2020/21 and increased thereafter to consider increased requirements for aging infrastructure replacement based on asset condition assessments.

The tables below show the changes in Base Targets with and without Major Projects > $50M.

Customer Service and Distribution Base Target

	Total	2015	2016	2017	2018	2019	2020-34
Previously Approved	NA	$ 207.6	$ 211.8	$ 229.2	$ 143.8	$ 134.3	$ 3 709.4
Increase (Decrease)		(10.6)	(29.1)	(19.6)	16.9	38.8	140.8
Revised Forecast	NA	$ 197.0	$ 182.6	$ 209.6	$ 160.7	$ 173.0	$ 3 850.2

Customer Service and Distribution Major & Base Target

	Total	2015	2016	2017	2018	2019	2020-34
Previously Approved	NA	$ 235.5	$ 240.9	$ 268.3	$ 181.7	$ 162.2	$ 3 718.6
Increase (Decrease)		-	-	-	24.3	43.8	144.2
Revised Forecast	NA	$ 235.5	$ 240.9	$ 268.3	$ 206.0	$ 206.0	$ 3 862.9

Manitoba Hydro
Consolidated Capital Expenditure Forecast (CEF14)
For the Years 2014/15 – 2033/34

Customer Care & Energy Conservation

Description:
This program covers the additions and replacements of meters, transformers and related equipment and is comprised of:

CUSTOMER SERVICE – Projects that address service to a customer or customer-driven requests, including costs associated with new and replacement metering equipment, metering transformers and associated equipment.

OTHER– Projects to acquire tools and equipment that support operation and maintenance of the electric system.

Justification:
As required for the connection of new customers to the system, as well as replacement of existing time expired or faulty meters.

Revision:
Increase due to the addition of meter exchanges and sampling which will be reclassified from operating expenses to capital upon adoption of IFRS in 2015/16.

	Total	2015	2016	2017	2018	2019	2020-34
Previously Approved	NA	$ 3.1	$ 3.2	$ 3.3	$ 3.3	$ 3.4	$ 59.8
Increase (Decrease)		-	0.8	0.8	0.8	0.8	1.7
Revised Forecast	NA	$ 3.2	$ 4.0	$ 4.1	$ 4.1	$ 4.2	$ 61.5

Human Resources & Corporate Services

Description:
The program consists of information technology hardware and software upgrades and application development, corporate building refurbishments and new building programs, fleet vehicle refurbishment and replacement as well as projects associated with property easements, and acquisition of equipment for the training centre, print shop, fleet, materials management, and facilities.

CORPORATE BUILDINGS - Projects associated with the cyclical acquisition, and/or replacement of corporate administrative facilities throughout the Province.

FLEET ACQUISITIONS - Projects associated with the cyclical procurement, refurbishment and/or replacement of corporate fleet vehicles and equipment.

INFORMATION TECHNOLOGY HARDWARE / SOFTWARE - Projects associated with the purchase and installation of hardware and software upgrades, personal computers, networks and cabling.

INFORMATION APPLICATION DEVELOPMENT - Projects associated with installing, developing or upgrading computer applications for the corporation.

OTHER – Projects associated primarily with property easements and equipment for the training centre, print shop, fleet, materials management and facilities.

Justification:
To provide safe, efficient and productive; corporate buildings, fleet vehicles and equipment. Also to enhance computer systems throughout the corporation to achieve ongoing improvement in productivity and reliability.

Revision:
Base targets revised through to 2020/21 including new district office buildings and completion of Enterprise Asset Management project and escalated at 2% thereafter to consider increased requirements for aging infrastructure replacement.

	Total	2015	2016	2017	2018	2019	2020-34
Previously Approved	NA	$ 75.7	$ 54.8	$ 54.8	$ 34.4	$ 32.1	$ 638.7
Increase (Decrease)		(0.7)	20.2	0.2	20.6	22.9	294.9
Revised Forecast	NA	$ 75.0	$ 75.0	$ 55.0	$ 55.0	$ 55.0	$ 933.6

Finance & Regulatory

Description:
This program is primarily for meter purchases (for load research monitoring), and handheld devices associated with the load research function. Other items include the purchase of additional servers and other information technology related equipment and specialized software.

Justification:
The load research program supports the development of customer rates and also supports Power Smart initiatives in terms of planning and support.

Revision:
None.

	Total	2015	2016	2017	2018	2019	2020-34
Previously Approved	NA	$ 0.2	$ 0.2	$ 0.2	$ 0.2	$ 0.2	$ 3.8
Increase (Decrease)		-	-	-	-	-	-
Revised Forecast	NA	$ 0.2	$ 0.2	$ 0.2	$ 0.2	$ 0.2	$ 3.8

GAS OPERATIONS:

Customer Service & Distribution

Description:
This program consists of projects required to extend, rebuild or upgrade: transmission pipelines, distribution pipelines, regulating stations, and customer service lines. This is comprised of:

SYSTEM IMPROVEMENTS – Projects relating to system modifications and betterment. Significant work includes capacity upgrades, system integrity upgrades, regulator station upgrades and cathodic protection upgrades.

NEW BUSINESS - Projects for installing new services and distribution mains for both commercial and residential customers.

Justification:
Required to provide ongoing safe and reliable supply of natural gas to customers.

Revision:
None.

	Total	2015	2016	2017	2018	2019	2020-34
Previously Approved	NA	$ 34.9	$ 49.0	$ 34.9	$ 22.3	$ 21.2	$ 501.7
Increase (Decrease)		-	-	-	-	-	-
Revised Forecast	NA	$ 34.9	$ 49.0	$ 34.9	$ 22.3	$ 21.2	$ 501.7

Manitoba Hydro
Consolidated Capital Expenditure Forecast (CEF14)
For the Years 2014/15 – 2033/34

Customer Care & Energy Conservation

Description:
This program consists primarily of costs to design, implement and deliver incentive based PowerSmart conservation programs to reduce gas consumption and greenhouse gas emissions in Manitoba, as well as meters, transformers and related equipment. This is comprised of:

GAS DEMAND SIDE MANAGEMENT – Projects to design, implement and deliver incentive based PowerSmart conservation programs to reduce gas consumption and greenhouse gas emissions in Manitoba.

CUSTOMER SERVICE – Projects that address service to a customer or customer-driven requests, including costs associated with new and replacement metering equipment, metering transformers and associated equipment.

Justification:
The natural gas Demand Side Management plan provides customers with exceptional value through the implementation of cost-effective energy conservation programs that are designed to minimize the total cost of energy services to customers, position the Corporation as a national leader in implementing cost-effective energy conservation and alternative energy programs, protect the environment and promote sustainable energy supply and service. Also required for the connection of new customers to the system, as well as replacement of existing time expired or faulty meters.

Revision:
Revisions to energy saving and expenditures for a number of programs to reflect current market information and designed to aggressively pursue cost-effective market-achievable savings. It is assumed that upon adoption of IFRS in 2015/16, the demand side management programs will continue to be capitalized, under the interim standard that continues to permit rate-regulated accounting.

Customer Care and Energy Conservation

	Total	2015	2016	2017	2018	2019	2020-34
Previously Approved	NA	$ 5.0	$ 5.1	$ 5.2	$ 5.3	$ 5.4	$ 95.0
Increase (Decrease)		(1.5)	0.3	(0.6)	(0.6)	(0.6)	(11.1)
Revised Forecast	NA	$ 3.4	$ 5.4	$ 4.6	$ 4.7	$ 4.8	$ 84.0

Gas Demand Side Management

	Total	2015	2016	2017	2018	2019	2020-34
Previously Approved	NA	$ 8.5	$ 7.2	$ 6.9	$ 4.8	$ 3.9	$ 42.1
Increase (Decrease)		1.2	3.2	4.1	4.5	4.8	74.6
Revised Forecast	NA	$ 9.6	$ 10.4	$ 11.0	$ 9.4	$ 8.7	$ 116.7

Tab 44

Executive Summary

Introduction

Manitoba Hydro, a Crown Corporation, is committed to maintaining reliable, affordable and environmentally sustainable energy for its customers, while ensuring long-term financial sustainability. Manitoba Hydro meets its commitment through investments in Demand Side Management (DSM or Power Smart), new generation, and by exporting surplus electricity to utilities in United States (U.S.) and Canada. Exports have been a key factor in keeping Manitoba rates among the lowest in North America, contributing close to one-third of Manitoba Hydro's total revenues over the past decade.

Manitoba Hydro is seeking government approval for its Preferred Development Plan, which requires the following commitments in June 2014:

- start construction of the Keeyask generating station (G.S.) for a 2019 in-service date (ISD)
- proceed with a 250 MW export agreement with Minnesota Power (MP)
- proceed with a 100 MW export agreement with Wisconsin Public Service (WPS)
- proceed with a 750 MW U.S. transmission interconnection
- proceed with a 300 MW export agreement with WPS subject to satisfactory conclusion of negotiations currently still underway.

In addition, the plan would include Conawapa G.S., 1,485 MW, with an earliest ISD of 2026, although decisions on whether to construct Conawapa and its timing are not required now and would be made over the next few years.

Undertaking this plan would not preclude modifying it should future conditions suggest that it is prudent to do so. Activities would continue by Manitoba Hydro to protect an ISD for Conawapa as early as 2026, but conditions will be continually monitored to determine if such continued investments are worthwhile and, ultimately, to determine if Conawapa should be constructed

and for what ISD. These decisions will be influenced by factors such as the 300 MW WPS export agreement, other export agreement possibilities, energy prices, capital cost and load growth. The early ISD of 2026 for Conawapa could be protected with a modest investment (approximately $50 million) up to the filing of the Environment Impact Statement in the summer 2015 after which the amount of investment would increase. A final decision on construction of Conawapa for an ISD of 2026 must be made by 2018.

In addition to the above major components, the Preferred Development Plan includes continued substantial investment in DSM/Power Smart and efficiency improvements to existing generation. Wind generation and natural gas generation will be incorporated into future development if and when required and other energy technologies may also be included in future development if and when they become economically viable.

Background

Purpose of the Needs For and Alternatives To Review

Manitoba Hydro has been created, and its activities governed, by *The Manitoba Hydro Act.* According to the Act, the purpose of Manitoba Hydro is to "provide for the continuance of a supply of power adequate for the needs of the province, and to engage in and to promote economy and efficiency in the development, generation, transmission, distribution, supply and end-use of power."

In light of a demonstrated need for new Manitoba power supply by around 2023, Manitoba Hydro has formulated a Preferred Development Plan. This plan and alternatives to it are being assessed through Needs For and Alternatives To (NFAT) review under the auspices of the Manitoba Public Utilities Board (PUB). The PUB panel is to provide a report with recommendations to the Minister responsible for the administration of *The Public Utilities Board Act* by no later than June 20, 2014.

In addition to the NFAT review and government approval process, generation and transmission projects included in the development plan are subject to other regulatory processes at federal and provincial levels, including comprehensive environmental impact assessments. Matters included in those reviews are not addressed in this NFAT submission.

Manitoba Hydro Profile

With over $14 billion in assets and 5,700 megawatts (MW) of installed electricity capacity, Manitoba Hydro is one of the largest integrated electricity and natural gas distribution utilities in Canada. Manitoba Hydro serves 548,000 electricity customers across Manitoba and 267,000 natural gas customers in the southern part of the province.

The vast majority of the electrical energy that Manitoba Hydro typically produces each year is from hydropower (approximately 98% on an energy basis). Manitoba Hydro also maintains two thermal generating stations to back up its hydro-electric system and purchases electricity from two independent wind farms. The provincial economy benefits from Manitoba Hydro's ongoing operations and future projects through employment, business transactions and the payment of taxes and levies.

Manitoba Hydro is highly rated (consistently higher than the national average for electric utilities) by its customers, according to the 2012 Canadian Electricity Association Public Attitudes Research Project, and continues to offer its customers the lowest average retail electricity price in North America.

Manitoba Hydro is committed to protecting the environment, contributing to the global reduction of greenhouse gas (GHG) emissions and maintains a diverse workforce including significant Aboriginal representation.

Manitoba Hydro recognizes the need for sustainability in all aspects of its operations. Economic, environmental and societal decision criteria are applied in the assessment of major projects and plans, including public and stakeholder consultation.

Manitoba Hydro's annual planning process includes the Corporate Strategic Plan, corporate-wide risk analysis, and an integrated planning cycle which includes development of an annual Economic Outlook, Load Forecast, Power Smart Plan, Power Resource Plan, Forecast of Interchange Revenues, Capital Expenditure Forecast and Integrated Financial Forecast.

Governance over Manitoba Hydro's plans is provided by the corporation's board, audit committee, Manitoba Crown Corporations Council, Crown Corporations Standing Committee of the Legislature and the Auditor General of Manitoba. Regulatory oversight is carried out by a number of provincial and federal authorities, including the Manitoba PUB.

Preferred Development Plan Facilities

The Preferred Development Plan consists of four main capital project components:

- the 695 MW Keeyask Project
- the 1,485 MW Conawapa Project
- the North-South Transmission Upgrade Project, with an ISD to coincide with the last units of Conawapa
- the 750 MW, 500 kilovolt (kV) Alternating Current (AC) Manitoba-Minnesota Transmission Project.

Keeyask

The Keeyask Project will take seven years to construct, with a total budgeted in-service cost estimate of $6.2 billion including interest and escalation based on a 2019/20 ISD. Manitoba Hydro will own and operate the Keeyask Transmission Project, whereas the Keeyask Generation Project will be owned by a partnership between Manitoba Hydro and four Keeyask Cree Nations (KCNs): Tataskweyak Cree Nation (TCN), War Lake First Nation (WLFN), York Factory

First Nation (YFFN) and Fox Lake Cree Nation (FLCN). The Joint Keeyask Development Agreement addresses the KCNs' income-sharing, training, employment, business opportunities, and involvement in environmental and regulatory affairs.

The Keeyask Infrastructure Project consists of the access road and the first stage of the construction camp. Work on this project is proceeding ahead of the decision to construct the generating station in order to provide employment, training and capacity building benefits to the four KCN partners, as well as to reduce lead times and risks for the project as a whole.

Efforts have been undertaken and continue with First Nation partners, to mitigate and reduce any adverse effects of the Keeyask Project and make environmental and socio-economic impacts as positive as possible.

Manitoba Hydro and its KCN partners are paying special attention to Lake Sturgeon. The Committee on the Status of Endangered Wildlife in Canada has designated the Nelson River sturgeon population as endangered, and the federal government is considering listing the species under the *Species at Risk Act*. Various measures will be implemented to address potential effects caused by the project: these include habitat replacement and a stocking program with the objective of an overall enhancement of sturgeon stocks in the Lower Nelson River.

Conawapa

The Conawapa Project will take 10 years to construct, with a budgeted in-service cost estimate of $10.2 billion, including interest and escalation based on a 2025/26 ISD.

Although the generation ownership structure has not been finalized, Manitoba Hydro is committed to providing the First Nations in the vicinity of the project with long-term sustainable benefits, early involvement and extensive consultations, and opportunities to participate in the environmental governance of the project. Manitoba Hydro has Conawapa

process agreements in place with the Cree Nations while discussions and negotiations take place.

As with the Keeyask Project, plans for the Conawapa Project will include positive measures to address environmental and socio-economic effects. Studies in the past decade have involved five local Cree Nations in the vicinity of the project: FLCN, YFFN, TCN, WLFN and, to a somewhat lesser extent, Shamattawa First Nation.

North-South Transmission System Upgrade Project

The majority of the Conawapa G.S. power will be transmitted from northern Manitoba to southern customers on Manitoba Hydro's high-voltage direct-current (HVDC) transmission system. To transmit south the full amount of generated power once both Keeyask and Conawapa are in place, upgrades are required to the existing northern 230 kV AC system. This North-South Transmission System Upgrade Project will have an ISD coinciding with that of the last Conawapa units. The upgraded North-South Transmission System would be owned and operated by Manitoba Hydro and would cost an estimated $500 million including interest and escalation.

Manitoba-Minnesota Transmission Project

This proposed project consists of a 750 MW, 500 kV AC transmission line[1] in southeastern Manitoba, connecting at the border with MP's proposed Great Northern Transmission Line with an ISD of 2020. The project would enable power to be exported to the U.S. based on current sales agreements, improve reliability and import capacity in emergency and drought situations, and increase access to markets in the U.S.

This project is still in the study and negotiation phase. Manitoba Hydro will be responsible for the Manitoba portion of the interconnection, which is estimated to cost $350 million. Manitoba

[1] It should be noted that the transmission lines can be described by voltage size (kV) or by transfer capability (MW).

Hydro will also be responsible for some portion of the capital and ongoing operating costs associated with the U.S. portion of the facilities. For the Preferred Development Plan, it is assumed that Manitoba Hydro will be responsible for 40% of the capital and ongoing operating costs associated with the U.S. portion of the 750 MW interconnection facilities, with the remainder of the transmission costs to be borne by MP and WPS. The total cost of the U.S. portion of the 750 MW interconnection is in the order of $700 M (2020 base dollars, not including interest).

However, WPS recently advised that an investment in the 750 MW Interconnection Transmission does not match their current business objectives and that they will not invest in the line. They also advised that they will continue to negotiate the 300 MW Power Purchase Agreement; as of this writing that negotiation is proceeding under the auspices of the term sheet agreed to previously. In order to avoid becoming a majority owner in a U.S. transmission line, Manitoba Hydro will only enter into an arrangement where it will not own more than 49% of the interconnection facilities in the U.S. In return for investing in the U.S. portion of the transmission interconnection, Manitoba Hydro will benefit by having the right to use and/or sell its proportionate share of the U.S. transmission service associated with the new interconnection. Manitoba Hydro will also have the right to sell its share in the future. In the development plans without the WPS sale but with a 750 MW interconnection, a conservative assumption has been used whereby Manitoba Hydro will be responsible for approximately two-thirds of the capital.

While the Preferred Development Plan includes a 750 MW interconnection, some alternative development plans reduce the interconnection capacity to 250 MW. With a 250 MW, 230 kV AC line, Manitoba Hydro would be responsible for $95 million (including interest and escalation) in capital costs for the Manitoba portion but would not be responsible for capital or ongoing operating costs associated with the U.S. portion of the interconnection facilities.

Trends and Factors Influencing North American Electricity Supply

Several notable trends and factors are currently influencing electricity markets and resource decisions. These trends affect existing resources, the need for new generation, the costs of competing resources, and the market price for electricity. The need for new generation in the U.S. and Canada is being driven by:

- modest load growth
- an aging generation fleet
- uncertainty as to the life expectancy of nuclear plants
- various environmental and energy policies that could hasten the retirement of coal plants.

North American Demand for Electricity

Electricity demand in both Canada and the U.S. is expected to continue to increase over the 35-year planning horizon, although at a slower rate than has been historically observed. Recent years have seen lower rates of demand growth for electricity throughout North America due largely to increasing energy efficiency and the migration of industrial processes to other countries. Despite this trend the U.S. Energy Information Administration's Annual Energy Outlook 2013 reference case projects overall U.S. load growth of 28% between 2011 and 2040 (0.9% per year).

Environmental and Energy Policies

Environmental considerations and policies are and will continue to be major factors influencing electric power resource choices and the market price for electricity. Policies such as renewable portfolio standards that encourage an increasing percentage of renewable energy within specific jurisdictions are widespread. The eligible renewable technologies within each specific program vary by state but in general are trending towards more inclusive treatment of hydropower. Minnesota's program includes hydropower from stations that are less than 100 MW while Wisconsin's program will include all new hydro regardless of its size.

Global interest and attention to the effects of climate change are having an impact on the energy industry. Manitoba Hydro expects that some form of significant climate change regulation or legislative action in the U.S. is likely within the next 10 years. This would be a significant driver for increasing electricity market prices and would favour hydropower as a virtually GHG-free form of generation.

Energy Price Considerations

Fuel pricing is one of the most important considerations driving electrical resource decisions and regional market prices for electricity. Recent reductions in cost due to developments in shale gas extraction have increased the attractiveness of natural gas as a supply source, particularly in relation to coal.

Natural gas prices have exhibited considerable historic volatility. However, industry analysts generally foresee a range of potential prices, with reference cases—i.e. most likely outcomes—that project moderate price growth over the next decade as marginal production costs rise and demand grows.

Market prices for electricity have dropped markedly since 2006-2008 in the Midcontinent Independent System Operator, Inc. (MISO) region. However, moderate real price growth is expected in the future, based on a corresponding escalation in natural gas and coal prices, increased environmental regulations, expected coal generation retirements and future regulations to reduce GHG emissions. The general outlook for moderate real growth in electricity prices is confirmed by independent North American price forecast consultants.

Implications For Preferred Development Plan

These industry trends support Manitoba Hydro's Preferred Development Plan in confirming that there is a need for new sources of supply, a growing preference for clean, renewable, non-emitting power and an expectation that wholesale electricity prices will increase in real terms.

While resulting in low emissions relative to coal, natural gas generation still carries a considerable GHG emission liability and as well is exposed to expected price increases and likely price volatility.

Manitoba Hydro's Need for New Power Resources

To determine Manitoba's electricity supply need, Manitoba Hydro regularly assesses domestic demand (load growth net of reductions resulting from DSM) and firm export commitments to arrive at total demand. Total demand is then compared to current supply. Total demand is currently projected to exceed existing supply beginning around 2023 even with no new export commitments. The need for new supply to meet Manitoba domestic load is the principal driver of the Preferred Development Plan.

Domestic Load Growth

Manitoba's electrical energy consumption has grown, on average, at an annual rate of 1.7% over the past 10 years. Over the next 20 years, growth in energy consumption is forecast to continue at an average annual rate of 1.6%. This trend takes into account the effects of future savings due to energy efficiency codes and standards but not DSM programs. When projected DSM (Power Smart) programs are taken into account, forecasted energy use growth rate is reduced by about 0.1% to 1.5%.

The Manitoba load is expected to grow in all sectors, the result of population growth, increased average energy use per residential customer and anticipated industrial and commercial expansion by a number of businesses.

Reducing Demand Through Demand Side Management

Manitoba Hydro's DSM programs consist of energy conservation and load management activities designed to reduce customer demand for power. Savings to date have deferred the need for new generation by 4 years. The 2013-2016 Power Smart Plan targets additional energy savings of 1,552 gigawatt (GWh) and 490 MW by 2027/28.

Manitoba Hydro's DSM strategy for the future involves a long-term commitment to pursuing all energy efficient opportunities which have been identified as being economically viable in Manitoba. An updated DSM Market Potential Study has recently been completed and is included in the NFAT submission. Manitoba Hydro will update its Power Smart Plan, in consultation with government by March, 2014 and will incorporate the information contained in the DSM Market Potential Study. The updated Power Smart plan will be included in future Power Resource Plans as part of any development plan that is pursued by Manitoba Hydro at the conclusion of the NFAT process.

Firm Export Sale Commitments

The wholesale electricity export market is integral to Manitoba Hydro fulfilling its mandate to provide economical and reliable power to Manitobans.

Export sales, both firm and surplus, provide an outlet for excess electricity in the early years of new hydropower generating stations and for the many years when water flows exceed minimum (dependable) levels. In times of drought or extremely cold weather or system emergencies, firm arrangements with export customers allow for imports to ensure reliability of supply.

Long-term firm export sales contracts entail an obligation to supply except in agreed-upon situations where security and reliability of supply to Manitoba customers would be compromised, for example during periods of system emergencies and under certain drought conditions.

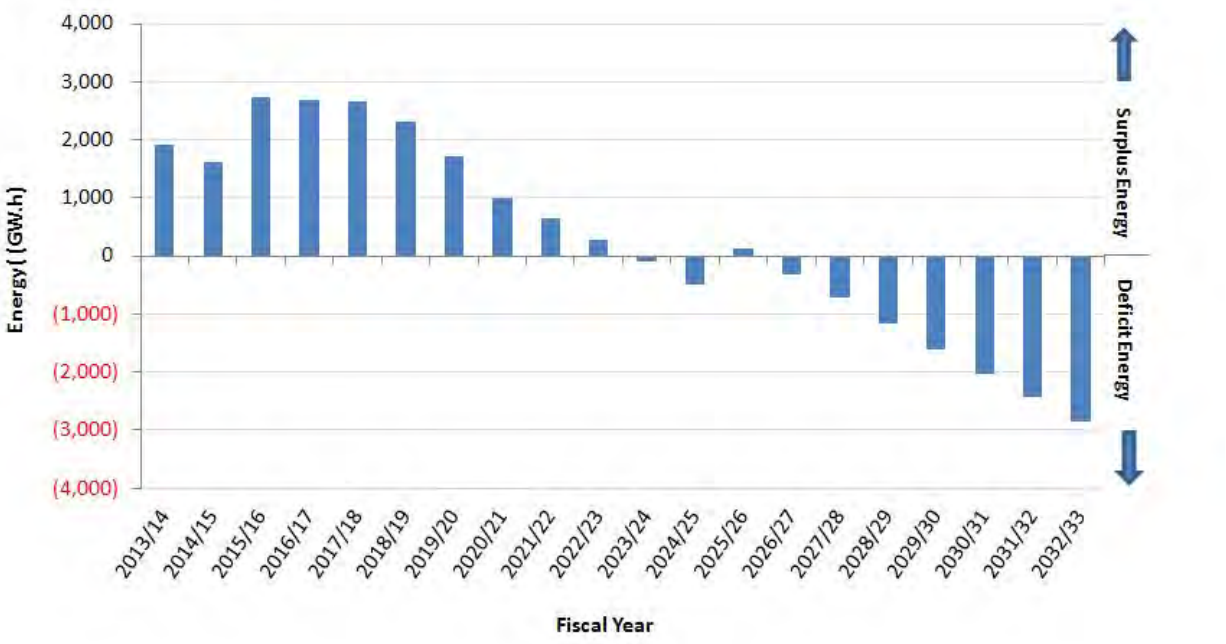
Supply and Demand

Manitoba Hydro plans its system so as to have sufficient dependable energy resources to supply firm energy demand in the event of a repeat of the lowest water supply conditions on record. System capacity must also be sufficient to meet the Manitoba winter peak demand. To

determine if new supply is needed, Manitoba Hydro annually compares supply and demand values for each year.

Manitoba Hydro's analysis of current supply shows that supply will be exceeded by demand in or around 2023.

Figure 1 ENERGY BALANCE – DEPENDABLE ENERGY SHOWING DEFICIT BY **2023**



The exact year that new supply is required will depend on load growth rates and supply factors such as earlier retirement of the natural gas generation at Selkirk and availability of dependable energy imports. It is prudent and necessary, therefore, to plan for providing new Manitoba supply starting in or around 2023.

The Manitoba Hydro System, Interconnections and Export Markets

Generation

Manitoba Hydro's existing supply resources can be divided into four resource types: hydro-electric generation, thermal generation, wind generation and imports. Hydro-electric power is by far the most significant resource in the Manitoba Hydro generating system, providing almost

90% of the generating capacity that Manitoba Hydro owns and typically about 98% of electrical energy.

Manitoba Hydro's generation is affected by variability in water supply. There is a 350% difference between the lowest and highest recorded water supply conditions on record. Generating stations are planned to meet the energy demand under the lowest flow on record (as well as the highest winter peak demand). As a result, in all but drought years there will be surplus energy which can be sold on the export market if transmission interconnections are available. Surplus energy is also available as a result of the large-scale increments of generation typical of hydro development. Until domestic load has caught up with the total supply from new hydro generation, this surplus energy is either exported or the production is foregone and the water is spilled.

Transmission

Electricity is delivered from Manitoba Hydro's generating stations to Manitoba customers over a network of transmission lines with two major components – the AC transmission system and the HVDC system, which transmits electricity south from the generating stations in the north.

Cross-Border Interconnections and Their Benefits

Manitoba Hydro's transmission interconnections with adjacent provinces and states are a very important part of Manitoba Hydro's transmission system, providing benefits as follows:

- improving reliability by enabling imports during drought conditions and under supply contingencies (e.g. temporary loss of supply due to equipment outages)
- increasing revenues by enabling the export of surplus hydro power and import of market energy at costs lower than the cost of thermal resources available within Manitoba
- providing the predominantly hydro system with needed resource diversity as a supplement to thermal generation in Manitoba

- displacing fossil fuel generation in export markets. Manitoba Hydro currently estimates that, globally, its exports displace 0.75 tonnes of CO_2 per megawatt-hour (MWh).

Manitoba Hydro currently has five cross-border interconnections with Saskatchewan, three interconnections with Ontario and four interconnections with the U.S. Current technical limits are indicated in Table 1:

Table 1 EXPORT TRANSFER LIMITS AND IMPORT TRANSFER LIMITS

Interconnection	Firm Export Schedule Limit	Firm Imports Transfer Capability for the Planning Horizon
U.S.	1,950 MW	700 MW
Ontario	200 MW	0 MW
Saskatchewan	150 MW	0 MW

The 1,950 MW export limit to U.S. markets is equivalent to 2% of the peak demand in the MISO region; the large size of the MISO system gives assurance that energy imports and emergency capacity support will be available for Manitoba when it is needed—both for the current interconnection size and if the import capability is expanded by the new interconnection from 700 MW to 1,450 MW. Similarly, the MISO market is large compared to Manitoba export levels, increasing confidence in the ability for Manitoba to obtain either short-term or long-term export sales.

In terms of opportunities in Canadian markets:

- The Ontario energy market is approximately one-quarter the size of the MISO market. There are two major barriers to a major long-term Manitoba Hydro power sale to Ontario: distance and Ontario government policy which strongly favours in-province generation. The Manitoba-Ontario interconnection is with Northwestern Ontario, a large, sparsely populated area with a proportionally small peak load of 750 MW.
- With respect to Saskatchewan, Manitoba Hydro and SaskPower have recently signed Memoranda of Understanding whereby the utilities are to engage in sale discussions for

existing and new hydro exports to both northern and southern Saskatchewan—across all time frames—for volumes ranging from 25 MW to 500 MW; discussions are also to include the possibility of new transmission interconnections.

The Window of Opportunity for a New U.S. Interconnection

When new transmission is added to the system, Manitoba Hydro's access to markets is enhanced for the entire life of the transmission facilities, not only for the term of committed contracts. Additional interconnection capacity is important to increase short-term export sales by helping to minimize spill at the hydro plants in periods of ample streamflow conditions and to maximize export of energy during the higher valued on-peak periods rather than off-peak periods.

Manitoba Hydro, working with its export customers, currently has the opportunity to influence what new transmission is built in the U.S. MISO region and to ensure that it is compatible with Manitoba Hydro's Preferred Development Plan. A new 750 MW interconnection is required to enable the additional long-term export sales to MP and WPS. These two sales, plus a sale to Northern States Power (NSP) which has already been approved, would provide financially attractive fixed prices. Manitoba Hydro would therefore receive predictable and stable revenue to reduce the costs borne by domestic customers. Specifically, these sales are:

- MP — 250 MW (2020-2035)
- WPS — 300 MW (2020-2040), subject to satisfactory conclusion of negotiations
- NSP — 125 MW expansion of existing approved sale (2021-2025).

There is risk inherent in deciding not to proceed with a new interconnection as part of the development plan. MP has committed to champion a new transmission interconnection with Manitoba through its service territory, in which it has a strong relationship with the local land owners—a critical component of building a new transmission line. However, the current favourable political, regulatory and business conditions in the U.S. for constructing a new transmission interconnection will not continue indefinitely. Our U.S. utility customers are

currently making decisions on their future energy supply mix, as they move away from nuclear and coal-generated energy and consider the price volatility of the natural gas market. Should Manitoba Hydro be unable to supply adequate amounts of hydropower, these utilities will pursue other supply sources. As well, federal and state administrations continuously modify their policies and it cannot be assumed that a new U.S. transmission interconnection can be approved and constructed at a given future date. This represents a window of opportunity for Manitoba Hydro given that it would be extremely difficult, probably impossible, for Manitoba Hydro to develop a line in the U.S. without the committed participation of a U.S. partner like MP.

Foregoing this opportunity would likely preclude the building of significant new interconnection capability until well beyond the required 2023 time horizon for new Manitoba energy supply.

Screening of Manitoba Resource Options

A multi-stage screening process was utilized to narrow the field of appropriate resource supply options. The candidates consisted of 17 resource option technologies potentially suitable for utility-scale generation, including DSM (Power Smart), imports, wind, solar, biomass, natural gas as well as hydro.

The screening process included evaluations of technical, environmental, socio-economic and economic characteristics of each of the options.

Based on these evaluations, resources such as solar, nuclear, coal and biomass were screened out as not sufficiently attractive to consider as primary supply contenders in the development plans.

Specific resource options were selected at the conclusion of the screening as suitable candidates to be included within individual development plans mainly because of their cost competitiveness and environmental attractiveness:

- additional DSM
- Keeyask G.S.
- Conawapa G.S
- GE 7FA Heavy Duty Combined-Cycle Gas Turbine
- GE 7FA Heavy Duty Simple-Cycle Gas Turbine
- GE LM6000 PH Aeroderivative Simple-Cycle Gas Turbine
- generic 65 MW Wind Farm
- contractual import agreements.

Determination of Potential Development Plans

The next step was to develop and evaluate potential alternative development plans using the short-listed resource options. The number and size of resource options were selected to cover Manitoba's energy and capacity needs for the next 35 years.

Different combinations of supply resources enable comparison of the trade-offs between their characteristics. For example, the low capital cost and high operating cost of gas turbines can be compared to the export revenue potential and low operating costs of hydro-electric generation. This analysis led to the identification of 15 alternative development plans that were evaluated based on three groupings:

- Keeyask 2019 with a 750 MW U.S. Interconnection
  - Both MP and WPS Sales - two plans (one with Conawapa (preferred) & one with gas generation to follow Keeyask)
  - MP Sale but not the WPS Sale – three plans
- Keeyask 2019 with a 250 MW U.S. Interconnection – three plans
- Plans that meet Manitoba Hydro's domestic load and firm export commitments starting in 2022/23 with no new export sales or U.S. interconnection – seven plans

(The 750 MW interconnection would have 750 MW of export and import capability whereas the 250 MW interconnection is assumed to have 250 MW of export capability but only 50 MW of import capability.)

Included in the 15 plans above, are two plans with wind generation which were also evaluated, but were found to be clearly uneconomic and thus were not carried through the full set of evaluations.

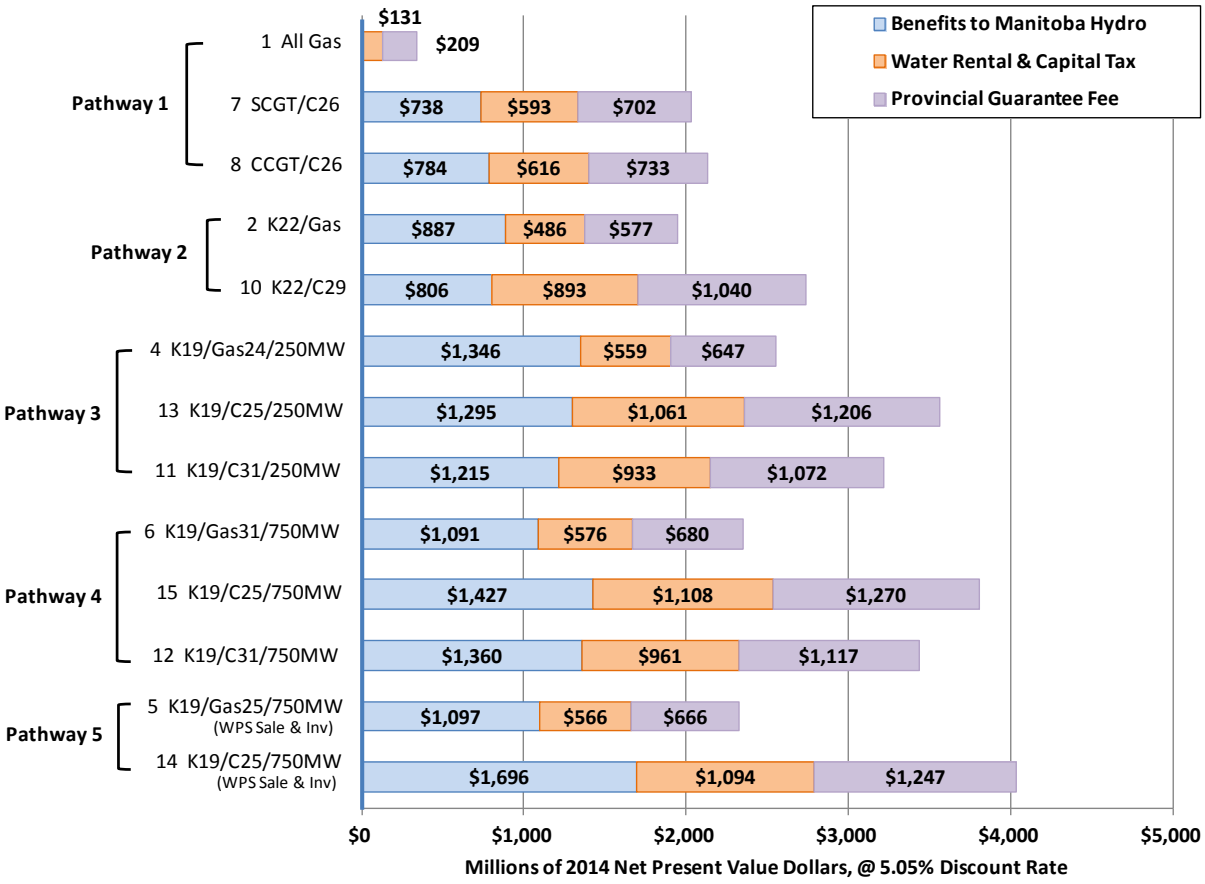
Economic Evaluation of the Potential Development Plans

The third step was to comparatively evaluate the preferred and alternative development plans using economic evaluation principles in order to allow the comparison of alternative options on the basis of their relative costs and benefits. The economic evaluation of development plans was conducted over four phases of analysis:

- analysis using "reference" (most likely) assumptions
- probabilistic analysis to test potential variations to reference assumptions
- sensitivity and "stress testing" of the proposed plan and the best alternative plans
- "Pathways" analysis to assess the flexibility of options to change course based on future conditions. The use of pathways recognizes the reality of allowing decisions to be made incrementally as uncertainties resolve.

The following figure sets out the Net Present Value (NPV) comparison for 13 of the development plans, including benefits to Manitoba Hydro and potential cash transfers to the Province through the provincial guarantee fee, water rental and capital tax. The calculations were done using reference assumptions and show the incremental net benefits accumulated during the life of each plan discounted to today's dollars.

Figure 2 COMPARISON OF DEVELOPMENT PLAN NET PRESENT VALUES INCLUDING POTENTIAL CASH TRANSFERS TO THE PROVINCE



Note: NPVs calculated with a real discount rate of 5.05%

This evaluation, based on 2012 reference scenario assumptions, indicates that:

- The plan with the 750 MW Interconnection and WPS sale ("the Preferred Development Plan") provides higher economic benefits than any of the other plans.
- The plans with the most benefit are those that include Keeyask G.S., Conawapa G.S. and a new interconnection.
- Compared to the All Gas Plan, the NPV benefit of the Preferred Development Plan is higher by $1,696 million considering only Manitoba Hydro economics and $3,697 million when also considering Manitoba Hydro transfers to the Province from provincial debt guarantee fees, water rentals and capital taxes. The total corporate and provincial economic NPV of $3,697 million is equivalent to almost $300 million (2020 $) per year

for 60 years starting in 2020 or about $600 per year for each of Manitoba's approximately 500,000 residential households.

Economic Uncertainty Analysis, Probabilistic Analysis and Sensitivities

Manitoba Hydro then tested the sensitivity of the most attractive development plans to changes in assumptions.

The uncertainty analysis was performed through a combination of (i) sensitivities, in which a single variable was tested, and (ii) scenarios, in which multiple variables were tested in combination. In order to fully understand the uncertainty of the evaluations, a comprehensive review was conducted of all the variables that contributed to the economic evaluations.

Analysis demonstrated that three of these variables had the most significant impact on the economic evaluations:

- energy market prices (natural gas and electricity)
- capital cost of new supply
- Manitoba Hydro discount rate (cost of capital).

The reference assumptions (i.e. most likely conditions) were combined with low and high assumptions for each of these three variables to create 27 (3 X 3 X 3) scenarios applied to each of the 15 plans, resulting in 405 (27 X 15) distinct cases. (The two wind generation plans are not included in the tables and figures). Probabilities were then assigned to the scenarios to determine the expected value for each development plan. Tables 2 and 3 summarize the resulting analysis and cases.

These 27 cases for each plan are combined using their respective probabilities to create cumulative probability curves for each plan which are a standard representation of this analysis. These curves were used to assess the relative attractiveness and risk profile of each plan under a broad range of potential future outcomes. The curves for selection of main plans are depicted

in Figures 3 and 4. An explanation of cumulative probability curves can be found in ***Chapter 10 - Economic Uncertainty Analysis - Probabilistic Analysis and Sensitivities***, Section 10.1.4.1 of the submission.

Table 2 depicts the economic evaluation comparisons to account for uncertainties in the export/gas prices, capital cost and discount rate. There are 27 scenarios comprising all the combinations of high, reference and low for each of the three parameters export/natural gas prices, capital cost and discount rate. Green and red shadings are used to indicate the relative favourability or un-favourability of results.

At the top of the table there is reference to five "pathways". Such groupings recognize the need for flexibility as to how any development plan will unfold over the long-term after the initial decisions are made at the completion of the NFAT process in mid-2014. The pathways are thus representative of the outcomes flowing from the choices that will be decided upon as the next step in Manitoba's electricity future. Some of the questions addressed in the pathway analysis include:

- Should the next major electrical resource in Manitoba be gas or hydro? (i.e., a choice between Pathway 1 and one of the other pathways)
- Should a 250 MW interconnection proceed along with the 250 MW MP sale? (i.e., should Pathway 3 proceed?)
- Should a 750 MW interconnection proceed along with the 250 MW MP sale? (i.e., should Pathway 4 proceed?)
- Should a 750 MW interconnection proceed along with the 250 MW MP sale, 300 MW WPS sale and transmission development agreements with both MP and WPS? (i.e., should Pathway 5 proceed?)

Pathways 4 and 5 are both associated with the Preferred Development Plan because, compared to the other pathways, the single most defining feature of the Preferred Development Plan relative to the other plans is the 750 MW interconnection. The main difference between

Pathway 4 and 5 is that in Pathway 5 it is assumed there is a concluded sale and related transmission development agreement with WPS, while in Pathway 4 this is not the case.

Table 2 NET PRESENT VALUE BENEFITS OF ALTERNATIVE DEVELOPMENT PLANS UNDER 2012 HIGH, REFERENCE AND LOW ASSUMPTIONS FOR ENERGY PRICES, CAPITAL COSTS AND DISCOUNT RATES

Pathway			Pathway 1			Pathway 2		Pathway 3			Pathway 4			Pathway 5	
Development Plan			1	7	8	2	10	4	13	11	6	15	12	5	14
			All Gas	SCGT/C26	CCGT/C26	K22/Gas	K22/C29	K19/Gas24 /250Mw	K19/C25 /250MW	K19/C31 /250MW	K19/Gas31 /750MW	K19/C25 /750MW	K19/C31 /750MW	K19/Gas25 /750MW	K19/C25 /750MW
														WPS Sale & Investment	
Energy Prices	Discount Rates	Capital Costs	Millions of 2014 NPV dollars												
Low	Low	H	0	734	514	251	-22	853	584	537	625	401	489	1188	1202
		Ref	0	648	567	517	263	1172	925	883	919	872	911	1433	1639
		L	0	592	620	657	474	1357	1178	1148	1072	1217	1224	1544	1955
	Ref	H	0	-834	-1068	-749	-2076	-448	-2047	-1698	-729	-2353	-1861	-267	-1692
		Ref	0	-790	-913	-487	-1704	-114	-1576	-1258	-393	-1768	-1362	49	-1137
		L	0	-744	-779	-342	-1428	87	-1223	-926	-202	-1335	-993	224	-730
	High	H	0	-1488	-1721	-1179	-2863	-1087	-3233	-2617	-1386	-3587	-2826	-1001	-3014
		Ref	0	-1385	-1521	-923	-2462	-744	-2701	-2141	-1029	-2950	-2299	-648	-2406
		L	0	-1292	-1352	-778	-2165	-534	-2303	-1787	-817	-2478	-1914	-440	-1958
Ref	Low	H	0	3253	3310	2502	4174	3218	5220	4680	2973	5511	5013	2910	5866
		Ref	0	3167	3364	2768	4458	3537	5561	5026	3267	5983	5435	3155	6304
		L	0	3111	3417	2908	4669	3721	5814	5291	3420	6327	5749	3266	6620
	Ref	H	0	694	628	625	434	1012	823	775	756	841	861	780	1141
		Ref	0	738	784	887	806	1346	1295	1215	1091	1427	1360	1097	1696
		L	0	784	917	1031	1083	1547	1648	1547	1282	1860	1729	1272	2103
	High	H	0	-429	-544	-218	-1140	-50	-1199	-917	-310	-1306	-942	-268	-1040
		Ref	0	-325	-344	39	-739	292	-668	-441	47	-669	-416	86	-432
		L	0	-233	-175	184	-441	503	-269	-87	259	-196	-30	294	16
High	Low	H	0	6079	6411	4936	8790	5742	10254	9230	5428	10890	9844	4740	10807
		Ref	0	5993	6465	5202	9074	6062	10595	9576	5722	11361	10266	4985	11244
		L	0	5937	6518	5342	9285	6246	10849	9841	5875	11706	10580	5096	11560
	Ref	H	0	2398	2494	2099	3172	2556	3903	3466	2285	4151	3729	1871	4098
		Ref	0	2442	2649	2361	3543	2890	4375	3906	2620	4736	4228	2187	4653
		L	0	2489	2783	2505	3820	3091	4728	4238	2812	5170	4597	2362	5060
	High	H	0	747	742	807	725	1036	961	917	783	1027	1019	482	994
		Ref	0	850	942	1064	1126	1379	1492	1392	1141	1664	1546	835	1602
		L	0	943	1111	1208	1424	1589	1891	1747	1353	2136	1931	1043	2050

Colour Legend: < -3000 | 0 | > 3000

Table 3 further analyses these results by providing the probabilistic average of the differences for each plan relative to the All Gas Plan and provides an indication of the upper and lower range of benefits each plan would be able to achieve.

Table 3 DEVELOPMENT PLAN ECONOMIC EVALUATION SUMMARY

Pathway	Pathway 1			Pathway 2		Pathway 3			Pathway 4			Pathway 5	
	All Gas with no new interconnection			Keeyask with no new interconnection		Keeyask with 250 MW new interconnection (MP Sale)			Keeyask with 750 MW new interconnection (MP Sale)			Keeyask with 750 MW new interconnection (WPS & MP Sales)	
Development Plan	1	7	8	2	10	4	13	11	6	15	12	5	14
	All Gas	SCGT/C26	CCGT/C26	K22/Gas	K22/C29	K19/Gas24 /250MW	K19/C25 /250MW	K19/C31 /250MW	K19/Gas31 /750MW	K19/C25 /750MW	K19/C31 /750MW	K19/Gas25 /750MW	K19/C25 /750MW
												WPS Sale & Investment	
	Millions of 2014 NPV dollars												
Ref-Ref-Ref NPV	0	738	784	887	806	1346	1295	1215	1091	1427	1360	1097	1696
Expected Value Difference From All Gas	0	525	529	634	418	1041	782	806	776	830	891	842	1155
90th Percentile - "Reward"	1905	1956	2070	2007	2601	2479	3180	2953	2215	3360	3220	2256	3377
10th Percentile -"Risk"	-3502	-1217	-1424	-1249	-1692	-898	-1988	-1362	-1181	-2186	-1594	-828	-1429

"Ref-Ref-Ref NPV" = results for reference scenario assumptions for energy prices, capital costs and discount rate (relative to All-Gas reference case result)

"Expected Value" = probabilistic weighted average of results for each of the 27 scenarios (relative to All-Gas Expected Value)

"90th Percentile-Reward"= 90th percentile probability upside benefit potential of that plan (relative to All-Gas reference scenario result)

"10th Percentile-Risk"= 10th percentile probability downside risk of that plan (relative to All-Gas reference scenario result)

Figure 3 PROBABILITY CURVES FOR 3 PLANS:
ALL GAS, 250 MW INTERCONNECTION 750 MW INTERCONNECTION & WPS

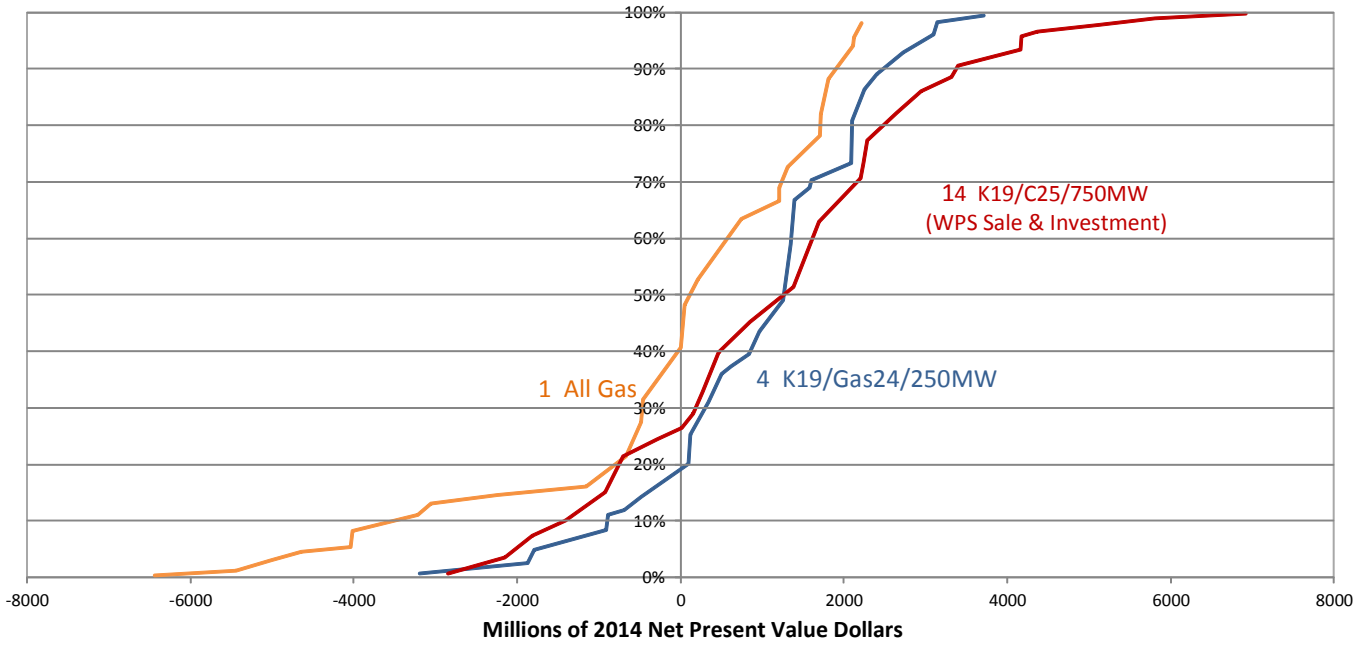
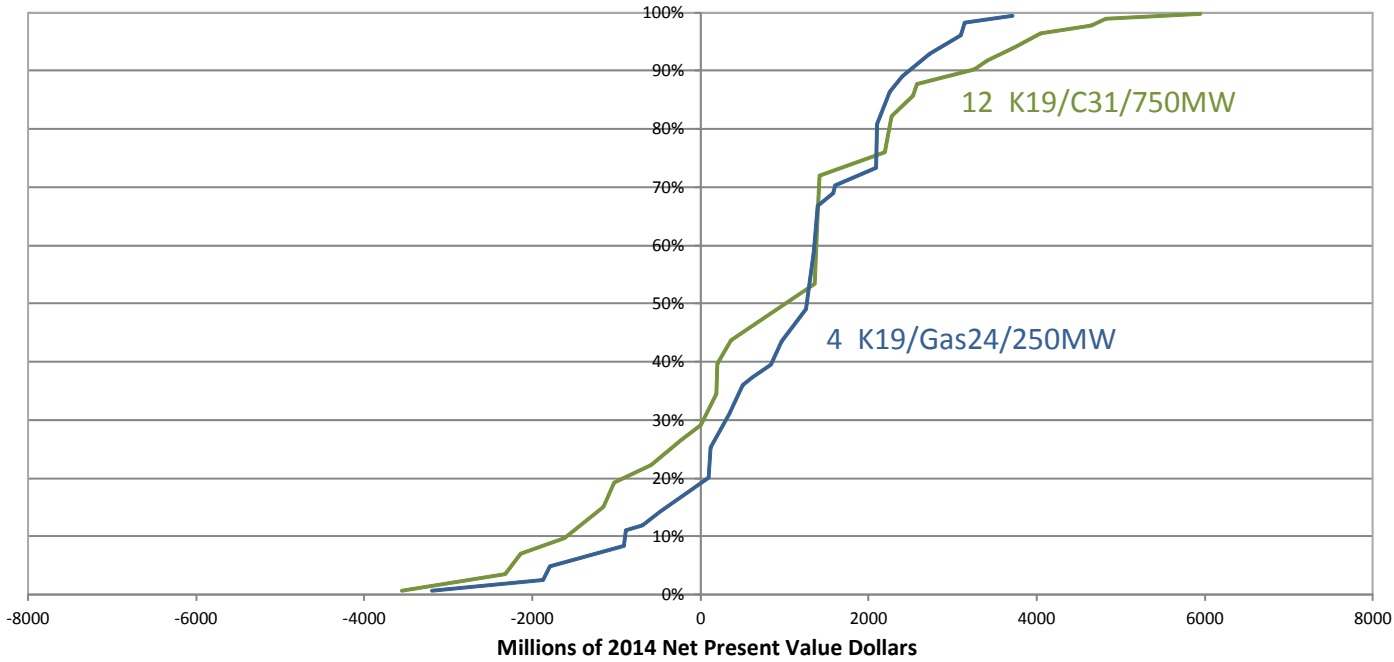


Figure 4 PROBABILITY CURVES FOR 2 PLANS: 750 MW INTERCONNECTION WITH
& WITHOUT WPS



The brief conclusions from the economic evaluations summarized above and contained in ***Chapters 9 - Economic Evaluations - Reference Scenario*** and ***Chapter 10 - Economic Uncertainty Analysis - Probabilistic Analysis and Sensitivities*** are:

- For plans with no new interconnection:
  - Plans with hydro next and no interconnection are clearly more economic than the All Gas Plan.
  - Plans with Keeyask G.S followed by Gas and no interconnection are more economic than plans with Conawapa G.S next.
- Plans with either 250 MW or 750 MW new interconnections are clearly more economic than plans with no new interconnections.
- Comparing plans with a 250 MW new interconnection (Pathway 3) and a 750 MW new interconnection but without the proposed 300 MW WPS sale (Pathway 4), the economic evaluations indicate no clear overall preference between Pathways 3 and 4 and suggest that:
  - If there is an expectation Conawapa will be built within the next two decades, the 750 MW interconnection (Pathway 4) is more economic.
  - If there is an expectation Conawapa will not be built for several decades, the 250 MW interconnection (Pathway 3) is more economic.
- The most economic plan with the 250 MW interconnection (Pathway 3) is more economic than the most economic plan with the 750 MW interconnection (Pathway 4).
- The Pathway 5 plan with the proposed 300 MW WPS Sale and WPS Transmission Agreement and Keeyask G.S. followed by Conawapa G.S. is generally more economic than the other plans. However, under certain scenarios it is less economic. One driver of such cases is when energy prices are low; this can be mitigated by displacing Conawapa G.S. with gas generation.
- The economic evaluations undertaken conclusively demonstrate that Pathway 3, 4 and 5 plans are clearly preferred to Pathway 1 and 2 plans. However, a clear and decisive preference between the 250 MW and 750 MW interconnection plans (Pathways 3, 4

and 5) cannot be established on the basis of only these evaluations but must consider additional information such as:

- qualitative consideration of factors not currently included in economic (and financial) evaluations such as the outcome of WPS negotiations, possible alternate or additional export agreements and updates to interconnection capital costs
- financial and multiple accounts evaluations
- flexibility and risks
- reliability and energy security
- environmental and socio-economic impacts and benefits.

Financial Evaluation of Development Plans

The financial evaluation was performed on 8 development plans that provide a representative sample of the range of potential plans with respect to the economics as well as mix of generation resources. The financial evaluation was prepared using information from pro forma financial statements that utilize the same framework for scenario uncertainty analysis that is used in the economic uncertainty. This resulted in 27 (3 x 3 x 3) scenarios for each of the 8 plans, for a total of 216 pro forma financial statements. The financial evaluation focused on the comparative impact on future customer rates and Manitoba Hydro's comparative exposure to financial risk of the various development plans.

Recognizing that during the capital investment period associated with new generation there will be downward pressure on Manitoba Hydro's financial ratios, the financial evaluation assumes even-annual rate increases in order to achieve the targeted debt:equity ratio of 75:25 by the end of 2031/32. Once the debt:equity target is reached, the projected annual rates for the remainder of the 50-year financial forecast period are calculated to maintain the corporation's interest coverage ratio target of 1.20. The financial evaluation has not been designed to establish specific rate strategies but to compare impacts on rates and on Manitoba Hydro's financial strength among alternative plans.

The following table sets out the projected key financial metrics for the 8 development plans evaluated, including cumulative nominal rate Increases by 2061/62 - compared to All Gas, projected even-annual rate increases (2014/15 to 2031/32), equivalent even-annual rate increases over the forecast period (50-years), the nominal balances of net fixed assets, net debt and retained earnings as at 2031/32 and 2061/62. The projected financial metrics are summarized from the pro forma financial statements using reference assumptions.

Table 4 FINANCIAL EVALUATION SUMMARY

Pathway	Interconnection	Development Plan	(A) Cumulative Nominal Rate Increases by 2061/62 - Compared to All Gas	(B) Projected Even-Annual Rate Increases (2014/15 to 2031/32)	(C) Equivalent Even-Annual Rate Increases over the Forecast period (50 Years)	(D) Net Fixed Assets	(E) Net Debt	(F) Retained Earnings	(G) Net Fixed Assets	(H) Net Debt	(I) Retained Earnings
						As at 2031/32 in Billions of Nominal Dollars			As at 2061/62 in Billions of Nominal Dollars		
1	No New Interconnection	1 All Gas	-	3.43%	2.07%	$20.2	$14.7	$4.8	$31.8	$15.5	$10.7
		7 Gas C26	-42%	3.86%	1.72%	$28.1	$20.4	$6.7	$34.4	$14.6	$13.7
2		2 K22 Gas	-36%	3.49%	1.77%	$25.3	$18.4	$6.0	$33.9	$15.3	$12.8
3	250 MW Interconnection	4 K19 Gas 250 MW	-33%	3.42%	1.80%	$24.8	$18.1	$5.9	$34.0	$15.6	$12.6
		13 K19 C25 250 MW	-65%	3.98%	1.50%	$32.7	$23.8	$7.9	$36.7	$15.0	$15.6
4	750 MW Interconnection	12 K19 Imp C31 750 MW	-65%	3.80%	1.50%	$35.2	$25.7	$8.5	$38.6	$15.6	$16.8
		6 K19 Imp Gas 750 MW	-33%	3.50%	1.79%	$25.0	$18.2	$6.0	$33.6	$15.2	$12.6
5		14 K19 Sales C25 750 MW	-70%	3.95%	1.44%	$32.9	$24.0	$7.9	$36.8	$15.1	$15.7

The following summarizes the financial evaluations, with a focus on the comparative impact on future customer rates and Manitoba Hydro's comparative exposure to financial risk:

Future Customer Rates

- Rate increases are required for all evaluated alternatives. The financial evaluation shows that higher rates are required in the medium term under all of the development plans, regardless of whether the plan is gas-based or hydro-based. New energy supply cannot be provided at the same current low rates that Manitoba Hydro customers have enjoyed over the last two decades.
- In the long-term, development plans with both Keeyask and Conawapa G.S. are projected to have the lowest cumulative rate increases which range between 65% to 70% lower than the All Gas plan under the reference scenario. Development plans with both Keeyask and Conawapa G.S. provide incremental dependable and surplus energy which translate to savings for Manitoba customers in the long run.
- In the medium term, the capital intensive plans that include both Keeyask and Conawapa G.S. are projected to have cumulative rate increases that are generally higher than other alternatives. Cumulative rates under the Preferred Development Plan "cross-over" compared to all other plans and begin to provide benefit to customers in a relatively short timeframe (10-15 years) following the ISD of the Conawapa G.S.
- The Preferred Development Plan is projected to have the lowest overall rates to Manitoba customers in the long-term.

Financial Risk

- In the long-term, development plans that include Keeyask and Conawapa G.S. have the strongest projected balance sheet with high levels of fixed assets and retained earnings. By the end of the study period retained earnings are projected to be between $4.9 billion to $6.1 billion higher than the All Gas plan.
- Net debt levels converge towards the end of the study period for all development plans.

- In the medium term, while net debt levels are the highest with the development plans that include both Keeyask and Conawapa G.S., as these plans have the overall highest capital investment, they also have the highest fixed assets and retained earnings.
- Development plans with both Keeyask and Conawapa G.S. are more robust in their ability to absorb adverse financial impacts, in the medium term and extending through to the end of the study period, given their comparatively higher level of retained earnings.

2013 Update to Forecasts and DSM Sensitivities

The economic and financial evaluations discussed above were based on the 2012 load forecast and other related planning assumptions, with the export price forecast adjusted, primarily downward in anticipation of 2013 updates. The following factors have changed for the 2013 analysis compared to the NFAT analysis:

- domestic load forecast is slightly lower
- export price forecasts are approximately 7% higher
- real discount rate has increased from 5.05% to 5.4%
- an export arrangement (the Great River Diversity Exchange) is extended to end in 2030 instead of 2025.

As a consequence of these changes, ISDs for new generation have been deferred by approximately 1-year, and NPVs have changed, though not to a degree that alters the conclusions as the relative ranking between the respective plans and pathways remains the same.

A sensitivity was undertaken using an increased level of DSM equal to 1.5 times the 2013 DSM forecast and a stress test was also undertaken using an increased level of DSM equal to 4.0 times the 2013 DSM forecast. The sensitivity and stress test demonstrated that increasing the DSM within a reasonable range (1.5 times) and for an ideal range (4.0 times): 1) did not change the conclusion that the plans with 750 MW or 250 MW interconnections are clearly more

economic compared to plans without new exports or new interconnection and 2) did not change the relative rankings of the 750 MW and 250 MW plans with respect to each other. Based on these results, it was not necessary to further include different levels of DSM in the detailed evaluations of the development plans to be able to assess the attractiveness of the plans with the new interconnections and exports.

In addition, some recent developments of strategic significance are:

WPS Export Sale and Transmission Investment Agreement Status

The proposed 300 MW WPS Export Sale and the transmission investment arrangements with WPS and MP are still in negotiation as of early August 2013 while this NFAT submission is being finalized. As noted earlier, WPS recently advised that they will not invest in the 750 MW interconnection transmission line but will still negotiate the 300 MW Power Purchase Agreement.

Concurrently, negotiations are proceeding between MP and Manitoba Hydro to revise the arrangement with MP to increase their investment in and ownership of the 750 MW Interconnection. Manitoba Hydro would increase its investment and ownership but would not become a majority owner.

It should be noted that, unlike the 300 MW WPS Sale, the 250 MW MP Sale Power Purchase Agreement is final, has been signed and has been approved by MP's state regulator but is still subject to other regulatory approvals in the U.S. and Canada.

Manitoba Hydro Investment in a 750 MW Interconnection

The evaluations of Pathways 4 and 5 assume that Manitoba Hydro will be investing in and owning a portion of the U.S. segment of the 750 MW, 500 kV interconnection and that the percentage amount owned stays constant for the life of the interconnection asset. It will be Manitoba Hydro's intent to arrange for some or all of the Manitoba Hydro ownership to be

transferred to another owner for the economic benefit of Manitoba Hydro as soon as an appropriate opportunity can be developed.

Decrease in Capital Cost Estimates for U.S. Portion of 750 MW Interconnection

Recent more detailed cost estimates are indicating that the costs of the U.S. portion of the 750 MW interconnection will be less than originally estimated. This would improve the economics of the interconnection in Pathways 4 and 5.

Other Potential Firm Export Sales in the U.S. and Canada

The MP and WPS sales will only utilize part of the 750 MW export capacity of the 750 MW interconnection leaving capacity available for long-term export contracts for additional sales to Wisconsin, Minnesota and to other utilities. In addition, early Conawapa G.S. would enable the extension of the 375/500 MW NSP sale which currently ends in 2025. This extension requiring advancement of Conawapa G.S. would benefit the economics of the 750 MW interconnection plans; the 250 MW plans would not benefit as much because the 250 MW interconnection would be already utilized by the 250 MW MP Sale.

In addition, Manitoba Hydro is in active negotiations with SaskPower regarding long-term export sale possibilities up to 500 MW, along with Saskatchewan interconnection transmission additions required to enable the sale. A sale would require early Conawapa G.S. (e.g. in-service prior to 2030). The excess power from Conawapa G.S. would also be exported over the U.S. 750 MW interconnection and improve its economics.

Integrated Comparisons of the Development Plans – Multiple Account Analysis

The results of a multiple account benefit-cost analysis (MA-BCA) are presented in ***Chapter 13 - Integrated Comparisons of Development Plans - Multiple Account Analysis***. The analysis compares Manitoba Hydro's Preferred Development Plan to a plan with a smaller interconnection and less firm export sales (K19/Gas 24/250MW), and two plans without a new

interconnection and firm export sales, one with Keeyask (K22/Gas) and one assuming All Gas to meet growing Manitoba requirements.

MA-BCA is a variant of traditional cost-benefit analysis. It extends Manitoba Hydro's economic evaluation of the different plans to take into account consequences and net benefits or costs for customers, taxpayers, workers and the economy, the environment, affected communities and Manitobans generally. These net benefits and costs are not reflected in the NPV of the different plans from the perspective of Manitoba Hydro and its project partners. The MA-BCA is intended to assist the NFAT panel address the question of the overall socio-economic benefit of the preferred and alternative plans, and more specifically the relative advantages and trade-offs they entail.

MA-BCA recognizes that not all consequences can be monetized in order to calculate a 'bottom line'; as well there are important distributional consequences that need to be considered in the assessment of the relative advantages or disadvantages and trade-offs that the different plans entail. The results of the MA-BCA are presented under a disaggregated set of evaluation accounts:

- market valuation
- customers
- government
- Manitoba economy
- environment
- social
- risk.

Table 5 presents a summary of the findings based on the NFAT Reference Scenario set of assumptions, with monetized values reported relative to the Preferred Development Plan (positive values indicating a net advantage relative to the Preferred Development Plan and negative values a net cost disadvantage).

Table 5 SUMMARY OF MULTIPLE ACCOUNTS ANALYSIS - REFERENCE SCENARIO ASSESSMENT

	Preferred Development Plan	K19/G24/250MW	K22/Gas	All Gas
Market Valuation • Net revenues (cost) to MH and partners	--	17.0	(270.5)	(654.1)
Customer Account • Cumulative rate increase	Preferred Development Plan has the lowest projected rate increases over long-term, with the highest projected rate increases in first 20 years.			
• Reliability	Preferred plan and to lesser extent the alternative with the smaller interconnection provides greater load carrying capability, lower expected loss of unserved energy and greater ability to manage extreme drought			
Government • Incremental revenues net of costs/risk	--	(353.5)	(395.9)	(674.2)
Manitoba Economy • Employment net benefits	--	(123.7)	(150.0)	(260.3)
Environment • Manitoba GHG external cost	--	(208.6)	(174.3)	(320.3)
• Global GHG impact	Preferred plan and to lesser extent the two plans with Keeyask would contribute to a reduction in global emissions by displacing thermal generation in US.			
• Manitoba CAC damage cost	--	(8.6)	(7.1)	(13.3)
• Residual biophysical	Aquatic and terrestrial impacts with hydro projects in preferred plan and plans with Keeyask; subject to detailed environmental hearings, residual effects and local external cost expected to be relatively small with initial design, extensive mitigation, monitoring, compensation and benefit-sharing arrangements.			
Social • Partner net return	Significant net returns from up to 25% interest in Keeyask and income benefits from Conawapa in preferred plan; significant benefits from up to 25% interest in two alternatives with Keeyask, greater with new sales and interconnection.			
• Community impacts	Wide range of potential impacts on local employment and business; population, infrastructure and service; social and community well-being; owners of land needed for rights of way and easements; major commitments and plans to minimize adverse residual effects with extensive mitigation, monitoring, compensation and partnership arrangements.			
• Other Manitoba	Potentially significant bequest value from the hydro assets remaining at end of planning period; greatest with preferred plan and to a lesser extent in the alternatives with Keeyask.			
Overall Monetized Net Benefit (Cost)	**--**	**(677.4)**	**(997.4)**	**(1922.2)**

(2014 Present Value in millions 2014$)

Overall, the main conclusions of the MA-BCA are as follows:

- Developing Keeyask G.S. to meet domestic load offers significant net benefits relative to the All Gas plan not only for Manitoba Hydro but also more broadly to society as a whole; it offers significant tax, employment, GHG and social benefits that go beyond the benefits to Manitoba Hydro.
- Plans that include a new interconnection offer significant net benefits to those that don't. They significantly enhance the net benefits for Manitoba Hydro and its partners.
- The alternative with the 250 MW interconnection and the development of Keeyask G.S. but not Conawapa G.S. offers the same expected net benefit to Manitoba Hydro and its partners as the Preferred Development Plan, without the short- to medium-term rate trade-off that the Preferred Development Plan gives rise to. At the same time it doesn't offer the same long-term legacy value or upside potential as the Preferred Development Plan. Nor does it offer the long-term rate, tax, employment, GHG and social benefits as the Preferred Development Plan.
    - The Preferred Development Plan offers the lowest rate impacts for the long-term and significantly greater benefits to society as a whole than the smaller tie alternative. It does, however, require higher rate increases in the short- to medium-term than the other plans. The more weight one places on the broader public interest consequences and the longer term effects, the more one would favour this plan.

Conclusions – Which Development Plan and Pathway to Choose

Planning for Uncertainty

The economic, financial and multiple accounts evaluations by necessity considered mainly plans with specific choices of generation options and timing. For example, the Preferred Development Plan was put forward as "Keeyask ISD 2019 followed by Conawapa ISD 2025," while the Natural Gas Plan was put forward as "Natural Gas Generation in 2022 followed only

by Natural Gas Generation in subsequent years." Clearly, in reality, such choices are not rigidly frozen but rather will respond over time to evolving conditions and societal expectations.

Load growth, Power Smart plans, new export contracts, natural gas price forecasts, export price forecasts, capital cost estimates, retirement of existing gas generation and other parameters will be continually monitored and reviewed. There are certain circumstances in which the passage of time will make updated information or learnings available, which can reduce uncertainty and allow decisions to be made more confidently in the future than if they were made now. For example, deciding the start of Conawapa construction in 2018 for a 2026 ISD would have 4 years less uncertainty than if that decision were made in 2014, more than 12 years in advance of the ISD.

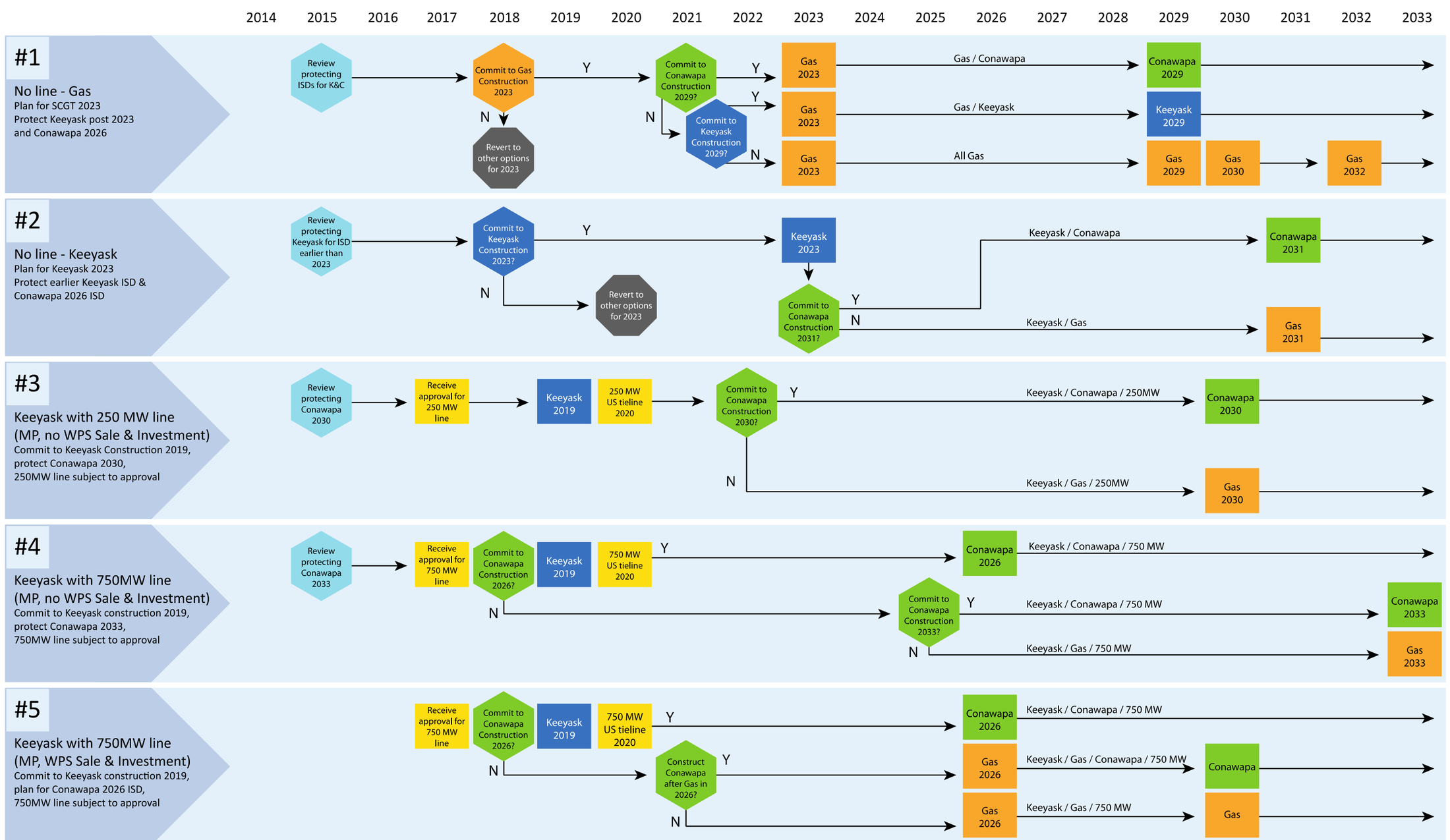
Alternative Development Pathways

The long-term flexibility to respond to events or the trajectory of critical parameters as they unfold over time is fundamental to managing risks and dealing with uncertainties. It is useful to consider the evaluations not as leading to a choice between fixed plans with fixed in-service dates, but rather a choice between different pathways. The five general approaches for "development plan implementation pathways" identified here are representative of the choices to be decided upon as the next step in Manitoba's electricity future:

- Pathway 1 Gas Only, No New Interconnection, No New Exports – domestic load only
- Pathway 2 Keeyask 2023, No New Interconnection, No New Exports – domestic load only
- Pathway 3 Keeyask 2019, 250 MW Interconnection, Small Export - 250 MW MP sale and 125 MW NSP extension; no WPS sale
- Pathway 4 Keeyask 2019, 750 MW Interconnection, Small Export - 250 MW MP sale and 125 MW NSP extension; no WPS investment in interconnection and no sale
- Pathway 5 Same as Pathway 4 but with Large Export - e.g. also includes WPS sale and investment in interconnection.

Figure 5 chronologically presents the decisions and options associated with each pathway.

Figure 5 PATHWAY DECISION TREE - ISDs BASED ON 2013 LOAD FORECAST AND RELATED ASSUMPTIONS



In-depth comparisons of the five pathways are contained in ***Chapter 14 - Conclusions*** of the submission. The Preferred Development Plan is included within Pathway 5 if the WPS sale is successfully concluded and in Pathway 4 if it is not. Both cases assume Keeyask in 2019, the 750 MW interconnection and the MP and NSP sales. Both cases provide the flexibility, if conditions change, to defer Conawapa or replace it with natural gas generation.

The use of pathways recognizes the reality that plans are continuously modified over time. A current example of such a modification is that the Conawapa planned ISD was recently deferred from 2025 to 2026 in association with a drop in the Manitoba load growth forecast.

In the future, if the Preferred Development Plan were adopted but then natural gas and export prices were found to be following a low price trajectory, Conawapa could be deferred or could be completely displaced with other new generation such as natural gas. Similarly, Conawapa could be delayed if there were a major reduction in forecast load growth or a major increase in power savings resulting from DSM.

Overall Conclusions

The economic, financial, multi-account and pathways analyses lead to the following broad conclusions in regard to the components, timing, expected impacts and risk/reward characteristics of Manitoba Hydro's Preferred Development Plan.

Components of Preferred Development Plan

- A plan comprising only natural gas additions is **not** attractive, economically, financially or environmentally.
- Plans which include the **new transmission interconnection and related hydro export sales** provide the highest expected economic and financial benefits in the long-term compared to plans with no new interconnection, whether they involve hydro or gas generation.
- **Keeyask** is the best option to meet the electricity supply gap in the early 2020s because it provides clean renewable energy and superior economic returns compared to natural gas

generation. Also, Keeyask's pre-construction phase is already underway and is supported by the in-vicinity Aboriginal communities.

- **Conawapa** is the more economic supply option after Keeyask in cases in which a large (750 MW) interconnection is installed. If the interconnection is smaller (250 MW), natural gas generation is more economic.
- **DSM** could be doubled or tripled without affecting the conclusions on the favourability ranking of plans with these components.

Timing

- Keeyask would come into service in 2019. The date could be deferred until 2023 if a decision were made not to proceed with the U.S. interconnection or related new export sales and net load did not increase. However, such a decision would give up substantial benefits and close the door to new export opportunities and a new interconnection for the foreseeable future.
- Conawapa could come into service at the earliest in 2026/27. Based on the 2013 load forecast and other 2013 assumptions, the date could be deferred to 2033 if the WPS sale or other attractive new export sales are not concluded. Activities would continue to protect an ISD for Conawapa as early as 2026, but conditions which are pertinent to this schedule will be continually monitored to determine if such continued investments are worthwhile and, ultimately, to determine if Conawapa should be constructed, for what ISD and if protection of an early ISD is warranted.
- The new interconnection is expected to receive U.S. approvals by no later than 2017 before Conawapa construction must be committed for a 2026 ISD.

Risk and Reward

- The Preferred Development Plan demonstrates greater economic variability (greater upside and downside) than plans which do not include new export sales and which are focused only on serving Manitoba needs.

- Financial resources may be strained in the medium-term if Conawapa is constructed for 2026 and if adverse conditions occur in the same time frame (e.g. higher capital costs, lower energy prices, low regional load growth, drought etc.).
- However, financial and other risks are mitigated by the ability to defer Conawapa or substitute gas generation if considered prudent to do so over the next few years.
- Greater variability also brings the possibility of higher reward. If energy prices are higher than forecast or even evolve as currently expected, the long-term benefits of the Preferred Development Plan could be substantially increased.
- Plans with the 750 MW interconnection provide overall the most flexibility to manage risks such as higher or lower load growth, uncertainty in level of future DSM, severe drought and increases and decreases in river flows due to climate change and to take advantage of future opportunities such as other export sales in addition to or instead of WPS.

Expected Benefits

Under expected conditions, the plans which include Keeyask 2019, 750 MW interconnection, new export sales, and Conawapa are generally expected to have the following positive impacts relative to other alternatives:

- Lower long-term customer rates (though generally higher during upcoming periods of construction).
- Supports Manitoba Hydro's long-term fiscal health with higher levels of fixed assets and retained earnings, which provide enhanced protection against adverse events such as severe drought.
- Highest level of system reliability (e.g. to deal with generation or major transmission outages or unexpectedly high load peaks) and energy security (e.g. to deal with unexpectedly severe droughts or unexpectedly high energy consumption).
- Greatest number of jobs and socio-economic benefits.
- Lowest GHG emissions and greatest support for Manitoba Clean Energy Strategy.
- Benefits to Aboriginal communities in the vicinity of the new dams.

- Use of Manitoba's renewable hydro resources rather than carbon-based energy from out of province.
- Largest payments to the Province through taxes and fees.
- Provision of an infrastructure legacy for future generations.

In summary the Preferred Development Plan as discussed on page 1 of this ***Executive Summary*** is preferred because it offers the greatest flexibility and largest range of potential benefits of any of the options examined.

Implementation and Risk Management Plan

Manitoba Hydro has a well-developed and comprehensive approach to undertake the plan and manage the risks of the Preferred Development Plan. This approach includes an implementation schedule containing portfolio risks, potential impacts and decision points. This schedule and a full range of risk mitigation measures are discussed throughout the submission and, in particular, in ***Chapter 15 – Implementation and Risk Management Plan for Preferred Development Plan***.

Tab 45

Provincial and Territorial Energy Profiles – Manitoba



Energy Production

Crude Oil

- In 2018, Manitoba produced 40 thousand barrels per day (Mb/d) of light crude oil (**Figure 1**). Manitoba accounted for less than 1% of total Canadian crude oil production (including condensate and pentanes plus).
- All of Manitoba's current oil production is located in the southwestern corner of the province.
- Manitoba's remaining resource of crude oil is estimated to be 747 million barrels when production to year-end 2018 is subtracted.

Refined Petroleum Products (RPPs)

Connect/Contact Us

Please send comments, questions, or suggestions to energy-energie@cer-rec.gc.ca

Table of Contents

Energy Production
Energy Transportation and Trade
Energy Consumption and Greenhouse Gas (GHG) Emissions
More Information

Figure 1: Hydrocarbon Production

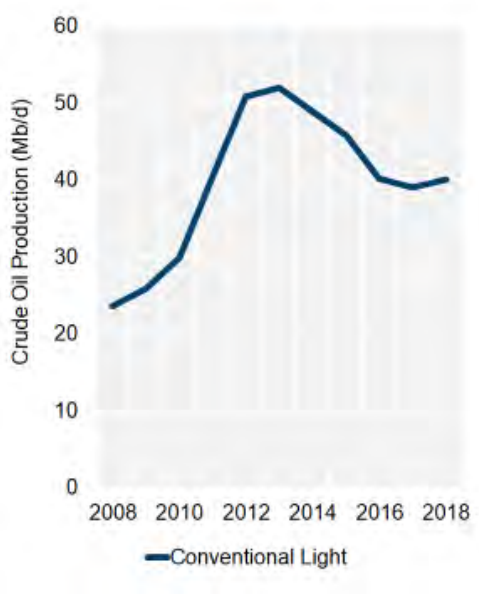
- There are no refineries in Manitoba.

Natural Gas/Natural Gas Liquids (NGLs)

- There is no natural gas or NGL production in Manitoba.

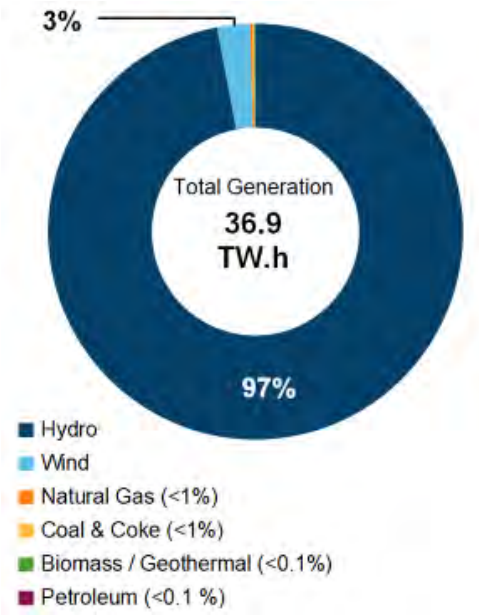
Electricity

- In 2018, Manitoba generated 36.9 terawatt hours (TW.h) of electricity (**Figure 2**), which is approximately 6% of total Canadian generation. Manitoba has a generating capacity of 6 141 megawatts (MW).
- Though 87% of Manitoba's installed generation capacity is hydroelectricity, 97% of its generation was derived from hydroelectricity. There are 15 major hydroelectric generating stations, the largest of which is located along the Nelson River (**Figure 3**).
- The Wuskwatim Generation Station on the Burntwood River was completed in 2012 with a capacity of 200 MW. This project, developed by Manitoba Hydro and the Nisichawayasihk Cree



▶ Source and Description:

Figure 2: Electricity Generation by Fuel Type (2018)

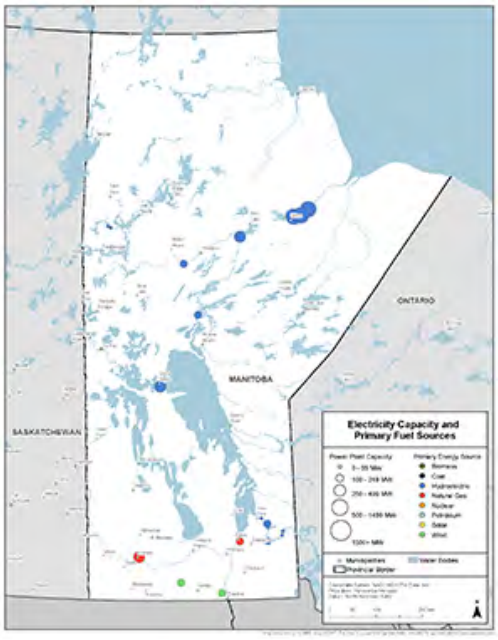


▶ Source and Description:

Figure 3: Electricity Capacity and Primary Fuel Sources Map

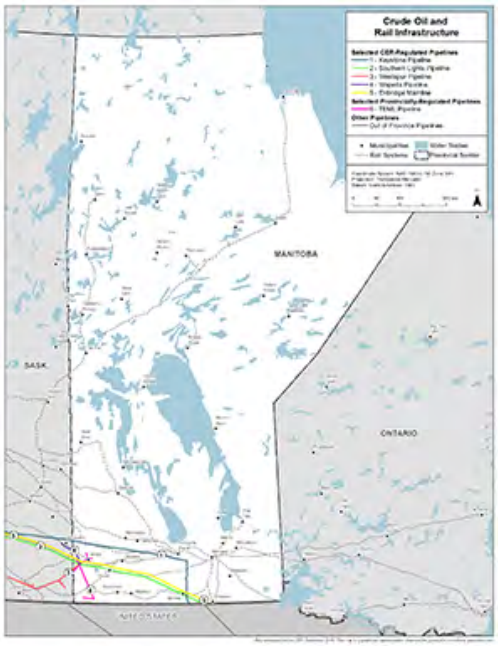
Nation, marked the first time Manitoba Hydro had entered into a formal partnership with a First Nation to develop and operate a hydroelectric project.

- Construction of the Keeyask Project 725 kilometres (km) northeast of Winnipeg on the lower Nelson River is scheduled to be completed by 2021, with its first generator expected to go into service October 2020. Once completed, Keeyask will be Manitoba's fourth largest generating station, with a capacity of 695 MW.
- In 2018, wind contributed approximately 3% to Manitoba's electricity generation. Between 2005 and 2018, over 238 MW of wind was added to Manitoba's power capacity.
- In August 2018, the last coal-fired generating unit in Manitoba ceased operation and is now being used as a synchronous condenser to help stabilize the transmission system.
- Manitoba Hydro is responsible for the design, construction, and operation of hydro facilities, and is the



▶ Source and Description:

Figure 4: Crude Oil Infrastructure Map



▶ Source and Description:

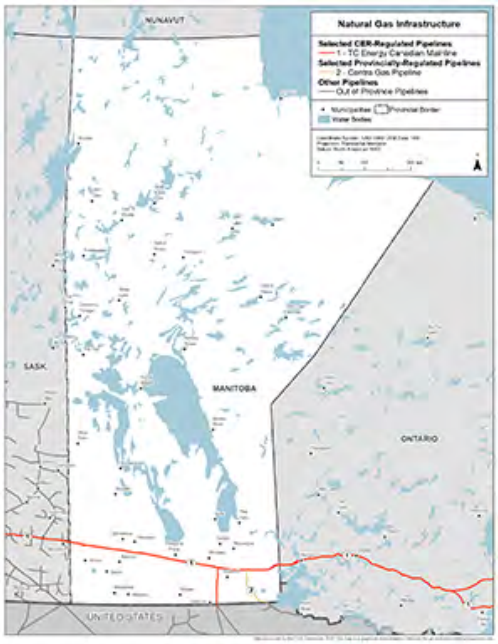
Figure 5: Natural Gas Infrastructure Map

largest producer of electricity in Manitoba. Manitoba Hydro also operates two natural gas-fired generating stations and four remote diesel generating stations. Wind, biomass, and some solar facilities are operated by independent producers.

Energy Transportation and Trade

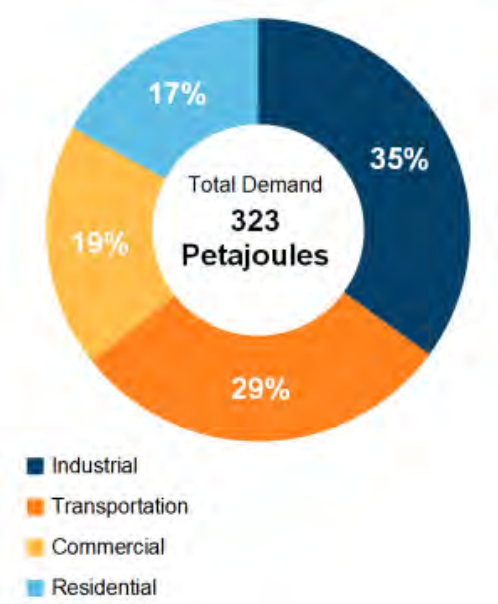
Crude Oil and Liquids

- There are two major export pipelines that pass through Manitoba: TC Energy's Keystone and Enbridge's Mainline.
- Keystone ships western Canadian crude oil from Hardisty, Alberta to U.S. Midwest refineries. Keystone also ships to the U.S. Gulf Coast markets via TC Energy's Marketlink Pipeline. Keystone delivered a record of nearly 590 Mb/d of crude oil in 2018, almost all of which was heavy oil.
- Enbridge Mainline ships western Canadian crude oil and liquids to the U.S. and Ontario markets. It enters Manitoba from



▶ Source and Description:

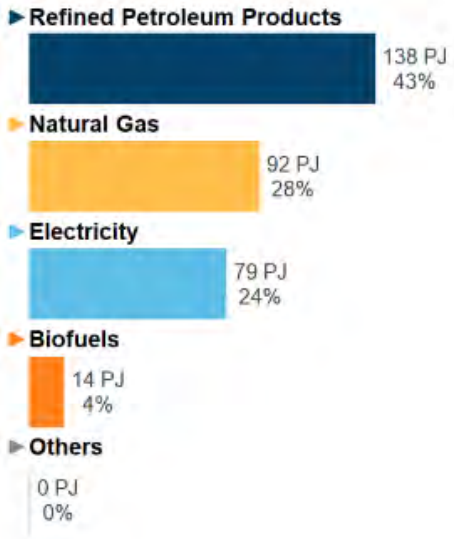
Figure 6: End-Use Demand by Sector (2017)



▶ Source and Description:

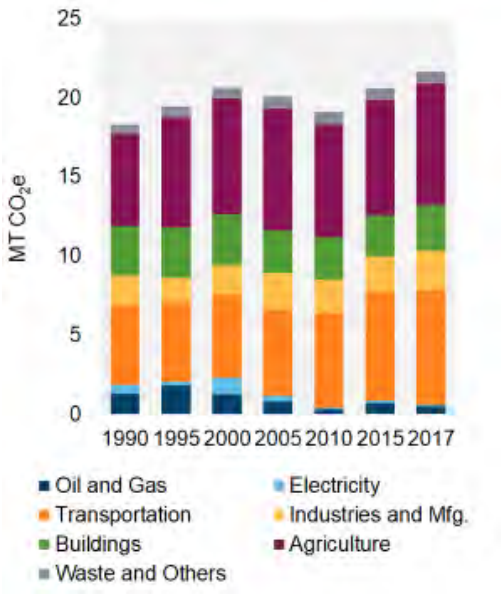
Figure 7: End-Use Demand by Fuel (2017)

Saskatchewan near Cromer, and exits at the U.S. border near Gretna, where it becomes the Enbridge Lakehead system. Enbridge Mainline is Canada's largest crude pipeline transporting nearly 2 700 Mb/d in 2018. Enbridge Mainline's Line 3 Replacement (L3R) Project is underway. The Canadian portion of L3R came into service in December 2019, while the U.S. portion is currently facing delays in receiving final approvals needed to complete construction.



▶ Source and Description:

Figure 8: GHG Emissions by Sector



▶ Source and Description:

- The Enbridge Cromer Terminal has a capacity of about 2.4 million barrels, and is the gathering point for all light and medium crude oil produced in southwestern Manitoba and southeastern Saskatchewan. The Enbridge Cromer Terminal connects the Mainline with Kingston Midstream's (formerly Tundra Energy Marketing) Westspur, Enbridge's Bakken, and Plain Midstream's Wapella pipelines (**Figure 4**). Westspur and Enbridge Bakken pipelines are two smaller pipeline systems that transport crude oil from North Dakota and south Saskatchewan to the Enbridge Mainline. The Wapella pipeline carries crude oil from southern Saskatchewan to the Enbridge Mainline.
- Enbridge's Southern Lights pipeline parallels the Enbridge Mainline in Manitoba, but it is used to import condensate from the U.S. to Alberta.
- The Winnipeg Products Pipeline delivers RPPs from the Enbridge Mainline at Gretna to Winnipeg.

- There are two crude oil rail loading facilities in Manitoba, with a total estimated capacity of 68 Mb/d. Cromer Rail Terminal, operated by Kingston Midstream, is the largest with a 60 Mb/d capacity. The CN/Watco Rail Terminal in Woodnorth is operated by Watco Terminal and Port Services.

Natural Gas

- TC Energy's Canadian Mainline crosses through southern Manitoba and carries natural gas from western Canada to markets in Manitoba, Ontario, Quebec, and the U.S. (**Figure 5**). Nearly all of the natural gas used in Manitoba is delivered on the Canadian Mainline.
- The Mainline has two interconnects at the Canada/U.S. border near Emerson, Manitoba: Emerson 1 connects with the Viking Gas Transmission Pipeline, and Emerson 2 connects with the Great Lakes Gas Transmission Pipeline. Exports averaged approximately 0.3 Bcf/d from Emerson 1 and 1.2 Bcf/d at Emerson 2 in 2018.
- Manitoba also can import gas from the U.S. at Emerson during periods of peak winter demand, although there have been no imports since 2016.
- Centra Gas distributes natural gas to over 275 000 customers in more than 100 communities in southern Manitoba. Centra is owned by Manitoba Hydro and is regulated by the Manitoba Public Utilities Board.
- A Manitoba Hydro compressed natural gas station in southwest Winnipeg provides back-up supply of natural gas for customers in southern Manitoba.

Liquefied Natural Gas (LNG)

- There are no proposed or existing LNG facilities in Manitoba.

Electricity

- In 2018, Manitoba's net electricity interprovincial and international outflows were 5.5 TW.h. Manitoba's trading partners include the U.S. Midwest, Ontario, and Saskatchewan.
- Manitoba has more than 13 800 km of electricity transmission lines and more than 75 500 km of distribution lines. Nine interconnections link Manitoba's electricity system with Saskatchewan, Ontario, and the U.S.
- Manitoba Hydro is building the Manitoba-Minnesota Transmission Line, a 500 kilovolt (kV) line in southeastern Manitoba with a projected mid-2020 in-service date. This new transmission line will allow for up to 883 MW of additional electricity to be exported to the U.S.
- The Bipole III Transmission Line was completed in July 2018, and now delivers electricity to southern Manitoba and the U.S.

- Manitoba Hydro has plans to construct a new 230 kV transmission line (the Birtle Transmission Project) to the Saskatchewan border. The new line would facilitate the sale of 100 MW of electricity from Manitoba to Saskatchewan.

Energy Consumption and Greenhouse Gas (GHG) Emissions

Total Energy Consumption

- End-use demand in Manitoba was 323 petajoules (PJ) in 2017. The largest sector for energy demand was industrial at 35% of total demand, followed by transportation at 29%, commercial at 19%, and residential at 17% (**Figure 6**). Manitoba's total energy demand was the 6th largest in Canada, and the 7th largest on a per capita basis.
- RPPs, including gasoline and diesel, were the largest fuel type consumed in Manitoba, accounting for 138 PJ, or 43%. Natural gas and electricity accounted for 92 PJ (28%) and 79 PJ (24%), respectively (**Figure 7**).

Refined Petroleum Products

- The majority of the gasoline consumed in Manitoba comes from refineries in Alberta and Saskatchewan. RPPs from Alberta are mainly transported by the Enbridge Mainline, while RPPs from Saskatchewan and elsewhere are delivered primarily by rail.
- Total 2018 demand for RPPs in Manitoba was 71 Mb/d, or 4% of total Canadian RPP demand. Of Manitoba's total demand, 35 Mb/d was for motor gasoline and 27 Mb/d was for diesel.
- Manitoba's per capita RPP consumption in 2018 was 3 101 litres (20 barrels), or 2% above the national average of 3 038 litres per capita.

Natural Gas

- Manitoba consumed an average of 213 million cubic feet per day (MMcf/d) of natural gas in 2018, which represented 2% of total Canadian demand.
- Manitoba's largest consuming sector for natural gas was the industrial sector, which consumed 84 MMcf/d in 2018. The commercial and residential sectors consumed 72 MMcf/d and 58 MMcf/d, respectively.

Electricity

- In 2017, annual electricity consumption per capita in Manitoba was 16.1 megawatt hours (MW.h). Manitoba ranked 6th in Canada for per capita electricity consumption and consumed 15% more than the national average.

- The largest consuming sector for electricity in Manitoba in 2017 was residential at 8.2 TW.h. The commercial and industrial sectors consumed 7.0 TW.h and 6.3 TW.h, respectively. Manitoba's electricity demand has grown 8% since 2005.

GHG Emissions

- Manitoba's GHG emissions in 2017 were 21.7 megatonnes (MT) of carbon dioxide equivalent (CO_2e) [1] . Manitoba's emissions have increased 18.4% since 1990.
- Manitoba's emissions per capita are 16.2 tonnes of CO_2e – 17% below the Canadian average of 19.6 tonnes per capita.
- The largest emitting sectors in Manitoba are agriculture at 35% of emissions, transportation at 33%, and buildings (residential and service industry) at 14% (**Figure 8**).
- Manitoba's GHG emissions from the oil and gas sector in 2017 were 0.5 MT of CO_2e, attributable to crude oil production and oil and gas transmission.
- Manitoba generates virtually all of its electricity from renewable sources. As such, it emits less than 0.1 MT CO_2e emissions from electricity generation, or 0.1% of total Canadian GHG emissions from power generation.

More Information

- Manitoba Public Utilities Board
- Manitoba Hydro
- Manitoba Petroleum Branch
- CER – Canada's Energy Future 2019 Report
- CER – Canada's Energy Future 2019 Supplemental Fact Sheet: Conventional, Tight, and Shale Oil Production
- CER – Market Snapshot: Of nearly 50 companies that export electricity, three account for more than half of all exports in 2019
- CER – Market Snapshot: Even though Canada exports a lot of electricity, it imports a lot too
- CER – Market Snapshot: Increasing western Canadian non-oil sands oil production varies by province
- CER – Market Snapshot: Canadian electricity exports to the U.S. focused on renewable power exports to specific markets
- CER – Market Snapshot: Canadian tight oil production decreased after 2014 due to less drilling activity

1 Data for Canada's GHG emissions are produced annually by Environment and Climate Change Canada (ECCC). GHG data for 2018 will be available on ECCC's website in April 2020.

Data Sources

Provincial & Territorial Energy Profiles aligns with CER's latest Canada's Energy Future 2019 datasets. Energy Future uses a variety of data sources, generally starting with Statistics Canada data as the foundation, and making adjustments depending on individual province/territory circumstances. Adjustments are necessary to ensure consistency and comparability across provinces/territories.

Date modified:

2020-09-29

Tab 46

Table of Contents

4 The Need for New Resources 1
4.0 Chapter Overview 1
4.1 Introduction 1
4.2 Total Demand on the Manitoba Hydro System 5
4.2.1 Manitoba Hydro's Domestic Electricity Load 5
4.2.1.1 Domestic Load Growth by Sector 9
4.2.1.2 Load Variation and Forecast Accuracy 15
4.2.2 Demand Side Management 18
4.2.2.1 Future DSM Plans 20
4.2.2.2 Assessing Economic DSM Opportunities 22
4.2.2.3 Additional DSM Opportunities 28
4.2.3 Manitoba Net Load 32
4.2.4 Export Commitments 34
4.2.5 Total Demand 34
4.3 Manitoba Hydro System Supply 35
4.3.1 Manitoba Hydro's Generation Planning Criteria 35
4.3.1.1 Capacity Criterion 36
4.3.1.2 Energy Criterion 37
4.3.2 Manitoba Hydro's Base Supply of Power – Planning Assumptions 39
4.3.3 Summary of Manitoba Hydro System Supply 44
4.4 Need for New Resources 46

This page is intentionally left blank.

4 The Need for New Resources

4.0 Chapter Overview

This chapter describes how Manitoba Hydro establishes the need for new supply resources in order to meet Manitoba Hydro's expected domestic load and firm export commitments. Both current load, and load growth assumptions, as well as Demand Side Management (DSM) programs are described and, when combined, result in net load in Manitoba. The remainder of the chapter describes Manitoba Hydro's existing sources of supply, which represent the ability of the current system to meet load without new resources. The determination of the need for new resources is then based on a comparison of load and supply. The information here provides the basis for the preparation of development plans, described in ***Chapter 8 — Determination and Description of Development Plans***.

Load information in this chapter is based on the 2012 Electric Load Forecast and supply information is based on the 2012/13 Power Resource Plan. The chapter also includes a discussion of Manitoba Hydro's 2013 - 2016 Power Smart Plan. In terms of DSM, the analysis contained in the NFAT submission is based upon DSM projections prepared early in 2012 as a component of the corporation's regular corporate planning cycle; for the purposes of the submission these projections are referred to as "the 2012 base DSM forecast". The 2012 base DSM forecast is consistent with and formalized under the 2013 - 2016 Power Smart Plan.

4.1 Introduction

As described in ***Chapter 1 —Introduction***, Manitoba Hydro is mandated by *The Manitoba Hydro Act* to provide for the continuance of a supply of power adequate for the needs of the province, and to engage in and to promote economy and efficiency in the development of generation, transmission, distribution supply and end-use of power. Manitoba Hydro conducts a review of

the need for new supply resources on an annual basis as part of the resource planning process described in ***Chapter 1 — Introduction***. Manitoba Hydro's commitments include:

- Manitoba domestic electricity load (net of DSM programs)
- long-term firm export sale commitments.

Manitoba's domestic electrical energy consumption has grown, on average, at an annual rate of 1.7% over the past ten years. Observed domestic energy usage includes the effect of energy codes and standards and Manitoba Hydro's past DSM programs. Manitoba's domestic energy usage would have grown another 0.4% per year in the absence of DSM.

Manitoba Hydro's forecast net energy load is determined by considering both domestic energy growth and forecast DSM programs. Over the next 20 years, a growth trend in energy consumption is forecast to continue at an average annual rate of 1.6% (2012 load forecast). This trend takes into account the effects of future savings due to energy efficiency codes and standards but not DSM programs. Projected DSM programs would reduce the energy use growth rate by approximately 0.1% to 1.5%.

Similarly, Manitoba's peak demand has grown, on average, at a rate of 1.4% per year over the past 10 years. The observed domestic demand includes the effect of codes and standards and Manitoba Hydro's past DSM programs. Manitoba's domestic demand would have grown another 0.4% per year if not for the effect of codes and standards and Manitoba Hydro's past DSM programs.

Manitoba Hydro's forecast net peak load is determined by considering both domestic demand growth and forecasted DSM programs. Peak demand is forecast to continue to grow at an average rate of 1.6% per year for the next 20 years. This reflects future savings due to codes and standards but not DSM programs. Forecast DSM programs would reduce the forecasted demand growth rate by approximately 0.1% resulting in an average rate after DSM of 1.5%.

In terms of causes for growth, the province of Manitoba is growing, both in population and economically. Growth in population results in more housing and in increases in related services within the commercial sector to accommodate that growth. Economic growth results in the anticipated expansion associated with commercial and industrial customers. Together, forecast population growth and economic growth result in a Manitoba load that is expected to grow in all sectors.

The electricity demands of a growing Manitoba population and a growing economy can be slowed but not reversed. DSM programs have been used successfully by Manitoba Hydro to reduce customer load in Manitoba, resulting in the deferral of new resources. By the end of fiscal year 2012/13, codes and standards and Power Smart programs were estimated to have achieved an annual load reduction of 1,990[1] gigawatt-hours (GWh) in energy and 586 megawatts (MW) in demand (at generation)[2] and have deferred the need for new resources by approximately four years. These savings are reflected in the historical domestic-load growth rates. Yet, despite the efforts of Manitoba Hydro with its industry-leading DSM programs, Manitoba electricity consumption is growing faster than it can be conserved.

Manitoba Hydro's future DSM strategy involves a continued long-term commitment to pursuing all available economic energy efficiency opportunities. The 2013–2016 Power Smart Plan targets additional energy savings of 1,552 GWh and 490 MW of capacity savings by 2027/28. This represents approximately four years of domestic energy load growth and six years of peak load growth. Forecast DSM defers the requirement for future generation by approximately three to four years.

Manitoba Hydro's primary focus is the provision of power to its Manitoba customers. Manitoba Hydro also exports surplus firm energy and capacity through long-term firm sale agreements,

[1] All load and supply values have been adjusted, as necessary, to reflect a common reference point. This reference is at the point of generation.
[2] Interim estimate as of March 31, 2013.

which form the second component of Manitoba Hydro's firm electricity commitments. However, in order to maintain security and reliability of supply to Manitoba customers, long-term firm sale agreements may contain reduced delivery obligations for example during periods of system emergencies and under certain drought conditions. Contracts which take the form of diversity agreements provide for the seasonal exchange of power between utilities during their respective peak load conditions, helping to optimize operations by having Manitoba Hydro export to customers with peak loads in the summer period while having the ability to import from these same customers during Manitoba's winter peak period. Such arrangements result in lower power costs to both parties by deferring the expansion of generating resources that would otherwise be required to meet peak load.

System supply evaluations are based on Manitoba Hydro's generation planning criteria and are assessed from the perspective of both dependable energy and peak winter capacity. The Manitoba Hydro base supply, including electricity imported from outside the province, is expected to provide 6,244 MW of winter peak capacity and 30,253 GWh of dependable energy in the year 2013/14 resulting in a surplus of 583 MW winter peak capacity and 1,536 GWh of dependable energy.

Based on 2012 planning assumptions, a surplus of dependable energy continues until 2022/23 when the base supply is no longer sufficient to satisfy anticipated energy demand. There continues to be surplus capacity in the system beyond 2022/23. Over the last five years, the requirement for new resources has varied from as early as 2019/20 to as late as 2022/23 and has consistently been due to a need for energy as opposed to capacity.

4.2 Total Demand on the Manitoba Hydro System

4.2.1 Manitoba Hydro's Domestic Electricity Load

Manitoba Hydro's forecast of electrical energy consumption and peak demand is detailed in the report 2012 Electric Load Forecast (hereinafter referred to as the "2012 Load Forecast"). This report is provided in ***Appendix C – 2012 Electric Load Forecast***. The load forecast is reviewed and updated on an annual basis as part of the annual corporate planning cycle.

Manitoba peak demand is defined to be "the maximum average hourly load, measured in MW, in Manitoba to be served by Manitoba Hydro's system". Energy consumption is defined to be "the electrical energy used by a customer, measured in kilowatt-hours (kWh) or megawatt-hours (MWh)".

Considerations for the 2012 Load Forecast:

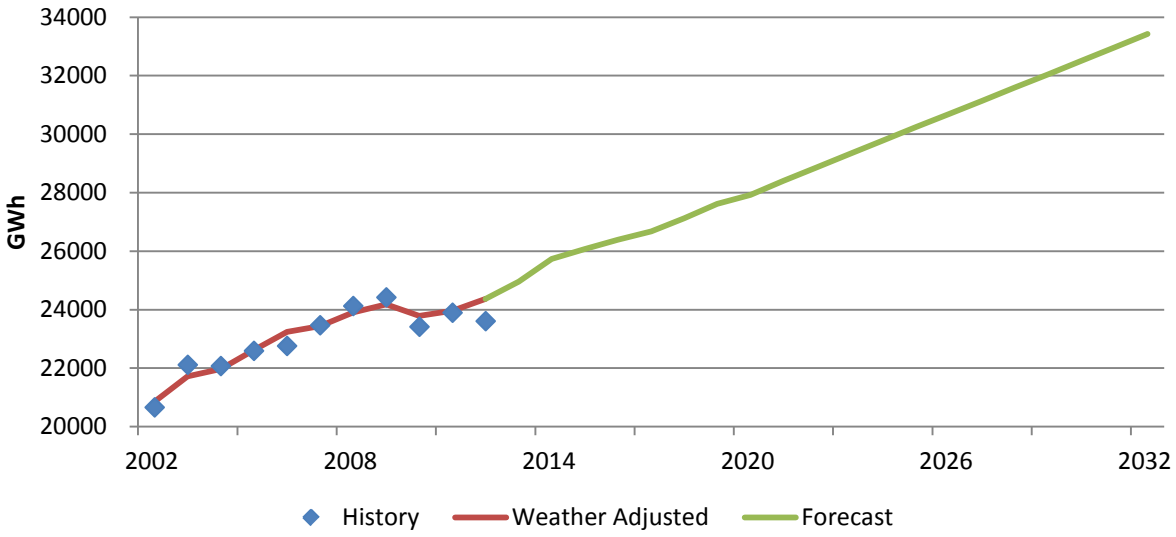
- Historical load values include the effect of Manitoba Hydro's past DSM, including both improvements to energy codes and standards as well as market-based programs.
- Forecasted load values reflect the future impact of implemented energy codes and standards, but not future activity under market-based DSM programs.
- Customer self-generation is recognized as avoided load; the avoided load is not in the load forecast.
- Given that forecast activity under market-based DSM programs has not been removed from the 2012 Load Forecast, Manitoba Hydro's forecast net load is determined by considering both forecast domestic energy growth and projected future DSM program activity.

As established in Table 3.1 of ***Chapter 3 – Trends and Factors Influencing North American Electricity Supply***, overall loads across Canada and the U.S. are projected to grow, with average

annual growth rates varying by region, reflecting the unique characteristics of their individual markets.

Historical and forecast energy consumption for Manitoba is shown in Figure 4.1. Energy consumption increased from 20,656 GWh in 2001/02 to 24,367 GWh in 2011/12, representing an approximate 18% increase over the past 10 years at a compounded growth rate of 1.7% per year. Energy use is forecast to grow another 18% over the next 10 years to 28,859 GWh in 2021/22, and 37% over the next 20 years to 33,425 GWh in 2031/32 at growth rates of 1.7% and 1.6% respectively. Forecast values assume normal weather (e.g., 25 year average) will occur, and are therefore comparable to historical weather-adjusted values.

Figure 4.1 MANITOBA ENERGY CONSUMPTION (GWH) – HISTORY & FORECAST

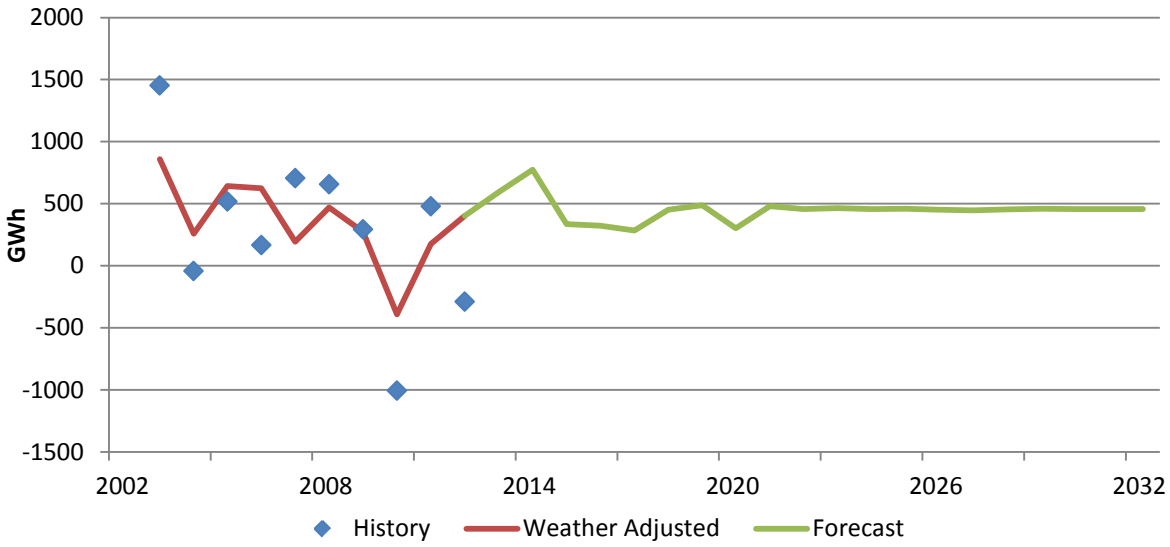


Manitoba's domestic energy consumption has grown, on average, at an annual growth rate of 1.7% or 371 GWh over the past 10 years. This growth trend is forecast to continue for the next 20 years at an average annual growth rate of 1.6% or 453 GWh. On an annual-average basis, forecast load growth is consistent with the average annual historical growth trend.

Annual energy growth varies from year to year. The variation is mostly due to increases or decreases in energy consumption by Manitoba's largest electricity customers. The effect of the

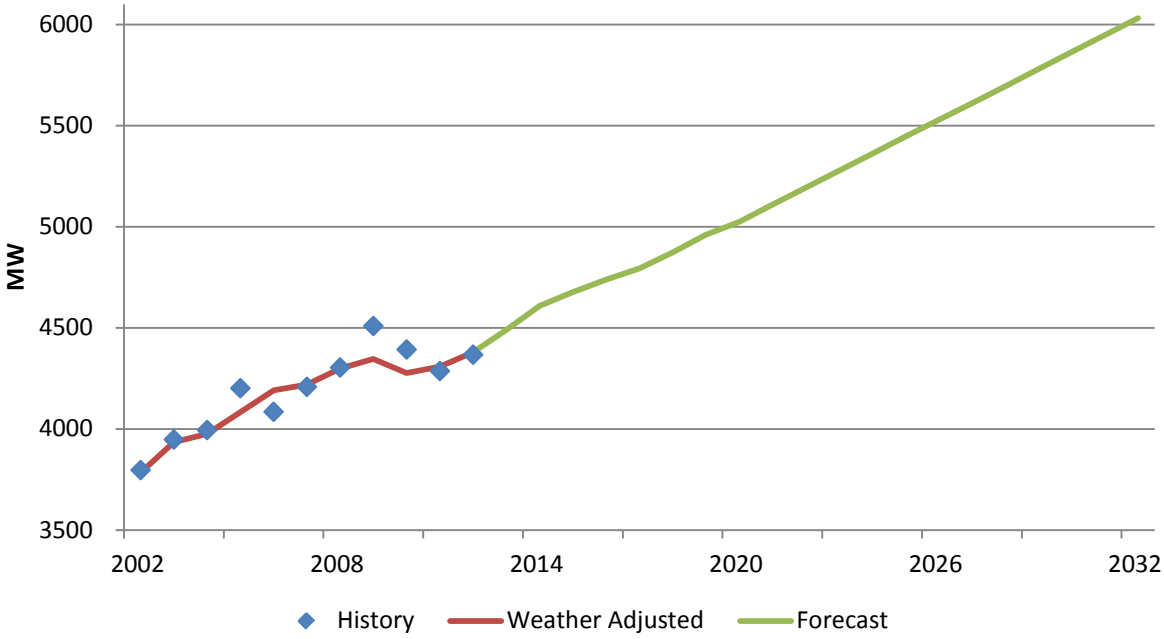
closure of one of these customers in 2009 can be clearly seen in the weather-adjusted history shown in Figure 4.2. The effect of major expansions by large customers in 2013, the planned closure of a smelter and refinery in 2015, and the drop of some operations in 2019 can be seen in the forecast.

Figure 4.2 MANITOBA ENERGY ANNUAL GROWTH (GWH)



Historical and forecast peak demand values are shown in Figure 4.3 below. Peak demand grew 15% over the past 10 years from 3,797 MW in 2001/02 to 4,380 MW in 2011/12. Peak demand is forecast to grow another 19% to 5,192 MW by 2021/22, and 38% to 6,032 MW by 2031/32. Forecasts are based on weather-adjusted values.

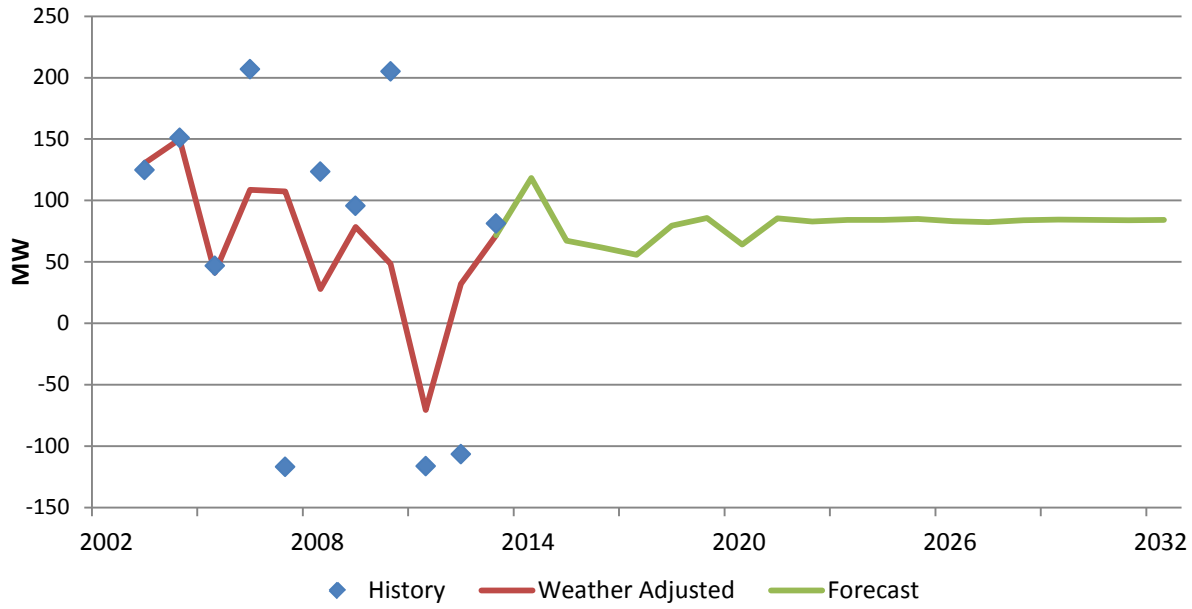
Figure 4.3 MANITOBA PEAK (MW) – HISTORY & FORECAST



As shown in Figure 4.4 below, Manitoba peak demand has grown, on average, at an annual growth rate of 1.4% or 58 MW per year over the past 10 years. It is forecast to grow at an average annual rate of 1.6% or 83 MW for the next 20 years. In the mid-2000s when large electricity customers were expanding, peak demand had been growing at a slower rate than energy consumption. However, increased growth in electric-heat customers is forecast to bring the future peak-demand growth rate up to that of Manitoba energy consumption (1.6%).

Manitoba peak demand tends to grow at a very similar rate to Manitoba energy consumption. It is of note that higher energy use by the largest electricity users in Manitoba, who have relatively constant consumption of energy over the year, causes the peak demand to grow at a slower rate than the requirement for energy. Conversely, electric-heat customers, who peak on the coldest day of the winter, cause peak demand to grow at a faster rate than the requirement for energy.

Figure 4.4 MANITOBA PEAK DEMAND ANNUAL GROWTH (MW)



Over the next 20 years, Manitoba energy consumption is forecast to grow at an average of 453 GWh per year and peak demand is forecast to grow at an average of 83 MW per year, with the expectation that in the future large electricity customers will continue to affect individual years, causing some years to be above and some years to be below that average.

4.2.1.1 Domestic Load Growth by Sector

Domestic load is forecast for the following sectors: Residential Basic, General Service - Mass Market, General Service - Top Consumers, Losses and Station Service, and Miscellaneous. Figure 4.5 and Figure 4.6 show the percentage breakdown by sector for the years 2011/12 and 2031/32 respectively. The sector percentages are not expected to change significantly since all sectors are expected to grow at approximately the same rate.

Figure 4.5 SECTORS OF DOMESTIC LOAD FOR 2011/12

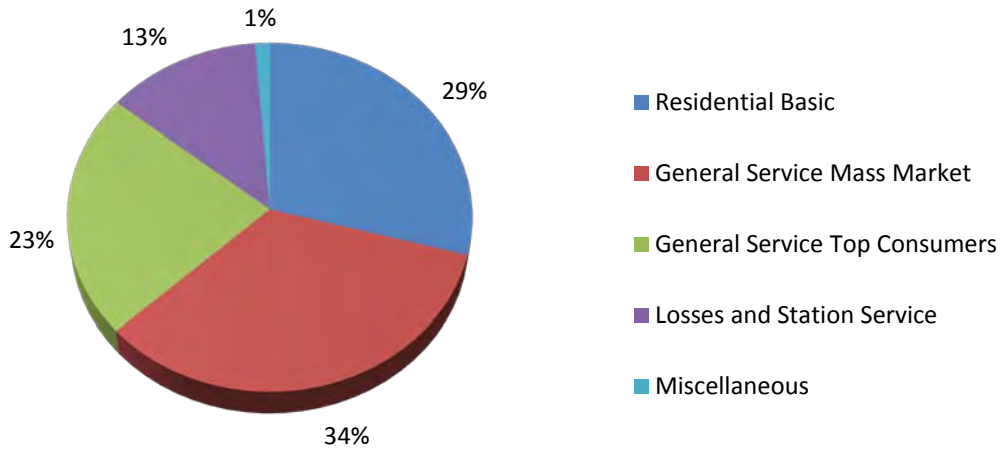
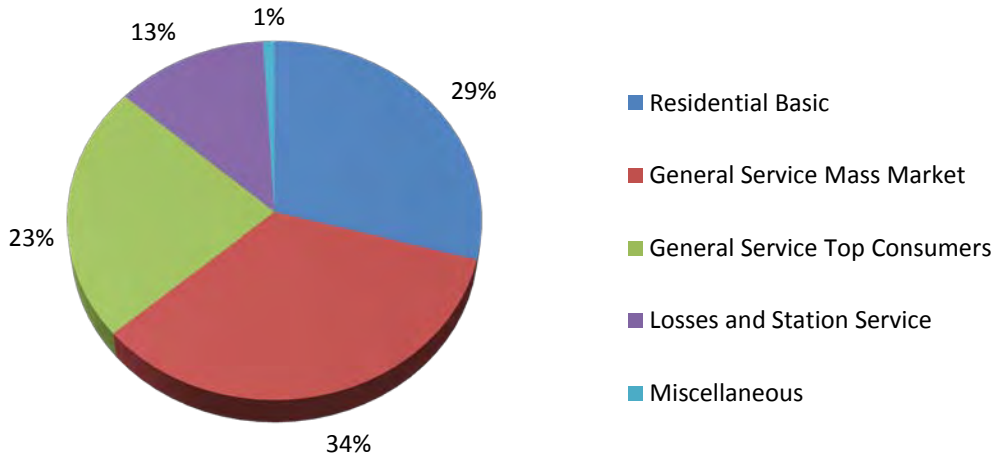


Figure 4.6 SECTORS OF DOMESTIC LOAD FOR 2031/32



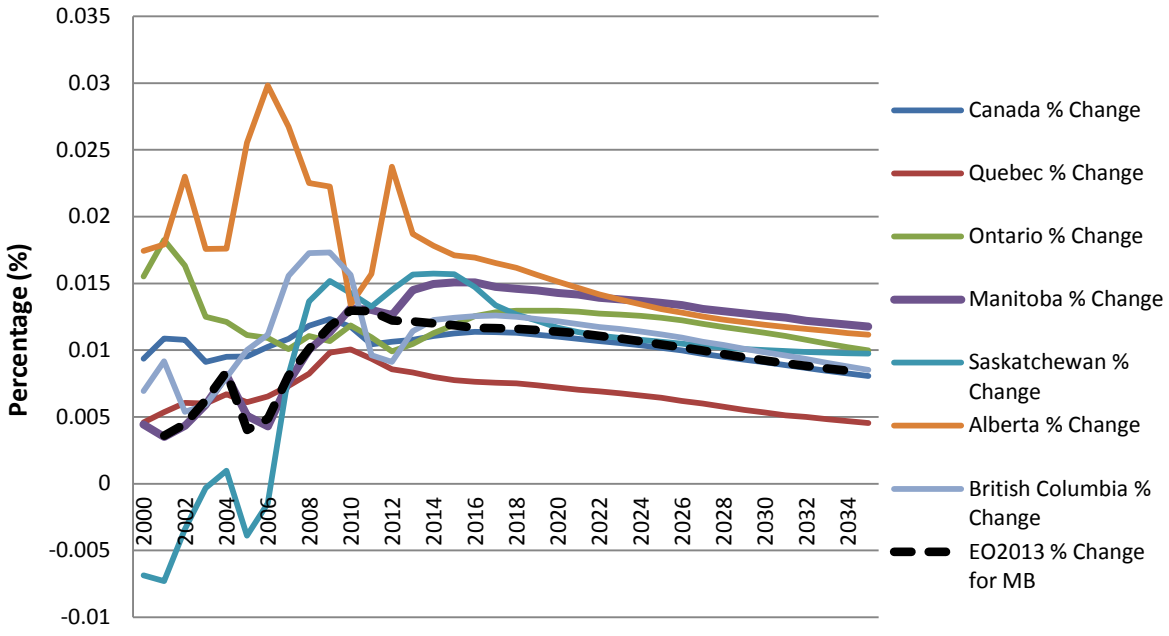
Residential Basic

The residential sector—excluding seasonal, diesel and flat-rate customers—is known as Residential Basic. Residential Basic had 450,748 customers in 2011/12, whose weather-adjusted energy consumption was 29% of the total energy consumed in Manitoba or 7,114 GWh. The major driver of Residential Basic load in the 2012 Load Forecast is the Manitoba population. Manitoba's population in 2011/12 was 1,255,000. Manitoba Hydro has one residential basic customer for every 2.8 people in Manitoba, and this ratio is expected to remain at about this level.

Under Manitoba Hydro's 2012 Economic Outlook, Manitoba's population is forecast to grow from 1,255,000 in 2011/12 to 1,596,000 in 2031/32, representing an average annual growth rate of 1.2%. In the 2012 Load Forecast, the number of Residential Basic customers is expected to grow at an average annual rate of 1.2% over the next 20 years, reaching 576,545 customers by 2031/32.

For the 2013 Load Forecast, the forecast population annual growth rate was reduced from 1.2% per year to 1.1% per year, with the Residential Basic customer forecast correspondingly reduced from 1.2% to 1.1%. Some industry forecasters, as evidenced in Figure 4.7, are projecting population growth in Manitoba to be among the highest in Canada contributing to the overall growth in Manitoba's future energy requirements. The effect of Manitoba Hydro's 2013 Economic Outlook and updated population forecasts, as noted by line EO2013 in Figure 4.7, are reflected in the 2013 Electric Load Forecast as outlined in ***Chapter 12 – Economic Evaluations – 2013 Update on Selected Development Plans***.

Figure 4.7 ANNUAL POPULATION GROWTH BY PROVINCE (%): COMPARISON TO EO2013



Source: Conference Board of Canada 2013 Values

Due to the expectation that a larger proportion of customers will continue to choose electricity for space and water heat as well as miscellaneous end-uses, the average energy usage per residential customer is expected to rise by 0.4% /year. Electricity is currently used for space heating by approximately 35% of Residential Basic customers—forecast to grow to approximately 40% by 2031/32 as a progressively higher percentage of new homes and apartments choose electricity for space heating.

Electric water heating is currently used by approximately 47% of Residential Basic customers—forecast to grow to approximately 69% by 2031/32 in the 2012 Load Forecast. The current trend is for new homes to install electric water heaters; in addition, a growing number of existing natural gas water heaters are also being replaced with electric units.

The influence of improved efficiency requirements for natural gas furnaces and resulting impact on the fuel choice for water heating on the average electricity usage per customer will differ from region to region. This difference depends upon the level of saturation of electric space and water heating in a region, building practices, historic and current energy pricing and other market characteristics. These trends in space and water heating in Manitoba are expected to be mitigated through the corporation's planned heating fuel choice initiatives, with the effects reflected in the 2013 Electric Load Forecast as outlined in ***Chapter 12 – Economic Evaluations – 2013 Update on Selected Development Plans***.

The 1.2% annual increase in Residential Basic customers due to population growth combined with the 0.4% annual increase in average electricity use results in an annual growth rate of 1.6% for the Residential Basic sector over the next 20 years.

General Service – Mass Market

The Mass Market sector is made up of commercial and industrial customers, excluding the Top Consumers. This sector had 65,546 customers in 2011/12, whose weather-adjusted energy

consumption was 8,270 GWh, or 34% of the total energy consumed in Manitoba. Over the past 10 years, this sector's consumption has grown at a fairly constant rate of 119 GWh (1.6%) per year, and is forecast to grow at a slightly higher rate averaging 161 GWh (1.7%) per year for the next 20 years due to the expected population growth in Manitoba. The number of Mass Market customers themselves is also expected to increase as more commercial entities seek to provide services for the growing population.

This sector is made up of a wide variety of commercial and small-industrial customers, including offices, retail, wholesale, apartment complexes, schools, hospitals, agriculture, and small manufacturing. Their energy use is not as significantly affected by the economy as other sectors as the related facilities continue to use energy between periods of tenancy.

General Service - Top Consumers

The Top Consumers sector is made up of the 17 industrial and commercial companies, which represent the largest energy users in Manitoba. In 2011/12, the Top Consumers used 5,531 GWh, or 23% of the total electricity consumed in Manitoba.

Energy use for Top Consumers is forecast on a per-company basis to include their respective short-term committed plans and expectations—the forecast excludes longer-term plans that are uncommitted or subject to change. The impact of these plans is reflected generally within the first three years of the load forecast.

During the recent economic slow-down, overall sector load declined due to the loss of one customer in the pulp and paper industry; another major reduction is currently projected in 2015 for primary metals. However, growth among other Top Consumers is expected to make up these load losses, primarily in the pipelines and chemical industries. Overall, short-term plans indicate that Top Consumers should grow by 680 GWh (12%) in the next two years, since a number of customers are planning major expansions.

For the longer term, the future energy requirements of individual customers within the Top Consumers sector cannot be reliably forecast: their growth is too dependent on their particular industry, the economy, and their own competitive situation. One company may be in the right industry at the right time and decide to expand; another may be forced, by a number of unforeseen circumstances, to cut back or even shut down.

To estimate the longer-term growth for the Top Consumer sector, the sector is forecast as a whole. The growth for the longer-term is called Potential Large Industrial Loads and includes consideration for company expansions, cutbacks and shutdowns; new startups of 50 GWh a year or more; and the long-term normal incremental growth of all the companies combined. Since short-term customer intentions are known, Potential Large Industrial Loads is not added to the first three years of the forecast.

In the past 20 years, there have been 14 major increases of load of 100 GWh or more, and two major losses of load of 100 GWh or more within the sector. The net effect has been an addition of about 85 GWh per year. Normal company growth among these customers has added another 7 GWh per year. The combined effect is that Top Consumers has grown from 3,783 GWh in 1992/93 to 5,531 GWh in 2011/12, a growth of 92 GWh or 2.0% per year.

Potential Large Industrial Loads are forecast to be 100 GWh per year. By 2031/32, their contribution is forecast to be 1,700 GWh. Including Potential Large Industrial Loads, General Service Top Consumers is forecast to grow from 5,531 GWh in 2011/12 to 7,698 GWh in 2031/32, for an average growth of 108 GWh or 1.7% per year.

In general, the economy continues to have a significant impact on Top Consumers. Their electricity consumption is dependent upon the state of the economy in their specific industries: in robust economic times they expand operations, increasing their electricity consumption;

while in recessionary times, they reduce shifts and cut back production, thereby decreasing consumption.

Manitoba recently went through an economic downturn, and with the loss of a major customer, electricity consumption of the Top Consumers sector still remains below what it was at its peak in 2008/09; however, Manitoba is a growing province in terms of population and gross domestic product. It is therefore not reasonable to expect that the recent experience of no growth in this sector will continue. It would only take one or two large new customers over the next 20 years to provide the entire additional load that is forecast for the Top Consumers sector until 2031/32.

Losses and Station Service

In 2011/12, distribution losses, transmission losses and station service accounted for 3,156 GWh or 13% of the total energy consumed in Manitoba. This percentage is expected to remain generally the same over the duration of the forecast. (The addition of Bipole III will reduce losses but this is captured separately in the Power Resource Plan due to it being a future project at this time.)

Miscellaneous

Miscellaneous sectors—including seasonal, flat rate, diesel and lighting—used a total of 296 GWh, or 1% of the total energy consumption in Manitoba. The growth in these sectors has minimal effect on overall domestic growth.

4.2.1.2 Load Variation and Forecast Accuracy

Load Variation

Uncertainty is an inherent characteristic of forecasting. The load will vary both year to year and in the long-term because of underlying changes in population growth, economic growth, changes in the operations of Top Consumers, and overall use patterns. An economic recession

will slow energy growth; an economic boom will increase it. Cycles cannot be predicted in advance so that an appropriate mid-point value must be chosen as the forecast.

As outlined in section 4.2.1, domestic energy is expected to increase from 24,367 GWh in 2011/12 to 33,425 GWh (+37%) in 2031/32 and, over the same period, peak demand is expected to grow from 4,380 MW to 6,032 MW (+38%). Such a forecast was created as Manitoba Hydro's best estimate of Manitoba's future energy requirement. The load forecast is based on information from the ***Appendix F - Economic Outlook 2012 - 2033***, including the forecasts of economic growth and population. These forecasts represent the best estimate of what will happen, and each has the expectation that there will be a 50% chance that actual growth will be higher than the forecast, and a 50% chance that actual growth will be lower than the forecast.

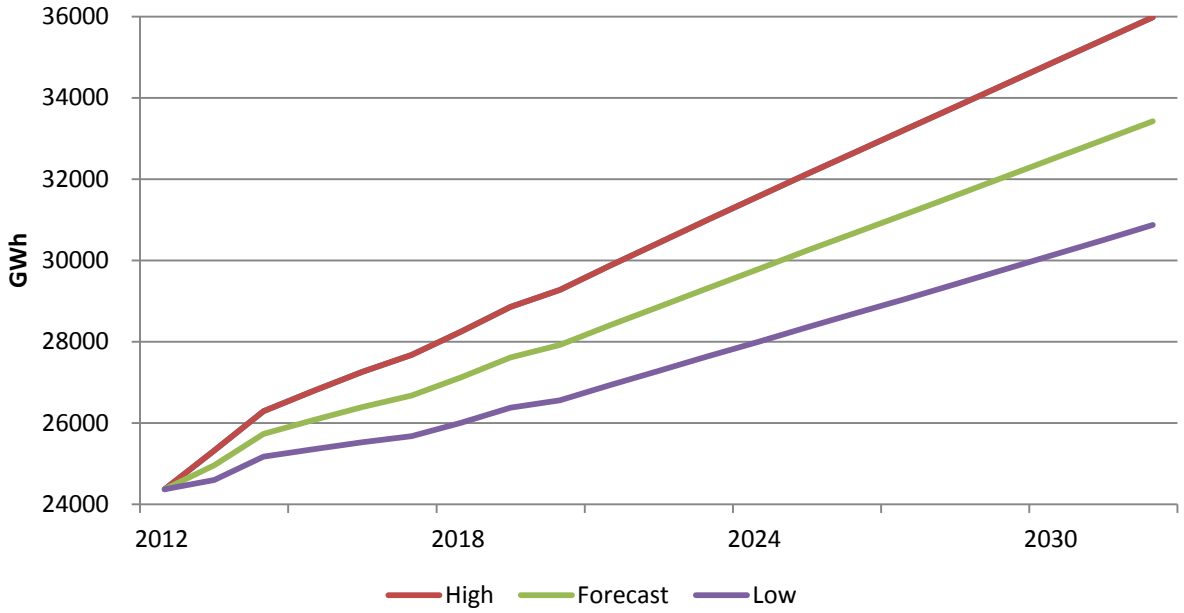
Using a mid-value forecast means that a period of high economic growth or higher-than-normal population growth will result in higher electricity consumption than has been forecasted. A period of low economic growth or low population growth will result in lower electricity consumption than forecasted.

To evaluate the potential for variation, historic load variability has been analyzed using a probabilistic-based approach, e.g., variations in annual weather-adjusted load that have occurred in the past are used to estimate future variation. This approach provides an estimate of the magnitude of the potential load variation from the forecast due to population, economy and other effects.

Figure 4.8 shows high and low probability bands of future requirements. Under this analysis, there is a 10% probability of actual loads being lower than the low band and a 10% probability of actual loads being higher than the high band. There is an 80% chance that the actual amount of electricity required will be between the low and high bands. These bands correspond to an

annual growth of 1.2% for the low band and 2.0% for the high band, compared to 1.6% for the base forecast (green line). What actually happens and where the load will be relative to the bands will depend on actual population growth and customer activity levels. By 2031/32, the actual amount of electricity required could therefore vary by over 2,500 GWh or ±8%.

Figure 4.8 ENERGY FORECAST PROBABILITY BANDS (GWH)



Forecast Accuracy

Due to the load variation caused by population growth and economic growth previously described, only a certain level of accuracy can be obtained. Looking 10 years ahead, the probability bands vary +/- 1,576 GWh from the forecast of 28,859. This means that there is an 80% chance that the actual load in 2021/22 will be within 5.5% of the forecast.

Recognizing the inherent uncertainty of forecasting, historic forecast variation has been tracked. Manitoba Hydro's objective is that a five-year forecast be within 5% and a 10-year forecast be within 10% of actuals. Generally, this objective has been achieved in more than half the years across 21 previous forecasts for both energy and peak as evidenced in Tables 35 and 36 of ***Appendix C – 2012 Electric Load Forecast***.

Whenever there are unexpected periods of recession or periods of higher than normal growth, previous forecasts will have overestimated or underestimated the load. These periods happen gradually and take a few years before they can be recognized as representing more than just year-to year-random variation.

Every year, a new load forecast is produced to take into account changes in the economy and in customer usage as well as new outlooks into the future. This allows the planning process at Manitoba Hydro to make annual adjustments to account for incremental changes and adjust for longer-term trends.

4.2.2 Demand Side Management

Manitoba Hydro's DSM initiative, Power Smart, consists of energy conservation and load management activities designed to capture energy efficiency and economic opportunities. Manitoba Hydro has been successfully delivering DSM for over 20 years in an effort to meet the energy needs of Manitoba in a more sustainable manner while assisting customers in using energy more efficiently and reducing their energy bills. Manitoba Hydro is committed to DSM with a focus on pursuing all cost-effective energy efficiency opportunities and continually monitoring the market for emerging trends and opportunities, which may become economically viable.

Manitoba Hydro's future DSM efforts and initiatives are provided in the corporation's 2013-2016 Power Smart Plan. Pursuant to s.7(1) of *The Energy Savings Act*, this plan was prepared in consultation with the Minister of Innovation, Energy and Mines and is provided in ***Appendix E – 2013 - 2016 Power Smart Plan***, along with the "2013 - 2016 Power Smart Plan – 15 Year Supplementary Analysis Report". The corporation's DSM plan is typically reviewed and updated on an annual basis as part of Manitoba Hydro's overall integrated planning process. DSM projections were prepared early in 2012 as a component of the regular corporate planning process for inclusion as the base DSM forecast within this submission. The 2012 base DSM

forecast represents an update to the approved 2011 Power Smart Plan and is consistent with the current approved 2013 - 2016 Power Smart Plan—the latter being a further update to the 2012 forecast.

The energy savings achieved through DSM is forecast separately from the electric load forecast as described in section 4.2. The energy savings forecast to be achieved through DSM is included as part of the Power Resource Plan and is evaluated utilizing corporate-approved and consistent economic data.

Manitoba Hydro currently offers a broad portfolio of programs in its effort to pursue all economic DSM opportunities. The Power Smart Commercial Lighting Program is one example of an energy efficiency initiative encouraging the installation of more energy-efficient lighting technologies that provide similar or improved lighting levels. A number of other energy efficiency initiatives are currently being offered.

Load-management initiatives are designed to capture available economic opportunities by modifying customer demand for energy at a particular time, or shifting demand from one period to another. Manitoba Hydro's Curtailable Rates Program is an example of a load-management initiative whereby participating customers curtail a contracted amount of load at Manitoba Hydro's request for a specified period of time.

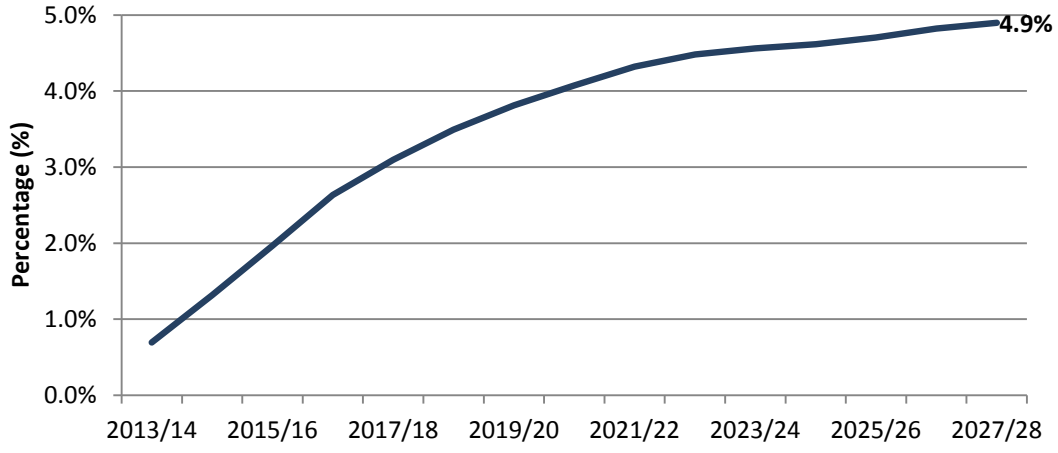
Another significant component of Manitoba Hydro's DSM plan involves permanently capturing energy efficiency opportunities through changes made in codes and standards. As a result of combined utility and government efforts, the market adoption of energy efficient products and activities has resulted in significant changes in manufacturers' performance standards and in efficiency legislation and codes.

Manitoba Hydro's long-term aggressive commitment to DSM has resulted in 90% awareness of the Power Smart brand in Manitoba, with over 60% of residential customers able to recall, unaided, Manitoba Hydro programs available to help manage their energy bills and a third of customers indicating they have participated in at least one program to date. By the end of 2012/13, Power Smart is estimated to have achieved an annual load reduction of 1,990 GWh and 586 MW (at generation)[3].

4.2.2.1 Future DSM Plans

Manitoba Hydro's future DSM strategy involves a continued long-term commitment to pursuing all available economic energy efficiency opportunities. The 2013 - 2016 Power Smart Plan outlines an additional investment of $83 million (2012$) to achieve electricity savings of 510 GWh/year and 280 MW by 2015/16. Beyond 2015/16, Manitoba Hydro has budgeted an investment increasing to $326 million (2012$) overall and expects energy savings to increase to 1,552 GWh/year and 490 MW by 2027/28, which represents 4.9% of the forecast electricity load at the benchmark year. See Figure 4.9.

Figure 4.9 CUMULATIVE DSM ELECTRICAL SAVINGS AS A % OF ANNUAL LOAD



[3] Interim estimate as of March 31, 2013.

Combined with energy savings achieved to date, total electrical savings of 3,113 GWh and 846 MW will be realized by 2027/28, with a cumulative investment of $762 million (2012$). See Figure 4.10 and Figure 4.11.

Figure 4.10 ANNUAL DSM ENERGY SAVINGS 1989 -2027 (GWH AT GENERATION)

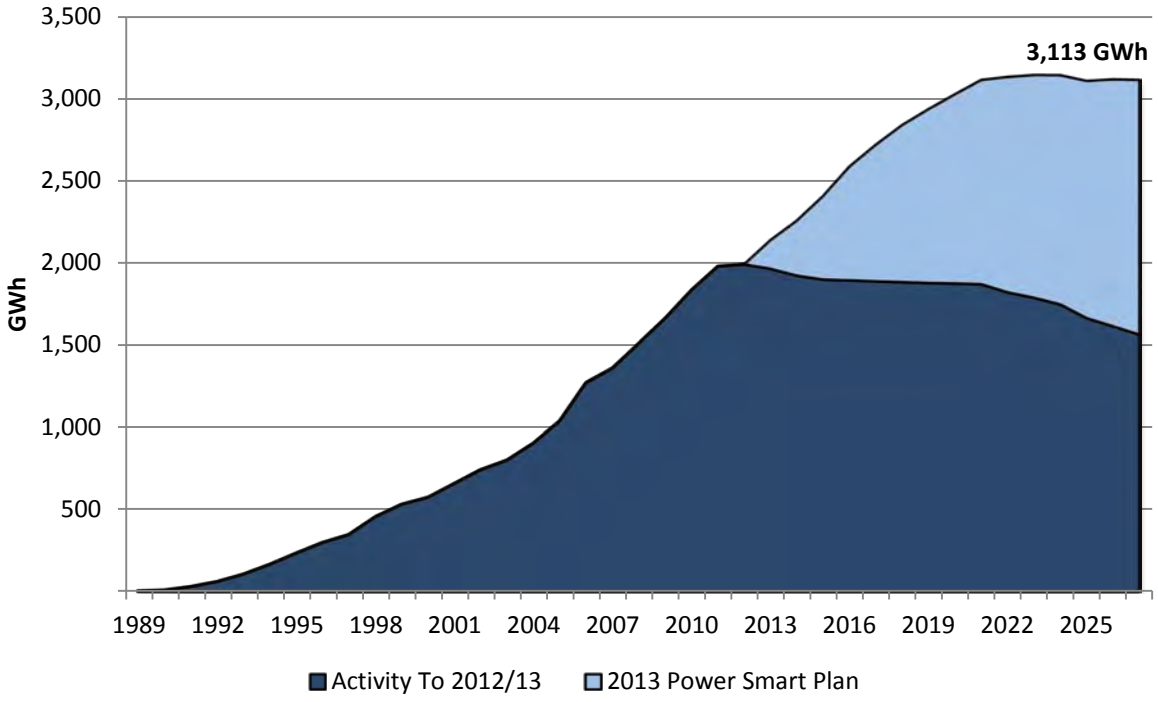
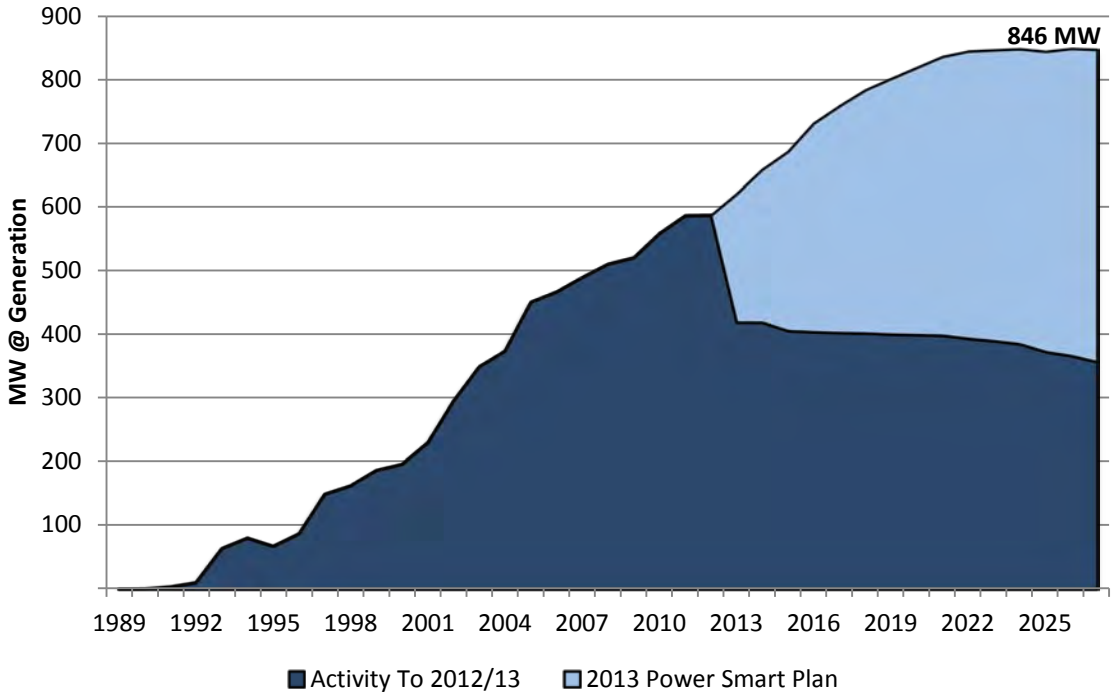


Figure 4.11 ANNUAL DSM CAPACITY SAVINGS 1989 – 2027 (MW AT GENERATION)



Through the planned DSM initiatives, participating customers can expect to save $52 million in 2027/28 and $486 million cumulatively by 2027/28 (2012$) on their electricity bills. When combined with electricity bill reductions achieved to date, participating customers can expect to save $91 million in 2027/28 and over $1.9 billion cumulatively (2012$).

4.2.2.2 Assessing Economic DSM Opportunities

In assessing DSM options, Manitoba Hydro considers the economics associated with DSM opportunities from a number of perspectives, including:

- The economics of implementing a specific DSM opportunity, irrespective of who benefits from and who pays for implementing the DSM initiative. The Marginal Resource Cost (MRC), Total Resource Cost (TRC) and the Societal Resource Cost (SRC) metrics are used for assessing the economics of a DSM opportunity from this perspective.
- The economics of implementing a specific DSM opportunity from an aggregate ratepayers' perspective. The Levelized Utility Cost (LUC) and Rate Impact Measure

metrics are used for assessing the general economics of a DSM opportunity from this perspective. Caution needs to be exercised in using the LUC, as this metric only assesses the costs associated with a DSM opportunity. The LUC for DSM opportunities cannot be simply assessed against alternative LUC's for generation options because the revenue impacts of DSM initiatives and supply-side options are different. In addition, DSM LUC's cannot be measured simply against the corporation's proxy for its marginal value (cost) as a single value due to the timing impacts on marginal values of energy. A proper economic assessment of DSM options relative to alternative supply-side options involves an assessment of the revenue and cost impacts.

- The economics of implementing a specific DSM opportunity from a participating customer's perspective. The Customer Simple Payback metric is used for this purpose.

To assess options for supporting and pursuing a DSM opportunity, Manitoba Hydro considers:

- the economics of the opportunity from all perspectives (e.g., irrespective of who benefits and pays; from the aggregate ratepayer perspective; and from the participating customer perspective)
- the barriers to participation and
- the fairness of all ratepayers (including non-participating) contributing to the paying for a DSM opportunity, which benefits only participating customers, along with the associated non-energy benefits.

To assist in assessing the merits of various approaches to supporting and promoting a DSM opportunity, Manitoba Hydro uses the above-mentioned metrics as guidelines in choosing a particular DSM strategy. In addition to quantitative assessments, Manitoba Hydro also considers various qualitative factors, including equity (e.g., reasonable participation by various ratepayer sectors such as lower income) and overall contribution towards having a balanced energy conservation strategy and plan.

Manitoba Hydro designs DSM programs balancing the following objectives:

- capturing all available economic energy-efficient opportunities
- being fiscally responsible as to how ratepayer dollars are spent and
- being considerate to the net impact on all customers.

In balancing these objectives, Manitoba Hydro attempts to direct or proportion DSM costs to those entities and customers who realize the benefits associated with the DSM initiatives. For example, the benefits/costs associated with a DSM opportunity (irrespective of who benefits and who pays the costs as measured by MRC, TRC and SRC) primarily consist of the benefits/costs of participating customers, non-participating customers and external parties (e.g., social or government agencies in the case of reduced energy bills being paid by Employment Income Assistance).

From the perspective of non-participating customers, the net benefit is the difference between the corporation's marginal value (cost) and the lost domestic revenue associated with the DSM opportunity (see Figure 4.12) and the cost is the DSM program costs associated with the DSM program (e.g., incentives, administration, marketing, etc).

From a participating customer's perspective, the benefits are reduced energy bills and any non-energy benefits (e.g., reduced maintenance cost) while the costs are those associated with installing the DSM opportunity (net of any incentives). The extent to which external parties may benefit from DSM programs varies by program; however, benefiting entities could include government social agencies (e.g., Employment Income Assistance when paying energy bills directly; and Manitoba Housing Authority when retrofits are undertaken in Government-owned homes) and society at large (e.g., environmental benefits).

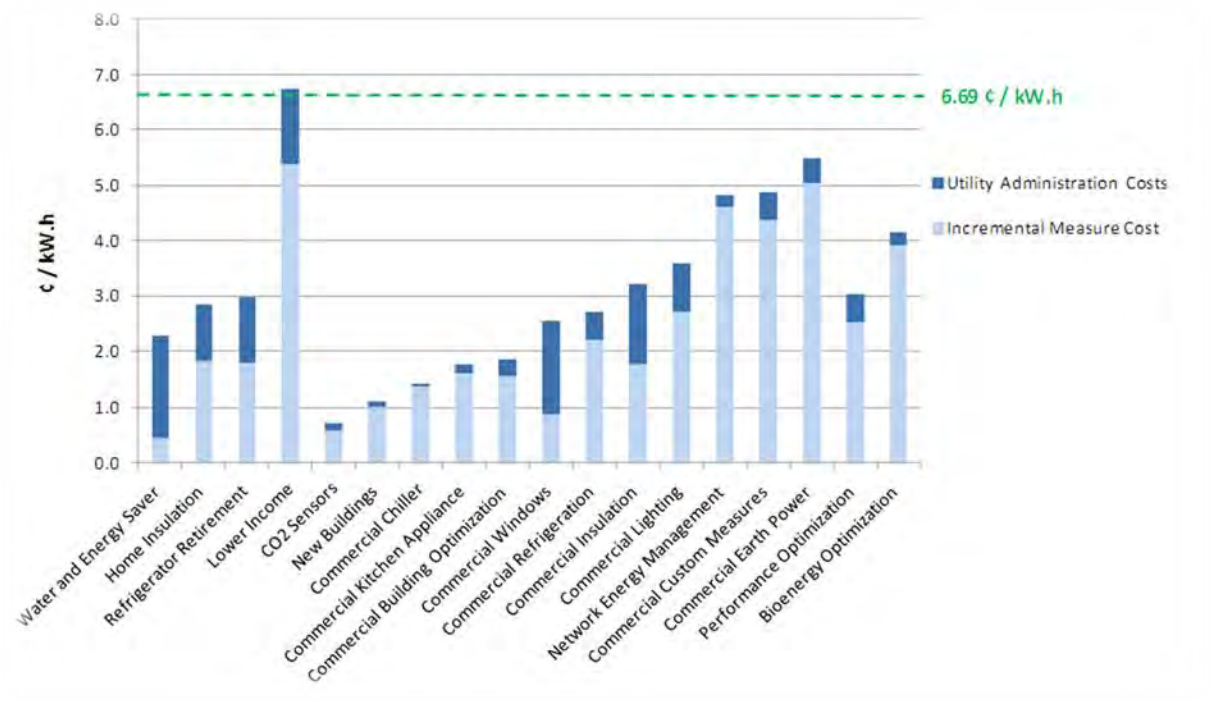
With DSM opportunities, it is important to recognize that the relevant cost associated with DSM opportunities is the total cost of DSM opportunities, which includes the participating customer's cost in addition to the utility's cost. Similar to supply-side options, ratepayers

ultimately pay the entire cost of DSM options; with DSM, the initiatives are paid for by participating customers and by ratepayers via a utility's investment in DSM initiatives.

As each DSM opportunity is an independent decision, Manitoba Hydro assesses the economics of pursuing each energy efficiency opportunity individually. This approach is consistent with assessing each supply-side option on its own merits. However, due to concerns regarding reasonable participation by specific market sectors such as the lower-income market, Manitoba Hydro also assesses the merits of pursuing energy efficiency opportunities within specific market sectors through a broader analysis, which includes fairness considerations.

Figure 4.12 presents the levelized resource costs for individual Power Smart opportunities included under the 2013 - 2016 Power Smart Plan.

Figure 4.12 LEVELIZED RESOURCE COST (2012$) 2013-2016 POWER SMART PLAN



The levelized Total Resource Costs for programs presented under this plan range from 1 cent/kWh to 6.7 cents/kWh, with an overall average levelized resource cost of 3.9 cents/kWh. The range in resource costs demonstrates Manitoba Hydro's commitment to pursue all those

DSM opportunities with a levelized resource cost less than the corporation's marginal cost value.

Manitoba Hydro is also committed to finding additional economic DSM opportunities and, as such, the corporation monitors technologies and programs being offered in other regions on an ongoing basis to assess their potential fit for Manitoba, while giving consideration to Manitoba's load characteristics, climate, and marginal values. The following are a select, but not exhaustive, list of technologies that have been assessed but are not being pursued at this time:

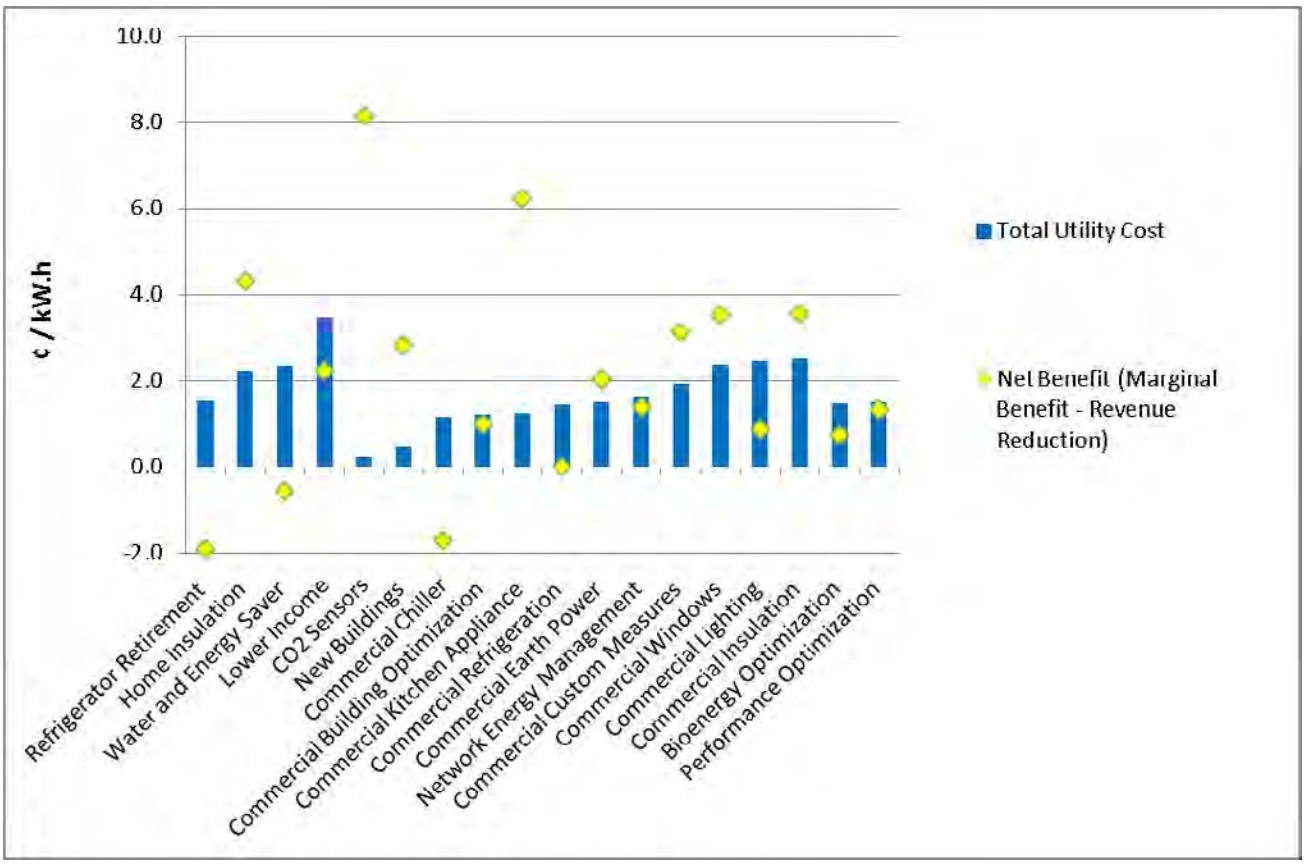
- Heat-pump water heaters are not suited to Manitoba's marketplace. The technology pulls heat out of the space in which the water heaters are located and puts that heat into the water. This technology is popular in more moderate climates and in regions where the water heater is not located in a conditioned space (e.g., mechanically heated or cooled). In Manitoba, due to our long heating season, water heaters are located inside our homes and buildings.
- With a levelized marginal-resource cost of 14 cents/kWh, solar water heaters are not cost effective in Manitoba.
- With a levelized cost of 24 cents/kWh, ductless heat pumps are not cost effective in Manitoba.
- With a levelized cost of 9 cents/kWh, initiatives promoting individuals to conserve energy through bill comparison challenges are not cost effective. Manitoba Hydro is currently monitoring the results of this opportunity within other regions and intends to maintain this option as a possible opportunity to consider in the future.

The approach and strategy undertaken by Manitoba Hydro to pursue each DSM opportunity is determined after undertaking a detailed assessment of each opportunity. The subsequent approach taken by Manitoba Hydro may consist of an incentive-based program, an education/awareness initiative, a code/regulation initiative or a combination of the available

approaches. The degree and context of Manitoba Hydro's support for a specific opportunity is dependent on many factors, including the economics of the DSM opportunity from the various perspectives and at what stage within the customer market-acceptance curve the specific opportunity is at within a particular time. For example, if an energy efficiency opportunity is not economic—irrespective of who benefits or pays (e.g., an emerging technology such as solar-assisted hot water tanks)—then Manitoba Hydro's approach for supporting the DSM opportunity may simply be through education, awareness and research initiatives. If a technology is at the latter stage of a market acceptance curve (e.g., Energy Star appliances), Manitoba Hydro support may be through awareness and education initiatives.

Figure 4.13 presents the levelized utility costs for individual Power Smart opportunities included under the 2013 - 2016 Power Smart Plan, with the net benefit to the utility (e.g., ratepayer) being the difference between the marginal cost and the foregone domestic revenues associated with each Power Smart opportunity. The average levelized utility cost of Manitoba Hydro's aggregate Power Smart plan is in the range of 2.4 cents/kWh, with individual DSM opportunities having levelized utility costs ranging from 0.2 to 3.5 cents/kWh.

Figure 4.13 LEVELIZED UTILITY COST (2012$) - 2013 - 2016 POWER SMART PLAN



4.2.2.3 Additional DSM Opportunities

Manitoba Hydro's DSM Plan only includes those technology initiatives identified as being available and economic today (e.g., energy savings are demonstrated and are economic under the current incremental installed cost compared to the forecast benefits to be realized over the expected life of the technology). As such, Manitoba Hydro recognizes its future DSM plan is conservative in nature. There are a number of possible initiatives and program strategies currently being explored that, once program implementation is approved, will be included in future DSM plans. Initiatives currently being investigated include, but are not limited to, a new home program, residential LED lighting program and LED street lighting conversion program. Recently, Manitoba Hydro approved a community-based residential geothermal program, which will be included in the next update of the corporation's Power Smart Plan.

To complement Manitoba Hydro's ongoing and internal efforts to identify and quantify potential DSM opportunities and energy savings, Manitoba Hydro hired a third-party consultant to undertake a DSM Market Potential Study in Manitoba in concert with the corporation. The study broadly examines, at a conceptual level, the market potential of existing energy-efficient technologies, which are economic in Manitoba and those technologies that may be "on the horizon". A copy of this study is provided in ***Appendix 4.3 – Demand Side Management Potential Study***.

For purposes of the study, DSM potential is defined within four contexts: 1) technical, 2) economic, 3) market and 4) achievable.

1. The absolute level of DSM without regard for cost and other barriers is defined as the technical potential.
2. "Economic potential" represents the adoption of all energy efficient measures that are cost-effective from a resource perspective (MRC > 1). Technical and economic potential both represent theoretical limits to efficiency savings.
3. Estimating market potential involves the inherent uncertainty of predicting human behaviors and responses to market conditions. This recognizes that any estimate of electricity consumption or potential savings that spans a 15-20 year period is necessarily subject to uncertainty. Numerous external factors create this uncertainty underlying the estimate, including varying levels of market barriers to adoption and factors beyond the influence of Manitoba Hydro (e.g., the levels of complementary support for energy efficiency provided by the federal or provincial governments). Market potential represents the absolute level of energy and demand savings that are technically feasible, economically attractive assuming ideal market conditions. These ideal market conditions could be characterized by the presence of a focused and coordinated effort across organizations/governments (federal, provincial and utilities) eliminating all material market barriers to adoption, such as product availability and market capacity, product awareness and knowledge, price differentials, etc. The probability of these ideal

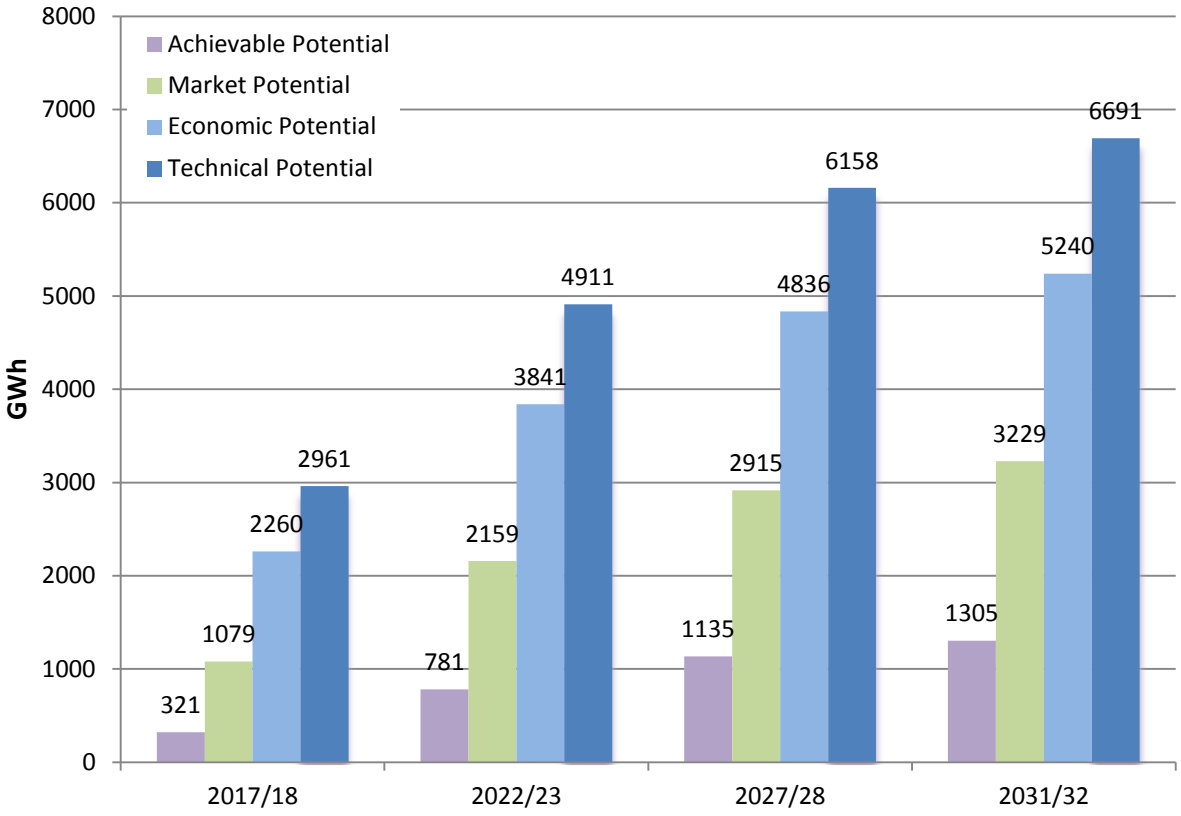
market conditions being present in combination is doubtful and therefore represents a theoretical limit.

4. "Achievable potential" recognizes that market conditions are not ideal and projects energy savings that may be reasonably captured recognizing that there are material market barriers to address.

Caution must be exercised in interpreting the results of a DSM market potential study: the estimates are forecast at a high level and do not account for the investment or the specific strategies required to support the market intervention required to eliminate market barriers, such as education, research and demonstrations, training, capacity-building, incentives, advertising, etc. The setting of specific Power Smart targets involves more detailed and market-specific analysis beyond the scope of the market potential study. The key to developing a sustainable realistic DSM program and overall plan is to recognize the real market constraints and to work within existing market channels (e.g., trade allies, retailers, distributors) to create an effective market change over time.

Figure 4.14 presents the conceptual-level projections of energy efficiency potential in Manitoba.

Figure 4.14 ENERGY EFFICIENCY POTENTIAL PROJECTIONS

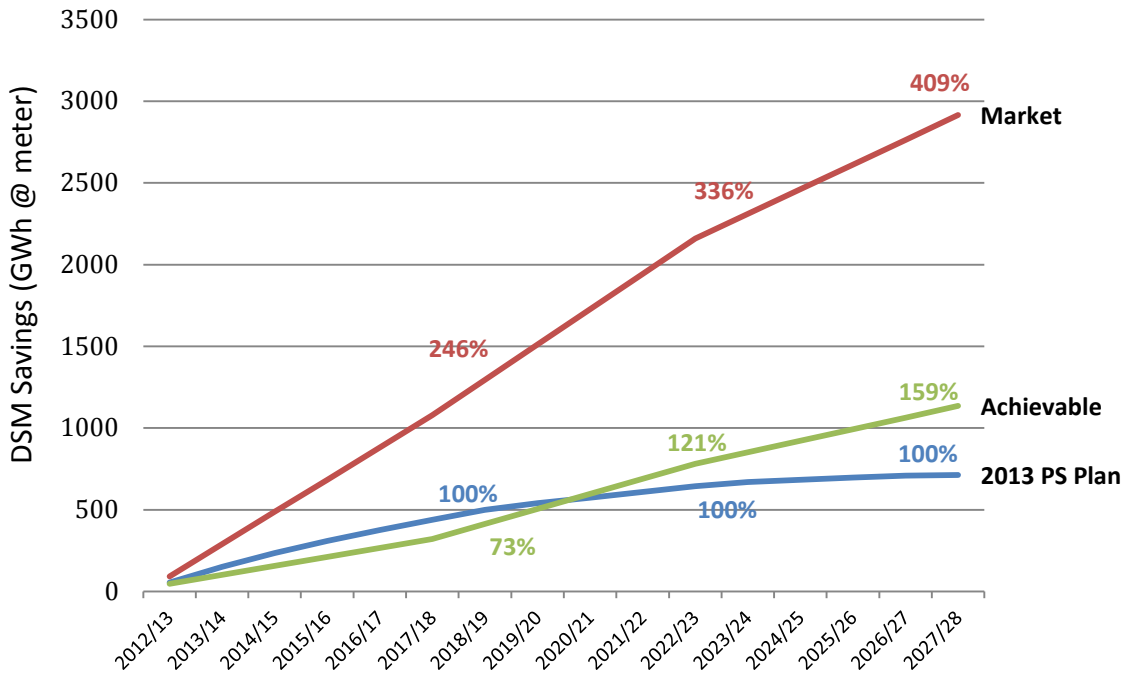


The DSM Market Potential Study undertaken for Manitoba Hydro indicated that, across all sectors, the energy savings range from 321 GWh for achievable potential to 1,079 GWh for market potential in 2017/18 and from 1,135 GWh for achievable potential to 2,915 GWh for market potential in 2027/28. Current projected savings under Manitoba Hydro's 2013 - 2016 Power Smart Plan represent approximately 62% of the forecast achievable potential in 2027/28.

For the purposes of this submission, a sensitivity analysis for increased DSM was undertaken, including increasing Manitoba Hydro energy savings through DSM by 1.5 times, and, similarly, a stress test for increased DSM was undertaken at 4 times the current planned DSM. Based on the results of the market potential study and as evidenced in the following graph, the sensitivity analyses capture the potential for increasing Manitoba Hydro's DSM plans to include both reasonable additional and "ideal" market-threshold energy savings through DSM initiatives. As

Figure 4.15, shows the Achievable Potential of 1,135 GWh and Market Potential of 2,915 GWh represents 159% and 409% respectively of the current planned savings for 2027/28.

Figure 4.15 COMPARISON OF THRESHOLDS FOR POTENTIAL ADDITIONAL DSM 2012/13 TO 2027/28



In accordance with Manitoba Hydro's planning cycle, the corporation's Power Smart Plan will be updated by March 31, 2014. The updated plan will be prepared in consultation with the Minister of Innovation, Energy and Mines and responsible for Manitoba Hydro as directed in *The Manitoba Energy Savings Act*.

4.2.3 Manitoba Net Load

Manitoba net load results from combining the load forecast for Manitoba with the expected savings from planned DSM programs. Figure 4.16 and Figure 4.17 show the Manitoba net load from the perspective of peak demand and energy, respectively.

Figure 4.16 MANITOBA NET LOAD – WINTER PEAK DEMAND

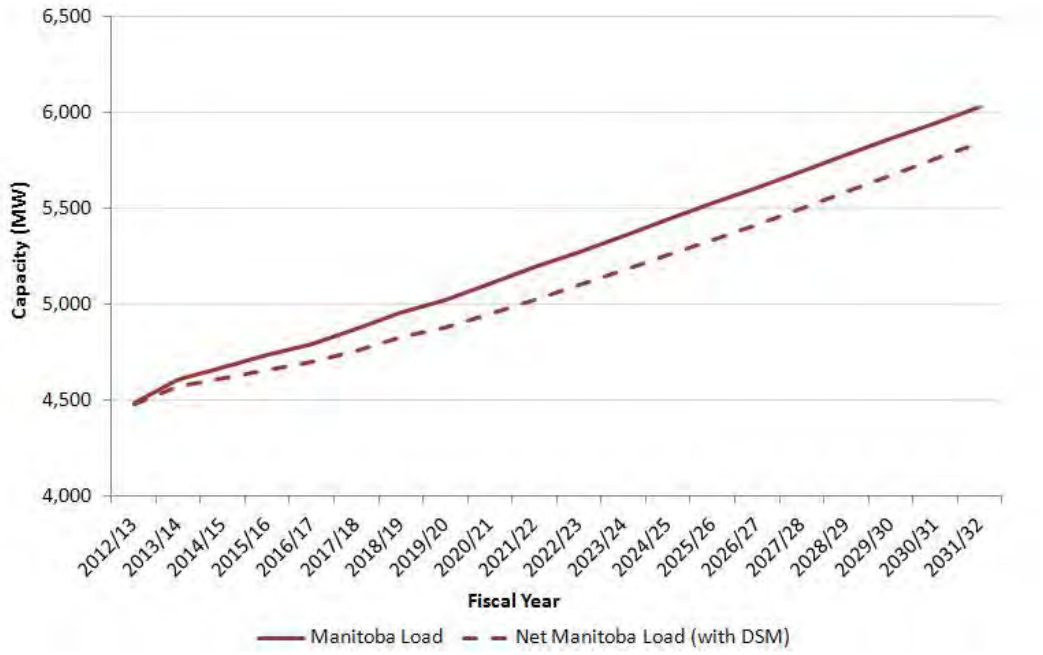
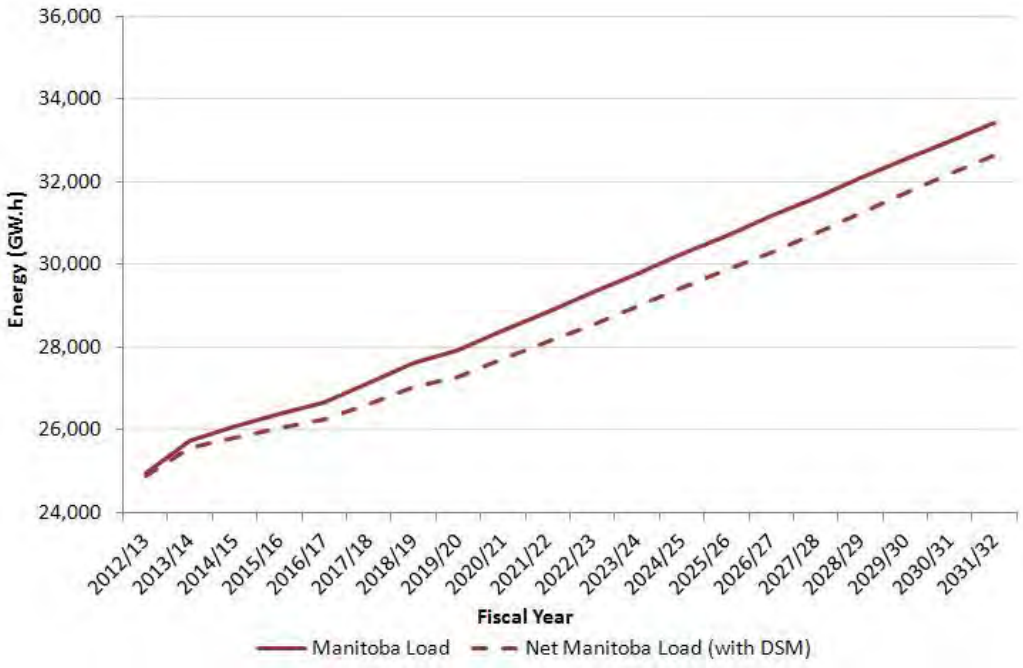


Figure 4.17 MANITOBA NET LOAD – ENERGY



4.2.4 Export Commitments

Manitoba Hydro exports firm energy and capacity surplus to the needs of Manitobans through long-term sale agreements with neighboring utilities. A calculation of the total demand on the Manitoba Hydro system must include—in addition to determining Manitoba net load—the requirements of long-term firm export sale commitments.

From the perspective of winter peak demand, the total of Manitoba Hydro's long-term firm export obligations during winter peak is currently 605 MW, reduces to 358 MW in 2015/16 and continues at this level until 2024/25 when the last contract expires.

The total of Manitoba Hydro's energy export obligations is 3,156 GWh in 2013/14. This obligation reduces to 1,804 GWh in 2016/17 and continues annually at this level to 2024/25. From 2025/26 to the end of the study period the firm export obligation is 145 GWh per year.

Manitoba Hydro currently has a portfolio of 500 MW of seasonal diversity contracts, which provide for the exchange of power between utilities during their respective peak load conditions. These contracts help to optimize operation of the utilities' respective systems and to minimize capital investment. Diversity arrangements allow Manitoba Hydro to purchase power in the winter season to meet peak heating demand and require Manitoba Hydro to sell power to U.S. utilities in the summer season to meet their peak air-conditioning load.

In addition, under certain circumstances, export contracts allow Manitoba Hydro to reduce its delivery obligations, for example, under low-water conditions.

4.2.5 Total Demand

The combined total of all demand components is shown in Table 4.1 and Table 4.4 below from the perspective of capacity and energy, respectively. In Section 4.4, the total demand will be compared to the total base supply.

Table 4.1 TOTAL WINTER PEAK DEMAND FOR SELECT YEARS (MW) @ GENERATION

Winter Peak Demand, MW				
Fiscal Year	2013/14	2021/22	2022/23	2026/27
Manitoba Load	4,609	5,192	5,276	5,611
2012 Base DSM Forecast	(36)	(165)	(176)	(194)
Manitoba Net Load	**4,573**	**5,027**	**5,100**	**5,417**
Existing Long-term Firm Export Sale Commitments	605	358	358	0
Total Peak Demand	**5,178**	**5,385**	**5,458**	**5,417**

Table 4.2 TOTAL ENERGY DEMAND FOR SELECT YEARS (GWH) @ GENERATION

Energy Demand, GWh				
Fiscal Year	2013/14	2021/22	2022/23	2026/27
Manitoba Domestic Load	25,734	28,859	29,322	31,158
2012 Base DSM forecast	(173)	(740)	(782)	(865)
Manitoba Net Load	**25,561**	**28,119**	**28,540**	**30,293**
Existing Long-term Firm Export Sale Commitments	3,156	1,804	1,804	145
Total Energy Demand	**28,717**	**29,923**	**30,344**	**30,438**

4.3 Manitoba Hydro System Supply

4.3.1 Manitoba Hydro's Generation Planning Criteria

Manitoba Hydro's generation planning criteria, as described in ***Appendix 4.1 Manitoba Hydro Generation Planning Criteria***, provides the basis for determining when new resources are required to ensure an adequate supply of capacity and energy for Manitoba. All development plans evaluated in this submission meet or exceed these planning criteria.

The generation planning criteria consist of two components, both of which must be satisfied. First, there is a capacity criterion, used to determine the minimum quantity of generation

capacity required. Second, there is an energy criterion, used to determine the minimum quantity of energy required. These two criteria are outlined in the following sections.

4.3.1.1 Capacity Criterion

Manitoba Hydro's capacity criterion, as described in ***Appendix 4.1 – Manitoba Hydro Generation Planning Criteria***, requires that:

> Manitoba Hydro will plan to carry a minimum reserve against breakdown of plant and increase in demand above forecast of 12% of the Manitoba forecast peak demand each year plus the reserve required by any export contract in effect at the time."

The reserve is intended to protect against capacity shortfalls resulting from breakdown of generation equipment, or increases in winter peak load due to unexpected load growth or extreme weather conditions. The reserve is calculated as 12% of the Manitoba forecast peak winter demand plus the reserve required by any export contract in effect at the time for each year that is forecasted.

The maximum demand for capacity in Manitoba occurs in the winter season, and therefore the reserve margin of 12% is applied to the winter peak demand.

Historically, the reserve margin of 12% has been adequate for Manitoba Hydro's predominantly hydro-electric generation based system because of relatively low outage rates combined with the relatively small size of hydro-generating units. In comparison, reserve margins in predominantly thermal generation based systems are typically in the 15% range.

Manitoba Hydro is a member of the North American Electric Reliability Corporation (NERC), whose mission is to ensure the reliability of the North American bulk power system. Manitoba

Hydro's capacity criterion is in alignment with recommendations provided by NERC on this subject as per the following:

> "Achieving reliability in the bulk electric systems requires, among other things, that the amount of generating capacity resources exceed customer demands by some amount. That amount (expressed as a percent of peak demand is termed a reserve margin and when expressed as a percent of generating capacity is termed capacity margin) must be sufficient to cover planned maintenance and unplanned or forced outages of generating equipment, de-ratings in the capability of demand-side and supply-side resources, system effects due to reasonably anticipated variations in weather, variations in customer demands or forecast demand uncertainty, delays in the construction of generating capacity, and other system operating requirements." (NERC Resource and Transmission Adequacy Recommendations, June 15, 2004, page 10).

4.3.1.2 Energy Criterion

In addition to a capacity criterion, Manitoba Hydro has an energy criterion which recognizes the energy-constrained limitation of a hydro-electric generating system during drought conditions.

Such an energy criterion is typical for a predominately hydro region as noted by NERC. Manitoba Hydro's system is another example of an energy constrained system:

> "In areas where the majority of supply-side resources are energy-constrained (such as the hydro-dominated Northwest[4]), achieving reliability may also require that the energy available to the area is, at least, equal to the customer demand and some reserve requirement during a certain critical design period for the constrained resources." (NERC Resource and Transmission Adequacy Recommendations, June 15, 2004, page 10)

[4] Manitoba Hydro notes that Manitoba, like the Northwest region of the U.S., is also energy constrained.

Manitoba Hydro's energy criterion, as described in more detail in ***Appendix 4.1 — Manitoba Hydro Generation Planning Criteria***, requires that the corporation plan to have adequate energy resources to supply the firm energy demand in the event that the lowest recorded coincident water supply conditions are repeated (e.g., "dependable energy"). Historic system inflows are derived from the available record of river flows (1912-2010), which have been adjusted to represent present-use conditions and to account for systemic changes due to expected future water use and withdrawals upstream of Manitoba.

Dependable energy available in the Manitoba Hydro system is the total energy supplied from:

- hydro-electric generating stations
- thermal generating stations
- wind generation (energy only)
- planned DSM
- imports from neighbouring utilities.

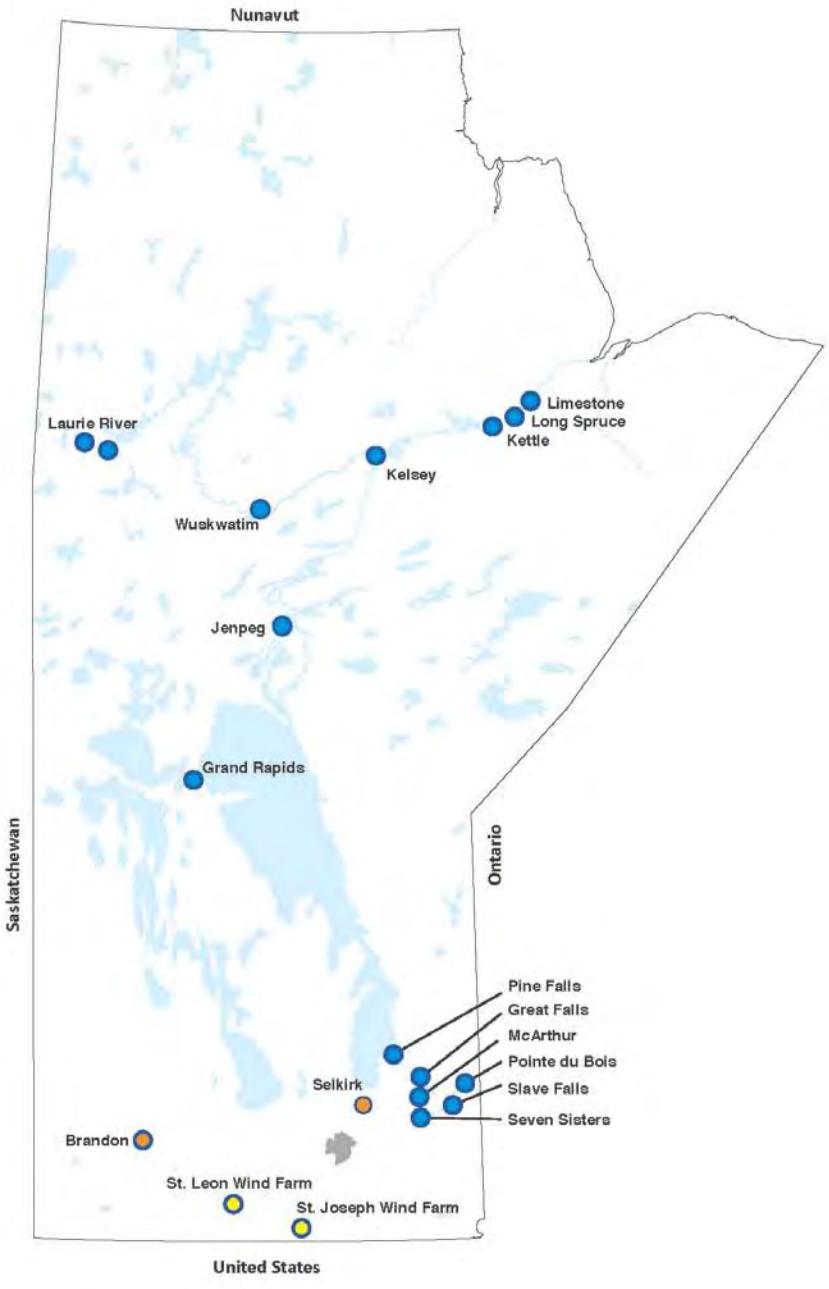
Imports may be considered as dependable energy resources under certain conditions. The total quantity of energy considered as dependable energy from imports is limited to that which can be imported during the off-peak period, and will not exceed the quantity of export contracts in effect at the time, plus 10% of the Manitoba load. The Midcontinent Independent System Operator, Inc. (MISO) market footprint has in the order of 130,000 MW of generating resources. In the off-peak period, MISO market loads are on the order of 60,000 MW or less, leaving ample surplus resources capable of generating energy for import to Manitoba.

4.3.2 Manitoba Hydro's Base Supply of Power – Planning Assumptions

This section provides an overview of the resources that form the base supply of power available to meet Manitoba Hydro's electricity load commitments. The base supply of power is comprised of the following system resources that are common to all development plans being evaluated:

- generating resources owned/operated by Manitoba Hydro including any planned upgrades
- power purchases from Manitoba wind generators
- imports from neighbouring U.S. utilities
- projects to replace existing generating resources where plans are in place
- reduced losses due to increased bipole capacity.

Figure 4.18 MANITOBA HYDRO'S BASE SUPPLY OF POWER



The following describes the resources that contribute to the base supply of power available to meet Manitoba Hydro load and firm export commitments.

Manitoba Hydro-Operated Facilities – Hydro and Thermal Generation

Manitoba Hydro currently operates facilities with a total generating capacity of approximately 5,700 MW. Hydro-electric power is the predominant generation resource in the Manitoba Hydro generating system, providing on average over 90% of the total generating capacity and 98% of electric energy.

Approximately 5,200 MW of renewable hydro-electric generating capacity is available from 15 stations on the Nelson, Winnipeg, Saskatchewan, Burntwood and Laurie rivers. The three hydro-electric generating stations located along the lower Nelson River—Limestone, Long Spruce and Kettle, account for approximately three-quarters of Manitoba Hydro's current hydro-electric capacity.

The remaining 500 MW of Manitoba Hydro generating capacity utilizes thermal technology. The Selkirk Generating Station (G.S.) consists of two natural gas-fired steam turbine generating units. At the Brandon G.S., there are two natural gas-fired combustion turbine generating units and one coal-fired steam turbine unit. For planning purposes, it is assumed that Manitoba Hydro's last coal-fired steam turbine unit, of approximately 100 MW, will be retired in 2019/20 reducing the total generating capacity to approximately 5,600 MW.

Manitoba Hydro Power Purchases - Wind Generation

Manitoba Hydro purchases power through contracts from privately owned wind facilities in southern Manitoba – St. Leon Wind Energy LP in St. Leon and Pattern Energy in St. Joseph with a total installed capacity of approximately 250 MW. For planning purposes, it is assumed these contracts will provide a combined total of 777 GWh of dependable energy each year. Contracted purchases of wind generation are assumed to be renewed using the same terms

and conditions after the expiration of the current contracts and to extend through to the end of the study period.

Wind turbines have operating restrictions during extremely cold weather, the very period in which the Manitoba load reaches its annual winter peak. Therefore, wind generation is not considered a capacity resource for the purpose of meeting winter peak loads as it is not assured to be available at the time of system peak loads.

Manitoba Hydro Power Purchases – Imports

As described in Section 4.2.4 Export Commitments, Manitoba Hydro currently has a portfolio of 500 MW of seasonal diversity contracts which provide for the seasonal exchange of power between utilities during their respective peak load seasons. The diversity agreements provide for an exchange of capacity of up to 500 MW in 2013/14, increasing to 550 MW in 2014/15 and remaining at that quantity until 2024/25 when the last of these contracts expires. In addition to the diversity agreements, Manitoba Hydro has a 500 MW Energy Service Agreement, which provides access to energy throughout the year, but as the contract does not have a capacity component it is not guaranteed for any particular hour.

Under these agreements, for planning purposes Manitoba Hydro can rely on 2,705 GWh of energy in 2013/14. The value reduces to 2,575 GWh by 2016/17 and continues at this quantity until 2024/25.

Although Manitoba Hydro has access to large quantities of energy under contract there are limitations to the amount of imports that can be relied upon for planning purposes. As described in more detail in ***Appendix 4.1 Manitoba Hydro Generation Planning Criteria***, Manitoba Hydro's long-term firm import limit on existing transmission lines from the U.S. is 700 MW. As a result, Manitoba Hydro cannot import the total amount of energy available to it under its import contracts, which in 2014/15 totals 1,050 MW—the situation will not change

until new transmission interconnections are built or existing transmission is upgraded. However, the excess of import capability under the contracts provides flexibility in choosing the source of its imports and recognizes that short-term import limits can be higher than the long-term firm limit of 700 MW.

There is no firm import capability from either Ontario or Saskatchewan that Manitoba Hydro can rely upon for planning purposes.

Manitoba Hydro also relies on market purchases up to the prescribed import limit to the extent permitted under the energy criterion described in Section 4.3.1.2 – Energy Criterion, for planning purposes. These purchased imports from the market are in addition to imports available under the long-term agreements described above.

Supply-Side Enhancements

The Manitoba Hydro system is continuously reviewed for opportunities to upgrade infrastructure that will result in increased output from existing facilities. These upgrades, referred to as "supply-side enhancement" projects, go beyond routine maintenance required to maintain supply and, from an efficiency perspective, are typically timed with major maintenance projects. In 2012 the Kelsey Rerunnering Project was in its final stages which, when completed, will add a total of 77 MW of winter capacity to the Manitoba Hydro generating system and will increase the amount of energy available, on average, from this plant.

Pointe du Bois Generating Station

No decision has been made on the future of the Pointe du Bois powerhouse. For planning purposes, the assumption has been made that the Pointe du Bois powerhouse will be rebuilt, resulting in an increase of 43 MW and 150 GWh over the existing plant ratings with first power to be delivered in 2030/31. Until Pointe du Bois is rebuilt, it is assumed that the existing facility

will be maintained to continue to operate at or near full capacity. This assumption is common to all development plans in this submission.

Reduced Losses due to Increased Bipole Capacity

Bipole III is a new high-voltage direct-current (HVDC) transmission project required to improve overall system reliability with a planned in-service date of 2017/18.

As a transmission project, Bipole III does not provide any new generation but will reduce the transmission losses that exist on the HVDC system by transmitting power over three bipoles rather than two, making more power available for use. The reduction in losses is expected to result in 90 MW of additional capacity and 239 GWh/year of energy under drought conditions. For planning purposes, the savings from reduced losses are included as part of the base supply of power. It is recognized that the loss savings would decrease as new northern generation is connected to the HVDC system.

4.3.3 Summary of Manitoba Hydro System Supply

Manitoba Hydro plans its system supply in accordance with the Generation Planning Criteria as described in Section 4.3.1. Since the demand on the Manitoba Hydro system peaks in the winter, primarily due to heating requirements, Manitoba Hydro plans its system capacity to meet the Manitoba winter peak. Manitoba Hydro plans its system supply to provide a supply of energy that is dependable under a repeat of the lowest recorded water supply conditions.

Summaries of Manitoba Hydro's system supply in terms of winter peak capacity and dependable energy are provided below.

Winter Peak Capacity

As shown in Table 4.3 below, the Manitoba Hydro system is capable of providing 6,244 MW of capacity at winter peak in 2013/14. For planning purposes, the winter peak capacity is reduced

to 5,679 MW by 2026/27 due to the anticipated retirement of the Brandon G.S.'s last coal-fired unit in 2019 and the expiration of certain import contracts. Reductions in transmission losses due to the construction of the Bipole III HVDC transmission line are expected to provide an additional 90 MW by 2017/18.

Table 4.3 TOTAL WINTER PEAK CAPACITY FOR SELECT YEARS (MW) @ GENERATION

Winter Peak Capacity, MW				
Fiscal Year	2013/14	2021/22	2022/2	2026/27
Hydro	5,177	5,177	5,177	5,177
Thermal	517	412	412	412
Wind (Power Purchase Agreements)	0	0	0	0
Imports	550	605	605	0
Bipole III Loss Reduction (2017/18 in-service date)	0	90	90	90
Total Base Supply	**6,244**	**6,284**	**6,284**	**5,679**

Dependable Energy

As shown in Table 4.4 below, the Manitoba Hydro system is capable of providing 30,253 GWh of dependable energy in 2013/14. For planning purposes, dependable energy is reduced to 29,176 GWh by 2026/27 due to the anticipated retirement of the Brandon G.S.'s last coal-fired unit in 2019 and the expiration of certain import contracts.

Table 4.4 TOTAL DEPENDABLE ENERGY FOR SELECT YEARS (GWH) @ GENERATION

Dependable Energy, GWh				
Fiscal Year	2013/14	2021/22	2022/23	2026/27
Hydro	22,290	22,684	22,674	21,810
Thermal	4,118	3,307	3,307	3,307
Wind (Power Purchase Agreements)	777	777	777	777
Imports	3,068	3,068	3,068	3,043
Bipole III Loss Reduction (2017/18 in-service date)	0	239	239	239
Total Base Supply	**30,253**	**30,075**	**30,065**	**29,176**

4.4 Need for New Resources

The need for new resources is determined by comparing annual supply and annual demand values for each year of the 35-year study period. This comparison determines the surplus or deficit of both winter peak capacity and dependable energy on an annual basis. The need for and timing of major new resources to address a deficit in either winter peak capacity or dependable energy is established when persistent deficits occur. Intermittent or short-term deficits would likely be met with imports, which would be arranged closer to, but in advance of the need.

The Need for Winter Capacity Resources

Figure 4.19 shows the capacity balance as either a surplus or deficit for the next 20 years (2012/13 to 2031/32), assuming no further resource additions to the system and no change to DSM. Similarly, Figure 4.20 compares the Manitoba Hydro base supply to the Manitoba net load and total demand to further demonstrate the need for and timing of new capacity resources.

Based on the current supply and demand assumptions for capacity, as described throughout this chapter, the Manitoba Hydro system will have a winter peak capacity surplus until the year 2025/26 at which time there will no longer be sufficient capacity in the winter available to meet the forecast Manitoba winter peak demand and export commitments. Without the savings

from Manitoba Hydro's DSM programs, new resources would have been required earlier, in 2023/24.

Figure 4.19 CAPACITY BALANCE – WINTER PEAK CAPACITY

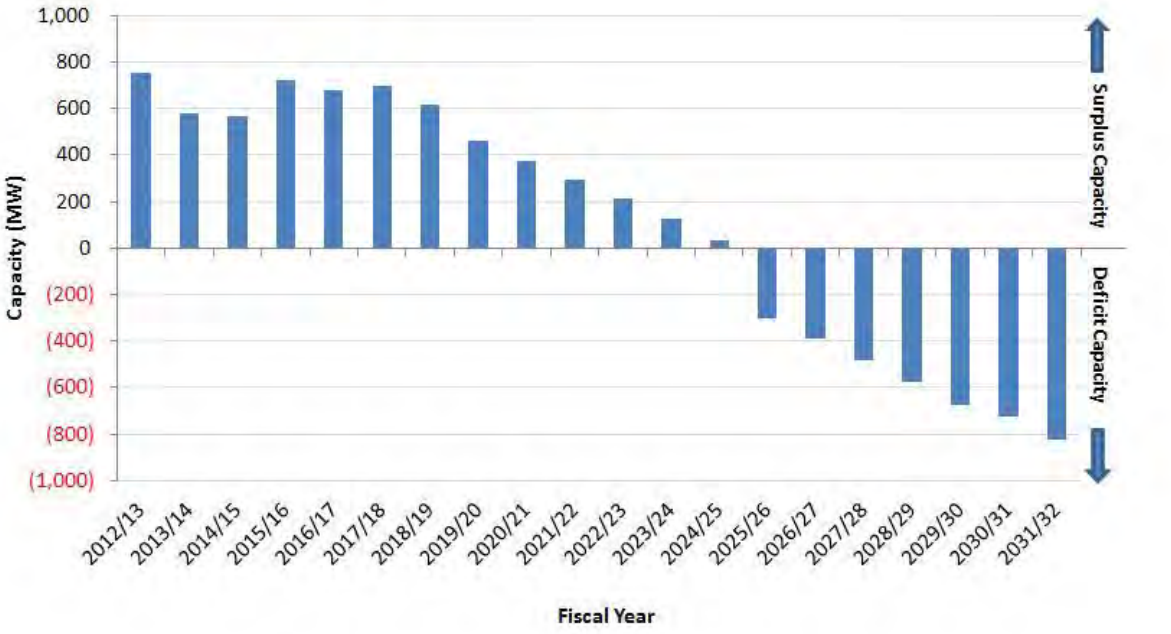
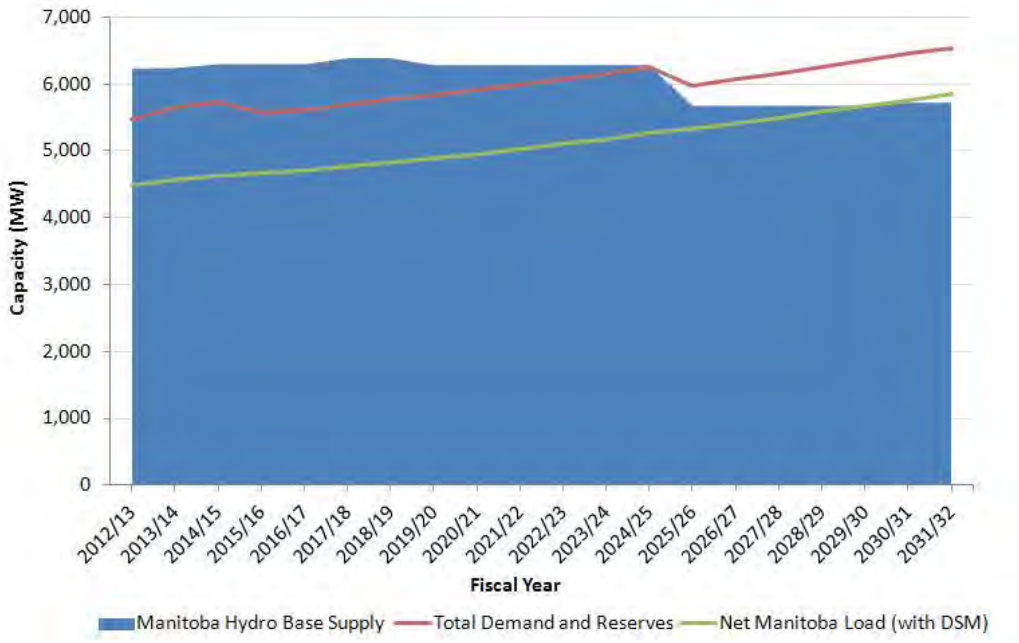


Figure 4.20 NEED FOR NEW RESOURCES – WINTER PEAK CAPACITY



The Need for Dependable Energy Resources

Figure 4.21 shows the dependable energy balance as either a surplus or deficit for the next 20 years (2012/13 to 2031/32), assuming no further resource additions to the system supply and no change to DSM. Similarly, Figure 4.22 compares the Manitoba Hydro base supply to the Manitoba net load and total demand to further demonstrate the need for and timing of new energy resources.

Based on the current supply and demand assumptions for energy, the Manitoba Hydro system will have a dependable energy surplus until the year 2022/23 at which time there will no longer be sufficient dependable energy available to meet the forecasted Manitoba energy demand and export commitments. Without the savings from Manitoba Hydro's DSM programs, new resources would have been required earlier, in 2020/21.

Figure 4.21 ENERGY BALANCE – DEPENDABLE ENERGY

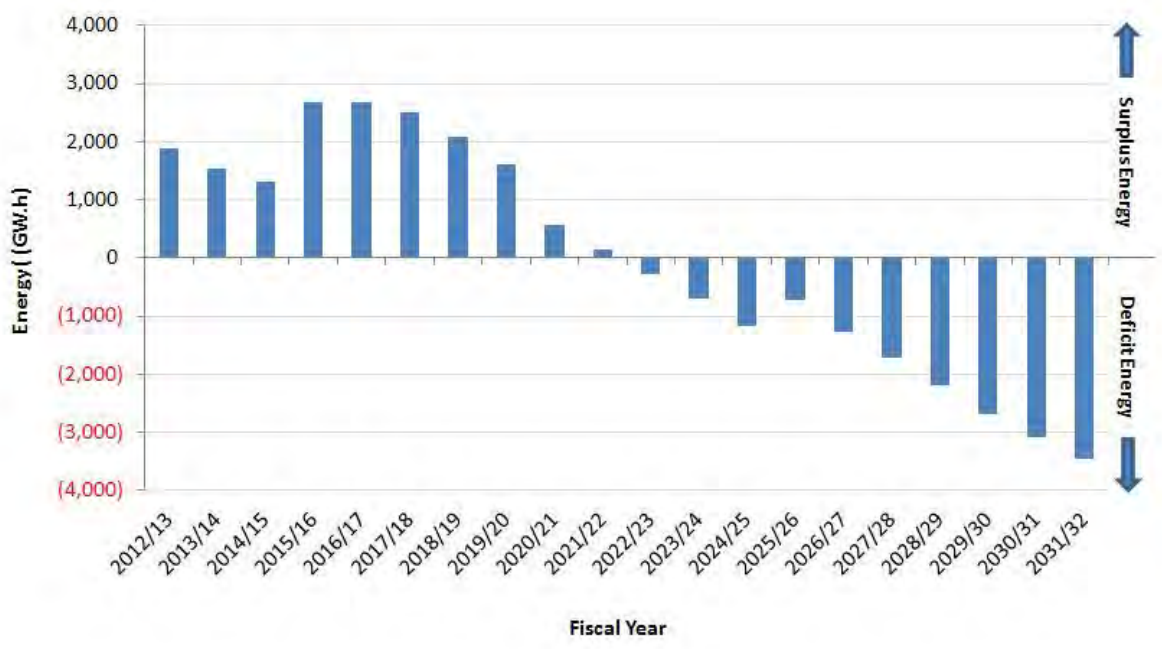
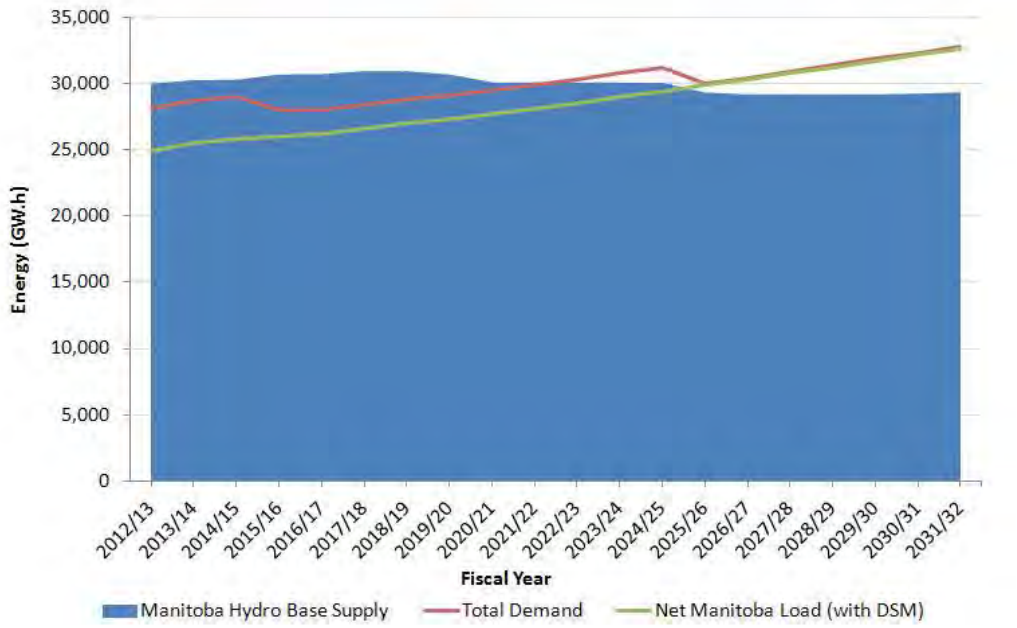


Figure 4.22 NEED FOR NEW RESOURCES – DEPENDABLE ENERGY



Since persistent dependable energy deficits begin earlier than persistent capacity deficits, it is the shortfall of dependable energy which drives the need for new resources in the year 2022/23.

The above analysis is based on 2012/13 resource planning assumptions. It is recognized that there is inherent variability in the assumptions, particularly due to the length of the planning horizon, which is 35 years. As a result, Manitoba Hydro updates this analysis each year incorporating the most current information, including updates to the load forecast, fuel price forecast, electricity export price forecast, capital cost estimates, plant assumptions, economic factors, and other planning assumptions as part of the power resource planning process as described in ***Chapter 1 – Introduction***.

Tables 4.5 and 4.6 summarize the supply and demand values for key dates from the 35-year study period to demonstrate whether a surplus or deficit is expected. More detailed versions of

these tables showing each year of the study period are included in ***Appendix 4.2 – Manitoba Hydro Supply and Demand Tables.***

Table 4.5 WINTER PEAK CAPACITY BALANCE FOR SELECT YEARS (MW) @ GENERATION

Winter Peak Capacity, MW				
Fiscal Year	2013/14	2021/22	2022/23	2026/27
Total Base Supply (From Table 4.3)	6,244	6,284	6,284	5,679
Total Peak Demand (from Table 4.1)	5,178	5,385	5,458	5,417
Reserves	483	603	612	650
System Surplus (Deficit)	583	296	214	(388)

Table 4.6 DEPENDABLE ENERGY BALANCE FOR SELECT YEARS (GWH) @ GENERATION

Dependable Energy, GWh				
Fiscal Year	2013/14	2021/22	2022/23	2026/27
Total Base Supply (from Table 4.4)	30,253	30,075	30,065	29,176
Total Energy Demand (from Table 4.2)	28,717	29,923	30,344	30,438
System Surplus (Deficit)	1,536	152	(279)	(1,262)

Tab 47

Needs For and Alternatives To

APPENDIX D

2013 Electric Load Forecast

This page is intentionally left blank.

2013 ELECTRIC LOAD FORECAST

(For External Use)



MARKET FORECAST
JUNE 2013

APPROVED JULY 2013

Manitoba Hydro

IMPORTANT:

THIS MATERIAL IS THE EXCLUSIVE PROPERTY OF MANITOBA HYDRO AND ALL RIGHTS ARE RESERVED. ANY RELEASE, REPRODUCTION OR OTHER USE THEREOF WITHOUT THE EXPRESS WRITTEN CONSENT OF MANITOBA HYDRO IS STRICTLY PROHIBITED.

EXECUTIVE SUMMARY

Overview

Gross Firm Energy is forecast to grow from weather adjusted value of 24,404 GW.h in 2012/13 to 28,605 GW.h in 2022/23. This average growth is 420 GW.h or 1.6% per year for 10 years. By 2032/33, Gross Firm Energy is forecast to be 32,667 GW.h, a twenty-year growth rate of 413 GW.h or 1.5% per year.

Gross Total Peak is forecast to grow at about the same pace, growing 79 MW or 1.7% a year for the next 10 years, and 76 MW or 1.5% a year for the next 20 years. In 20 years, the peak will grow 1,527 MW to 5,959 MW.

Growth is expected in all sectors. The 20 year growth rates in the Residential Basic, General Service Mass Market and General Service Top Consumers sectors are forecast to be 1.4%, 1.5% and 1.6% respectively.

During the last 10 years, Gross Firm Energy has grown 266 GW.h or 1.2% per year. This ten year period includes the 2009 economic downturn that slowed growth.

The primary driver of growth in Manitoba is the population, with the secondary driver being the economy. Manitoba Hydro's 2013 Economic Outlook provides both the forecast of the population and the resulting forecast of Residential Basic customers that is used in this document. The population of Manitoba has grown from 1,156,600 people in 2002 to 1,267,000 people in 2012 averaging 0.9% growth per year. The forecast is that Manitoba's population will grow to 1,568,500 by 2032, averaging 1.1% per year. The primary reason for the expected increase of population growth in Manitoba is due to government immigration initiatives.

Residential Basic customer growth is expected to mimic population growth, growing 1.1% per year over the next 20 years. An increase in average use per customer adds 0.3% to the growth and is primarily due to increased use of electric space heating and electric water heating in homes.

General Service Mass Market is forecast to grow at an average 1.5% per year, comparable to its historic growth of 1.4% per year over the past ten years.

General Service Top Consumers is forecast to grow at 1.6% per year. This is higher than its 0.5% growth per year during the past ten years which included the loss of a customer and an economic downturn. But it is less than the 3.3% growth per year during the prior ten years. Combined, the 20 year historical growth of the Top Consumers has been 2.0% per year. Short term committed customer plans will amount to 355 GW.h of growth, even after accounting for the expected major load decrease by 2016 of one customer.

Comparison with the 2012 Forecast

The Gross Firm Energy forecast is down 495 GW.h in 2013/14 due to initial-year decreases to the GS Mass Market and GS Top Consumers forecasts and associated decreases to losses. The growth of Residential Basic customers has been reduced from the 2012 forecast resulting in a lower Residential and GS Mass Market forecast. Gross Firm Energy is down 717 GW.h (1½ years of load growth) in 2022/23 and down 1159 GW.h (almost 3 years of load growth) in 2031/32.

The reduction in peak in 2022/23 is 54 MW, about 2/3 of a year of load growth. The reduction in peak in 2031/32 of 146 MW amounts to a reduction of almost 2 years of load growth.

Load Variability and Possible Events

The forecast presented in this document is Manitoba Hydro's best estimate of Manitoba's future electricity requirements. Analysis of historical variation indicates there is an 80% chance that by 2032/33, the load could vary by ±2,471 GW.h (7.6%) from the forecast.

In addition, Manitoba Hydro examines possible events of interest for their potential impact on system load requirements. These events are deemed to be captured within the overall load variability analysis of the forecast, but are presented so their individual effects may be considered from a sensitivity perspective if the need arises:

	Energy Effect (GW.h)	Peak Effect (MW)
Climate Change per Degree Celsius Warmer	+100	-40
One New Very Large Industrial Customer	+1,500	+180
One Less Very Large Industrial Customer	-1,500	-180
Additional Load if Electric Vehicles Grow to 70%	+2,312	+289
10% of all Res Customers switch to Electric Heat	+746	+246
10% of all Res Customers switch to Electric Water Heaters	+198	+23

(For comparison, 1 year of load growth is approximately 420 GW.h or 80 MW)

GROSS FIRM ENERGY AND GROSS TOTAL PEAK
History and Forecast
2002/03 - 2032/33

	Gross Firm Energy		Gross Total Peak		Load Factor
Fiscal Year	(GW.h)	Growth (%)	(MW)	Growth (%)	(%)
2002/03	22110		3948		63.9%
2003/04	22069	-0.2%	3994	1.2%	63.1%
2004/05	22589	2.4%	4201	5.2%	61.4%
2005/06	22757	0.7%	4085	-2.8%	63.6%
2006/07	23464	3.1%	4208	3.0%	63.7%
2007/08	24122	2.8%	4304	2.3%	64.0%
2008/09	24417	1.2%	4509	4.8%	61.8%
2009/10	23412	-4.1%	4393	-2.6%	60.8%
2010/11	23892	2.1%	4286	-2.4%	63.6%
2011/12	23605	-1.2%	4367	1.9%	61.7%
2012/13	24759	4.9%	4559	4.4%	62.0%
2012/13 Wadj	24404	-1.4%	4432	-2.8%	62.9%
10 Year Avg Gr.	266	1.2%	48	1.2%	
2013/14	25239	3.4%	4601	3.8%	62.6%
2014/15	25676	1.7%	4680	1.7%	62.6%
2015/16	26013	1.3%	4742	1.3%	62.6%
2016/17	26322	1.2%	4801	1.2%	62.6%
2017/18	26606	1.1%	4857	1.2%	62.5%
2018/19	27003	1.5%	4930	1.5%	62.5%
2019/20	27398	1.5%	5002	1.5%	62.5%
2020/21	27789	1.4%	5074	1.4%	62.5%
2021/22	28197	1.5%	5147	1.5%	62.5%
2022/23	28605	1.4%	5222	1.4%	62.5%
10 Year Avg Gr.	420	1.6%	79	1.7%	
2023/24	29013	1.4%	5296	1.4%	62.5%
2024/25	29418	1.4%	5369	1.4%	62.5%
2025/26	29822	1.4%	5443	1.4%	62.6%
2026/27	30225	1.4%	5516	1.3%	62.6%
2027/28	30625	1.3%	5588	1.3%	62.6%
2028/29	31041	1.4%	5664	1.4%	62.6%
2029/30	31453	1.3%	5739	1.3%	62.6%
2030/31	31863	1.3%	5813	1.3%	62.6%
2031/32	32265	1.3%	5886	1.3%	62.6%
2032/33	32667	1.2%	5959	1.2%	62.6%
20 Year Avg Gr.	413	1.5%	76	1.5%	

GROSS FIRM ENERGY AND GROSS TOTAL PEAK
Change from Previous Forecast
2013/14 - 2032/33

Fiscal Year	Gross Firm Energy			Gross Total Peak		
	2013 Forecast (GW.h)	2012 Forecast (GW.h)	Change (GW.h)	2013 Forecast (MW)	2012 Forecast (MW)	Change (MW)
2012/13 Act	24759			4559		
Weather Adj.	-356			-127		
2012/13 Wadj	24404	24961	(557)	4432	4491	(59)
2013/14	25239	25734	(495)	4601	4609	(8)
2014/15	25676	26071	(395)	4680	4677	3
2015/16	26013	26393	(380)	4742	4738	4
2016/17	26322	26677	(355)	4801	4794	7
2017/18	26606	27128	(522)	4857	4874	(17)
2018/19	27003	27616	(614)	4930	4959	(29)
2019/20	27398	27919	(521)	5002	5024	(22)
2020/21	27789	28400	(611)	5074	5109	(35)
2021/22	28197	28859	(661)	5147	5192	(45)
2022/23	28605	29322	(717)	5222	5276	(54)
10 Year	420	436		79	79	
Avg Gr.	1.6%	1.6%		1.7%	1.6%	
2023/24	29013	29779	(766)	5296	5360	(64)
2024/25	29418	30239	(821)	5369	5445	(76)
2025/26	29822	30691	(869)	5443	5528	(85)
2026/27	30225	31138	(913)	5516	5611	(95)
2027/28	30625	31594	(968)	5588	5695	(107)
2028/29	31041	32053	(1012)	5664	5779	(115)
2029/30	31453	32511	(1058)	5739	5863	(124)
2030/31	31863	32967	(1104)	5813	5947	(134)
2031/32	32265	33425	(1159)	5886	6032	(146)
19 Year	414	445	-32	77	81	-5
Avg Gr.	1.5%	1.5%	-0.1%	1.5%	1.6%	-0.1%

TABLE OF CONTENTS

EXECUTIVE SUMMARY I

TABLE OF CONTENTS V

LIST OF TABLES AND FIGURES VI

INTRODUCTION 1

FORECAST OVERVIEW 4

- General Consumers Customer Forecast 4
- General Consumers Sales Forecast 6
- Manitoba Energy Forecast 8
- Comparison of the 2012 Forecast to Actuals 10
- Change between the 2012 and 2013 Forecasts 12

FORECAST DETAILS 17

- Residential Basic 17
- Residential Diesel, Seasonal, and Flat Rate Water Heating 19
- General Service Mass Market 20
- General Service Top Consumers 21
- General Service Diesel, Seasonal, and Flat Rate Water Heat 23
- General Service Surplus Energy Program 23
- Plug-In Electric Vehicles 24
- Area & Roadway Lighting 27
- Total General Consumers Sales 29
- Diesel Sales 30
- Distribution Losses 31
- Construction Power 32
- Manitoba Load at Common Bus 33
- Transmission Losses 34
- Station Service 35
- Gross Firm Energy 37
- Gross Total Peak 39

VARIABILITY AND ACCURACY 42

- Weather Effect and Weather Adjustment 42
- Effect of Extreme Weather 43
- Load Variability 44
- 5 and 10 Year Forecast Accuracy 47

POSSIBLE EVENTS 50

ASSUMPTIONS 55

- Economic Assumptions 55
- Normal Weather Assumptions 56
- Demand Side Management (DSM) in the Forecast 57

METHODOLOGY 59

GLOSSARY OF TERMS 67

LIST OF TABLES AND FIGURES

TABLE 1 - GROSS ENERGY AND PEAK III
TABLE 2 - CHANGE IN ENERGY AND PEAK IV
TABLE 3 - COMPONENTS OF MANITOBA ELECTRICITY USE 3
TABLE 4 - GENERAL CONSUMERS SALES CUSTOMERS 5
TABLE 5 - GENERAL CONSUMERS SALES ENERGY 7
TABLE 6 - COMPONENTS OF MANITOBA ENERGY 9
TABLE 7 - 2012/13 FORECAST TO ACTUAL 11
FIGURE 1 - CHANGE OF RES BASIC FORECAST 12
TABLE 8 - CHANGE OF RES BASIC FORECAST 12
FIGURE 2 - CHANGE OF GS MASS MARKET FORECAST 13
TABLE 9 - CHANGE OF GS MASS MARKET FORECAST 13
FIGURE 3 - CHANGE OF GS TOP CONSUMER FORECAST 14
TABLE 10 - CHANGE OF GS TOP CONSUMER FORECAST 14
FIGURE 4 - CHANGE OF ENERGY FORECAST 15
TABLE 11 - CHANGE OF ENERGY FORECAST 15
FIGURE 5 - CHANGE OF PEAK FORECAST 16
TABLE 12 - CHANGE OF PEAK FORECAST 16
FIGURE 6- RESIDENTIAL BASIC SALES 17
TABLE 13 - RESIDENTIAL SALES 17
TABLE 14 - RESIDENTIAL BASIC SALES 18
FIGURE 7 - GENERAL SERVICE MASS MARKET 20
TABLE 15 - GENERAL SERVICE MASS MARKET 20
FIGURE 8 - GENERAL SERVICE TOP CONSUMERS 21
TABLE 16 - GENERAL SERVICE TOP CONSUMERS 21
FIGURE 9 - PLUG-IN ELECTRIC VEHICLES 24
TABLE 17 - PLUG-IN ELECTRIC VEHICLES 26
FIGURE 10 - AREA & ROADWAY LIGHTING 27
TABLE 18 - AREA & ROADWAY LIGHTING 27
TABLE 19 - AREA & ROADWAY LIGHTING 28
FIGURE 11 - GENERAL CONSUMERS SALES 29
TABLE 20 - GENERAL CONSUMERS SALES 29
FIGURE 12 - DIESEL SALES 30
TABLE 21 - DIESEL SALES 30
FIGURE 13 - DISTRIBUTION LOSSES 31
TABLE 22 - DISTRIBUTION LOSSES 31
FIGURE 14 - CONSTRUCTION POWER 32
TABLE 23 - CONSTRUCTION POWER 32
FIGURE 15 - MANITOBA LOAD AT COMMON BUS 33
TABLE 24 - MANITOBA LOAD AT COMMON BUS 33
FIGURE 16 - TRANSMISSION LOSSES 34
TABLE 25 - TRANSMISSION LOSSES 34
FIGURE 17 - STATION SERVICE 35
TABLE 26 - STATION SERVICE 35
TABLE 27 - MONTHLY STATION SERVICE ENERGY 36
TABLE 28 - MONTHLY STATION SERVICE PEAK 36

FIGURE 18 - GROSS FIRM ENERGY 37
TABLE 29 - GROSS FIRM ENERGY 37
TABLE 30 - MONTHLY GROSS FIRM ENERGY 38
FIGURE 19 - GROSS TOTAL PEAK 39
TABLE 31 – GROSS TOTAL PEAK 39
TABLE 32 - MONTHLY GROSS TOTAL PEAK 40
FIGURE 20 - ENERGY VARIABILITY 45
TABLE 33 – ENERGY VARIABILITY 45
FIGURE 21 - PEAK VARIABILITY 46
TABLE 34 – PEAK VARIABILITY 46
FIGURE 22 - ENERGY ACCURACY 48
TABLE 35 - ENERGY ACCURACY 48
FIGURE 23 - PEAK ACCURACY 49
TABLE 36 - PEAK ACCURACY 49

INTRODUCTION

This document is prepared annually as Manitoba Hydro's forecast of its future load requirements for its service area. The service area consists of all of Manitoba (99.83% of sales), as well as two resale customers that supply energy to Creighton, Sask. (0.14% of sales) and the Northwest Angle, Minn. (0.03% of sales). Exports of power to other utilities are not included.

This information is provided for several purposes. Rate making and accounting require short term forecasts of sales by billing month within rate groups so they can forecast revenue. Operations and power planning require short and long term forecasts of energy and peak by calendar month so they can determine supply requirements.

A "customer" in this document usually refers to a metered electrical service. Unmetered services, such as flat rate water heating and sentinel rentals do not count as customers, and street lights group a number of services as one customer. A customer is not the same as a building. One building can have multiple electric services and may count as more than one customer, or multiple buildings may have only one service and may count as only one customer. A customer in this document is also not the same as a customer on the billing system. The latter is a person or organization that Manitoba Hydro serves. One billing customer may pay the bill for multiple services and thus count as multiple customers in this document.

Electric consumption is read from a customer's meter in units of kilowatt-hours (kW.h). A typical home not using electricity for heating might use 10,000 kW.h per year. This document reports electric use in terms of gigawatt-hours (GW.h). One GW.h equals one million kW.h, which is approximately the energy of 100 typical homes not using electricity for heating.

The highest load requirement for a time period is known as the peak load. It is given in terms of megawatts (MW). One MW equals one thousand kilowatts (kW). A typical home not using electricity for heating would use a maximum of about 2.5 kW sometime during the year. However, homes will not all be at their maximum use at the same hour. The maximum use at the same hour is known as the coincident load at the system peak hour. A typical home not using electricity for heating would use about 1.6 kW at the coincident peak. Therefore 1 MW is approximately the coincident peak requirement of 600 typical homes not using electricity for heating.

Components of Manitoba's Electricity Use – 2012/13

General Consumers Sales (also referred to as Total Sales) includes the energy supplied to all of Manitoba Hydro's individually billed customers. In 2012/13, Manitoba Hydro averaged 545,660 General Consumers Sales customers who used 21,477 GW.h.

The major groups include

(1) Residential Basic, with 456,130 customers who used 7,223 GW.h or 33.6% of Sales. These are mostly residences that include single-family homes, multi-family homes and apartment suites.
(2) General Service Mass Market, with 65,974 customers who used 8,434 GW.h or 39.3% of Sales. These are small to large Commercial and Industrial customers.
(3) General Service Top Consumers, with 31 customers who used 5,560 GW.h or 25.9% of sales. These are 17 high-usage companies (some count as multiple customers) that are forecast individually.

The remaining customers include Seasonal customers (billed twice a year rather than monthly), Diesel customers (four remote towns not connected to the integrated grid system), Flat Rate Water Heating and Area and Roadway Lighting. Their electricity use totals only 260 GW.h or 1.2% of Total Sales. Over 50,000 of these services do not count as customers.

Manitoba Load at Common Bus is the total load metered at all the substations in the province that supplies Manitoba Hydro's non-Diesel customers and includes Distribution Losses and Construction Power. In 2012/13, Common Bus was 22,699 GW.h or about 5.7% more than Total Sales.

Gross Firm Energy is the total load needed to be generated for domestic firm load requirements on the Integrated System (excludes diesel). It includes Transmission Losses and Station Service. Some customers are on non-firm contracts (Surplus Energy Program), and their load is not included as part of Manitoba Hydro's generation requirement. In 2012/13, Gross Firm Energy was 24,759 GW.h or about 15.3% more than Total Sales.

COMPONENTS OF MANITOBA ELECTRICITY USE 2012/13 (Customers, Consumption and Average Use)				
Forecast Group	**Cust/Serv**	**GW.h**	**% of Sales**	**kW.h/cust**
Residential Basic	456,130	7,223	33.6%	15,836
Residential Diesel	577	8	0.0%	14,632
Residential Seasonal	20,731	81	0.4%	3,911
Residential Flat Rate Water Heating	4,089	21	0.1%	5,088
Total Residential	477,438	7,334	34.1%	
GS Mass Market	65,974	8,434	39.3%	127,839
GS Top Consumers	31	5,560	25.9%	179,345,515
GS Diesel	175	5	0.0%	31,069
GS Seasonal	850	5	0.0%	6,048
GS Flat Rate Water Heat	408	7	0.0%	18,236
GS Surplus Energy Program	28	28	0.1%	996,707
Total General Service	67,058	14,040	65.4%	
Sentinal Flat Rate	20,238	12	0.1%	568
Sentinal Rental	25,613	-	0.0%	-
Street Lighting	1,164	92	0.4%	78,979
Total Lighting	1,164	103	0.5%	
Total General Consumer Sales	545,660	21,477	100.0%	
Less Diesel Sales		(14)	-0.1%	
Distribution Losses		1,176	5.5%	
Construction Power		59	0.3%	
Manitoba Load at Common Bus		22,699	105.7%	
Transmission Losses		1,952	9.1%	
Less Non-Firm Energy		(28)	-0.1%	
Station Service		137	0.6%	
Gross Firm Energy		24,759	115.3%	
* flat rate and rental services are shown in yellow, which do not count as customers				

FORECAST OVERVIEW

General Consumers Customer Forecast

In 2012/13, there was an average of 545,660 General Consumer Sales customers. These were made up of 456,130 Residential Basic customers, 65,974 General Service Mass Market customers, 31 General Service Top Consumers customers, 28 SEP (Surplus Energy Program, i.e. non-firm) customers, with the rest being Diesel, Seasonal and Area and Roadway Lighting.

During the last 10 years, Residential Basic customers have grown at an average of 4,232 (1.0%) per year. Manitoba Hydro's 2013 Economic Outlook provides the forecast of Residential Basic customers, and this document uses that forecast. It calls for a growth of 5,577 (1.2%) per year over the next ten years and 5,423 (1.1%) per year over the next 20 years. The primary reason for the increase is an expectation of increased population growth in Manitoba due to government immigration initiatives which will impact both the Residential and Commercial Sectors.

General Service Mass Market customers have grown 571 (0.9%) per year over the last 10 years. They are forecast to grow 545 (0.8%) over the next ten years and 512 (0.7%) over the next 20 years.

Residential Seasonal customers, who are mainly cottages with lower usage, are growing at a slower rate than Residential Basic averaging 51 (0.3%) customers per year over the last 10 years. They are forecast to grow at 96 (0.5%) over the next 10 years and 98 (0.5%) over the next 20 years.

Area and Roadway Lighting customers were re-grouped in 2006 when Manitoba Hydro changed its billing system, and the lighting customer counts changed at that time. Area and Roadway Lighting is expected to grow at 4 (0.4%) customers over the next 10 years and 5 (0.4%) over the next 20 years.

Manitoba Hydro purchased Winnipeg Hydro in September 2002. Their customers were integrated into the Manitoba Hydro billing system in June 2004. Historical customer and energy numbers in this document include Winnipeg Hydro customers.

Table 4 - General Consumers Sales Customers

GENERAL CONSUMERS SALES (Ave. Customers) History and Forecast 2002/03 - 2032/33										
Fiscal	Residential			General Service					Lighting	Total
Year	Basic	Diesel	Seas	Mass Mkt	Top Cons	Diesel	Seas	SEP		Custs
2002/03	413,812	499	20,219	60,265	26	148	786	33	755	496543
2003/04	416,690	500	20,056	60,672	27	151	788	33	757	499674
2004/05	420,135	508	20,075	60,924	26	160	793	31	759	503411
2005/06	423,742	519	20,145	61,491	26	168	814	28	793	507726
2006/07	427,886	525	20,312	63,596	26	169	783	28	1129	514454
2007/08	432,144	531	20,437	63,855	26	175	798	27	1,142	519135
2008/09	437,263	540	20,648	64,140	26	178	818	24	1,175	524812
2009/10	441,710	539	20,839	64,758	26	177	830	24	1,191	530094
2010/11	445,882	550	20,950	65,193	26	176	842	24	1,184	534827
2011/12	450,748	568	20,844	65,546	32	174	847	26	1,155	539940
2012/13	456,130	577	20,731	65,974	31	175	850	28	1,164	545660
10 Year	4232	8	51	571	1	3	6	-1	41	4912
Avg Gr.	1.0%	1.5%	0.3%	0.9%	1.8%	1.7%	0.8%	-1.6%	4.4%	0.9%
2013/14	461,763	581	20,786	66,568	30	176	851	32	1,163	551950
2014/15	467,291	588	20,886	67,106	30	178	856	34	1,168	558137
2015/16	472,817	595	20,986	67,654	30	179	861	36	1,173	564331
2016/17	478,333	602	21,086	68,224	30	181	866	38	1,178	570538
2017/18	483,871	610	21,186	68,789	31	182	871	40	1,183	576763
2018/19	489,452	617	21,286	69,332	31	184	876	40	1,188	583006
2019/20	495,061	624	21,386	69,862	31	185	881	40	1,193	589263
2020/21	500,681	631	21,486	70,387	31	187	886	40	1,198	595527
2021/22	506,300	638	21,586	70,908	31	188	891	40	1,203	601785
2022/23	511,900	645	21,686	71,426	31	190	896	40	1,208	608022
10 Year	5577	7	96	545	0	2	5	1	4	6236
Avg Gr.	1.2%	1.1%	0.5%	0.8%	0.0%	0.8%	0.5%	3.6%	0.4%	1.1%
2023/24	517,463	652	21,786	71,939	31	191	901	40	1,213	614216
2024/25	522,976	659	21,886	72,446	31	193	906	40	1,218	620355
2025/26	528,431	666	21,986	72,945	31	194	911	40	1,223	626427
2026/27	533,822	673	22,086	73,437	31	196	916	40	1,228	632429
2027/28	539,143	680	22,186	73,922	31	197	921	40	1,233	638353
2028/29	544,387	687	22,286	74,397	31	199	926	40	1,238	644191
2029/30	549,550	694	22,386	74,864	31	200	931	40	1,243	649939
2030/31	554,634	702	22,486	75,322	31	202	936	40	1,248	655601
2031/32	559,644	709	22,586	75,771	31	203	941	40	1,253	661178
2032/33	564,585	716	22,686	76,214	31	205	946	40	1,258	666681
20 Year	5423	7	98	512	0	2	5	1	5	6051
Avg Gr.	1.1%	1.1%	0.5%	0.7%	0.0%	0.8%	0.5%	1.8%	0.4%	1.0%

General Consumers Sales Forecast

During 2012/13, Total General Consumer Sales was 21,477 GW.h. The fiscal billing year (using weather from March 16, 2012 to March 15, 2013) was warmer than normal in the winter months resulting in a winter weather adjustment of 98 GW.h, and was hotter than normal in the summer resulting in a summer weather adjustment of -130 GW.h. Overall, the weather adjustment for the year was -32 GW.h giving a weather adjusted Total Sales value of 21,445 GW.h.

During the last 10 years, Total Sales have grown at 258 GW.h (1.3%) per year. The growth was 1.8% per year in Residential Basic, 1.4% per year in General Service Mass Market, but only 0.5% in General Service Top Consumers due to the economic downturn in 2009 that included the loss of one Top Consumer customer. This historical growth includes the effect of past Demand Side Management (DSM) initiatives.

Sales are forecast to grow at 364 GW.h (1.6%) per year over the next 10 years and 361 GW.h (1.5%) over the next 20 years before accounting for future market-based DSM programs as outlined on page 57.

Most of the growth is forecast to occur in General Service Mass Market, growing 144 GW.h (1.5%) per year over the next twenty years, followed by Residential Basic at 112 GW.h (1.4%). Top Consumers are expected to return to their normal growth rate and are forecast to grow at 103 (1.6%) per year.

Table 5 - General Consumers Sales Energy

GENERAL CONSUMERS SALES (GW.h) History and Forecast 2002/03 - 2032/33												
Fiscal	Residential				General Service						Lighting	Total
Year	Basic	Diesel	Seas	FRWH	Mass Mkt	Top Cons	Diesel	Seas	FRWH	SEP		Sales
2002/03	6266	6	54	35	7467	5282	4	4	14	25	90	19246
2003/04	6170	6	56	34	7460	5423	5	5	13	17	91	19280
2004/05	6275	7	58	31	7516	5714	5	5	10	25	91	19735
2005/06	6171	7	59	30	7587	5948	5	5	9	23	91	19935
2006/07	6443	7	60	29	7839	5989	5	4	9	23	101	20510
2007/08	6736	7	68	27	8006	6075	5	4	9	24	101	21061
2008/09	6847	7	74	25	8049	6065	5	5	8	22	102	21210
2009/10	6786	7	81	24	7985	5461	6	5	8	20	102	20486
2010/11	6952	8	77	23	8258	5324	5	5	8	24	103	20786
2011/12	6818	8	83	22	8162	5531	5	5	8	25	103	20771
2012/13	7223	8	81	21	8434	5560	5	5	7	28	103	21477
Weather Adj.	-4	0	0	0	-28	0	0	0	0	1	0	-32
2012/13 Wadj	7219	8	81	21	8406	5560	5	5	7	29	103	21445
10 Year Wadj	121	0	3	-1	107	28	0	0	-1	0	1	258
Avg Gr.	1.8%	3.6%	4.2%	-5.1%	1.4%	0.5%	2.1%	1.7%	-6.0%	1.7%	1.4%	1.3%
2013/14	7339	8	83	20	8550	5925	5	5	7	30	104	22076
2014/15	7458	9	85	19	8701	6036	5	5	7	32	104	22460
2015/16	7538	9	86	18	8858	6110	6	5	6	34	105	22774
2016/17	7624	9	88	17	9018	6145	6	5	6	36	106	23059
2017/18	7730	9	90	16	9174	6140	6	5	6	38	106	23319
2018/19	7842	9	92	15	9325	6232	6	5	5	38	107	23677
2019/20	7953	10	93	15	9470	6322	6	5	5	38	107	24024
2020/21	8063	10	95	14	9613	6412	6	5	5	38	108	24369
2021/22	8173	10	97	13	9756	6517	6	5	5	38	108	24728
2022/23	8290	10	99	12	9898	6615	6	5	4	38	109	25087
10 Year	107	0	2	-1	149	106	0	0	0	1	1	364
Avg Gr.	1.4%	2.0%	2.0%	-5.0%	1.6%	1.8%	0.7%	0.6%	-5.0%	2.8%	0.5%	1.6%
2023/24	8405	11	101	12	10040	6715	6	5	4	38	109	25446
2024/25	8520	11	103	11	10179	6815	6	6	4	38	110	25802
2025/26	8635	11	105	11	10318	6915	6	6	4	38	110	26158
2026/27	8750	11	106	10	10456	7015	6	6	4	38	111	26513
2027/28	8864	11	108	10	10592	7115	6	6	3	38	111	26865
2028/29	8983	12	110	9	10736	7215	6	6	3	38	112	27230
2029/30	9102	12	112	9	10878	7315	6	6	3	38	112	27593
2030/31	9219	12	114	8	11020	7415	6	6	3	38	113	27954
2031/32	9337	12	116	8	11154	7515	6	6	3	38	113	28308
2032/33	9454	13	118	7	11288	7615	6	6	3	38	114	28662
20 Year	112	0	2	-1	144	103	0	0	0	0	1	361
Avg Gr.	1.4%	2.0%	1.9%	-5.0%	1.5%	1.6%	0.8%	0.6%	-5.0%	1.4%	0.5%	1.5%

Manitoba Energy Forecast

The actual Gross Firm Energy was 24,759 GW.h in 2012/13. Gross Firm Energy has grown 266 GW.h (1.2%) per year for the past 10 years. This historical growth reflects the effect of past Demand Side Management (DSM) initiatives. Gross Firm energy is forecast to grow to 32,667 GW.h by 2032/33 at an average growth of 413 GW.h or 1.5% per year. This is before accounting for future market-based DSM programs as noted on page 57.

Distribution losses, which is the difference between Manitoba Hydro's substations and the customers' meters, has a wide variance from year to year and has ranged between 3.5% and 5.5% of Total Sales. It is forecast to be 4.4% of Sales for the entire forecast.

Transmission Losses which is the difference between the generators and the substations is forecast to be 9.3% of Total Sales for the entire forecast.

Distribution Losses, Transmission Losses, Construction and Station Service amount to an additional 14% that needs to be added to Total Sales to estimate Gross Firm Energy. This 14% value should generally be used to estimate load at generation when only load at the customer's meter is known, for example to convert Power Smart program savings from the customer meter to generation. The exception is for large General Service customers who own their own transformation and incur minimal Distribution Losses. For these customers, a 10% value should be used.

Table 6 - Components of Manitoba Energy

MANITOBA FIRM ENERGY (GW.h)
History and Forecast
2002/03 - 2032/33

Fiscal Year	General Consumer Sales less Diesel	Dist. Losses	Dist. Loss %	Const. Power	Manitoba Load at Common Bus	Trans. Losses	Trans. Loss %	Less Non Firm Energy	Station Service	Gross Firm Energy
2002/03	19236	671	3.5%	46	19953	2012	10.5%	24	170	22110
2003/04	19269	804	4.2%	43	20116	1792	9.3%	17	179	22069
2004/05	19724	830	4.2%	46	20600	1852	9.4%	26	163	22589
2005/06	19923	797	4.0%	42	20761	1860	9.3%	23	158	22757
2006/07	20497	900	4.4%	45	21442	1885	9.2%	22	159	23464
2007/08	21049	940	4.5%	47	22036	1949	9.3%	24	161	24122
2008/09	21198	1052	5.0%	56	22305	1979	9.3%	22	154	24417
2009/10	20473	813	4.0%	75	21361	1934	9.4%	20	137	23412
2010/11	20773	947	4.6%	85	21806	1977	9.5%	25	134	23892
2011/12	20757	736	3.5%	67	21560	1939	9.3%	25	131	23605
2012/13	21463	1176	5.5%	59	22699	1952	9.1%	28	137	24759
Weather Adj.	-32	-295		0	-327	-29		0	0	-356
2012/13 Wadj	21431	881	4.1%	59	22372	1923	9.0%	28	137	24404
10 Year Wadj	258	16		1	275	-6		0	-3	266
Avg Gr.	1.3%	2.0%		2.7%	1.3%	-0.3%		1.4%	-2.1%	1.2%
2013/14	22062	971	4.4%	43	23076	2058	9.3%	30	134	25239
2014/15	22446	988	4.4%	45	23479	2094	9.3%	32	134	25676
2015/16	22759	1001	4.4%	29	23790	2122	9.3%	34	134	26013
2016/17	23044	1014	4.4%	17	24075	2148	9.3%	36	134	26322
2017/18	23304	1025	4.4%	9	24338	2171	9.3%	38	134	26606
2018/19	23661	1041	4.4%	0	24703	2204	9.3%	38	134	27003
2019/20	24009	1056	4.4%	0	25065	2236	9.3%	38	134	27398
2020/21	24353	1072	4.4%	0	25425	2268	9.3%	38	134	27789
2021/22	24712	1087	4.4%	0	25799	2301	9.3%	38	134	28197
2022/23	25071	1103	4.4%	0	26174	2335	9.3%	38	134	28605
10 Year	364	22		-6	380	41		1	0	420
Avg Gr.	1.6%	2.3%		-100.0%	1.6%	2.0%		3.0%	-0.2%	1.6%
2023/24	25429	1119	4.4%	0	26548	2368	9.3%	38	134	29013
2024/25	25786	1135	4.4%	0	26920	2401	9.3%	38	134	29418
2025/26	26141	1150	4.4%	0	27291	2435	9.3%	38	134	29822
2026/27	26496	1166	4.4%	0	27661	2468	9.3%	38	134	30225
2027/28	26847	1181	4.4%	0	28029	2500	9.3%	38	134	30625
2028/29	27213	1197	4.4%	0	28410	2534	9.3%	38	134	31041
2029/30	27575	1213	4.4%	0	28788	2568	9.3%	38	134	31453
2030/31	27936	1229	4.4%	0	29165	2602	9.3%	38	134	31863
2031/32	28290	1245	4.4%	0	29534	2635	9.3%	38	134	32265
2032/33	28643	1260	4.4%	0	29903	2667	9.3%	38	134	32667
20 Year	361	19		-3	377	37		0	0	413
Avg Gr.	1.5%	1.8%		-100.0%	1.5%	1.7%		1.5%	-0.1%	1.5%

Comparison of the 2012 Forecast to Actuals

Comparison of the 2012 Forecast to the 2012/13 Weather Adjusted Actuals

The weather adjusted General Consumer Sales for 2012/13 was 21,445 GW.h which was 352 GW.h lower than the 2012 forecast of 21,797 GW.h.

The weather adjusted Residential Basic sector for 2012/13 was 7,219 GW.h which was 9 GW.h lower than the 2012 forecast of 7,227 GW.h. The weather adjusted General Service Mass Market sector for 2012/13 was 8,406 GW.h which was 82 GW.h lower than the 2012 forecast of 8,488 GW.h.

The Top Consumers sector for 2012/13 was 5,560 GW.h which was 261 GW.h lower than the 2012 forecast of 5,821 GW.h primarily due to project delays by two Top Consumers. Projected load growth for those specific projects is still expected and is included in the 2013 Forecast.

Distribution losses were forecast to be 950 GW.h, but came in at 1,176 GW.h. Distribution Losses account for the difference between Common Bus and General Consumer Sales. Common Bus is measured month-end to month-end at the substation level, whereas Sales are measured at the customer's meter and by billing cycle, which generally map to mid-month. The extreme warm weather that occurred from March 16 to 31, 2012 combined with the extreme cold weather experienced from March 16 to 31, 2013 resulted in about 300 Heating Degree Days difference between the two measurements. This also caused a very large weather adjustment of -295 GW.h. After accounting for weather adjustment, Distribution Losses were 881 GW.h which was 69 GW.h lower than the 2012 forecast of 950 GW.h.

Weather adjusted transmission losses were 1,923 GW.h which was 112 GW.h less than the 2012 forecast of 2,034 GW.h.

Overall, the weather adjusted Gross Firm Energy was 24,404 GW.h which was 557 GW.h lower than the 2012 forecast of 24,961 GW.h due to delays in the plans of two Top Consumers and lower than normal Distribution and Transmission Losses.

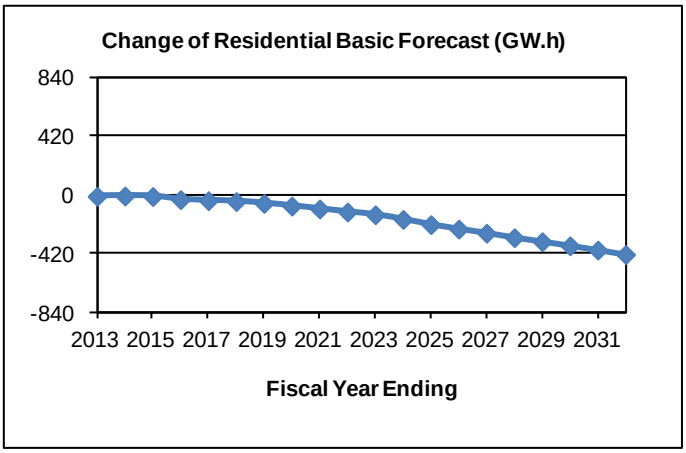
Table 7 - 2012/13 Forecast to Actual

2012 FORECAST COMPARED TO WEATHER ADJUSTED ACTUALS 2012/13 (GW.h)					
Forecast Group	Actuals	Weather Adjustment	Wthr Adj Actuals	2012 Forecast	WA Actuals less Forecast
Residential Basic	7,223	(4)	7,219	7,227	(8)
Residential Diesel	8	-	8	8	0
Residential Seasonal	81	-	81	85	(4)
Residential Flat Rate Water Heating	21	-	21	21	(0)
Total Residential	7,334	(4)	7,330	7,341	(11)
GS Mass Market	8,434	(28)	8,406	8,488	(82)
GS Top Consumers	5,560	-	5,560	5,821	(261)
GS Diesel	5	-	5	6	(0)
GS Seasonal	5	-	5	5	0
GS Flat Rate Water Heat	7	-	7	7	0
GS Surplus Energy Program	28	1	29	27	2
Total General Service	14,040	(27)	14,012	14,353	(340)
Sentinal Flat Rate	12	-	12	12	(0)
Sentinal Rental	-	-	-	-	-
Street Lighting	92	-	92	92	(0)
Total Lighting	103	-	103	104	(0)
Total General Consumer Sales	21,477	(32)	21,445	21,797	(352)
Less Diesel Sales	(14)	-	(14)	(14)	(0)
Distribution Losses	1,176	(295)	881	950	(69)
Construction Power	59	-	59	78	(18)
Manitoba Load at Common Bus	22,699	(327)	22,372	22,812	(440)
Transmission Losses	1,952	(29)	1,923	2,034	(112)
Less Non-Firm Energy	(28)	0	(28)	(27)	(2)
Station Service	137	-	137	141	(4)
Gross Firm Energy	24,759	(356)	24,404	24,961	(557)

Change between the 2012 and 2013 Forecasts

Change Between the 2012 and 2013 Residential Basic Forecast

Figure 1 - Change of Res Basic Forecast



The Residential Basic Forecast is down from the 2012 forecast. By 2031/32 the difference is 423 GW.h or 4.3%. This is equivalent to about 1 year of Manitoba system load growth (1 year = approximately 420 GW.h).

Changes made (and the 2031/32 effect):

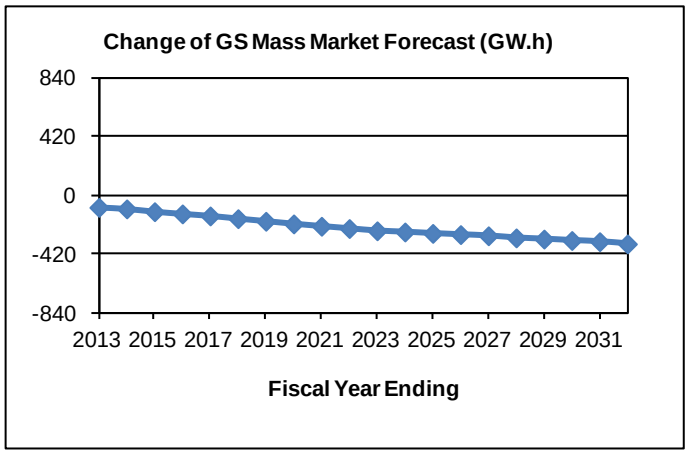
1. The customer forecast was reduced by 16,901 customers (-282 GW.h).
2. The appliance unit energy consumptions (UECs) or average use per appliance per year were updated in the Residential End Use model. The update was done using a preliminary Conditional Demand Analysis of the 2009 Residential Energy Use Survey data with customer billing data (+212 GW.h).
3. An adjustment to reflect initiatives being undertaken by Manitoba Hydro was included to reduce the number of customers choosing electric space and water heat (-366 GW.h).

Table 8 - Change of Res Basic Forecast

CHANGE OF RESIDENTIAL BASIC FORECAST (GW.h) Comparison of 2012 to 2013 forecast										
Fiscal Year	2012 Fcst	2013 Fcst	Change	%		Fiscal Year	2012 Fcst	2013 Fcst	Change	%
2012/13	7227	7219	(8)	-0.1%		2022/23	8429	8290	(139)	-1.6%
2013/14	7344	7339	(5)	-0.1%		2023/24	8577	8405	(172)	-2.0%
2014/15	7467	7458	(9)	-0.1%		2024/25	8730	8520	(210)	-2.4%
2015/16	7569	7538	(31)	-0.4%		2025/26	8877	8635	(241)	-2.7%
2016/17	7662	7624	(38)	-0.5%		2026/27	9021	8750	(271)	-3.0%
2017/18	7774	7730	(45)	-0.6%		2027/28	9167	8864	(303)	-3.3%
2018/19	7900	7842	(58)	-0.7%		2028/29	9315	8983	(332)	-3.6%
2019/20	8030	7953	(77)	-1.0%		2029/30	9463	9102	(361)	-3.8%
2020/21	8161	8063	(97)	-1.2%		2030/31	9611	9219	(392)	-4.1%
2021/22	8292	8173	(119)	-1.4%		2031/32	9760	9337	(423)	-4.3%

Change Between the 2012 and 2013 GS Mass Market Forecast

Figure 2 - Change of GS Mass Market Forecast



The General Service Mass Market Forecast is down 343 GW.h in 2031/32, primarily due to the reduction in the residential customer forecast, which also affects commercial growth. This represents less than a year of Manitoba system load growth (1 year = approximately 420 GW.h).

Changes made (and the 2031/32 effect):

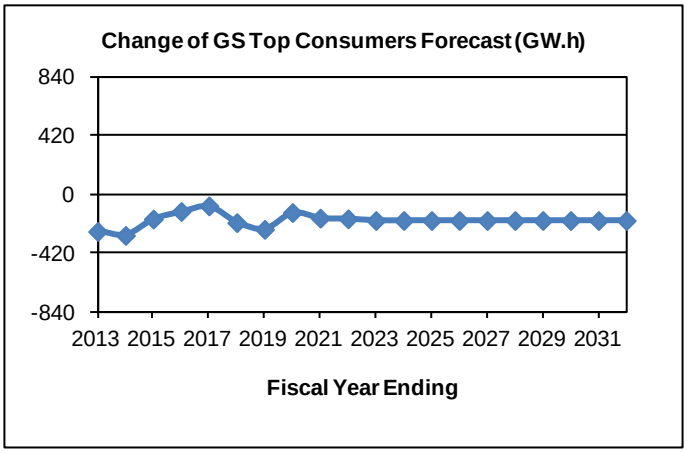
1. The residential customer forecast was reduced leading to a reduction in the GS Mass Market customers (-191 GW.h).
2. The average use per customer in each size class was updated and reduced the overall GS Mass Market load. (-107 GW.h).

Table 9 - Change of GS Mass Market Forecast

CHANGE OF GS MASS MARKET FORECAST (GW.h) Comparison of 2012 to 2013 forecast										
Fiscal Year	2012 Fcst	2013 Fcst	Change	%		Fiscal Year	2012 Fcst	2013 Fcst	Change	%
2012/13	8488	8406	(82)	-1.0%		2022/23	10147	9898	(249)	-2.5%
2013/14	8643	8550	(93)	-1.1%		2023/24	10298	10040	(258)	-2.5%
2014/15	8814	8701	(113)	-1.3%		2024/25	10447	10179	(268)	-2.6%
2015/16	8986	8858	(128)	-1.4%		2025/26	10595	10318	(276)	-2.6%
2016/17	9161	9018	(143)	-1.6%		2026/27	10741	10456	(285)	-2.7%
2017/18	9336	9174	(163)	-1.7%		2027/28	10892	10592	(300)	-2.8%
2018/19	9506	9325	(181)	-1.9%		2028/29	11045	10736	(308)	-2.8%
2019/20	9670	9470	(200)	-2.1%		2029/30	11197	10878	(319)	-2.8%
2020/21	9830	9613	(217)	-2.2%		2030/31	11347	11020	(327)	-2.9%
2021/22	9989	9756	(233)	-2.3%		2031/32	11497	11154	(343)	-3.0%

Change Between the 2012 and 2013 GS Top Consumers Forecast

Figure 3 - Change of GS Top Consumer Forecast



The General Service Top Consumers is down 289 GW.h in 2013/14 due to delays in some of the short term committed customer plans. By 2031/32, the decrease is 182 GW.h. This is equal to the loss of slightly less than a half year of Manitoba system load growth (1 year = approximately 420 GW.h).

Changes made (and the 2031/32 effect):

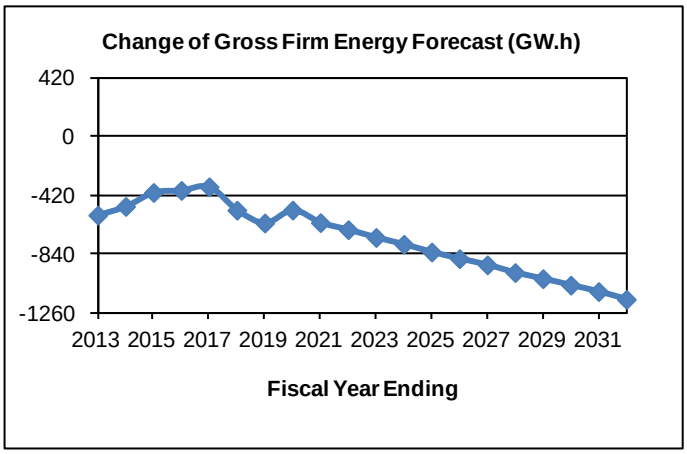
1. Short term committed plans of two Top Consumers were delayed with an effect of 305 GW.h in the first two years of the forecast (0 GW.h)
2. Potential Large Industrial Loads begins in the 4th year of the forecast, which in the 2013 forecast is one year later giving one less year of PLIL growth (-100 GW.h).
3. Changes to the forecasts of the Top Consumers up to 2021/22 mostly in the Primary Metals sector (-83 GW.h).

Table 10 - Change of GS Top Consumer Forecast

CHANGE OF GS TOP CONSUMERS FORECAST (GW.h) Comparison of 2012 to 2013 forecast										
Fiscal Year	2012 Fcst	2013 Fcst	Change	%		Fiscal Year	2012 Fcst	2013 Fcst	Change	%
2012/13	5821	5560	(261)	-4.5%		2022/23	6798	6615	(183)	-2.7%
2013/14	6214	5925	(289)	-4.7%		2023/24	6898	6715	(183)	-2.7%
2014/15	6208	6036	(172)	-2.8%		2024/25	6998	6815	(183)	-2.6%
2015/16	6228	6110	(118)	-1.9%		2025/26	7098	6915	(183)	-2.6%
2016/17	6223	6145	(78)	-1.3%		2026/27	7198	7015	(183)	-2.5%
2017/18	6338	6140	(198)	-3.1%		2027/28	7298	7115	(183)	-2.5%
2018/19	6478	6232	(246)	-3.8%		2028/29	7398	7215	(183)	-2.5%
2019/20	6448	6322	(126)	-2.0%		2029/30	7498	7315	(183)	-2.4%
2020/21	6578	6412	(166)	-2.5%		2030/31	7598	7415	(183)	-2.4%
2021/22	6688	6517	(171)	-2.6%		2031/32	7698	7515	(183)	-2.4%

Change Between the 2012 and 2013 Gross Firm Energy Forecast

Figure 4 - Change of Energy Forecast



The Gross Firm Energy forecast is down 557 GW.h in 2013/14 due to initial-year decreases to the GS Mass Market and GS Top Consumers forecasts and associated decreases to losses. This difference grows to 1159 GW.h by 2031/32 due to the reduction of the Residential Basic customer forecast and its effect on the Residential and GS Mass Market forecasts. This is a 3.5% reduction in the forecast of 2031/32, which is equivalent to a loss of almost 3 years of load growth (1 year = approximately 420 GW.h).

Changes made (and the 2031/32 effect):

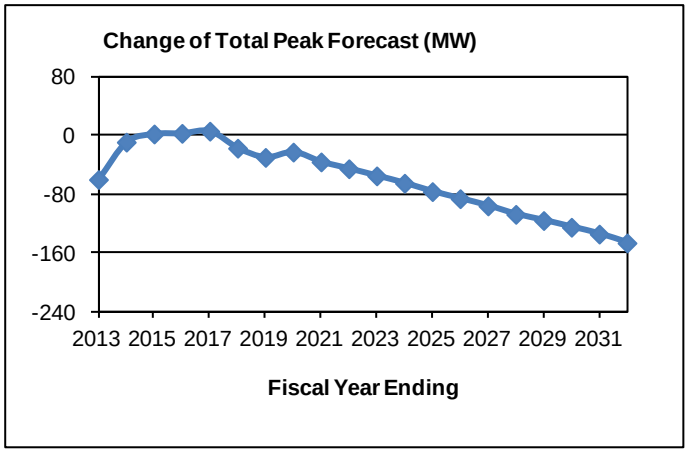
1. Residential Basic forecast (-423 GW.h), primarily due to the decrease in the forecast of Residential Basic customers and heating fuel choice initiatives being undertaken by Manitoba Hydro.
2. General Service Mass Market forecast (-343 GW.h), primarily due to the decrease in the forecast of Residential Basic customers.
3. General Service Top Consumers forecast (-183 GW.h), mostly in the Primary Metals sector.
4. Other Sales and Losses (-210 GW.h).

Table 11 - Change of Energy Forecast

GROSS FIRM ENERGY (GW.h) Comparison of 2012 to 2013 forecast										
Fiscal Year	2012 Fcst	2013 Fcst	Change	%		Fiscal Year	2012 Fcst	2013 Fcst	Change	%
2012/13	24961	24404	(557)	-2.2%		2022/23	29322	28605	(717)	-2.4%
2013/14	25734	25239	(495)	-1.9%		2023/24	29779	29013	(766)	-2.6%
2014/15	26071	25676	(395)	-1.5%		2024/25	30239	29418	(821)	-2.7%
2015/16	26393	26013	(380)	-1.4%		2025/26	30691	29822	(869)	-2.8%
2016/17	26677	26322	(355)	-1.3%		2026/27	31138	30225	(913)	-2.9%
2017/18	27128	26606	(522)	-1.9%		2027/28	31594	30625	(968)	-3.1%
2018/19	27616	27003	(614)	-2.2%		2028/29	32053	31041	(1012)	-3.2%
2019/20	27919	27398	(521)	-1.9%		2029/30	32511	31453	(1058)	-3.3%
2020/21	28400	27789	(611)	-2.2%		2030/31	32967	31863	(1104)	-3.3%
2021/22	28859	28197	(661)	-2.3%		2031/32	33425	32265	(1159)	-3.5%

Change Between the 2012 and 2013 Gross Total Peak Forecast

Figure 5 - Change of Peak Forecast



The Gross Total Peak forecast is down 146 MW (2.4%) by 2031/32 from the 2012 forecast. The peak forecast very closely follows the energy forecast, and the reasons for reduction in peak are similar to those for energy.

The reduction in peak in 2022/23 amounts to 54 MW, less than one year of load growth. The reduction in peak in 2031/32 of 146 MW amounts to a reduction of almost 2 years of load growth. (1 year = approximately 80 MW).

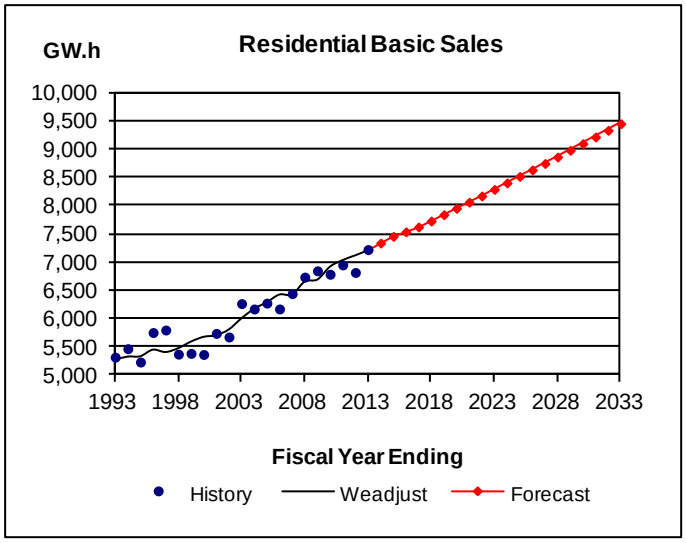
Table 12 - Change of Peak Forecast

GROSS TOTAL PEAK (MW) Comparison of 2012 to 2013 forecast										
Fiscal Year	2012 Fcst	2013 Fcst	Change	%		Fiscal Year	2012 Fcst	2013 Fcst	Change	%
2012/13	4491	4432	(59)	-1.3%		2022/23	5276	5222	(54)	-1.0%
2013/14	4609	4601	(8)	-0.2%		2023/24	5360	5296	(64)	-1.2%
2014/15	4677	4680	3	0.1%		2024/25	5445	5369	(76)	-1.4%
2015/16	4738	4742	4	0.1%		2025/26	5528	5443	(85)	-1.5%
2016/17	4794	4801	7	0.1%		2026/27	5611	5516	(95)	-1.7%
2017/18	4874	4857	(17)	-0.3%		2027/28	5695	5588	(107)	-1.9%
2018/19	4959	4930	(29)	-0.6%		2028/29	5779	5664	(115)	-2.0%
2019/20	5024	5002	(22)	-0.4%		2029/30	5863	5739	(124)	-2.1%
2020/21	5109	5074	(35)	-0.7%		2030/31	5947	5813	(134)	-2.2%
2021/22	5192	5147	(45)	-0.9%		2031/32	6032	5886	(146)	-2.4%

FORECAST DETAILS

Residential Basic

Figure 6- Residential Basic Sales



In 2012/13, there were 456,130 Residential Basic customers. 80% are single detached, 7% multi attached, and 13% individually metered apartment suites. 54% are in Winnipeg where natural gas is available, 28% in natural gas available areas outside Winnipeg, and 18% do not have natural gas available.

Residential Basic has grown 99 GW.h (1.6%) per year for the past 20 years and 121 GW.h per year (1.8%) for the past 10 years which includes the effect of past Demand Side Management (DSM) initiatives. It is forecast to grow 107 GW.h (1.4%) per year for the next 10 years and 112 GW.h (1.4%) per year for the next 20 years.

The primary drivers of Residential Basic growth are population and average use per customer. The population is forecast to grow 1.1% per year over both the next 10 and next 20 years. The increase in average use per customer is expected to add another 0.3% to the growth.

Table 13 - Residential Sales

RESIDENTIAL BASIC (GW.h) HISTORICAL/WEATHER ADJUSTMENT/FORECAST					
Fiscal Year	Sales	Weather Adjust	Adjusted Sales	Fiscal Year	Forecast Sales
1993/94	5467	-135	5332	2013/14	7339
1994/95	5230	107	5337	2014/15	7458
1995/96	5753	-299	5454	2015/16	7538
1996/97	5797	-385	5412	2016/17	7624
1997/98	5370	111	5481	2017/18	7730
1998/99	5384	213	5597	2018/19	7842
1999/00	5364	318	5682	2019/20	7953
2000/01	5737	-26	5711	2020/21	8063
2001/02	5674	140	5814	2021/22	8173
2002/03	6266	-255	6011	2022/23	8290
2003/04	6170	10	6181	2023/24	8405
2004/05	6275	22	6297	2024/25	8520
2005/06	6171	263	6434	2025/26	8635
2006/07	6443	-9	6434	2026/27	8750
2007/08	6736	-71	6664	2027/28	8864
2008/09	6847	-146	6701	2028/29	8983
2009/10	6786	144	6930	2029/30	9102
2010/11	6952	94	7046	2030/31	9219
2011/12	6818	313	7131	2031/32	9337
2012/13	7223	-4	7219	2032/33	9454

Table 14 - Residential Basic Sales

RESIDENTIAL BASIC SALES
History and Forecast
2011/12 - 2031/32

Fiscal	Electric Heat Billed			Other			Total Basic			% Elec Space	% Elec Water
Year	Custs	GW.h	kW.h/cust	Custs	GW.h	kW.h/cust	Custs	GW.h	kW.h/cust	Heat	Heat
2012/13	165576	4255	25701	290554	2964	10201	456130	7219	15827	36.3%	49.0%
2013/14	169399	4342	25635	292364	2997	10250	461763	7339	15894	36.7%	50.1%
2014/15	173080	4425	25568	294212	3033	10309	467292	7458	15961	37.0%	51.2%
2015/16	176666	4492	25428	296150	3046	10284	472816	7538	15943	37.4%	52.2%
2016/17	180099	4559	25313	298234	3065	10277	478333	7624	15938	37.7%	53.2%
2017/18	183380	4629	25244	300492	3100	10318	483872	7730	15975	37.9%	54.1%
2018/19	186502	4698	25191	302950	3144	10378	489452	7842	16023	38.1%	54.8%
2019/20	189479	4763	25140	305582	3190	10439	495061	7953	16065	38.3%	55.6%
2020/21	192355	4826	25089	308326	3237	10500	500681	8063	16105	38.4%	56.2%
2021/22	195141	4886	25041	311159	3286	10562	506300	8173	16142	38.5%	56.9%
2022/23	197812	4947	25010	314088	3343	10643	511900	8290	16194	38.6%	57.5%
2023/24	200399	5006	24978	317064	3399	10721	517463	8405	16242	38.7%	58.0%
2024/25	202950	5064	24950	320026	3456	10800	522976	8520	16292	38.8%	58.6%
2025/26	205463	5121	24925	322968	3514	10880	528431	8635	16341	38.9%	59.1%
2026/27	207935	5178	24903	325887	3572	10960	533822	8750	16391	39.0%	59.6%
2027/28	210365	5235	24884	328778	3630	11040	539143	8864	16442	39.0%	60.1%
2028/29	212752	5292	24876	331635	3691	11130	544387	8983	16502	39.1%	60.6%
2029/30	215094	5349	24870	334457	3752	11219	549551	9102	16562	39.1%	61.1%
2030/31	217392	5406	24866	337243	3814	11308	554635	9219	16622	39.2%	61.6%
2031/32	219649	5462	24866	339995	3875	11397	559644	9337	16684	39.2%	62.0%
2032/33	221868	5518	24869	342718	3937	11487	564586	9454	16746	39.3%	62.5%

Electric Heat Billed: Customers who have electric space heating included with their electric bill.
Other: Customers who do not have electric space heating included with their electric bill.
% Elec Space Heat: The proportion of Total Basic customers who are Electric Heat Billed.
% Elec Water Heat: The proportion of Total Basic customers who have Electric Water Heaters.

The average use (kW.h/customer) for Electric Heat Billed customers is decreasing as apartments are making up a higher proportion of the growth and as existing homes become better insulated. The average use for Other customers is increasing primarily due to the increase in electric water heaters.

Residential Diesel, Seasonal, and Flat Rate Water Heating

Residential Diesel

There were 577 Residential Diesel customers that used 8 GW.h in 2012/13 at an average of 14,640 kW.h per customer. They have 60 amp service that does not allow for electric space heating. Space heating in these four communities is mainly provided by fuel oil. The number of customers is expected to grow to 716 and usage is expected to increase 2.0% a year to 13 GW.h by 2032/33 under the assumption that the communities continue to be separate from the Integrated System.

Residential Seasonal

There were 20,731 Residential Seasonal customers in 2012/13. The number of customers is expected increase to 22,686 customers by 2032/33. Seasonal customers are billed only twice a year either due to low usage (being a seasonal residence or cottage) or because of a location that makes it difficult to access for more frequent meter readings. The average use of a seasonal customer is 3,911 kW.h per year. The usage of Residential Seasonal customers is expected to increase 1.9% a year to 118 GW.h in 2032/33.

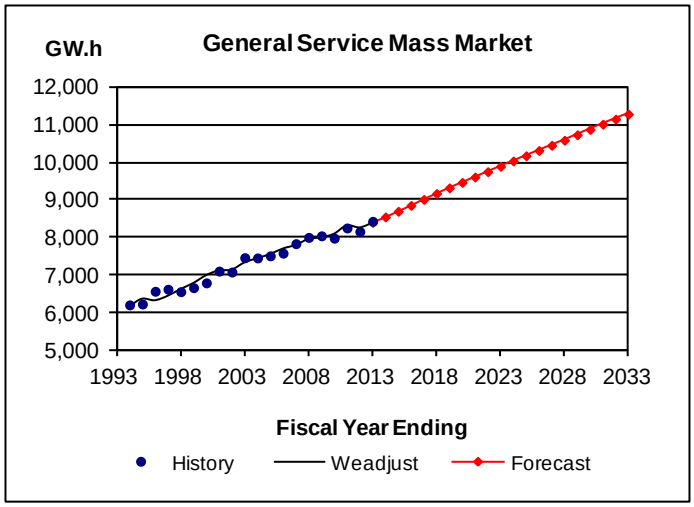
Residential Flat Rate Water Heating

Residential Water Heating is a flat rate unmetered service. This service has not been available to new customers since November 12, 1969. There were 4,089 remaining services in 2012/13. The number of services and usage is expected to decrease 5% per year throughout the forecast period. Usage was 21 GW.h in 2012/13 and that will decrease to 7 GW.h by 2032/33.

General Service Mass Market

General Service Mass Market includes all Commercial and Industrial customers, excluding the General Service Top Consumers. There were 65,974 General Service Mass Market customers in 2012/13. Approximately 85% are Commercial and the others are Industrial.

Figure 7 - General Service Mass Market



GS Mass Market has grown 118 GW.h (1.7%) per year for the past 20 years and 107 GW.h per year (1.4%) for the past 10 years. This historical growth includes the effect of past Demand Side Management (DSM) initiatives. It is forecast to grow 149 GW.h (1.6%) per year for the next 10 years and 144 GW.h (1.5%) per year for the next 20 years.

The primary driver for growth in the GS Mass Market is the number of Residential Basic customers. As population grows, commercial and industrial services grow to service the population. The secondary driver is the economy. Changes in the Manitoba Gross Domestic Product (GDP) are reflected in the GS Mass Market's electricity use.

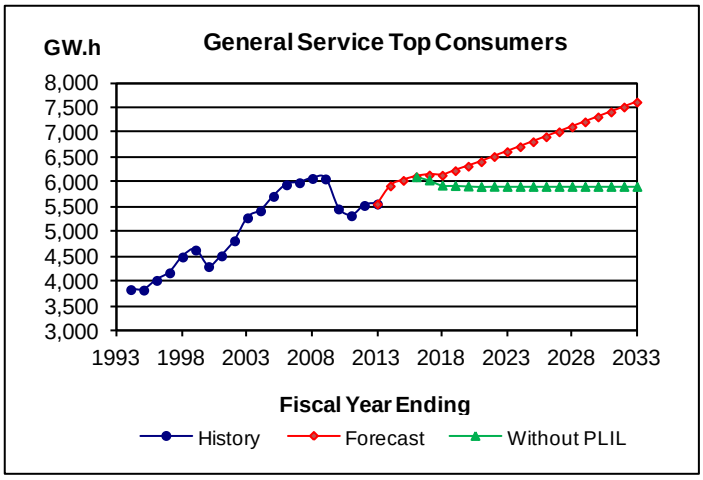
Table 15 - General Service Mass Market

GENERAL SERVICE MASS MARKET (GW.h) HISTORICAL/WEATHER ADJUSTMENT/FORECAST					
Fiscal Year	Sales	Weather Adjust	Adjusted Sales	Fiscal Year	Forecast Sales
1993/94	6210	-53	6158	2013/14	8550
1994/95	6233	130	6363	2014/15	8701
1995/96	6573	-251	6322	2015/16	8858
1996/97	6627	-186	6441	2016/17	9018
1997/98	6562	60	6623	2017/18	9174
1998/99	6668	116	6784	2018/19	9325
1999/00	6796	197	6993	2019/20	9470
2000/01	7110	15	7125	2020/21	9613
2001/02	7084	60	7144	2021/22	9756
2002/03	7467	-129	7338	2022/23	9898
2003/04	7460	-9	7451	2023/24	10040
2004/05	7516	48	7564	2024/25	10179
2005/06	7587	124	7711	2025/26	10318
2006/07	7839	-31	7808	2026/27	10456
2007/08	8006	-39	7967	2027/28	10592
2008/09	8049	-36	8012	2028/29	10736
2009/10	7985	124	8109	2029/30	10878
2010/11	8258	76	8333	2030/31	11020
2011/12	8162	117	8279	2031/32	11154
2012/13	8434	-28	8406	2032/33	11288

General Service Top Consumers

General Service Top Consumers includes the top energy consuming businesses in Manitoba and represents 26% of all General Consumers Sales. GS Top Consumers includes 17 companies that account for 31 customers in the Primary Metals, Chemicals, Petrol/Oil/Natural Gas, Pulp/Paper, Food/Beverage and Colleges/Universities sectors.

Figure 8 - General Service Top Consumers



GS Top Consumers has grown 91 GW.h (2.0%) per year over the past 20 years and but only 28 GW.h per year (0.5%) over the past 10 years. The loss of one Top Consumer and the effect of the economic downturn from 2008 to 2011 lowered the past 10 year growth rate. The 2013 forecast is expected to grow 106 GW.h (1.8%) per year for the next 10 years and 103 GW.h (1.6%) per year for the next 20 years. A loss of a major load is expected by 2016. This loss is more than offset by confirmed plans and expected increases of other Top Consumers. In the long term, GS Top Consumers is expected to grow at a rate reflective of its historic growth.

Table 16 - General Service Top Consumers

GENERAL SERVICE TOP CONSUMERS (GW.h) HISTORICAL/FORECAST WITH PLIL					
Fiscal Year	Sales	Fiscal Year	Individual	PLIL	Total
1993/94	3836	2013/14	5925	0	5925
1994/95	3825	2014/15	6036	0	6036
1995/96	4021	2015/16	6110	0	6110
1996/97	4173	2016/17	6045	100	6145
1997/98	4493	2017/18	5940	200	6140
1998/99	4632	2018/19	5932	300	6232
1999/00	4299	2019/20	5922	400	6322
2000/01	4515	2020/21	5912	500	6412
2001/02	4818	2021/22	5917	600	6517
2002/03	5282	2022/23	5915	700	6615
2003/04	5423	2023/24	5915	800	6715
2004/05	5714	2024/25	5915	900	6815
2005/06	5948	2025/26	5915	1000	6915
2006/07	5989	2026/27	5915	1100	7015
2007/08	6075	2027/28	5915	1200	7115
2008/09	6065	2028/29	5915	1300	7215
2009/10	5461	2029/30	5915	1400	7315
2010/11	5324	2030/31	5915	1500	7415
2011/12	5531	2031/32	5915	1600	7515
2012/13	5560	2032/33	5915	1700	7615

GS Top Consumers are forecast individually as their usage does not grow in a slow, steady, predictable pattern. These types of load changes are not conducive to econometric forecasting models and must be examined on an individual basis. The forecast for each company includes their short term committed plans and expectations over the next several years, but excludes longer term plans that are uncommitted and subject to change.

The sum of the individual company forecasts grow from 5,560 GW.h in 2012/13 to 5,915 GW.h by 2022/23. This growth of 355 GW.h includes the load changes due to committed plans of companies, and also includes an expected major load decrease by 2016 of one customer.

Top Consumers do not add small amounts of load on a regular basis. Instead, they make major changes that add or remove a large amount of load at one time. Load changes are related to individual business cycles and it may be years between one of these changes.

For the longer term, an average expected growth is included for all customers together. This added growth is called Potential Large Industrial Loads (PLIL). It includes consideration for company expansions, cutbacks and shutdowns, new startups of 100 GW.h a year or more, and the long term normal incremental growth of all the companies within the Top Consumers sector combined. Since customer intentions are generally known for the first three years, PLIL is not added until 2016/17, the fourth year of the forecast.

GS Top Consumers has grown at 91 GW.h (2.0%) per year over the past twenty years. During that time, there were four new customers totaling 1,100 GW.h of consumption, nine instances of customers with major expansions totaling 1,400 GW.h, and two existing customers who closed operations reducing consumption by 700 GW.h. None of these events could have been predicted five years before they occurred. One new customer and four expansions occurred within the past 10 years despite the economic downturn. These major events amount to a net 1,800 GW.h increase in the past 20 years. On this basis, PLIL has been set to be 100 GW.h (1.5%) per year starting in the fourth year of the forecast and will total 1,700 GW.h by 2032/33, the 20th year of the forecast.

1,700 GW.h is approximately equivalent to the load of Manitoba Hydro's largest consumer. If only one other customer of similar size starts up in Manitoba within the next 20 years, this one new customer alone would consume all of the provision that PLIL has allowed.

General Service Diesel, Seasonal, and Flat Rate Water Heat

General Service Diesel

In 2012/13, there were 175 General Service Diesel Full Cost customers. They used 5 GW.h in 2012/13. The group is forecast to use 6 GW.h by 2032/33.

General Service Seasonal

There were 850 General Service Seasonal customers in 2012/13. Consumption was 5 GW.h in 2012/13 and is expected to grow to 6 GW.h by 2032/33.

General Service Flat Rate Water Heating

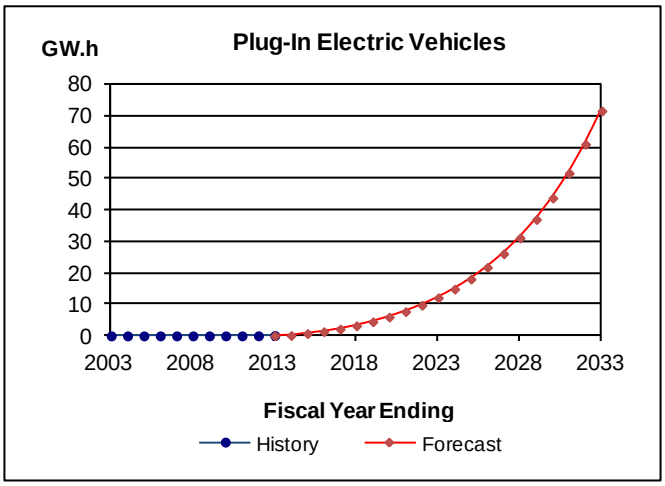
General Service Water Heating is a flat rate unmetered service that has not been available to new customers since November 12, 1969. There were 408 remaining services in 2012/13. The number of services is expected to decrease 5% per year throughout the forecast period. Consumption was 7 GW.h in 2012/13 and that is forecast to decrease to 3 GW.h by 2032/33.

General Service Surplus Energy Program

Participants in the Surplus Energy Program (SEP) used 28 GW.h in 2012/13 and are expected to grow to use 38 GW.h per year by 2017/18 and continue at that rate for the remainder of the forecast. This energy is considered to be “interruptible” and thus “non-firm”. The energy used by these customers is included in Sales. But it is excluded from the Gross Firm Energy forecast.

Plug-In Electric Vehicles

Figure 9 - Plug-In Electric Vehicles



This forecast includes an estimate of the future adoption of Plug-In Electric Vehicles (PEVs). This is made up of two types:

(1) Plug-In Hybrid Electric Vehicles (PHEVs) that run on an electric battery but use an internal combustion engine (ICE) when the electricity runs low. An example is the Chevrolet Volt.

(2) Battery Electric Vehicles (BEVs) that run only on electric battery power, such as the Nissan Leaf.

The forecast of PEVs does not include Hybrid Electric Vehicles (HEVs). These vehicles, such as the Toyota Prius, have an internal combustion engine as well as a battery and electric motor to drive the wheels. The HEV battery is charged with power from the ICE and through regenerative breaking. It is not charged by plugging in and therefore does not affect electricity consumption in Manitoba. As of March 1, 2013 and after 12 years in the market, there were only 3,581 HEVs registered in Manitoba, making up about 0.46% of all registered vehicles.

For the most part, electric cars have not enjoyed their expected success anywhere. Range anxiety and price are cited as the main reasons for limited sales. In general, electric vehicles are part of a niche market whose demographic is the environmentally aware, very well educated, upper-middle class white male in his late 40s to early 50s with a garage equipped with an electric outlet. General Motors expected to sell 60,000 Chevy Volts globally in 2012, but sold just half that many. Sales of Nissan's all-electric Leaf grew 22% around the world last year to 26,000, short of Nissan's projected 50% growth. One exception has been American high end electric car maker Tesla Motors, which recently posted the first profitable quarter in its 10-year history and whose share price exceeded $100 US for the first time on May 28, 2013. The price of Tesla shares has almost tripled this year, and its $90,000 Model S sedan got a near-perfect rating from May 2013 Consumer Reports. On March 1, 2013 there were 4 Tesla vehicles registered in Manitoba with one more on order.

The Electric Vehicle Forecast

As of March 1st, 2013, there were 37 plug-in electric vehicles registered in Manitoba according to the Manitoba Public Insurance Corporation. The 2012 Load Forecast had predicted 34 such vehicles to be registered in Manitoba at fiscal year ending 2013. The number of new PEVs is expected to slowly increase until it reaches about 1.3% of vehicle sales (828 per year) in 2022/23 and 5.4% of sales (4,576 per year) in 2032/33. The total number of electric vehicles on the road is expected to be 4,038 (0.4%) in 2022/23 and 23,879 (2.1%) in 2032/33.

The EPA rating for the pure electric 2012 Nissan Leaf is 3,400 kW.h for 16,000 km. Other electric vehicles, including the plug-in hybrid Chevrolet Volt, have similar EPA ratings. Actual usage depends on the distance driven. For this forecast, the average PEV is assumed to use 3,000 kW.h per year, which is almost equivalent to the annual energy use of an electric hot water tank. There are different opinions on average peak contribution per vehicle, but an acceptable expectation is that peak load use will approximately be equal to non-peak use. A load factor of 91% was chosen to derive the load coincident to Manitoba Hydro's system peak on a cold winter day.

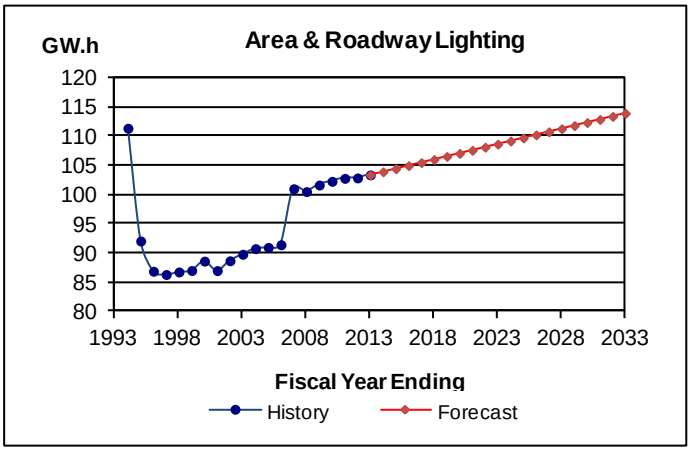
The following table provides the estimate of the number of new vehicles and total vehicles each year in Manitoba, as well as the corresponding numbers for Plug-In Electric Vehicles. The PEV MW is at Hydro's system peak. Forecast energy usage for PEVs in Manitoba is expected to be 12 GW.h in 2022/23 and 72 GW.h in 2032/33. Forecast peak usage at system peak is expected to be 1.5 MW in 2022/23 and 9.0 MW in 2032/33.

Table 17 - Plug-In Electric Vehicles

PLUG-IN ELECTRIC VEHICLE FORECAST History and Forecast 2002/03 - 2032/33								
Fiscal Year	New Vehicles Purchased	New PEV Purchased	New PEV %	Total Vehicles	Total PEV	Total % PEV	Cumul Total PEV GW.h	Cumul Total PEV MW
2002/03	47770	-	0.0%	634798	-	0.0%	0	0
2003/04	44825	-	0.0%	646925	-	0.0%	0	0
2004/05	43412	-	0.0%	657773	-	0.0%	0	0
2005/06	44931	-	0.0%	665911	-	0.0%	0	0
2006/07	45924	-	0.0%	677922	-	0.0%	0	0
2007/08	47099	-	0.0%	696186	-	0.0%	0	0
2008/09	48029	-	0.0%	711412	-	0.0%	0	0
2009/10	43995	-	0.0%	723823	-	0.0%	0	0
2010/11	45355	1	0.0%	738299	1	0.0%	0	0
2011/12	48546	8	0.0%	762214	9	0.0%	0	0
2012/13	52236	28	0.1%	779935	37	0.0%	0	0
2013/14	52949	66	0.1%	798369	103	0.0%	0	0.0
2014/15	53669	134	0.3%	816707	237	0.0%	1	0.1
2015/16	54397	204	0.4%	834962	441	0.1%	1	0.2
2016/17	55129	276	0.5%	853141	717	0.1%	2	0.3
2017/18	55867	349	0.6%	871253	1066	0.1%	3	0.4
2018/19	56606	425	0.8%	889303	1491	0.2%	4	0.6
2019/20	57348	502	0.9%	907296	1992	0.2%	6	0.7
2020/21	58089	591	1.0%	925233	2573	0.3%	8	1.0
2021/22	58828	697	1.2%	943116	3250	0.3%	10	1.2
2022/23	59564	828	1.3%	960944	4038	0.4%	12	1.5
2023/24	60296	977	1.5%	978715	4955	0.5%	15	1.9
2024/25	61024	1167	1.7%	996427	6022	0.6%	18	2.3
2025/26	61745	1392	2.0%	1014077	7264	0.7%	22	2.7
2026/27	62461	1665	2.3%	1031660	8709	0.8%	26	3.3
2027/28	63170	1980	2.7%	1049176	10389	1.0%	31	3.9
2028/29	63873	2374	3.1%	1066619	12343	1.2%	37	4.6
2029/30	64571	2832	3.5%	1083988	14614	1.3%	44	5.5
2030/31	65262	3370	4.0%	1101280	17255	1.6%	52	6.5
2031/32	65949	3928	4.7%	1118494	20323	1.8%	61	7.6
2032/33	66471	4576	5.4%	1135467	23879	2.1%	72	9.0

Area & Roadway Lighting

Figure 10 - Area & Roadway Lighting



The Area and Roadway Lighting sector represents 0.5% of all sales within Manitoba. This sector includes electricity sales for the Sentinel Lighting and Street Lighting rate groups. Sentinel Lighting is an outdoor lighting service where units are available either as rentals to an existing metered service or on an unmetered, flat rate basis. Street Lighting includes all roadway lighting in Manitoba. Energy-efficient street lighting initiatives caused the significant drop in usage in the mid 1990's. In 2006, a readjustment of the rate classes moved some flat rate General Service meters into the Lighting sector. Only Street Lights count as customers.

The Area and Roadway Lighting sector is forecast to increase from 103 GW.h in 2012/13 to 114 GW.h by 2032/33 at an average growth rate of 1 GW.h or 0.5% per year.

Table 18 - Area & Roadway Lighting

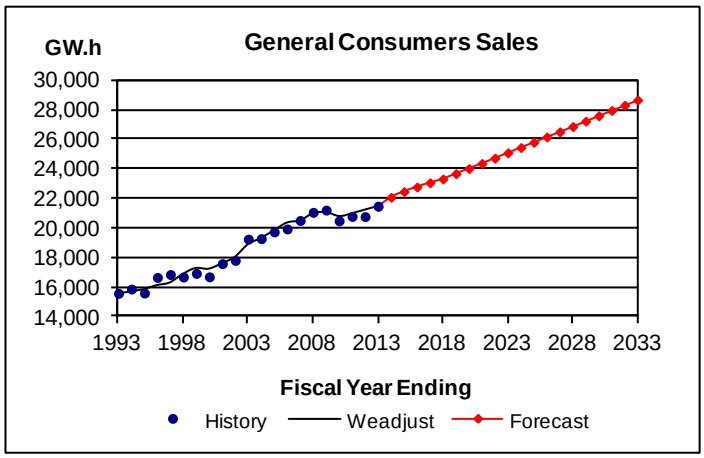
AREA & ROADWAY LIGHTING (GW.h) HISTORICAL/WEATHER ADJUSTMENT/FORECAST					
Fiscal Year	Sales	Weather Adjust	Adjusted Sales	Fiscal Year	Forecast Sales
1993/94	111	0	111	2013/14	104
1994/95	92	0	92	2014/15	104
1995/96	87	0	87	2015/16	105
1996/97	86	0	86	2016/17	106
1997/98	87	0	87	2017/18	106
1998/99	87	0	87	2018/19	107
1999/00	89	0	89	2019/20	107
2000/01	87	0	87	2020/21	108
2001/02	89	0	89	2021/22	108
2002/03	90	0	90	2022/23	109
2003/04	91	0	91	2023/24	109
2004/05	91	0	91	2024/25	110
2005/06	91	0	91	2025/26	110
2006/07	101	0	101	2026/27	111
2007/08	101	0	101	2027/28	111
2008/09	102	0	102	2028/29	112
2009/10	102	0	102	2029/30	112
2010/11	103	0	103	2030/31	113
2011/12	103	0	103	2031/32	113
2012/13	103	0	103	2032/33	114

AREA AND ROADWAY LIGHTING History and Forecast 2002/03 - 2032/33								
Fiscal	Sentinal Flat Rates		Sentinal Rentals		Street Lighting		Total Lighting	
Year	(Services)	(GW.h)	(Services)	(GW.h)	(Custs)	(GW.h)	(Custs)	(GW.h)
2002/03	19446	10	5477	0	755	80	755	90
2003/04	19527	10	5505	0	757	81	757	91
2004/05	19648	10	5519	0	759	81	759	91
2005/06	19652	10	7826	0	793	81	793	91
2006/07	18669	11	23994	0	1129	90	1129	101
2007/08	18947	11	24272	0	1142	90	1142	101
2008/09	19228	11	24542	0	1175	91	1175	102
2009/10	19539	11	24886	0	1191	91	1191	102
2010/11	19835	11	25216	0	1184	92	1184	103
2011/12	20033	11	25427	0	1155	91	1155	103
2012/13	20238	12	25613	0	1164	92	1164	103
2013/14	20472	12	25862	0	1163	92	1163	104
2014/15	20705	12	26130	0	1168	93	1168	104
2015/16	20938	12	26398	0	1173	93	1173	105
2016/17	21171	12	26666	0	1178	93	1178	106
2017/18	21404	12	26934	0	1183	94	1183	106
2018/19	21637	12	27202	0	1188	94	1188	107
2019/20	21870	12	27470	0	1193	95	1193	107
2020/21	22103	13	27738	0	1198	95	1198	108
2021/22	22336	13	28006	0	1203	95	1203	108
2022/23	22569	13	28274	0	1208	96	1208	109
2023/24	22802	13	28542	0	1213	96	1213	109
2024/25	23035	13	28810	0	1218	97	1218	110
2025/26	23268	13	29078	0	1223	97	1223	110
2026/27	23501	13	29346	0	1228	97	1228	111
2027/28	23734	13	29614	0	1233	98	1233	111
2028/29	23967	14	29882	0	1238	98	1238	112
2029/30	24200	14	30150	0	1243	99	1243	112
2030/31	24433	14	30418	0	1248	99	1248	113
2031/32	24666	14	30686	0	1253	99	1253	113
2032/33	24899	14	30954	0	1258	100	1258	114

Total General Consumers Sales

Figure 11 - General Consumers Sales

General Consumers Sales includes sales to all of Manitoba Hydro's individually billed customers, but excludes export sales. This includes the total of all sales from the Residential, General Service and Lighting sectors. The General Service sector makes up about two-thirds, the Residential sector makes up about one-third and the Lighting group is only 0.5% of all sales.



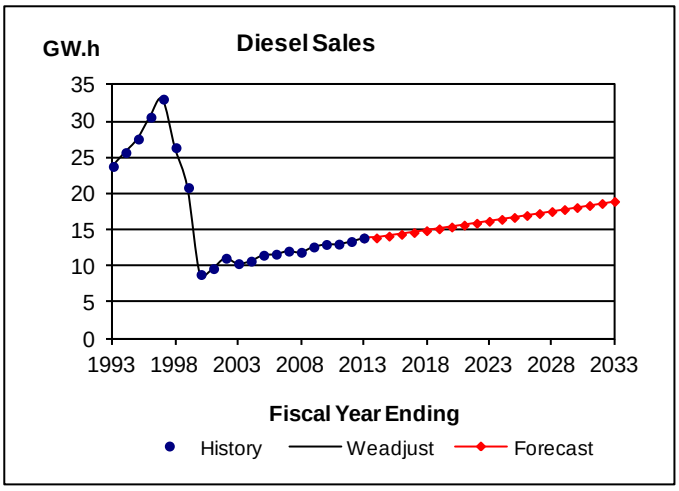
Weather adjusted General Consumers Sales has grown 303 GW.h (1.7%) per year for the past 20 years and 258 GW.h (1.3%) per year over the past 10 years. This historical growth includes the effect of past Demand Side Management (DSM) initiatives. Sales are forecast to grow 364 GW.h (1.6%) per year for the next 10 years and 361 GW.h (1.5%) per year for the next 20 years.

Table 20 - General Consumers Sales

GENERAL CONSUMERS SALES (GW.h) HISTORICAL/WEATHER ADJUSTMENT/FORECAST					
Fiscal Year	Sales	Weather Adjust	Adjusted Sales	Fiscal Year	Forecast Sales
1993/94	15870	-190	15681	2013/14	22076
1994/95	15600	236	15836	2014/15	22460
1995/96	16654	-550	16104	2015/16	22774
1996/97	16851	-572	16279	2016/17	23059
1997/98	16681	172	16852	2017/18	23319
1998/99	16929	329	17258	2018/19	23677
1999/00	16696	517	17213	2019/20	24024
2000/01	17590	-12	17578	2020/21	24369
2001/02	17805	201	18006	2021/22	24728
2002/03	19246	-384	18862	2022/23	25087
2003/04	19280	2	19282	2023/24	25446
2004/05	19735	69	19804	2024/25	25802
2005/06	19935	389	20323	2025/26	26158
2006/07	20510	-39	20471	2026/27	26513
2007/08	21061	-111	20950	2027/28	26865
2008/09	21210	-184	21026	2028/29	27230
2009/10	20486	269	20755	2029/30	27593
2010/11	20786	169	20956	2030/31	27954
2011/12	20771	432	21202	2031/32	28308
2012/13	21477	-32	21445	2032/33	28662

Diesel Sales

Figure 12 - Diesel Sales



There are four communities served by diesel generation in Manitoba: Brochet, Lac Brochet, Tadoule Lake and Shamattawa. Sales within these communities are included in General Consumers Sales, but are not part of the Integrated System, and are thus not part of Common Bus or Gross Firm Load.

Between 1997 and 1999, eleven communities previously served by diesel generation were connected to the Integrated System resulting in the drop in overall sales. The four sites that were to remain diesel were converted from 15 amp service to 60 amp service between 1991 and 2001 causing the increase in those years.

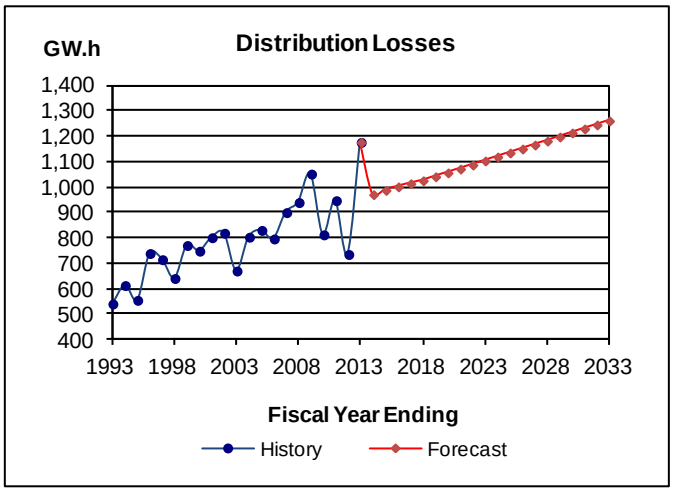
Diesel customers do not have electric heat, which requires a minimum 200 amp service, therefore there is no weather effect.

Table 21 - Diesel Sales

DIESEL SALES (GW.h) HISTORICAL/WEATHER ADJUSTMENT/FORECAST					
Fiscal Year	Sales	Weather Adjust	Adjusted Sales	Fiscal Year	Forecast Sales
1993/94	26	0	26	2013/14	14
1994/95	28	0	28	2014/15	14
1995/96	31	0	31	2015/16	14
1996/97	33	0	33	2016/17	15
1997/98	26	0	26	2017/18	15
1998/99	21	0	21	2018/19	15
1999/00	9	0	9	2019/20	15
2000/01	10	0	10	2020/21	16
2001/02	11	0	11	2021/22	16
2002/03	10	0	10	2022/23	16
2003/04	11	0	11	2023/24	16
2004/05	12	0	12	2024/25	17
2005/06	12	0	12	2025/26	17
2006/07	12	0	12	2026/27	17
2007/08	12	0	12	2027/28	18
2008/09	13	0	13	2028/29	18
2009/10	13	0	13	2029/30	18
2010/11	13	0	13	2030/31	18
2011/12	13	0	13	2031/32	19
2012/13	14	0	14	2032/33	19

Distribution Losses

Figure 13 - Distribution Losses



Distribution Losses are made up of the power loss between the distribution substation (Manitoba Load at Common Bus less Construction) and the customer's meter (General Consumers Sales less Diesel), as well as all other differences between what was billed and what was metered. The other differences include:

1. The offset between cycle billing (General Consumers Sales) and actual calendar month usage (Common Bus).
2. Customer Accounting adjustments,
3. Inaccuracies associated with estimated billing (including flat rate estimates),
4. The metered but unbilled consumption of Manitoba Hydro offices, and
5. Energy lost due to theft.

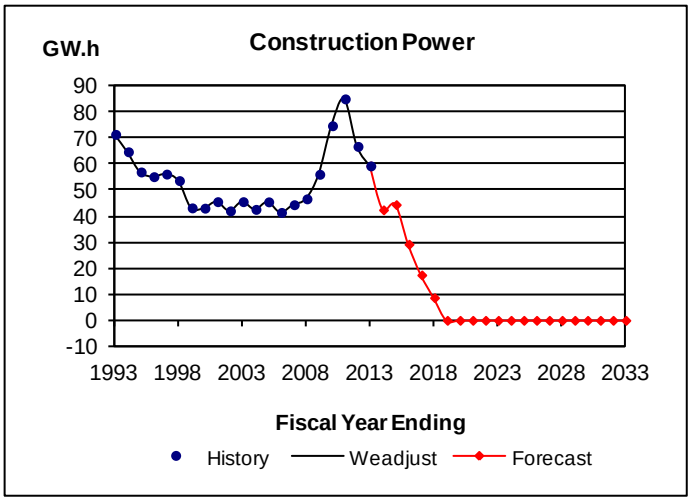
Distribution Losses are forecast in 2013/14 to be 4.4% of the General Consumers Sales less Diesel and remain at about that level throughout the forecast.

Table 22 - Distribution Losses

DISTRIBUTION LOSSES (GW.h) HISTORICAL / PERCENT OF SALES / FORECAST							
Fiscal Year	Losses	Sales less Diesel	% Losses	Fiscal Year	Forecast Losses	Sales less Diesel	% Losses
1993/94	614	15845	3.9%	2013/14	971	22062	4.4%
1994/95	556	15572	3.6%	2014/15	988	22446	4.4%
1995/96	740	16623	4.4%	2015/16	1001	22759	4.4%
1996/97	715	16818	4.3%	2016/17	1014	23044	4.4%
1997/98	641	16655	3.9%	2017/18	1025	23304	4.4%
1998/99	771	16908	4.6%	2018/19	1041	23661	4.4%
1999/00	749	16687	4.5%	2019/20	1056	24009	4.4%
2000/01	802	17580	4.6%	2020/21	1072	24353	4.4%
2001/02	819	17793	4.6%	2021/22	1087	24712	4.4%
2002/03	671	19236	3.5%	2022/23	1103	25071	4.4%
2003/04	804	19269	4.2%	2023/24	1119	25429	4.4%
2004/05	830	19724	4.2%	2024/25	1135	25786	4.4%
2005/06	797	19923	4.0%	2025/26	1150	26141	4.4%
2006/07	900	20497	4.4%	2026/27	1166	26496	4.4%
2007/08	940	21049	4.5%	2027/28	1181	26847	4.4%
2008/09	1052	21198	5.0%	2028/29	1197	27213	4.4%
2009/10	813	20473	4.0%	2029/30	1213	27575	4.4%
2010/11	947	20773	4.6%	2030/31	1229	27936	4.4%
2011/12	736	20757	3.5%	2031/32	1245	28290	4.4%
2012/13	1176	21463	5.5%	2032/33	1260	28643	4.4%

Construction Power

Figure 14 - Construction Power



Construction Power represents the energy used by Manitoba Hydro and its contractors in the construction of major capital works such as generating stations, converter stations and major transmission lines. Construction Power also includes Station Service until a plant is commissioned. Until 2013, about 48 GW.h of heating load at the Gillam, Limestone and Kettle town sites was included in Construction Power. This energy is now included in Distribution Losses.

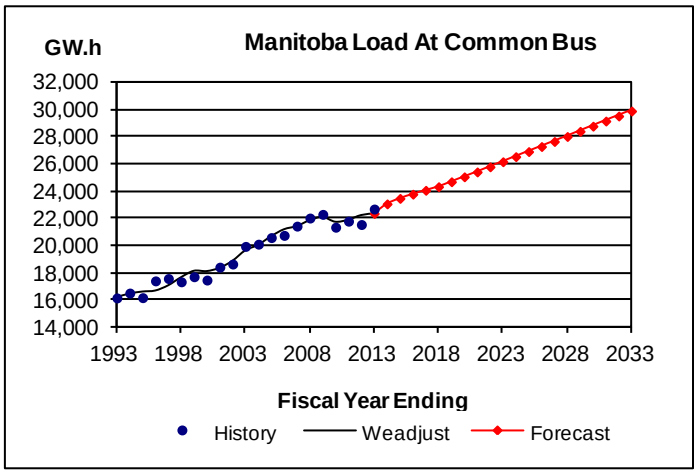
The Construction Power forecast includes: (1) the Wuskwatim generating station, now in-service with completion expected in 2013/14, (2) the Pointe Du Bois spillway replacement started in April 2013 with expected completion in January 2015, and (3) the Keewatinoow Converter Station, started in January 2012 with expected completion in December 2017. Construction Power does not include construction power estimates for any sites that do not yet have a committed inservice date (e.g. Keeyask and Conawapa).

Table 23 - Construction Power

CONSTRUCTION POWER (GW.h) HISTORICAL/WEATHER ADJUSTMENT/FORECAST					
Fiscal Year	Usage	Weather Adjust	Adjusted Usage	Fiscal Year	Forecast Usage
1993/94	65	0	65	2013/14	43
1994/95	57	0	57	2014/15	45
1995/96	55	0	55	2015/16	29
1996/97	56	0	56	2016/17	17
1997/98	54	0	54	2017/18	9
1998/99	43	0	43	2018/19	0
1999/00	43	0	43	2019/20	0
2000/01	46	0	46	2020/21	0
2001/02	42	0	42	2021/22	0
2002/03	46	0	46	2022/23	0
2003/04	43	0	43	2023/24	0
2004/05	46	0	46	2024/25	0
2005/06	42	0	42	2025/26	0
2006/07	45	0	45	2026/27	0
2007/08	47	0	47	2027/28	0
2008/09	56	0	56	2028/29	0
2009/10	75	0	75	2029/30	0
2010/11	85	0	85	2030/31	0
2011/12	67	0	67	2031/32	0
2012/13	59	0	59	2032/33	0

Manitoba Load at Common Bus

Figure 15 - Manitoba Load at Common Bus



Manitoba Load at Common Bus is the total load measured from all the distribution points (i.e. substations) within Manitoba. It includes all energy supplied to General Consumers Sales customers, Construction Power plus associated Distribution Losses, but excludes Diesel customers, Transmission Losses and Station Service.

Common Bus is metered and totaled to correspond exactly to each calendar month. Weather adjustment is done on a calendar month basis.

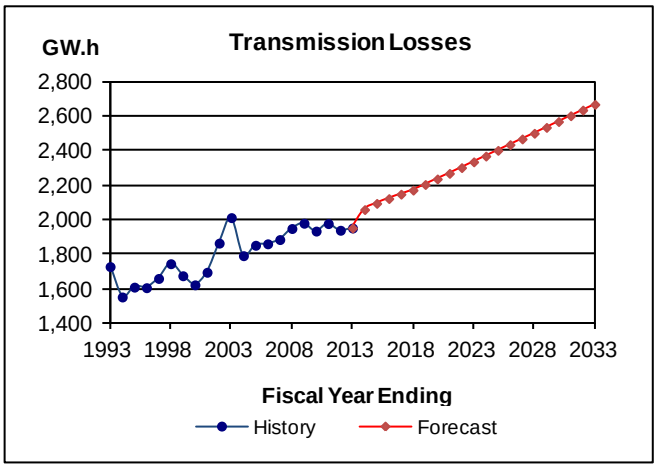
Weather adjusted Common Bus has grown 314 GW.h (1.6%) per year for the past 20 years and 275 GW.h (1.3%) per year during the past 10 years reflecting the recent economic downturn. This historical growth includes the effect of past Demand Side Management (DSM) initiatives. Common Bus is forecast to grow 380 GW.h (1.6%) per year for the next 10 years and 377 GW.h (1.5%) per year for the next 20 years.

Table 24 - Manitoba Load at Common Bus

MANITOBA LOAD AT COMMON BUS (GW.h) HISTORICAL/WEATHER ADJUSTMENT/FORECAST					
Fiscal Year	Energy	Weather Adjust	Adjusted Energy	Fiscal Year	Forecast Energy
1993/94	16523	-124	16399	2013/14	23076
1994/95	16185	366	16550	2014/15	23479
1995/96	17418	-792	16626	2015/16	23790
1996/97	17590	-579	17011	2016/17	24075
1997/98	17350	264	17614	2017/18	24338
1998/99	17722	374	18096	2018/19	24703
1999/00	17479	595	18073	2019/20	25065
2000/01	18428	-111	18316	2020/21	25425
2001/02	18655	185	18839	2021/22	25799
2002/03	19953	-335	19618	2022/23	26174
2003/04	20116	-83	20033	2023/24	26548
2004/05	20600	67	20667	2024/25	26920
2005/06	20761	426	21187	2025/26	27291
2006/07	21442	-14	21429	2026/27	27661
2007/08	22036	-175	21861	2027/28	28029
2008/09	22305	-196	22109	2028/29	28410
2009/10	21361	390	21751	2029/30	28788
2010/11	21806	94	21900	2030/31	29165
2011/12	21560	688	22247	2031/32	29534
2012/13	22699	-327	22372	2032/33	29903

Transmission Losses

Figure 16 - Transmission Losses



Transmission Losses are the amount of energy lost while delivering power from the generation stations to all of the distribution substations that make up Common Bus. Transmission Losses only contains losses associated with supplying Manitoba customers. Losses attributable to exports and the gains attributable to imports are excluded. Transmission Losses are substantial because most of the northern generation is transmitted to southern distribution points 900 kilometers away. Transmission Losses vary year to year depending on water conditions, system configuration, outages and the magnitude of the load. Losses were up significantly in 2002/03 due to two High Voltage Direct Current (HVDC) transformer failures.

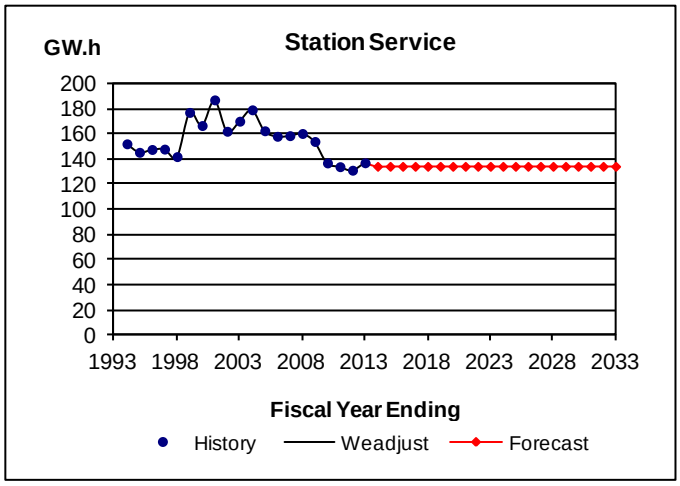
Transmission Losses are forecast to be 9.3% of the General Consumers Sales less Diesel Sales.

Table 25 - Transmission Losses

TRANSMISSION LOSSES (GW.h) HISTORICAL / PERCENT OF SALES / FORECAST							
Fiscal Year	Losses	Sales less Diesel	% Losses	Fiscal Year	Forecast Losses	Sales less Diesel	% Losses
1993/94	1552	15845	9.8%	2013/14	2058	22062	9.3%
1994/95	1609	15572	10.3%	2014/15	2094	22446	9.3%
1995/96	1606	16623	9.7%	2015/16	2122	22759	9.3%
1996/97	1660	16818	9.9%	2016/17	2148	23044	9.3%
1997/98	1745	16655	10.5%	2017/18	2171	23304	9.3%
1998/99	1675	16908	9.9%	2018/19	2204	23661	9.3%
1999/00	1623	16687	9.7%	2019/20	2236	24009	9.3%
2000/01	1696	17580	9.6%	2020/21	2268	24353	9.3%
2001/02	1864	17793	10.5%	2021/22	2301	24712	9.3%
2002/03	2012	19236	10.5%	2022/23	2335	25071	9.3%
2003/04	1792	19269	9.3%	2023/24	2368	25429	9.3%
2004/05	1852	19724	9.4%	2024/25	2401	25786	9.3%
2005/06	1860	19923	9.3%	2025/26	2435	26141	9.3%
2006/07	1885	20497	9.2%	2026/27	2468	26496	9.3%
2007/08	1949	21049	9.3%	2027/28	2500	26847	9.3%
2008/09	1979	21198	9.3%	2028/29	2534	27213	9.3%
2009/10	1934	20473	9.4%	2029/30	2568	27575	9.3%
2010/11	1977	20773	9.5%	2030/31	2602	27936	9.3%
2011/12	1939	20757	9.3%	2031/32	2635	28290	9.3%
2012/13	1952	21463	9.1%	2032/33	2667	28643	9.3%

Station Service

Figure 17 - Station Service



Station Service is the energy used by power plants to generate power and service their own load. Station Service energy was not measured prior to 1993/94 but was previously included within Transmission Losses.

Station Service energy is forecast to be 134 GW.h from 2013/14 to 2032/33. Station Service for non-committed sites (e.g. Conawapa and Keeyask) is not included in the forecast.

Table 26 - Station Service

STATION SERVICE (GW.h) HISTORICAL/WEATHER ADJUSTMENT/FORECAST					
Fiscal Year	Usage	Weather Adjust	Adjusted Usage	Fiscal Year	Forecast Usage
1993/94	152	0	152	2013/14	134
1994/95	146	0	146	2014/15	134
1995/96	148	0	148	2015/16	134
1996/97	148	0	148	2016/17	134
1997/98	142	0	142	2017/18	134
1998/99	177	0	177	2018/19	134
1999/00	167	0	167	2019/20	134
2000/01	187	0	187	2020/21	134
2001/02	162	0	162	2021/22	134
2002/03	170	0	170	2022/23	134
2003/04	179	0	179	2023/24	134
2004/05	163	0	163	2024/25	134
2005/06	158	0	158	2025/26	134
2006/07	159	0	159	2026/27	134
2007/08	161	0	161	2027/28	134
2008/09	154	0	154	2028/29	134
2009/10	137	0	137	2029/30	134
2010/11	134	0	134	2030/31	134
2011/12	131	0	131	2031/32	134
2012/13	137	0	137	2032/33	134

Table 27 - Monthly Station Service Energy

MONTHLY STATION SERVICE ENERGY (GW.h) History and Forecast													
Fiscal Year	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Total
2002/03	15.5	13.9	9.4	13.8	8.6	8.2	11.3	14.0	17.6	19.9	18.6	19.4	170.3
2003/04	16.0	11.6	9.7	11.7	12.5	12.7	13.3	17.7	18.6	23.2	16.8	15.6	179.4
2004/05	11.8	10.4	8.1	8.1	8.0	9.6	12.0	15.9	21.2	21.6	17.9	18.0	162.7
2005/06	12.6	11.0	10.0	11.1	10.1	9.6	11.8	15.2	18.4	16.7	17.0	14.9	158.3
2006/07	10.2	8.9	8.4	10.3	9.3	8.6	13.4	16.1	16.7	18.6	19.7	18.7	158.8
2007/08	15.7	12.1	9.1	8.2	8.4	7.3	8.7	14.7	19.2	18.6	19.7	18.8	160.5
2008/09	13.8	9.4	7.5	9.5	10.4	7.1	10.6	15.1	20.1	20.4	14.9	15.5	154.2
2009/10	11.8	10.3	7.9	7.2	7.4	7.2	10.8	14.2	18.8	15.5	13.3	12.7	137.1
2010/11	10.2	9.9	7.3	6.7	7.2	7.4	9.5	12.9	16.4	17.1	14.4	15.0	134.1
2011/12	12.0	9.9	7.5	7.1	7.3	6.7	9.5	13.1	15.1	16.0	13.8	13.1	131.3
2012/13	11.0	9.4	7.7	7.0	6.7	8.0	11.5	14.3	16.2	16.6	13.7	15.2	137.2
2013/14 - 2032/33	11.1	9.7	7.5	6.9	7.1	7.4	10.2	13.5	15.9	16.6	14.0	14.5	134.4

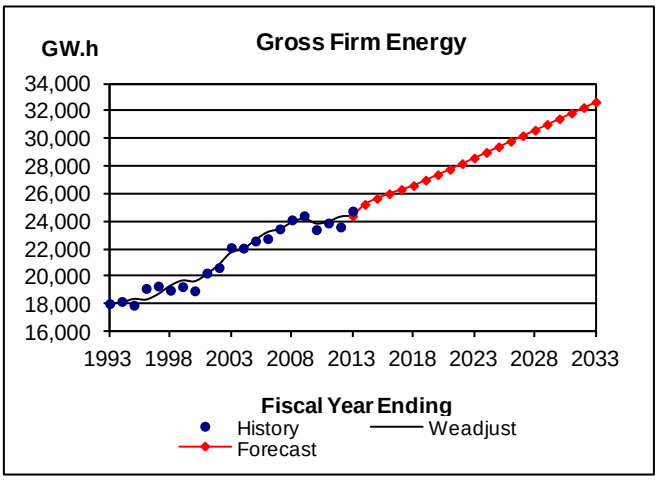
Table 28 - Monthly Station Service Peak

MONTHLY STATION SERVICE PEAK (MW) History and Forecast													
Fiscal Year	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Annual
2012/13 Actual	19	14	9	9	8	10	16	26	26	25	26	24	26
2013/14 - 2032/33	18	14	9	11	8	10	17	23	24	25	24	23	24

Gross Firm Energy

Figure 18 - Gross Firm Energy

Gross Firm Energy is the energy required to serve Manitoba Hydro's customers on the Integrated System. It excludes exports, interruptible (non-firm) loads, Diesel Sales and Station Service for non-committed plants.



Gross Firm Energy has grown steadily during the past twenty years, except for the economic slowdown in the early 1990's and more recently in 2009.

Weather adjusted Gross Firm Energy has grown 334 GW.h (1.6%) per year for the past 20 years and 266 GW.h (1.2%) per year during the past 10 years reflecting the recent economic downturn. This historical growth includes the effect of past Demand Side Management (DSM) initiatives. Energy is forecast to grow 420 GW.h (1.6%) per year for the next 10 years and 413 GW.h (1.5%) per year for the next 20 years.

Table 29 - Gross Firm Energy

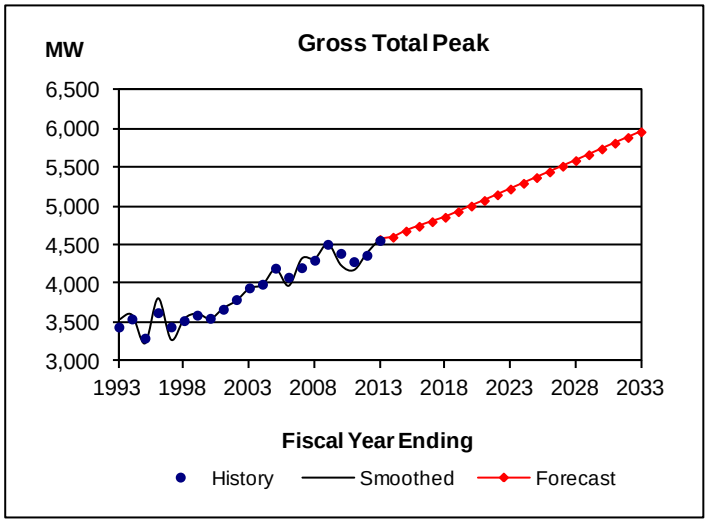
GROSS FIRM ENERGY (GW.h) HISTORICAL/WEATHER ADJUSTMENT/FORECAST					
Fiscal Year	Energy	Weather Adjust	Adjusted Energy	Fiscal Year	Forecast Energy
1993/94	18201	-134	18067	2013/14	25239
1994/95	17929	404	18334	2014/15	25676
1995/96	19148	-864	18284	2015/16	26013
1996/97	19321	-631	18690	2016/17	26322
1997/98	19014	290	19304	2017/18	26606
1998/99	19273	408	19681	2018/19	27003
1999/00	18971	651	19622	2019/20	27398
2000/01	20262	-118	20144	2020/21	27789
2001/02	20656	202	20859	2021/22	28197
2002/03	22110	-367	21743	2022/23	28605
2003/04	22069	-93	21976	2023/24	29013
2004/05	22589	75	22663	2024/25	29418
2005/06	22757	463	23220	2025/26	29822
2006/07	23464	-15	23449	2026/27	30225
2007/08	24122	-188	23934	2027/28	30625
2008/09	24417	-210	24207	2028/29	31041
2009/10	23412	426	23838	2029/30	31453
2010/11	23892	105	23998	2030/31	31863
2011/12	23605	746	24351	2031/32	32265
2012/13	24759	-356	24404	2032/33	32667

MONTHLY GROSS FIRM ENERGY (GW.h)
History and Forecast
2002/03 - 2032/33

Fiscal Year	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Total
2002/03	1727	1629	1538	1617	1554	1535	1811	1964	2149	2341	2142	2104	22110
2003/04	1657	1579	1520	1573	1685	1548	1688	2024	2198	2479	2088	2029	22069
2004/05	1699	1683	1545	1579	1575	1574	1793	1952	2411	2539	2098	2140	22589
2005/06	1727	1698	1660	1735	1649	1610	1781	2045	2301	2240	2171	2139	22757
2006/07	1712	1690	1681	1826	1746	1622	1870	2092	2303	2458	2304	2159	23464
2007/08	1842	1701	1663	1820	1727	1650	1836	2108	2490	2584	2427	2273	24122
2008/09	1881	1737	1662	1730	1787	1681	1874	2154	2652	2702	2226	2331	24417
2009/10	1861	1744	1671	1667	1644	1672	1888	1935	2560	2524	2213	2032	23412
2010/11	1699	1692	1611	1716	1698	1638	1778	2129	2563	2682	2322	2364	23892
2011/12	1862	1751	1603	1789	1741	1643	1814	2125	2435	2526	2251	2064	23605
2012/13	1802	1698	1693	1870	1727	1606	1941	2265	2665	2765	2342	2386	24759
11/12 Wadj	1856	1746	1700	1716	1731	1583	1906	2215	2618	2757	2343	2233	24404
10 Year Hist	19	18	18	15	14	6	24	28	34	39	32	18	266
Avg Growth	1.1%	1.1%	1.1%	0.9%	0.8%	0.4%	1.4%	1.3%	1.4%	1.6%	1.5%	0.9%	1.1%
2013/14	1914	1813	1734	1845	1808	1734	1955	2228	2704	2772	2385	2347	25239
2014/15	1947	1845	1764	1877	1840	1764	1989	2267	2750	2820	2426	2387	25676
2015/16	1972	1869	1787	1902	1865	1788	2015	2296	2786	2857	2458	2418	26013
2016/17	1996	1891	1809	1925	1887	1809	2039	2323	2819	2890	2486	2446	26322
2017/18	2017	1912	1829	1947	1908	1829	2061	2348	2849	2921	2513	2473	26606
2018/19	2047	1940	1856	1976	1937	1857	2092	2383	2891	2964	2550	2509	27003
2019/20	2077	1969	1883	2005	1966	1884	2122	2417	2933	3008	2588	2546	27398
2020/21	2106	1997	1910	2034	1994	1911	2153	2452	2975	3051	2625	2582	27789
2021/22	2137	2026	1938	2064	2023	1939	2184	2488	3019	3095	2663	2620	28197
2022/23	2168	2055	1967	2093	2052	1967	2216	2524	3063	3140	2702	2658	28605
10 Year Fcst	31	31	27	38	32	38	31	31	44	38	36	42	420
Avg Growth	1.6%	1.6%	1.5%	2.0%	1.7%	2.2%	1.5%	1.3%	1.6%	1.3%	1.4%	1.8%	1.6%
2023/24	2199	2085	1995	2123	2081	1995	2247	2560	3106	3185	2740	2696	29013
2024/25	2230	2114	2022	2153	2111	2023	2279	2596	3150	3229	2779	2734	29418
2025/26	2260	2143	2050	2183	2140	2051	2310	2631	3193	3274	2817	2771	29822
2026/27	2291	2172	2078	2212	2168	2079	2341	2667	3236	3318	2855	2809	30225
2027/28	2321	2201	2105	2241	2197	2106	2372	2702	3279	3362	2893	2846	30625
2028/29	2353	2230	2134	2272	2227	2135	2404	2739	3323	3407	2932	2884	31041
2029/30	2384	2260	2162	2302	2257	2163	2436	2775	3367	3453	2971	2923	31453
2030/31	2415	2290	2191	2332	2286	2191	2468	2811	3411	3498	3010	2961	31863
2031/32	2446	2318	2218	2361	2315	2219	2499	2847	3454	3542	3048	2998	32265
2032/33	2476	2347	2246	2391	2344	2246	2530	2882	3497	3586	3085	3036	32667
20 Year Fcst	31	30	27	34	31	33	31	33	44	41	37	40	413
Avg Growth	1.5%	1.5%	1.4%	1.7%	1.5%	1.8%	1.4%	1.3%	1.5%	1.3%	1.4%	1.5%	1.5%

Gross Total Peak

Figure 19 - Gross Total Peak



Gross Total Peak is the maximum integrated (i.e. average) hourly load required to serve Manitoba Hydro's customers on the Integrated System. It excludes exports and Diesel Sales. It includes Station Service and Curtailable Loads.

Typically, the peak occurs on a very cold winter weekday either in the morning (often from 8 a.m. to 9 a.m.) or in the afternoon, (from 5 p.m. to 6 p.m.) Electric heating contributes by placing the peak on one of the coldest days, whereas the operation or lack thereof of large industrials often makes the difference as to the specific day and peak hour.

Weather adjusted Gross Total Peak has grown from 3,547 MW in 1993/94 to 4,559 MW in 2012/13 at an average growth of 44 MW or 1.2% per year. It is forecast to grow to 5,959 MW at 76 MW (1.5%) per year by 2032/33.

Table 31 – Gross Total Peak

GROSS TOTAL PEAK (MW) HISTORICAL/WEATHER ADJUSTMENT/FORECAST					
Fiscal Year	Peak	Weather Adjust	Adjusted Peak	Fiscal Year	Forecast Peak
1993/94	3547	0	3546	2013/14	4601
1994/95	3299	251	3550	2014/15	4680
1995/96	3628	-126	3502	2015/16	4742
1996/97	3444	83	3528	2016/17	4801
1997/98	3525	73	3598	2017/18	4857
1998/99	3596	20	3616	2018/19	4930
1999/00	3555	20	3575	2019/20	5002
2000/01	3672	-7	3665	2020/21	5074
2001/02	3797	-1	3795	2021/22	5147
2002/03	3948	2	3950	2022/23	5222
2003/04	3994	0	3994	2023/24	5296
2004/05	4201	-82	4119	2024/25	5369
2005/06	4085	136	4220	2025/26	5443
2006/07	4208	46	4254	2026/27	5516
2007/08	4304	43	4347	2027/28	5588
2008/09	4509	-108	4401	2028/29	5664
2009/10	4393	-55	4338	2029/30	5739
2010/11	4286	73	4359	2030/31	5813
2011/12	4367	56	4423	2031/32	5886
2012/13	4559	-127	4432	2032/33	5959

MONTHLY GROSS TOTAL PEAK (MW)
History and Forecast
2002/03 - 2032/33

Fiscal Year	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Annual
2002/03	3079	2820	2781	2911	2738	2691	3039	3397	3660	3848	3948	3813	3948
2003/04	3242	2587	2871	2877	2921	2901	2988	3467	3791	3994	3743	3465	3994
2004/05	2868	2773	2713	2893	2632	2748	2980	3598	4057	4201	3843	3577	4201
2005/06	2959	2845	3052	3116	3050	2837	2948	3672	3912	3630	4085	3498	4085
2006/07	3092	2821	3015	3141	3040	2954	3220	3789	4011	4208	4203	3847	4208
2007/08	3494	2736	3042	3294	3033	2777	2979	3996	4078	4304	4289	4095	4304
2008/09	3221	2893	2952	2920	3110	2726	3159	3804	4427	4509	4196	4223	4509
2009/10	3196	2933	3000	2758	2933	2982	3054	3297	4393	4256	4092	4235	4393
2010/11	2905	2843	2805	2991	3163	2709	3056	3927	4195	4286	4250	4169	4286
2011/12	3183	2886	3056	3278	3189	3045	3129	3756	4095	4367	4270	3608	4367
2012/13	3328	2775	3161	3260	3253	2870	3312	4087	4410	4559	4543	4013	4559
10 Year Hist	25	-5	38	35	51	18	27	69	75	71	60	20	61
Avg Growth	0.8%	-0.2%	1.3%	1.1%	1.7%	0.6%	0.9%	1.9%	1.9%	1.7%	1.4%	0.5%	1.5%
2013/14	3320	2991	3110	3290	3224	3046	3260	3931	4530	4577	4493	4107	4601
2014/15	3373	3040	3157	3340	3275	3103	3319	4002	4611	4658	4573	4182	4680
2015/16	3417	3080	3200	3384	3319	3143	3363	4054	4671	4719	4633	4237	4742
2016/17	3458	3117	3239	3423	3361	3181	3403	4103	4726	4775	4688	4288	4801
2017/18	3496	3152	3277	3462	3401	3216	3441	4148	4777	4826	4739	4335	4857
2018/19	3549	3199	3326	3509	3458	3264	3492	4209	4848	4897	4809	4399	4930
2019/20	3601	3246	3375	3561	3509	3312	3543	4271	4919	4969	4880	4464	5002
2020/21	3652	3292	3423	3612	3559	3359	3593	4332	4989	5040	4950	4527	5074
2021/22	3706	3341	3473	3664	3611	3408	3646	4395	5063	5114	5022	4594	5147
2022/23	3759	3389	3524	3717	3663	3458	3699	4459	5136	5188	5095	4660	5222
10 Year Fcst	43	61	36	46	41	59	39	37	73	63	55	65	66
Avg Growth	1.2%	2.0%	1.1%	1.3%	1.2%	1.9%	1.1%	0.9%	1.5%	1.3%	1.2%	1.5%	1.4%
2023/24	3813	3437	3574	3770	3715	3507	3751	4522	5209	5262	5167	4726	5296
2024/25	3866	3485	3624	3823	3767	3556	3804	4585	5282	5336	5240	4792	5369
2025/26	3919	3533	3673	3875	3819	3605	3856	4648	5354	5409	5311	4858	5443
2026/27	3972	3581	3723	3928	3871	3653	3908	4711	5427	5482	5383	4924	5516
2027/28	4025	3628	3772	3980	3922	3702	3959	4773	5499	5554	5454	4989	5588
2028/29	4079	3677	3823	4034	3975	3752	4013	4838	5573	5630	5528	5056	5664
2029/30	4133	3726	3874	4087	4028	3802	4066	4902	5647	5704	5602	5123	5739
2030/31	4187	3775	3924	4140	4080	3851	4119	4966	5721	5779	5675	5190	5813
2031/32	4240	3823	3974	4193	4132	3900	4171	5028	5793	5852	5747	5255	5886
2032/33	4293	3870	4023	4245	4183	3948	4223	5091	5865	5925	5818	5321	5959
20 Year Fcst	48	55	43	49	47	54	46	50	73	68	64	65	70
Avg Growth	1.3%	1.7%	1.2%	1.3%	1.3%	1.6%	1.2%	1.1%	1.4%	1.3%	1.2%	1.4%	1.3%

Peak load is measured and recorded differently than energy data. The system load at every hour is calculated by System Operations as:

Hourly Gross Total Peak (t)

= Hourly Total Generation (t)

- Hourly Metered Exports (t) + Hourly Metered Imports (t)

- Losses Associated with Exports (t) + Gains Associated with Imports (t)

+ Curtailments (t)

Losses for exports and gains for imports are only known on a monthly energy basis. The hourly value is obtained by using the ratio of exports/imports for the hour to the total exports/imports for the month and applying that to the total metered loss/gain for the month. The remaining difference between the balance of the load and Common Bus is taken as the Transmission Losses associated with Manitoba load.

Curtailments for individual customers are calculated as the difference between what the customer would have used if not curtailed versus what they did use. This is not the same as the calculation used for billing.

Annual Peak

The forecast annual peak is higher than the maximum of the monthly peaks. This is due to the peak being possible in any of the winter months and must be higher than the peak of the other months. For studies requiring yearly data, the annual peak should be used.

16 Hour Peak

The peaks in this document are integrated hourly peaks. For some studies and analysis of avoided cost or DSM savings, an estimate of the average peak during onpeak hours (from 6 a.m. to 10 p.m.) may be desired. To convert hourly peak to 16 hour peak, multiply the hourly peak in the associated month by the following percentages:

Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
94.4%	94.9%	95.8%	96.0%	96.3%	96.0%	96.6%	95.6%	95.8%	96.6%	95.6%	95.5%	94.8%

VARIABILITY AND ACCURACY

Weather Effect and Weather Adjustment

The weather effect is determined in any sector by regressing the last two years of actual monthly energies against the actual DDH and DDC for the month. This results in a GW.h per DDH effect and a GW.h per DDC effect for that sector.

Only sectors whose major variation is due to weather can have a weather effect estimated. Sectors that vary primarily due to industrial output levels or seasonal but non-weather reasons may yield false weather effects if estimated. Weather effects are not determined for the GS Top Consumers, Seasonal, Diesel, Water Heating and Lighting sectors. Assigning them a weather affect and weather adjusting them will not improve their forecast.

For sectors where a weather effect is calculated, this document will show energy as the reported value and as a weather adjusted value. Forecasts are based on the weather adjusted values. The calculations are:

Weather Adjustment = DDH weather effect * (DDH actual - DDH normal)
+ DDC weather effect * (DDC actual - DDC normal)

Weather Adjusted Actual = Actual - Weather Adjustment

Following are the DDH and DDC weather effect factors by sector:

Residential: 0.6 GW.h / DDH, 1.1 GW.h / DDC
GS Mass Market: 0.3 GW.h / DDH, 0.9 GW.h / DDC
General Consumers Sales: 0.8 GW.h / DDH, 2.0 GW.h / DDC
Gross Firm Energy: 1.1 GW.h / DDH, 2.3 GW.h / DDC
Gross Total Peak: 40 MW / degree (at -30 degrees Celsius),
120 MW / degree (at +30 degrees Celsius)

Effect of Extreme Weather

A record cold winter will increase load 4% and a record warm winter will decrease it 4%. An additional 2% load increase is possible due to a record hot summer and a 1% decrease due to a record cool summer.

The effect of extreme weather is larger on a monthly basis, and even larger on a daily basis.

		Effect of Weather due to Winter Extremes on Gross Firm Energy							
	GW.h/DDH	Normal		Record Warm			Record Cold		
	1.1	DDH	GW.h	DDH	GW.h	Effect	DDH	GW.h	Effect
Year:	2013/14	4541	25239	3678	24289	-4%	5439	26227	4%
Month:	Jan 2014	944	2772	663	2463	-11%	1261	3122	13%
Day:	Jan 2014	30	89	6	63	-30%	56	118	31%

		Effect of Weather due to Summer Extremes on Gross Firm Energy							
	GW.h/DDC	Normal		Record Cool Summer			Record Hot Summer		
	2.3	DDC	GW.h	DDC	GW.h	Effect	DDC	GW.h	Effect
Year:	2013/14	190	25239	69	24960	-1%	364	25639	2%
Month:	July 2013	71	1845	6	1695	-8%	142	2007	9%
Day:	July 2013	2	60	0	54	-9%	14	86	45%

The residential sector has a larger proportional effect of weather, varying from an increase of 7% in a record cold winter to a decrease of 7% in a record warm winter, and a possible additional increase of 3% due to a record hot summer and a 2% decrease due to a record cool summer.

		Effect of Weather due to Winter Extremes on Residential Energy							
	GW.h/DDH	Normal		Record Warm			Record Cold		
	0.6	DDH	GW.h	DDH	GW.h	Effect	DDH	GW.h	Effect
Year:	2013/14	4541	7339	3678	6821	-7%	5439	7878	7%
Month:	Jan 2014	944	996	663	827	-17%	1261	1187	19%
Day:	Jan 2014	30	32	6	18	-45%	56	47	48%

		Effect of Weather due to Summer Extremes on Residential Energy							
	GW.h/DDC	Normal		Record Cool Summer			Record Hot Summer		
	1.1	DDC	GW.h	DDC	GW.h	Effect	DDC	GW.h	Effect
Year:	2013/14	190	7339	69	7206	-2%	364	7531	3%
Month:	July 2013	71	426	6	355	-17%	142	504	18%
Day:	July 2013	2	14	0	11	-18%	14	27	94%

Load Variability

Uncertainty is an inherent characteristic of forecasting. The load will vary both year to year and long term because of underlying changes in population growth, economic growth, changes in the operations of Top Consumers, and overall use patterns. An economic recession will slow energy growth. An economic boom will increase it. Cycles cannot be predicted in advance so some appropriate midpoint must be chosen as the forecast.

This forecast was created as Manitoba Hydro's best estimate of Manitoba's future energy requirement. The expectation is that there will be a 50% chance that actual growth will be higher than the forecast, and a 50% chance that actual growth will be lower than the forecast.

To evaluate the potential for variation, historic load variability has been analyzed using a probabilistic-based approach. Variations in annual weather adjusted load that have occurred in the past are used to estimate future variation. Doing this provides an estimate of the magnitude of the potential load variation from the forecast due to population, economy and other effects. 10% and 90% confidence bands (-/+ 1.28 standard deviations) were selected to be a proxy for the Low and High Load Forecast Scenarios for use in risk analysis studies. They are calculated as follows:

Load = Base Forecast -/+ 1.28 x Standard Deviation

For other probability points, substitute for the 1.28 the following numbers:

Prob	0.1%	2.5%	10%	20%	50%	80%	90%	97.5%	99.9%
Z(Prob)	-3.09	-1.96	-1.28	-0.84	0.00	0.84	1.28	1.96	3.09

This calculation gives the variability due to long term economic effects. It does not include variability due to weather which was removed through the use of weather adjusted load.

If variability due to weather is needed, the standard deviation of annual energy or annual peak due to weather has been found to be approximately 2% of the load. This 2% of load can be used as the standard deviation in a probability point calculation. The resulting variance can be added to the economic-based variance if a combined variance is needed. A straight addition of variances can be done because the weather is mostly independent of the economy.

The following four charts and tables summarize the variability for energy and peak. By 2032/33, the Load Forecast has an 80% probability of being accurate to within ±2,471 GW.h or ±7.6%. Due to the inherent variability of the load, this is the best level of accuracy possible.

Figure 20 - Energy Variability

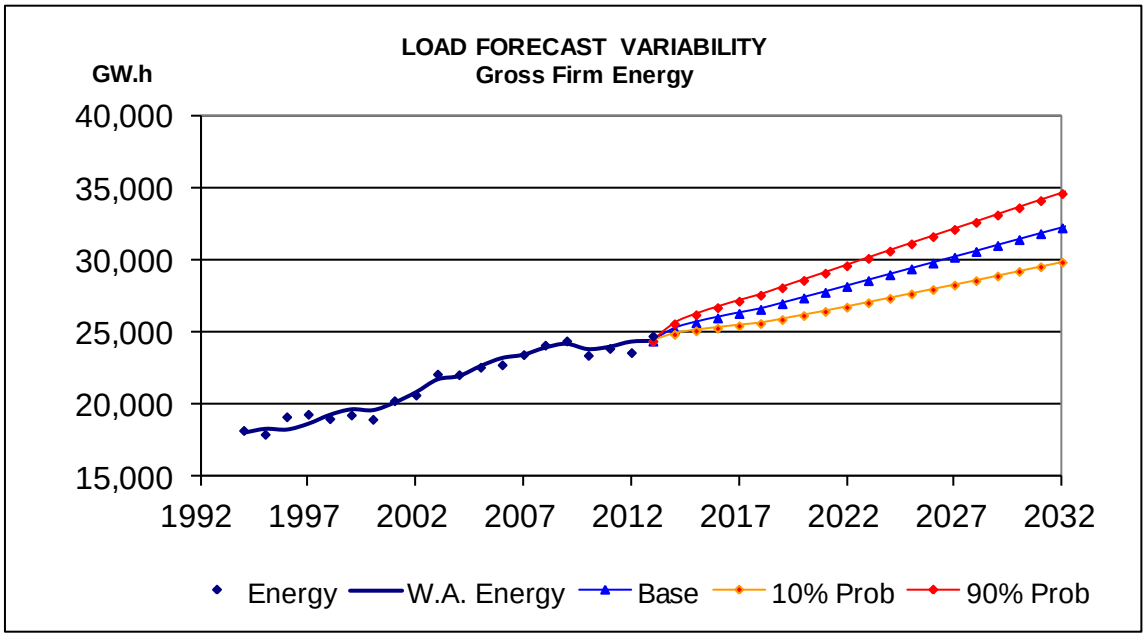


Table 33 – Energy Variability

Fiscal Year	Gross Firm Base Fcst	Long Term Economic Std Dev	10.0% Prob Point	90.0% Prob Point
2013/14	25239	284	24875	25603
2014/15	25676	434	25119	26232
2015/16	26013	557	25299	26727
2016/17	26322	667	25468	27176
2017/18	26606	767	25623	27589
2018/19	27003	862	25898	28107
2019/20	27398	951	26178	28617
2020/21	27789	1038	26460	29119
2021/22	28197	1121	26761	29634
2022/23	28605	1202	27065	30145
2023/24	29013	1280	27372	30654
2024/25	29418	1357	27679	31157
2025/26	29822	1433	27986	31658
2026/27	30225	1507	28295	32156
2027/28	30625	1579	28602	32649
2028/29	31041	1651	28925	33156
2029/30	31453	1721	29246	33659
2030/31	31863	1791	29568	34159
2031/32	32265	1860	29882	34649
2032/33	32667	1928	30196	35138

Figure 21 - Peak Variability

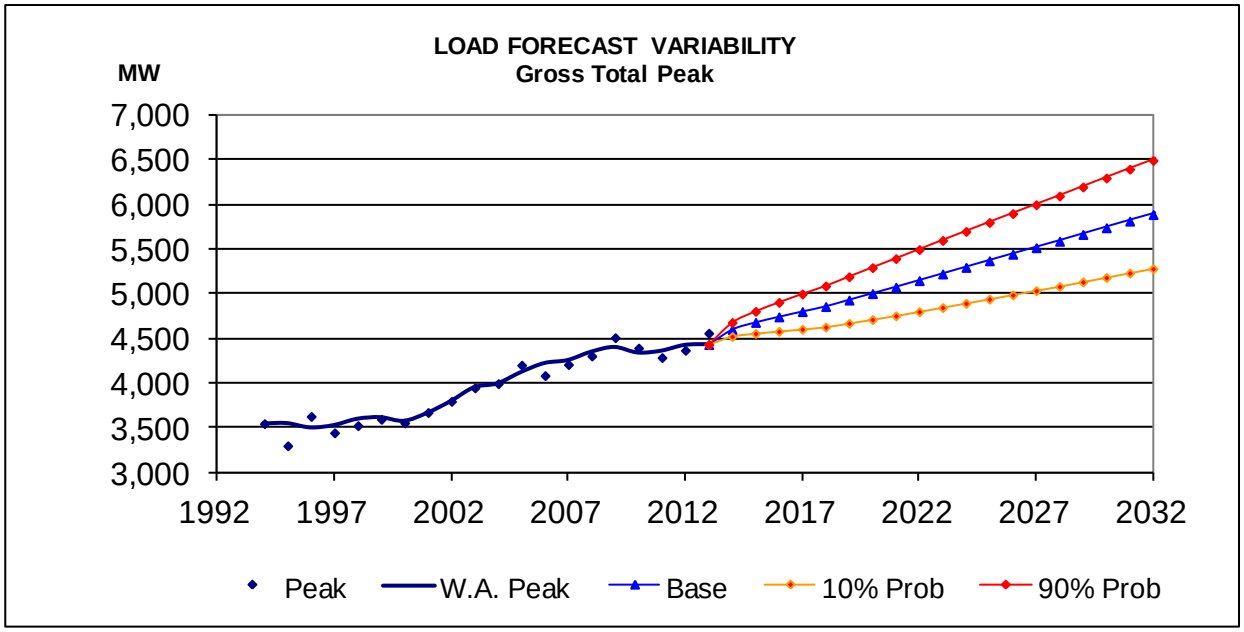


Table 34 – Peak Variability

Fiscal Year	Gross Total Peak Base Fcst	Long Term Economic Std Dev	10.0% Prob Point	90.0% Prob Point
2013/14	4601	61	4522	4679
2014/15	4680	97	4556	4804
2015/16	4742	127	4579	4904
2016/17	4801	154	4603	4998
2017/18	4857	179	4628	5087
2018/19	4930	204	4669	5191
2019/20	5002	227	4711	5293
2020/21	5074	249	4754	5393
2021/22	5147	271	4800	5495
2022/23	5222	293	4846	5597
2023/24	5296	314	4893	5698
2024/25	5369	335	4940	5798
2025/26	5443	355	4988	5898
2026/27	5516	375	5035	5997
2027/28	5588	395	5082	6095
2028/29	5664	415	5132	6195
2029/30	5739	434	5182	6295
2030/31	5813	454	5232	6395
2031/32	5886	473	5280	6492
2032/33	5959	492	5329	6590

5 and 10 Year Forecast Accuracy

Due to the load variation caused by population growth and economic growth, there is only a certain level of accuracy possible. Recognizing the inherent uncertainty of forecast, historic forecast variation has been tracked. Manitoba Hydro's objective is that a five year forecast is within 5% and a ten year forecast is within 10%.

The following four figures and tables compare previous load forecasts to actual results 5 and 10 years later.

The energy savings achieved under Manitoba Hydro's market-based DSM programs between the year the forecast was prepared and the year being forecast was subtracted first from the forecast value. The difference is taken as the accuracy of the forecast.

The following figures and tables may seem to give the impression that there may be cycles in the forecast made up of alternating periods of over-forecasting and under-forecasting. But these are not so much due to a bias in the forecast as they are due to unexpected periods of recession or economic growth. Once one of these unexpected periods occur, it will affect the accuracy of the previous five 5-year forecasts for 5 years, and the accuracy of the previous ten 10-year forecasts for ten years.

Compensation for these periods of over and under-forecasting cannot be applied until after the events occur and only then can be identified and quantified. The forecast assumes average expected economic conditions. When that does not occur, the forecast will be high or low.

The weather adjusted Gross Firm Energy is shown in two separate columns in the Energy Accuracy table and they vary in each year due to the difference in weather normals used in each of the respected forecasts. Those weather normals differences are due to the use of a 25 year rolling average which relies on the previous 25 years of weather data at the time the forecast is created.

Figure 22 - Energy Accuracy

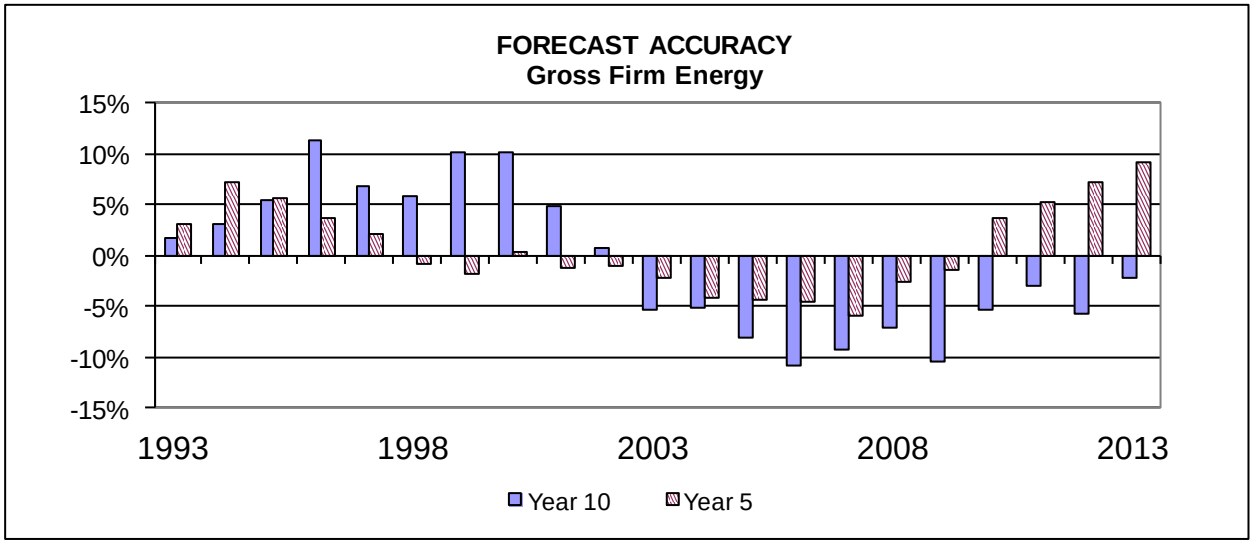


Table 35 - Energy Accuracy

Fiscal Year	Actual Gross Firm Energy	Forecast Prepared 5 Years Previous	W.A. Gross Firm Energy	5 Year Percent Accuracy	Forecast Prepared 10 Years Previous	W.A. Gross Firm Energy	10 Year Percent Accuracy
1992/93	17894	18533	17974	3.1%	18253	17950	1.7%
1993/94	18201	19440	18113	7.3%	18674	18101	3.2%
1994/95	17929	19400	18365	5.6%	19357	18365	5.4%
1995/96	19148	18985	18318	3.6%	20450	18370	11.3%
1996/97	19321	19198	18810	2.1%	19970	18716	6.7%
1997/98	19014	19258	19429	-0.9%	20452	19320	5.9%
1998/99	19273	19476	19818	-1.7%	21696	19708	10.1%
1999/00	18971	19767	19703	0.3%	21611	19629	10.1%
2000/01	20262	20018	20241	-1.1%	21083	20103	4.9%
2001/02	20656	20783	20980	-0.9%	21146	20979	0.8%
2002/03	22110	21395	21861	-2.1%	20703	21868	-5.3%
2003/04	22069	21134	22062	-4.2%	20975	22107	-5.1%
2004/05	22589	21693	22664	-4.3%	20870	22714	-8.1%
2005/06	22757	22216	23277	-4.6%	20812	23346	-10.9%
2006/07	23464	22107	23489	-5.9%	21395	23595	-9.3%
2007/08	24122	23353	23962	-2.5%	22328	24034	-7.1%
2008/09	24417	23926	24259	-1.4%	21756	24320	-10.5%
2009/10	23412	24734	23850	3.7%	22611	23892	-5.4%
2010/11	23892	25270	24020	5.2%	23330	24071	-3.1%
2011/12	23605	25951	24202	7.2%	22966	24376	-5.8%
2012/13	24759	26522	24280	9.2%	23902	24443	-2.2%

Figure 23 - Peak Accuracy

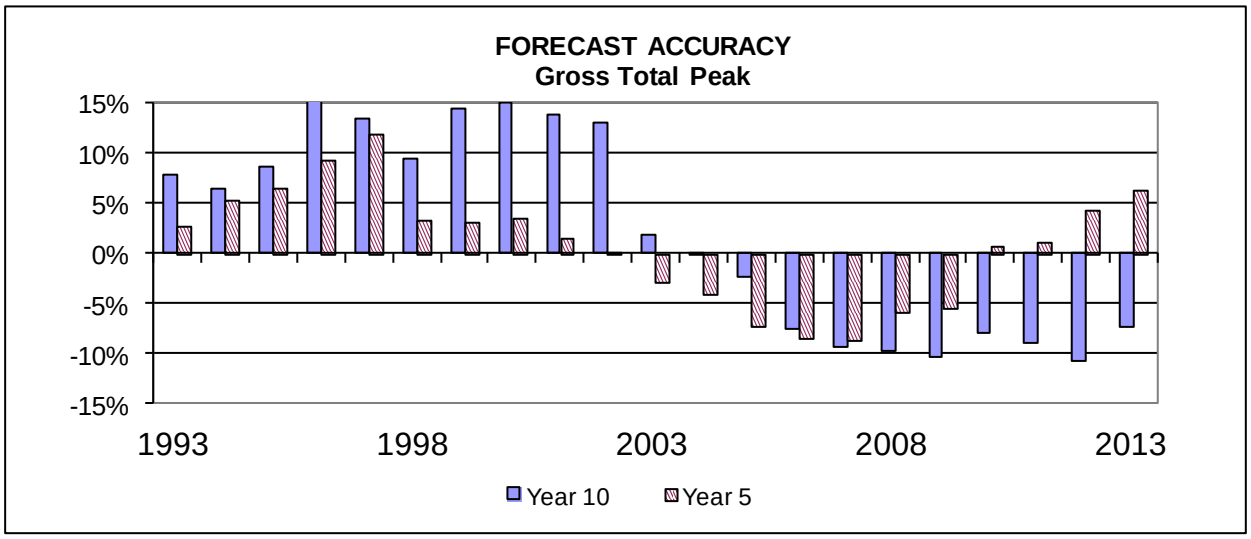


Table 36 - Peak Accuracy

Fiscal Year	Actual Gross Total Peak	Forecast Prepared 5 Years Previous	W.A. Gross Total Peak	5 Year Percent Accuracy	Forecast Prepared 10 Years Previous	W.A. Gross Total Peak	10 Year Percent Accuracy
1992/93	3443	3621	3523	2.8%	3799	3523	7.8%
1993/94	3547	3754	3567	5.3%	3799	3567	6.5%
1994/95	3299	3829	3593	6.6%	3904	3593	8.7%
1995/96	3628	3850	3523	9.3%	4081	3523	15.8%
1996/97	3444	3906	3491	11.9%	3962	3491	13.5%
1997/98	3525	3768	3646	3.3%	3990	3646	9.4%
1998/99	3596	3703	3592	3.1%	4108	3592	14.4%
1999/00	3555	3738	3608	3.6%	4152	3608	15.1%
2000/01	3672	3758	3699	1.6%	4210	3699	13.8%
2001/02	3797	3759	3758	0.0%	4251	3758	13.1%
2002/03	3948	3801	3917	-3.0%	3989	3917	1.8%
2003/04	3994	3833	3994	-4.0%	3990	3994	-0.1%
2004/05	4201	3817	4119	-7.3%	4023	4119	-2.3%
2005/06	4085	3860	4221	-8.5%	3899	4221	-7.6%
2006/07	4208	3894	4267	-8.7%	3868	4267	-9.4%
2007/08	4304	4097	4351	-5.8%	3927	4351	-9.8%
2008/09	4509	4161	4401	-5.4%	3948	4401	-10.3%
2009/10	4393	4371	4338	0.8%	3993	4338	-8.0%
2010/11	4286	4406	4359	1.1%	3967	4359	-9.0%
2011/12	4367	4616	4423	4.4%	3952	4423	-10.6%
2012/13	4559	4715	4434	6.3%	4108	4434	-7.3%

POSSIBLE EVENTS

Manitoba Hydro examines possible events of interest for their potential impact on system load requirements. These events are deemed to be captured within the overall load variability analysis of the forecast. Although not specifically identified within the analysis, they are presented so their individual effects may be considered from a sensitivity perspective if the need arises. These events are summarized in the following table.

	Energy Effect (GW.h)	Peak Effect (MW)
Climate Change per Degree Celsius Warmer	+100	-40
One New Very Large Industrial Customer	+1,500	+180
One Less Very Large Industrial Customer	-1,500	-180
Additional Load if Electric Vehicles Grow to 70%	+2,312	+289
10% of all Res Customers switch to Electric Heat	+746	+246
10% of all Res Customers switch to Electric Water Heaters	+198	+23

To provide context for the previous table, one year of energy growth is approximately 420 GW.h and one year of peak growth is approximately 80 MW.

Climate Change

The Intergovernmental Panel on Climate Change projects an increase in global temperature as a result of rising concentrations of greenhouse gases in the atmosphere. Changes to temperature and extreme events have the potential to influence future energy demands.

In the last 100 years, the city of Winnipeg's 25-year average temperature has resulted in Degree Days Heating (DDH) in the range of 4500 to 5000 each year. A 25 year moving average has been selected for the forecast to help minimize the effects of year to year variability and to represent the long term climatology. This section quantifies the general effect caused by a 1°C increase in average daily temperature throughout the year.

In Manitoba Hydro's case, if Winnipeg experienced a uniform 1°C warming throughout the year, winter months would be subject to less heating while summer months would be subject to more cooling. Over 200 winter days, every degree Celsius of temperature rise above average conditions will result in an approximate decrease of 200 Degree Days Heating (DDH) per year, and a corresponding approximate increase of 100 Degree Days Cooling (DDC) per year over 100 summer days.

Applying the Weather effect for Manitoba Hydro at Generation gives:

Decrease of 200 DDH ➔ -200 GW.h and -40 MW in the winter

Increase of 100 DDC ➔ +300 GW.h and +120 MW in the summer

The resulting total effect of every one degree increase in temperature would be:

An increase of 100 GW.h to annual energy and a decrease of 40 MW to system peak.

	Energy (GW.h)	**Peak (MW)**
Climate Change per Degree Celsius Warmer	+100	-40

Potential Load from Very Large Industrial Customers

This forecast includes an expectation that there may be new large industrial users of electricity that may come to Manitoba. GS Top Consumers includes a Potential Large Industrial Loads category that adds 1,700 GW.h to GS Top Consumers by 2031/32. This is expected to be made up of increases and decreases by current top consumers, additions of new top consumers and company closures. However, this forecast does not anticipate the scenario of a single customer using up the entire PLIL category.

Manitoba Hydro's largest customer currently uses in excess of 1,500 GW.h annually and has a coincident peak load of about 180 MW. It is feasible that one or more customers of this size could decide to start up in Manitoba in the next 20 years. A single large new customer could use the entire 1,700 GW.h of energy that has been reserved in the Potential Large Industrial Loads category.

Similarly, there is a chance that one or more very large customers can close down. This could also be the equivalent of losing Manitoba Hydro's largest customer.

	Energy (GW.h)	**Peak (MW)**
Additional Load for one new very large customer	+1,500	+180
Loss of Load for the loss of our largest customer	-1,500	-180

Potential Load from High Adoption of Electric Vehicle Technology

This forecast already assumes there will be a noticeable impact due to adoption of electric vehicles within Manitoba over the next twenty years. The specifics have been detailed in the Plug-In Electric Vehicles section of this document.

But there is a possibility that the current technological challenges will be solved, price will match those of internal combustion vehicles, and range anxiety will be alleviated. Should breakthroughs and advances in battery technology, changes in consumer perceptions, and price reductions happen in the next few years, it is possible that electric vehicles may grow to be the dominant vehicle. Under this assumption, electric vehicles may grow to be 70% of the market share in 20 years.

Assuming 70% of all vehicles in Manitoba in 2032/33 are Plug-In Electric Vehicles (PEVs), then these vehicles would use 2,384 GW.h and 298 MW. Currently, the forecast includes 72 GW.h and 9 MW for PEVs, therefore 70% saturation would be an increase of 2,312 GW.h (5½ years of load growth) and 289 MW (about 3½ years of peak growth).

	Energy (GW.h)	Peak (MW)
Additional Load with 70% Electric Vehicle Saturation Rate	+2,312	+289

Increased Residential Use of Electricity for Space heat

Under current natural gas prices, it is cheaper to heat one's home with a high efficiency natural gas furnace than with electricity. This forecast assumes that natural gas will retain its price advantage over electricity over the next 20 years. The forecast is that by 2032/33, 221,868 or 39.3% of Residential Basic customers will heat their home with electricity.

However, there is a possibility that more customers could switch to electric space heat. If the percentage of electric heat billed customers rises by 10% to 49.3%, then by 2032/33, 278,341 electric heat customers would use 24,869 kW.h each, and 286,245 other customers would use 11,487 each. Total usage would be 746 GW.h higher than forecast (almost 2 years of load growth) in 2032/33. At a 35% load factor, this would add 246 MW to the peak (3 years of peak growth).

	Energy (GW.h)	Peak (MW)
10% of all Res Customers switch to Electric Heat	+756	+246

Increased Residential Use of Electricity for Water heat

New homes are now primarily built with electric water heaters rather than natural gas water heaters regardless of their space heat fuel choice. In existing homes, as standard and mid-efficiency gas furnaces are being replaced with a high efficiency gas furnace, some homeowners are choosing to replace their existing natural gas water heaters with electric water heaters.

However, there is a possibility that more customers could switch to electric water heaters. If the percentage of customers with electric water heaters rises by 10% to 72.5%, then by 2032/33, 56,459 additional electric water heaters would use 3,500 kW.h each. Additional usage would be 198 GW.h (about ½ year of load growth). At a 100% load factor, this would add 23 MW to the peak (about ¼ of a year of peak growth).

	Energy (GW.h)	Peak (MW)
10% of all Res Customers switch to Electric Water Heaters	+198	+23

ASSUMPTIONS

Economic Assumptions

Economic forecast assumptions are taken from the 2013 Economic Outlook and the 2013 Energy Price Outlook. These documents contain Manitoba Hydro's forecasts of economic variables including prices of electricity, natural gas and oil, Gross Domestic Product (GDP), Manitoba population and residential customers.

The following are the economic variables used in the preparation of this Electric Load Forecast:

Residential Customers - The number of Residential Basic customers in Manitoba is forecast to increase by 1.2% (5,633 units) in 2013/14 and averages 1.1% per year over the forecast period. This compares to a historical average increase of 1.0% per year over the last ten years. This is used in the Residential and GS Mass Market customer forecasts.

Electricity Prices - The electricity price forecast is based on CPI and rate increase projections contained in the Integrated Financial Forecast. The real electricity price is forecast to increase by 1.7% in 2013/14, and then increase by 2.0% per year throughout the rest of the forecast period.

Natural Gas Prices – Manitoba Hydro views the natural gas price forecast as commercially sensitive information. Consistent with the Clean Environment Commission and Electric General Rate Application, this information will not be publicly disclosed.

Gross Domestic Product (GDP) - Real economic growth in Manitoba is forecast to be 2.4% in 2013/14. It is expected to stay at approximately that level for several years, then decline to 1.7% by 2019/20 and remain at that level for the remainder of the forecast period. This is used in the GS Mass Market customer forecast.

Normal Weather Assumptions

Weather for forecast purposes is measured by degree days. Winnipeg temperatures are used, as Winnipeg is central to most of the weather-dependent load (Residential and General Service Mass Market) in Manitoba.

Cold weather is expressed in Degree Days Heating (DDH), which is the number of average degrees colder than 14 degrees Celsius each day. Hot weather is expressed in Degree Days Cooling (DDC), which is the number of average degrees warmer than 18 degrees Celsius each day. Daily temperature is the average of the high and low temperature for the day. The equations are:

DDH = sum (max(0, 14 - (Daily high + Daily low) / 2))

DDC = sum (max(0, (Daily high + Daily low) / 2) - 18)

The base temperature of 14 degrees for DDH is the temperature below which most buildings have their heating systems (furnaces) running.

The base temperature of 18 degrees for DDC is the temperature above which buildings start to run their space cooling systems (air-conditioning).

The forecast is prepared assuming normal weather. Normal weather is determined from the 25 year average of Degree Days Heating and Degree Days Cooling in Winnipeg over the period April 1988 to March 2013.

The 25 year weather normals used for every year of this forecast are 4,541.3 DDH and 190.1 DDC. This is an increase of 22.9 DDH from last year's normal of 4,518.4 DDH, and an increase of 2.0 DDC from last year's normal of 188.1 DDC.

The range of DDH from 1988 to 2013 was from a warm winter of 3,677.6 DDH in 2011/12 (863.7 DDH below normal) to a cold winter of 5,439.3 DDH in 1995/96 (898.0 DDH above normal).

The range of DDC from 1988 to 2013 was from a cool summer of 71.8 DDC in 2004/05 (118.3 DDC below normal) to a hot summer of 364.1 DDC in 1988/89 (174.0 DDC above normal).

Demand Side Management (DSM) in the Forecast

This forecast reflects future DSM savings associated with existing Provincial building codes and improved equipment efficiency standards (Codes and Standards). This is the only DSM initiative that is specifically accounted for in the forecast.

Savings due to DSM programs to date are embedded in the historical data that is the basis for this forecast. The current level of past achieved DSM savings is assumed to remain in place throughout the future. Future DSM savings arising from future Power Smart offerings and market engagement above the current level and incremental to the above mentioned Codes and Standards are treated as a supply-side resource and are not included in this forecast. They are accounted for separately in Manitoba Hydro's Power Smart Plan and Power Resource Plan.

As a result, historical growth rate in this document are not directly comparable to future growth rates because the history includes the effect of past DSM initiatives, but the forecast does not.

For customers involved in DSM initiatives such as the Load Displacement and Alternative Energy, the most recent years of history are used as the basis of their forecast. Any increase or loss to their alternative energy supply will not be included in the forecast, and are accounted for with the other DSM initiatives within the Power Smart Plan.

METHODOLOGY

Residential Basic Methodology

The Residential Basic forecast was determined using a combined electricity and natural gas end use approach. The end use assumptions include usage information and efficiency improvement information. The number of appliances and their estimated usage were multiplied together to calculate an energy forecast for each end use, and then all uses were combined to calculate the total use for the Residential End Use Forecast. The following steps were used:

1. **Total Number of Residential Customers** - The forecast of the total number of Residential Basic customers for the 2013/14 to 2032/33 period is taken from Manitoba Hydro's 2003 Economic Outlook that is produced by the Economic Analysis Department. This customer forecast was the primary input for the Residential End Use Model.

2. **Residential Survey Data** – The 2009 Residential Survey was used to provide estimates as of November 2009 of the following:

    a) **Customers by Dwelling Type and Area:** Dwelling types include: Single Detached, Multi-family Attached, and Individually-Metered Apartments. Single detached dwelling types are sub classified into three Areas: Winnipeg, Gas Available Areas Outside of Winnipeg, and Gas Unavailable Areas.

    b) **Customers by Heating Type** - Each combination of Dwelling Type and Area are divided into three Heating Types: Electric Heat Billed customers, Natural Gas Heat Billed customers and Other Heat customers. Electric Heat Billed customers pay for their space heat with their electricity bill. Natural Gas Heat Billed customers pay for their space heat with their natural gas bill. Other Heat customers may use fuel oil, propane or wood, or may use electric or natural gas heat but are not billed on their own electricity or natural gas bill for their heat.

    c) **Age of Home and Heating System** – Home age was used to determine new home construction rates by dwelling type, area and heating type. Heating system age was used to determine heating system replacement rates.

d) **Appliance Saturations and Ages** – Appliance saturations were used to estimate the number of various types of appliances, and appliance ages were used to estimate their replacement rates.

3. **Determination of Average Use** – Conditional Demand Analysis was then performed on the Residential Survey data combined with the Billing data to derive the average annual energy use per appliance calibrated to the whole-house usage. Usage of newer appliances can differ from that of older appliance. Average use for new appliances was determined where there was a difference.

4. **Calibrate Starting Year** – Customers, saturations and average usage were combined to give starting values for the 2009/10 fiscal year corresponding to the 2009 Residential Survey results. These were also calibrated to the billing data for 2009/10.

5. **Calibrate History** – Growth and replacement rates from the Survey were applied to starting year values to derive values for 2010/11, 2011/12 and 2012/13. These were calibrated to billing data for those same years.

6. **Future Growth** – Forecasts of the number of homes, heating systems and appliances, their average usage and their total use were calculated as follows:

   a) **New Construction** - The percentage of newly constructed homes choosing electric space heat was forecast for each area using the 2009 Residential Survey estimate. This estimate was adjusted to reflect Manitoba Hydro's initiatives being undertaken to reduce the number of customers choosing electricity for space and water heat.

   b) **Appliance Forecast** - Historical saturation and age distribution data was collected from the 2009 Manitoba Hydro Residential Survey. Saturations were forecast using a birth/death/replacement model.

   c) **New Appliance Usage** - Average use for new appliances was taken from Conditional Demand Analysis.

d) **Total Energy Use -** The forecast number of appliances was multiplied by the forecast average use to get the total forecast usage for each appliance. The appliance usages were summed to get the total forecast energy use for the Residential Basic rate class.

7. **Final Adjustments** – Electric Vehicles were added, and savings from Standards and Codes are subtracted.

   Ninety percent of the Plug-In Electric Vehicle forecast was added to the Residential GW.h. (The other ten percent of the electric vehicle forecast was allocated to the General Service Mass Market forecast.)

   Estimates of improvements due to future Codes and Standards that were not handled by the new appliance average usages were obtained from the Power Smart Planning and Evaluation Research Department and were subtracted.

General Service Mass Market Methodology

A) General Service Mass Market Customer Forecast

Econometric analysis of sales data is used to develop models for the number of customers. Forecasts of Manitoba GDP and Manitoba Hydro Residential Customers from the Manitoba Hydro 2013 Economic Outlook are then input into the models, which generate forecasts for the number of customers for each year of the forecast period.

The number of customers at fiscal yearend was forecast using the following calculations for each year (t):

Number of Customers (t)
= Number of Customers (t-1)
+ Change in the Number of Customers (t)

Change in the Number of Customers (t)

= Number of Customers (t-1)
x Percentage Change in Number of Customers (t)

The percentage change in number of customers was modeled using yearend historical customer data from 1984/85 to 2012/13. The resulting model and parameters are as follows:

Percentage Change in Number of Customers (t)
= -0.003 + 0.132 x CGDP + 0.660 x CRES

CGDP - Annual Percentage Change in Manitoba Gross Domestic Product
CRES - Annual Percentage Change in Residential Basic Customers

R-squared: 58.9%
T-stats:
Constant : -1.58
CGDP : 3.72
CRES : 4.05

General Service Mass Market customer growth is allocated to Medium and Large classes using their 10 year average percentage of Mass Market customer growth, the Small Non-Demand class is allocated 10% of new customers, and the rest of the growth is allocated to the Small Demand class.

B) General Service Mass Market Average Use Forecast

Average use for new customers in each rate class is forecast to be the five year average use of its respective class for the duration of the forecast period. Specifically these are:

i) Small Non-Demand - 31,075 kW.h per year
ii) Small Demand – 166,315 kW.h per year
iii) Medium - 1,572,917 kW.h per year
iv) Large - 5,834,523 kW.h per year

Top Consumer customers are excluded from these classes for forecasting purposes.

Customers are assigned to a rate class depending on their usage. If usage by an individual customer increases (or decreases) sufficiently then they will be re-assigned to the appropriate rate class. These shifts tend to offset each other over time so individual classes have not shown significant upward or downward trends in average use. By definition, the truncation of these classes results in relatively stable average use for each class.

C) General Service Mass Market Total Use Forecast

Total GW.h for the General Service Mass Market sector is forecast by multiplying the forecast number of customers in each rate class by the forecast average use per customer in each rate class. The total number of customers in the GS Mass Market sector is forecast using econometric models, and then the total is allocated among the rate classes based on historical data. The average use per customer is forecast using the five year average for each rate class.

Ten percent of the Plug-In Electric Vehicle forecast is added to the GW.h for the Small Non-Demand rate class. (The other ninety percent of the electric vehicle forecast is allocated to the Residential forecast.) Forecast savings from future Codes and Standards are taken off of the forecast to calculate the Total Use.

Total Use (t) in GW.h

= Weather Adjusted Actual Usage for the Current Year
+ Number of New Small Non-Demand Customers (t)
x Average Annual Use of Small Non-Demand Customers (t)
+ 10% of Plug-in Electric Vehicle Forecast
+ Number of New Small Demand Customers (t)
x Average Annual Use of Small Customers (t)
+ Number of New Medium Customers (t)
x Average Annual Use of Medium Customers (t)
+ Number of New Large Customers (t) x Average Annual Use of Large Customers (t)
- Forecast Savings from Codes and Standards (t)

General Service Top Consumers Methodology

Top Consumers is made up of the largest electricity users of Manitoba Hydro. The general criterion is that a company needs to have used 80 GW.h in a year, or have the potential to consume 80 GW.h in a year. A Top Consumer is not necessarily located in one place, but may consist of services at number of locations throughout the Province. A Top Consumer will be one company, but may count as multiple billing customers.

Each company in the Top Consumers group is forecast individually. Information on individual company operating plans is collected from industry news, Manitoba Hydro's economic experts and Manitoba Hydro's Key & Major Account representatives. This information is used to prepare company specific forecasts.

Normally, information is only available over the next 3 to 5 years for any company. These short term considerations are taken into account, and then the company's individual forecast is held constant.

To account for longer term growth in this group of consumers, a special classification called Potential Large Industrial Loads (PLIL) has been created. PLIL is used instead of attempting to forecast each consumer individually for the long term. It represents the natural growth of all the top consumers as a group, as well as unexpected major expansions, new customers, or loss of customers from GS Top Consumers.

Starting in 2014/15, 100 GW.h a year is forecast for PLIL to account for unforeseen expansion, contraction and growth. This will result in the addition of 1,700 GW.h of PLIL after 20 years.

Electric Vehicles

The methodology for forecasting Electric Vehicles was to research relevant recent literature and to apply appropriate assumptions from this literature to Manitoba's situation. Historical data on automobile registrations per year in Manitoba was used to help estimate future trends. The forecast section on Electric Vehicles provides the details.

Other Sectors

Seasonal, Water Heating, Lighting

Most of the smaller sales sectors, including Seasonal, Flat Rate Water Heating and Area and Roadway Lighting were done by analysis of changes in the number of customers or services and in changes in average use per customer or service. Growth rates were applied based on history and a best estimate as to what the future will bring.

Diesel

Each of the diesel towns was individually forecast and included in the forecast under the assumption that the diesel towns will not be part of the Integrated System during the forecast period.

Monthly Sales Allocations

Monthly percentages of customer growth through the year and GW.h for the month of the year were averaged for the past five years. These were then applied to the forecast annual customers and kW.h to get the monthly forecast.

Monthly and Annual Gross Firm Energy and Gross Total Peak

The 5 year monthly percentage of Common Bus and Station Service are applied to their annual energy to calculate their monthly values. Transmission Losses are calculated using a 5 year average of their ratio to Common Bus. Monthly Common Bus, Transmission Losses and Station Service are added up to give the Monthly System Energy. Monthly Common Bus, Transmission Losses, Station Service and Gross Firm Energy are totaled to give the Annual Gross Firm Energy.

The Gross Total Peak is calculated from Load Factors applied to the forecast monthly Gross Total Energy. Prior to calculating the Load Factors, the Top Consumer energy and peak are subtracted because the Top Consumers have a higher average hourly energy relative to their peak value than the Residential and General Service Mass Market Customers. A 10 year

historical average Load Factor is calculated for the remaining energy and is applied to the forecast monthly and annual energy to get the peaks for the remaining energy. The Top Consumer peaks are added using an 85% Load Factor applied to the Top Consumer monthly and annual energy.

A 10 year average Load Factor is used instead of a 5 year average due to its variability from year to year. Historical weather adjusted energy is used to calculate Load Factors. The number of hours in the month is used to calculate monthly Load Factors and the number of hours in the year is used to calculate annual Load Factors.

GLOSSARY OF TERMS

Area and Roadway Lighting sector - includes electricity sales for the Sentinel Lighting and Street Lighting rate groups.

Common Bus - is the total load measured from all the distribution points (i.e. substations) within Manitoba. It includes all energy supplied to General Consumers Sales customers, Construction Power plus associated Distribution Losses, but excludes Diesel customers, Transmission Losses and Station Service.

Customer – Most metered electrical services count as a customer. Unmetered services such as flat rate water heating and sentinel rental services do not count as a customer. Street lighting counts all the services grouped as a premise as one customer.

Codes and Standards – A Demand Side Management (DSM) initiative associated with existing Provincial building codes and improved equipment efficiency standards. This is the only DSM initiative that is specifically accounted for in the forecast.

Curtailable - is a load that can be curtailed on short notice. A discount is given for subscribing to this program. Curtailable loads can affect peak demand because some periods of curtailment may be at or near the system peak.

Degree Days Cooling (DDC) - DDC is a measurement designed to reflect the demand for energy needed to cool a building. DDC is the number of degrees warmer than 18 degrees Celsius each day is, based on the average of the high and low temperature of the day.

DDC = sum (max(0, (Daily high + Daily low) / 2) - 18)

Degree Days Heating (DDH) – DDH is a measurement designed to reflect the demand for energy needed to heat a building. DDH is the number of degrees colder than 14 degrees Celsius each day is, based on the average of the high and low temperature of the day.

DDH = sum (max(0, 14 - (Daily high + Daily low) / 2))

Gas Available Area – A city or town in Manitoba where customers have natural gas service available and can choose to heat their home with either natural gas or electricity.

Approximately 82% of Residential Basic customers, including the entire city of Winnipeg, have gas available.

General Consumers Sales - includes the energy supplied to all of Manitoba Hydro's individually billed customers. It excludes export sales.

General Service Mass Market - includes all Commercial and Industrial customers, excluding the Top Consumers group.

General Service sector - made up of sales to Commercial and Industrial businesses served by Manitoba Hydro. This sector consists of five rate groups (Basic, Diesel, Seasonal, Flat Rate Water Heating and Surplus Energy Program).

General Service Top Consumers - is made up of the largest electricity users of Manitoba Hydro.

Gross Firm Energy - is the energy required to serve Manitoba Hydro's customers on the Integrated System. It excludes exports, interruptible (non-firm) loads and diesel customers.

Gross Total Peak - is the maximum integrated (i.e. average) hourly load required to serve Manitoba Hydro's customers on the Integrated System. It excludes exports and diesel customers. It includes curtailable loads.

GW.h (gigawatt-hour): The unit of energy primarily used in this document. One GW.h equals one million kW.h (kilowatt-hours), which is approximately equal to the energy of 100 typical homes not using electricity for heating, or 40 homes that use electricity for heating.

Integrated System - is the power grid that connects Manitoba Hydro's generation sources to its customers. All Manitoba Hydro's customers except diesel are on the Integrated System.

Interruptible (Non-Firm) Energy - includes all energy sold to Manitoba customers on a non-firm basis. Currently, the only rate group for this is the Surplus Energy Program (SEP).

kW.h/cust (kilowatt-hours per customer): The unit of energy primarily used in this document to represent the average use of one customer. The total usage in GW.h of a group of customers is divided by the number of customers and then multiplied by one million.

Load Factor - is the ratio of the average hourly energy over a period, usually a year, divided by the energy used at a specific hour, usually the hour of system peak. A load factor of 25% means that the average energy is one-quarter of what is used at system peak. A load factor greater than 100% means that the average hourly energy is more than what is used at system peak. Given a specific energy, a lower load factor means a higher peak. The equation is:

Load Factor = (Total Energy / Hours) / (Energy over the hour of system peak)

Manitoba Load at Common Bus - is the total load measured from all the distribution points (i.e. substations) within Manitoba. It includes all energy supplied to General Consumers Sales customers plus associated Distribution Losses, but excludes diesel customers, Transmission Losses and Station Service.

MW (megawatt): The unit of peak demand primarily used in this document. One MW is a million watts. One thousand MW of peak demand for one hour equals one GW.h of energy. Alternatively, one MW for a thousand hours also equals one GW.h of energy.

Net Firm Energy and **Net Total Peak** - are the same as Gross Firm Energy and Gross Total Peak except they exclude Station Service. The reporting of Manitoba Load in the Load Forecast used "Net" until 2008. It presented both until 2011. Starting with the 2012 forecast, only the "Gross" is presented. Net can be calculated when needed by subtracting Station Service from the Gross.

Residential Basic – is the primary residential customer group made up of single detached and multi-family dwellings as well as individually metered apartment suites.

Residential sector - made up of sales to residential customers for non-business operations. The Residential sector is comprised of four rate groups (Basic, Diesel, Seasonal, and Flat Rate Water Heating).

Station Service - is the energy used by power plants to generate power and service their own load.

Tab 48

Need, Alternatives and Economic Valuation

MANITOBA HYDRO PANEL 2
MARCH 10, 2014

Need, Alternatives & Economic Evaluation

- Need for New Resources
- Generation Planning Criteria
- Screening of Resource Options
- Exports and Window of Opportunity
- Development Plans
- Economic Analysis Methodology
- Economic Uncertainty Analysis Methodology
- Economic Indicators
- MISO Pricing Trends & Energy Policy
- Transmission Facilities
- Reliability - Resource Adequacy Analysis
- Economic Evaluation – Interconnection Assumptions
- Capital Costs for Thermal and Wind
- Capital Costs for Keeyask and Conawapa
- Economic Evaluation Results
- Pathways & Optionality

Need for New Resources

JOANNE FLYNN
MARCH 10, 2014

Need for New Resources (with no new exports)

	Dependable Energy	Winter Peak Capacity
2012 Planning Assumptions	2022/23	2025/26
2013 Planning Assumptions	2023/24	2026/27
NFAT DSM 1	2028/29	2030/31
NFAT DSM 2	2031/32	2031/32
NFAT DSM 2 with increased pipeline load	2027/28	2030/31
NFAT DSM 3	2033/34	2033/34
NFAT DSM 3 with increased pipeline load	2029/30	2030/31

Calculations of # Years Advancement of Keeyask for MP, WPS & NSP Sales

NFAT Submission assumed Keeyask Advancement would be:

- 3 to 4 years with base load growth
- 9 years with low load growth
- 11 years with base load and 4X DSM

1. NFAT DSM 2 (all of Option 2) = 2031 Keeyask ISD
2. NFAT DSM 2 (reduced somewhat) = 2029 to 2030 Keeyask ISD
3. Add pipeline load & reduce growth due to elasticity, codes and fuel choice = 2026 to 2028 Keeyask ISD

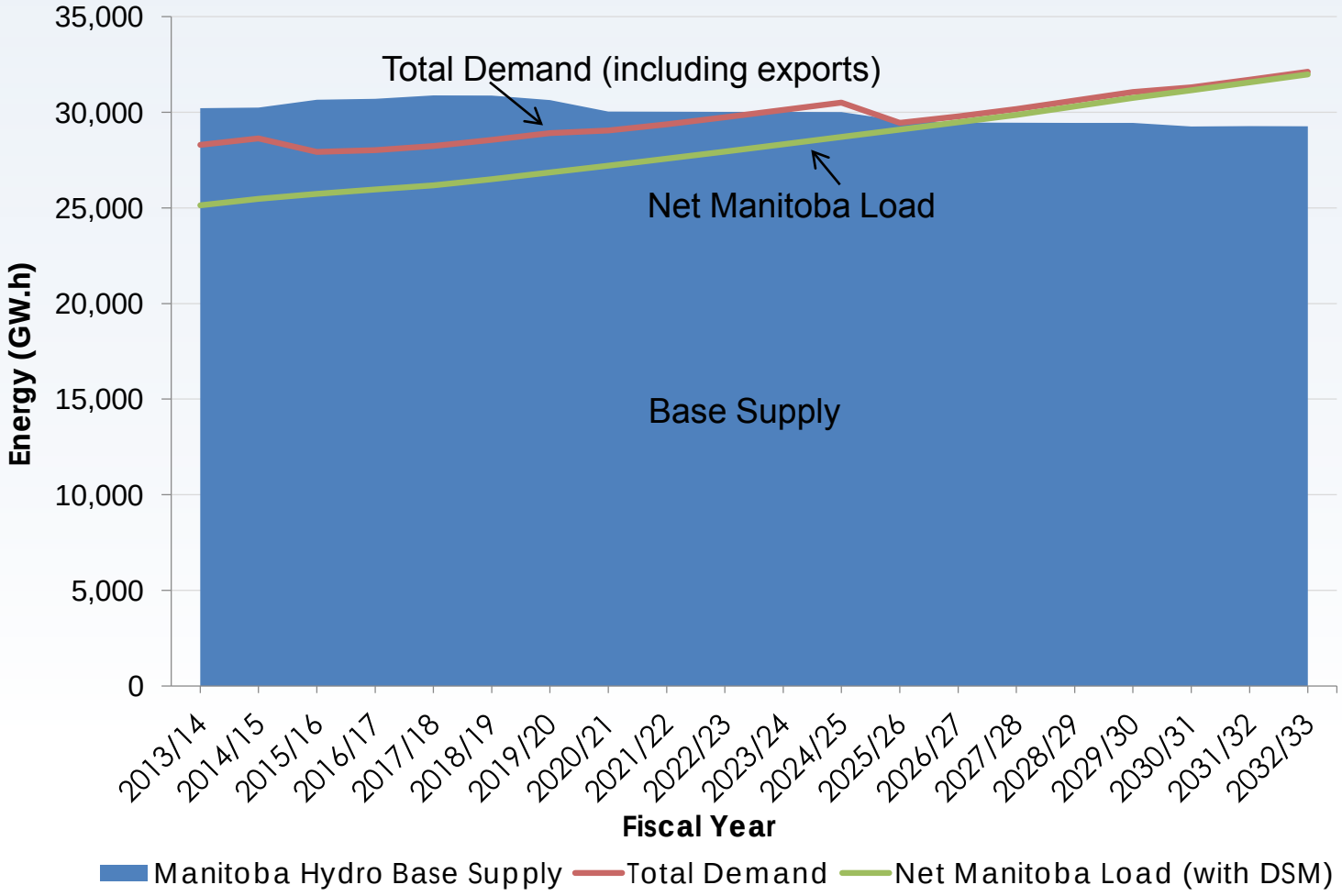
<u>Keeyask Advancement from 2019 = 7 to 9 years</u>

4. If Keeyask deferred from 2019 to 2020

<u>Keeyask Advancement from 2020 = 6 to 8 years</u>

Thus overall, **<u>Keeyask Advancement likely would be from 6 to 9 years</u>**

Need for New Resources - 2013 Dependable Energy



Generation Planning Criteria

JOANNE FLYNN
MARCH 10, 2014

Manitoba Hydro's Generation Planning Criteria

- Fundamental criteria design is to ensure that the "lights stay on" for many years into the future
- Technical criteria designed to ensure "the continuance of a supply of power adequate for the needs of the province"
- Determines when new supply is needed, and how much
- Does not determine what type of new supply is chosen – that is the purpose of the economic and financial analysis
- Criteria described in Chapter 4, Section 4.3.1 and Appendix 4.1- Generation Planning Criteria of the NFAT submission

Elements of the Generation Planning Criteria

- Capacity Criterion
  - Utilized in all power systems
  - A reserve of generation capacity above the forecast peak load to account for weather related load forecast uncertainty and outages or breakdowns of generation equipment
  - Pertains to system peak conditions – experienced a small number of hours per year
  - MH carries a 12% reserve
- Energy Criterion
  - Utilized only in predominately hydro or other systems where running out of energy due to an extreme drought or fuel supply limitations are a possibility
  - Ensure sufficient energy will be available during a critical energy event – generally the worst drought on record for a hydro system (dependable flow year)
  - Imports are considered as dependable energy resources under certain conditions
  - Pertains to energy use throughout the entire year

Degree of Reliance on Imports

- Limiting imports is reasonable and necessary to ensure an adequate supply of energy for the province of Manitoba.
- Degree of reliance limited for system design to manage the risk associated with energy contingencies at time of operation such as
  - Weather colder than expected (50 percentile) forecast
  - Extended outages of thermal generation or transmission capability for imports
  - Water flow uncertainty within the operating year (in a severe drought)
  - Possibility of a drought worse than the drought of record
- Such import / interconnection limits are common in power system planning
  - Despite having projected loads which are over 2x larger than that of MH and import capability that is 4x larger than MH, BC Hydro relies on a lower percentage imports than does MH
  - US Pacific Northwest has similar restrictive limits on imports from California

Screening of Resource Options

JOANNE FLYNN
MARCH 10, 2014

Screening of Resource Options

- MH monitors a wide range of resource supply options and maintains an inventory of options which are potentially available to meet future Manitoba needs.
- 16 utility-scale supply technologies were considered in the screening process.
- Screening characteristics are grouped into the following categories:
  - Technical
  - Environmental
  - Social and Policy
  - Economic

Resource Screening Characteristics

- **Technical**
  - Maturity of Technology
  - Technical Challenges in Manitoba
  - Ease of Integration into System
  - Intermittency of Energy Supply
  - Seasonality of Energy Supply
- **Social & Policy**
  - Proximity to Load Center (includes issues associated with longer transmission)
  - Regulatory Constraints
  - Social Acceptability
- **Environmental**
  - Water Quality Impacts
  - Hazardous Air Pollutants
  - Greenhouse Gas Emissions
  - Land Use Impacts
  - Wildlife Species of Interest
- **Economic**
  - Delivered Fuel Costs in Manitoba
  - Levelized Cost of Energy - independently sourced & publically available

Technologies Screened Out

- Of the 10 resource technology categories screened, which include16 technologies, 5 were screened out:
  - Coal, nuclear, enhanced geothermal, biomass and solar

- Utility Scale Solar Generation
  - Screened out as utility scale generation resource on basis of
    - Cost
    - Intermittency – requires either backup generation or storage technology
    - Manitoba peak load occurs in winter when there are reduced sunlight hours

Selected Resource Options

- DSM
- Hydro
  - Keeyask
  - Conawapa
- On-shore Wind Generation
- Natural Gas-fired Generation - SCGT and CCGT
- Imports

Exports

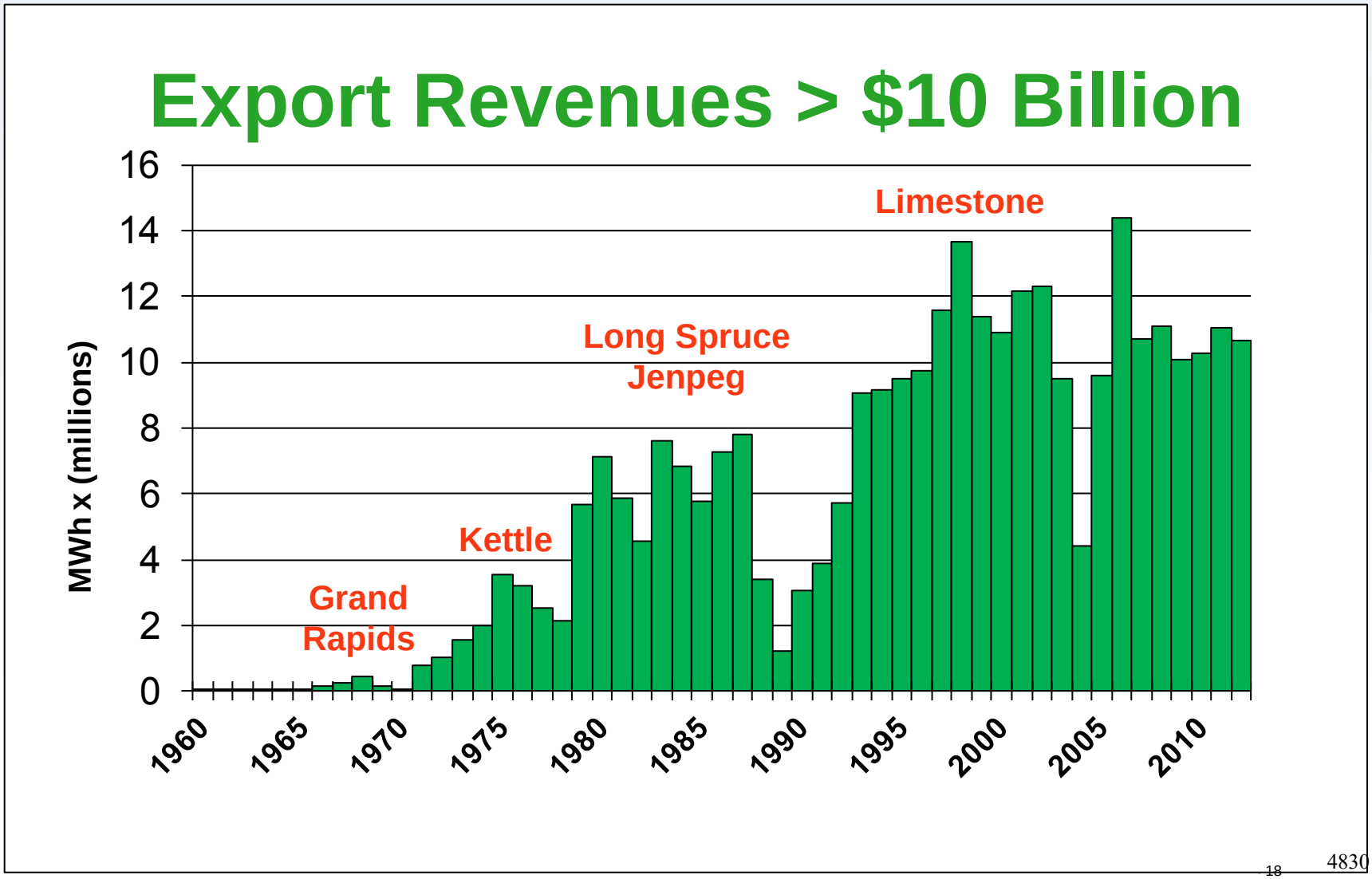
A. DAVID CORMIE, P. ENG.
MARCH 2014

Benefiting from Neighbours Working Together

- Efficient Use of Capital
  - Utilizing surplus capacity
  - Optimizing capacity in-service dates
  - Sharing capacity as a result of load diversity
  - Generation reserve sharing
- Production Cost Savings
  - Economic dispatch
  - Minimizing wasted resources
- Emergency Assistance
- Protecting the Environment
  - NOx, SOx, Hg, particulates
  - Greenhouse gases

Interconnecting Transmission is the Key

50 Years of Being Interconnected



4830

Window of Opportunity
Neighbours Are Making Strategic Decisions Now

- MP, WPS, NSP, GRE, SPC
  - Load is growing
  - Fleet is aging
  - Emissions are being outlawed
  - Gas prices are volatile
  - Wind and gas are only partial solutions
- Hydro purchase is an attractive option
  - Discussions, planning, and agreements since 2008
  - Long term commitments
  - Stable predictable pricing
  - Resource diversity
  - Long term access to surplus hydro energy
  - MH reputation

Window of Opportunity
Signed Agreements

- NSP 125 MW System Power Sale
  - May 1, 2021 – April 30, 2025
  - Subject to Keeyask
- WPS 100 MW System Power Sale
  - June 1, 2021 – May 31, 2027
  - Subject to Keeyask
- MP 250 MW System Power Sale
  - June 1, 2020 – May 31, 2035
  - Subject to Keeyask and new US interconnection
- WPS 308 MW System Power Sale
  - 2027 – May 31, 2036
  - Subject to Keeyask, Conawapa and new US interconnection

These MH supply obligations have displaced the need for other resources

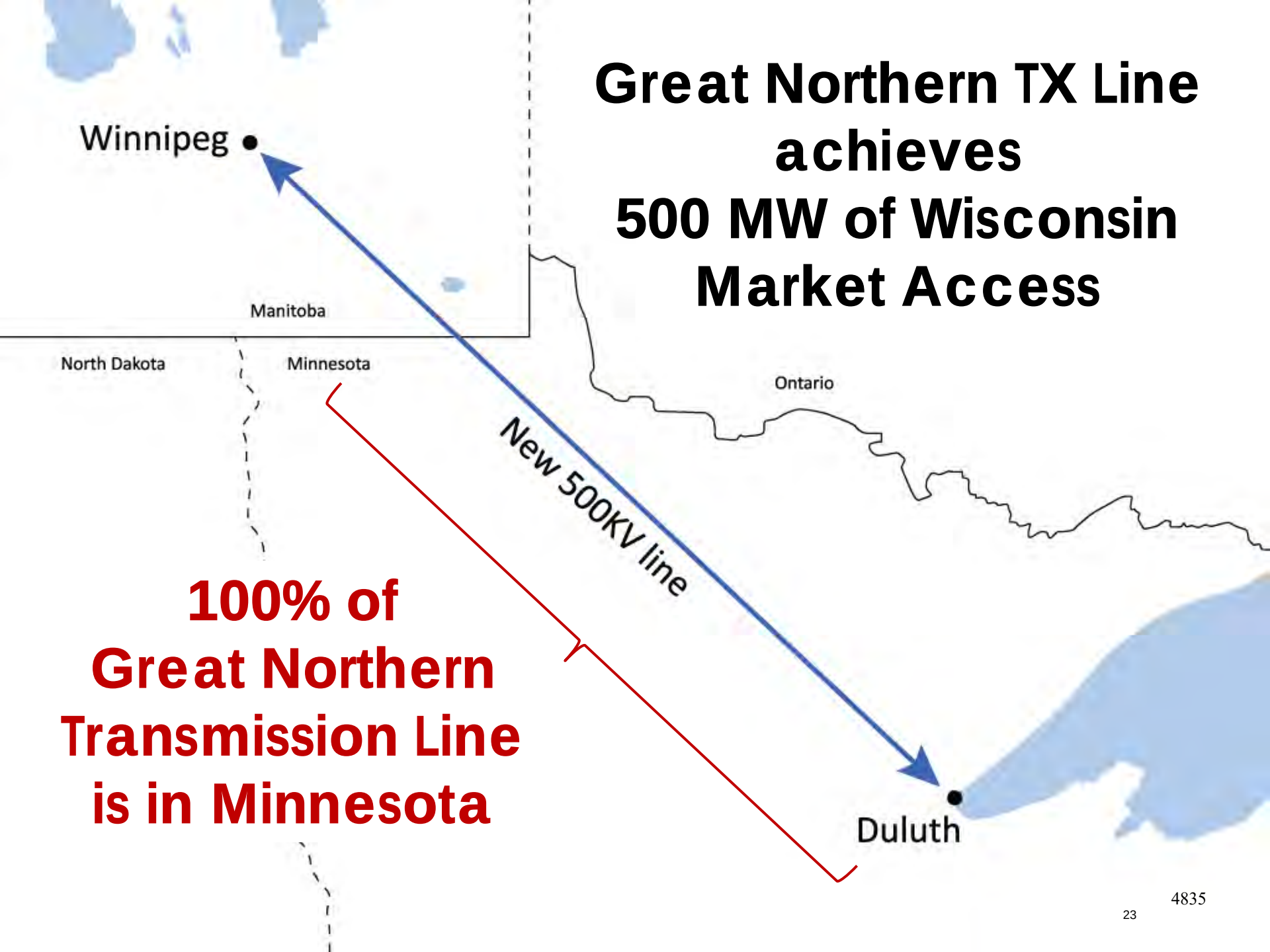
Window of Opportunity
Potential Sale Agreements

- WPS - 500 MW Term Sheet
  - up to 200 MW beyond the 308 MW
  - Subject to Keeyask, Conawapa and new US interconnection
- GRE - 600 MW MOU
  - Subject to Keeyask, Conawapa and new US interconnection
- SPC - 500 MW MOU
  - 25 MW Term Sheet
  - Additional MW subject to Keeyask, Conawapa and new transmission
- Others - 250 MW
  - In various stages of discussions
  - Subject to Keeyask, Conawapa and new transmission

Window of Opportunity
MP Will Champion Major Interconnection

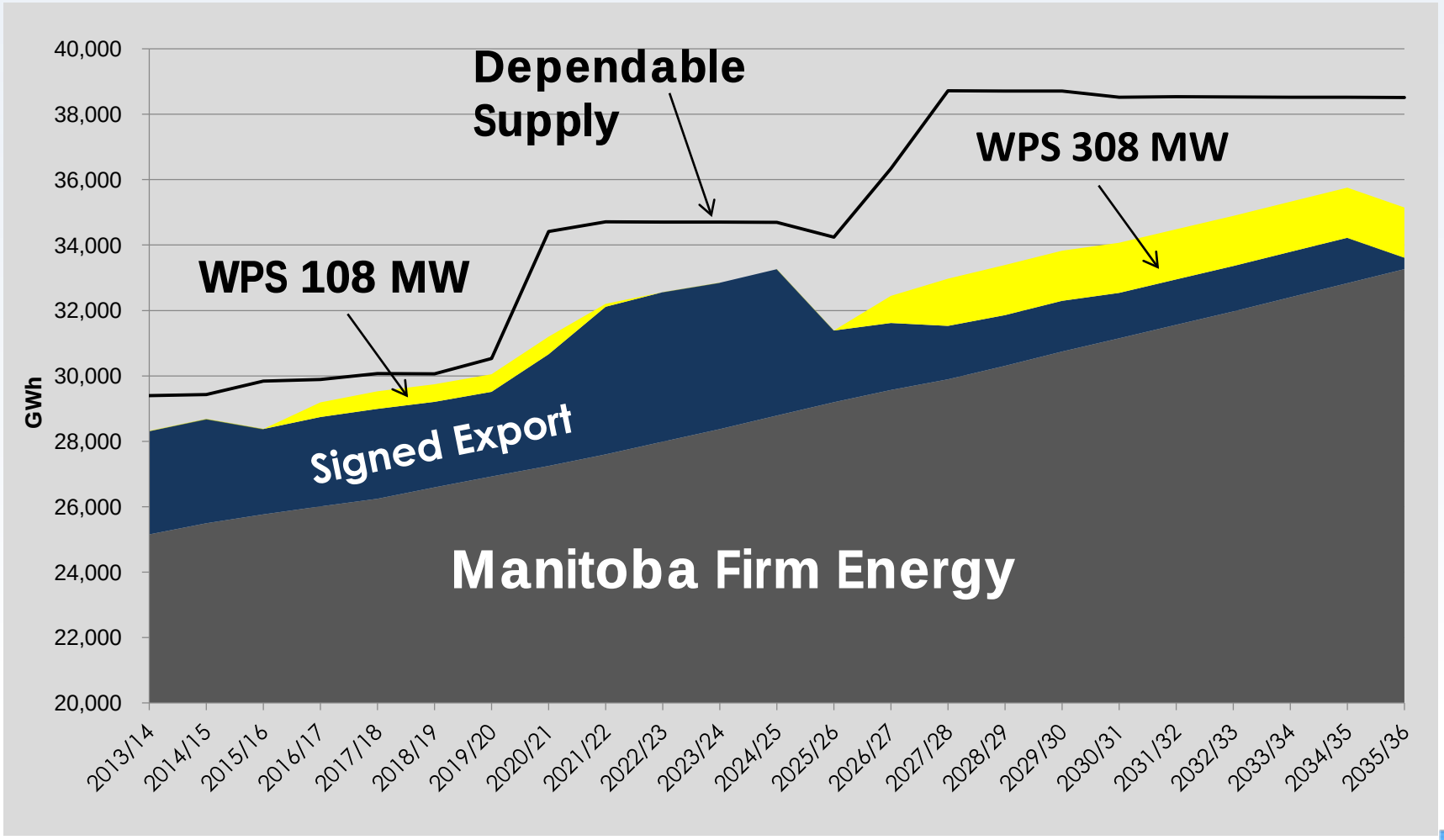
- US transmission required under MP 250 MW Sale Agreement
  - Minnesota Public Utilities Commission has recognized the need
- MP has agreed to permit and construct 750 MW line
  - At least 750 MW export and import capability
  - Great Northern Transmission Line project
  - Subject to compensation and additional consideration
  - Significant scale of economy transmission cost savings
- 500 MW of market access to Wisconsin
  - 2008 Term Sheet
  - Possible because of 2008 MISO Transmission Service Requests

Great Northern TX Line achieves 500 MW of Wisconsin Market Access



100% of Great Northern Transmission Line is in Minnesota

New WPS Agreements



New WPS Agreements

- 108 MW System Power Sale
  - 2016 – 2021
  - Fixed price energy 5 days/week x 16 hrs/day
  - From existing generation and transmission resources
- 308 MW System Power Sale
  - Fixed price energy 7 days/week x 16 hrs/day
  - Up to ten year agreement terminating May 31, 2036
  - Commences with in-service of a 4th Conawapa unit
  - No obligation to build
  - Requires 200 MW of new transmission service on the new 500 kV line to US
    - MH recovers transmission costs in PPA price
- Energy deliveries relative to Conawapa generation
  - 1400 GWh - 33% of dependable energy
  - 1800 GWh - 29% of average energy

Other New WPS Agreements

- 200 MW Energy Purchase Agreement
  - 2020 – 2036
  - Secures 1,600 GWh of dependable energy if needed
  - Dependant on new 500 kV interconnection
- 8 MW Energy Sale Agreement
  - 2023 – 2029
  - Surplus energy sale to bridge between 108 MW and 308 MW sales
- 500 MW Term Sheet Extended

MP-MH
US Interconnection Term Sheet

- Who will build? – Minnesota Power Great Northern Transmission Line
- Who will invest and own?
  - 51% Minnesota Power
  - 49% Manitoba Hydro
    - Owner of last resort – ongoing discussions with other US transmission owners
    - Business structure under negotiation
- Who will pay?
  - First 33% - Minnesota Power
  - Next 66% - Manitoba Hydro
  - Interconnection Term Sheet
    - Necessary to increase MP ownership to 51%
    - Under negotiation
- Who will use? – Manitoba Hydro has first dibs
  - Southbound
    - 250 MW MP - MH 250 MW Power Sale Agreement
    - 200 MW WPS - MH 308 Power Sale Agreement
    - 300 MW - Manitoba Hydro
  - Northbound -100% Manitoba Hydro



Great Northern Transmission Line 750 MW

- October 2013
  - MP filed for Certificate of Need with Minnesota PUC
- Spring 2014
  - Business arrangements with MH finalized
  - US Presidential Permit Approval Request
  - Facility Construction Agreement Signed
- October 2014
  - Public hearings commence
- Spring 2015
  - Certificate of Need approval
  - Presidential Permit Approval
- Fall 2016
  - Construction commences
- Spring 2020 - In-service



Great Northern Transmission Line 250 MW option is hypothetical

- Minnesota Power Certificate of Need filing
  - 250 MW project would not meet the long-term needs of the region
  - 250 MW project would not prove to be cost-effective for customers
  - Not environmentally preferable over the long-term
    - Maximize use of transmission corridors
    - Size it right in the first instance
- 250 MW option eliminates wind storage synergies
  - Conawapa and 750 MW line produce wind storage synergies
  - Minnesota Power, other Minnesota and MISO utilities would lose significant load cost savings
- In-service date at risk if switch is required
  - Current process for 750 MW line would have to be abandoned
  - Public, state and federal regulatory processes would have to be restarted
- Additional costs may jeopardize the 250 MW Sale Agreement
  - Loss of economy of scale savings
  - Loss of other significant benefits from 500 kV Term Sheet

Great River Energy
200 MW Diversity Exchange Agreement

- Term - November 1, 2014 to April 30, 2030
- Provides Manitoba Hydro with
  - 200 MW winter capacity
  - Secures 1908 GWh dependable energy
  - Rights to 200 MW firm northbound MISO TX
- Part of Preferred Development Plan
- No capital investment required
- No net cost
- NEB approval received



Development Plans

JOANNE FLYNN
MARCH 10, 2014

Formulation of Development Plans

- All plans meet expected domestic load and existing firm commitments for the 35 year detailed study period.
- Development Plans are formulated using the resource options selected through screening.
- Consider strategic opportunities for the overall benefit of Manitoba.
  - Window of opportunity for new US interconnection

Development Plans

2012 Assumptions	2013 Assumptions
Plans with a 750 MW Interconnection 14. K19/C25/750MW (WPS Sale & Inv) 15. K19/C25/750MW 5. K19/Gas25/750MW (WPS Sale & Inv) 12. K19/C31/750MW 6. K19/Gas31/750MW	**Plans with a 750 MW Interconnection** 14. K19/C25/750MW (WPS Sale & Inv) 12. K19/C31/750MW
Plans with a 250 MW Interconnection 13. K19/C25/250MW 4. K19/Gas24/250MW 11. K19/C31/250MW	**Plans with a 250 MW Interconnection** 4. K19/Gas30/250MW
Plans with No New US Interconnection 1. All Gas 2. K22/Gas 3. Wind/Gas 7. SCGT/C26 8. CCGT/C26 9. Wind/C26 10. K22/C29	**Plans with No New US Interconnection** 1. All Gas 2. K23/Gas

Development Plans

Economic Analysis with 2014 Updated Capital Costs for Keeyask and Conawapa
Plans with a 750 MW Interconnection 14. K19/C25/750MW (WPS Sale & Inv) 5. K19/Gas25/750MW (WPS Sale & Inv)
Plans with a 250 MW Interconnection 4. K19/Gas24/250MW
Plans with No New US Interconnection 1. All Gas 2. K22/Gas 8. CCGT/C26

Updated DSM Evaluation

Development Plans
1. All Gas 5. K19/Gas/750MW (WPS Sale) 14. Preferred Development Plan

DSM Options	2027/28 Energy levels	
2013 DSM	773 GWh	(1x DSM)
Level 1	1,704 GWh	(2x DSM)
Level 2	2,961 GWh	(4x DSM)
Level 2 DSM with New Pipeline Load Net Reduction in Load	2,961 GWh -1,478 GWh 1,483 GWh	(2x DSM)
Level 3 DSM	3,546 GWh	(5x DSM)
Level 3 DSM with New Pipeline Load Net Reduction in Load	3,546 GWh -1,478 GWh 2,068 GWh	(2.7x DSM)

DSM Options Evaluated 2013 Reference Scenario

DSM Levels	Plan 14 Preferred Plan Keeyask19 Conawapa 750 MW	Plan 5 Keeyask19 Gas 750 MW	Plan 1 All Gas Plan
2013 DSM (1 X DSM)	X	X	X
2014 Level 1 (2 X DSM)	X	X	X
2014 Level 2 (4 X DSM)	X P	X P	X P
2014 Level 3 (5 X DSM)	X P	X P	X P

P = Expected Pipeline Load

3 plans x 4 levels of DSM = 12 cases without pipeline load
3 plans x 2 levels of DSM = 6 cases with expected pipeline load

2013 Planning Assumptions with updated capital costs for Keeyask and Conawapa, no WPS investment in interconnection.

Economic Analysis Methodology

JOANNE FLYNN
MARCH 10, 2014

NFAT Analysis is Robust

MH has provided 3 major sets of analysis:

- Economic
  - Overall economic value each plan creates relative to other plans
  - Evaluated over the life of the longest lived assets
- Financial
  - Future customer rate impacts
  - Exposure to financial risk
  - Affordability
  - Temporal distribution of costs and benefits
- Multiple Account
  - Overall socio-economic benefit

Economic Evaluation

- Evaluate overall economic value each plan creates relative to other plans

- Compare the incremental costs and benefits associated with one alternative development plan to another from an overall project perspective

- Economic Evaluation does not include:
  - costs and benefits common to all plans
  - sunk costs which cannot be changed relative to the decision point

Net Present Value

- Standard Economic Analysis for project evaluation.
- Allows for comparison of development plans on an equivalent basis.
- Requires that benefits and costs over the entire life of the assets be included.
- Discounted at Manitoba Hydro's real weighted average cost of capital.
  - Constant dollars with real escalation, ignoring general inflation

Residual Value

NPV analysis includes the benefits and costs over the entire life of the assets in the evaluation. Residual value is required if the life of assets is greater than the end of the study period.

Residual Value is determined by either:

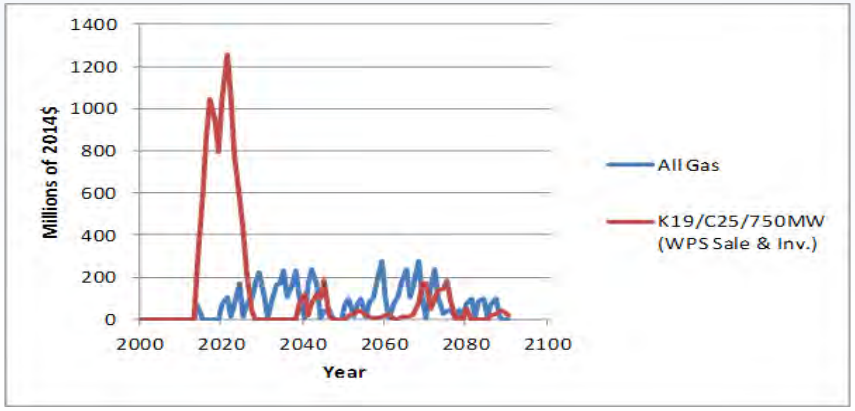
- Calculating the salvage value of the asset and subtracting it from the asset cost
- Indentifying the remaining market value of the assets and adding it to the analysis.

Residual value allows for comparability between plans.

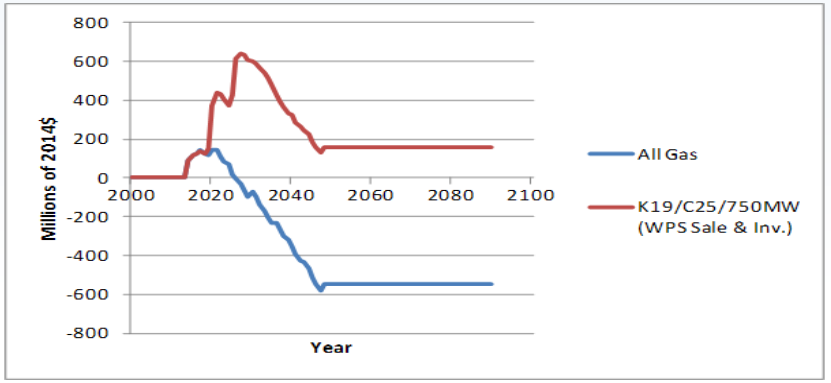
78 Year Study Period

- Economic analysis is meant to determine the investment value over the asset life
- 78 year study period captures the economic lives of assets which extend beyond the 35 year detailed study period
  - combines 35 year detailed evaluation with the extension of
    - Replacement capital costs
    - Fixed O&M costs and average net revenues

Timing and Value of Replacement Capital Costs: Total Capital



Timing and Value of Net Production Costs: Net Revenue



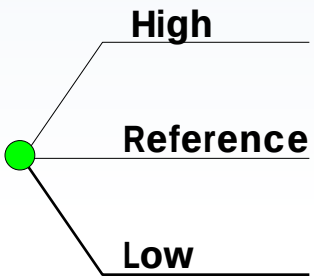
4854

Uncertainty Analysis - Probabilistic Analysis using Scenarios

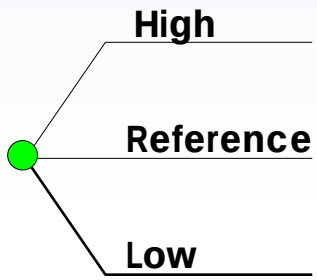
- Reference Scenario
  - Inputs and Assumptions associated with “most likely” outcomes

- Probabilistic Analysis
  - reference, high and low values for the high impact factors

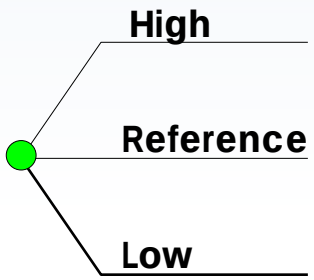
Energy Prices



Capital Costs



Discount Rate



3^3 = 27 distinct scenarios per development plan

Sensitivity Analysis

- Determine the effect on the economic value of selected development plans of single high impact variables.
- Sensitivity Analysis was conducted for:
  - Drought
  - Climate Change
  - Manitoba Load
  - In-Service Date Delay
- DSM Sensitivities
  - 1.5 times DSM
  - 4 times DSM

Economic Indicators

IAN PAGE
MARCH 10, 2014

Economic Outlook

- Annual forecast of key economic variables for Corporate use
- Consensus forecast from numerous sources

Projected Long-Term Economic Variables

Variable	2012 Application	2013 Update
Manitoba CPI	1.9%	2.0%
MH Long Term Debt	6.3%	6.75%
Canadian/US Exchange	1.04	1.03
MB Real GDP Growth	1.7%	2.0%
MB Population Growth Rate	1.2%	1.0%
Real Weighted Average Cost of Capital	5.05%	5.40%

Basis for Economic Analysis

- Net Present Value primary measure from Hydro's perspective
- NPV a measure of projected wealth creation: Is the project or plan worth pursuing?
- Summation of cash outflows and inflows discounted to reflect time value of money
- Other methods used to supplement economic decisions as well as considering perspectives of ratepayers and broader societal impacts

Different Discount Rates for Different Perspectives

Perspective	Discount Rate	Discount Rate Value
Market Valuation Economics CH9-10,12,	WACC	5.05% (5.40% 2013) (Real)
	Low Case	3.35% (Real)
	High Case	6.5% (Real)
Social Benefit Cost Ch 13	Social Discount	6.0% (Real)
MH Customer (Cumulative present value of consumers general revenue) CH 11 & PUB/MH I-149a	Social Time Preference & Opportunity Cost of Capital	1.86% (Real)

Selection of the Discount Rate

- Opportunity cost of investing in a project versus an alternative of similar risk
- For a utility, the opportunity cost is typically their weighted average cost of capital (WACC) plus any necessary risk adjustments
- Many utilities regulated on a rate of return basis so the cost of capital is approved by the regulator
- Manitoba Hydro is regulated differently so a proxy is used to estimate an appropriate cost of capital (2012 calc):
  - MH cost of debt (6.3%) + 3% return on equity x 25%
  - MH cost of debt (6.3%) x 75%
  - 7.05% nominal, 5.05% real

Risk Adjusted Discount Rates

- Investors often use a risk-adjusted discount rate to calculate Net Present Value
- MH base WACC incorporates a 3% equity premium to accommodate normal business risks including ongoing contributions to retained earnings
- MH policy is to adjust WACC to incorporate additional risks: corollary is that if risk has been accounted for by some other means, then the risk adjustment factor can be reduced accordingly
- For the PDP, detailed probabilistic approach to large impact risks, rather than attempt to capture these risks in the discount rate

Economic Uncertainty Analysis

DR. ADAM BORISON
NAVIGANT CONSULTING
SAN FRANCISCO, CA

MARCH 10, 2014

©2013 Navigant Consulting, Inc.
Confidential and proprietary. Do not distribute or copy.

NAVIGANT
ENERGY

Overview

- The Manitoba Hydro (MH) planning environment includes a variety of uncertainties. Under the direction of Dr. Adam Borison, Navigant helped MH analyze these uncertainties in three major steps:
  - Formulation – deciding on the elements of the analysis and their relationships
  - Inputs – collecting and processing the data that goes into the analysis
  - Outputs – generating and interpreting the results of the analysis
- Adam Borison is a Director in Navigant's Energy Practice.
  - Expert in decision/risk analysis, economic and financial analysis, real options, optimization, and related methods
  - Nearly 30 years of consulting experience applying these methods to investments and operations in electric power, oil/gas and biofuels
  - Particular expertise in electric power resource planning, beginning with Stanford Ph.D. work on generation expansion planning under uncertainty sponsored in part by the Electric Power Research Institute (EPRI)
- Navigant is a NYSE–listed specialized consulting company with more than 2,500 employees and 50 offices. Navigant's Energy Practice has over 350 professionals, along with dozens of specialized independent advisors.

©2013 Navigant Consulting, Inc.
Confidential and proprietary. Do not distribute or copy.

Formulation

- Formulation specifies four elements of uncertainty analysis:
  - Decisions
    - Resource options to be screened; resource plans to be evaluated
  - Uncertainties
    - Eleven potentially-important uncertainties identified
    - Three selected for probabilistic evaluation
      - energy market prices (natural gas, electricity and carbon)
      - new supply construction cost
      - MH discount rate (cost of capital).
  - Objectives
    - Many metrics (IRR, near-term NPV) considered
    - Long-term (78-year) NPV chosen as best for economic evaluation
  - Optionality
    - Value of learning and adaptation incorporated

©2013 Navigant Consulting, Inc.
Confidential and proprietary. Do not distribute or copy.

NAVIGANT
ENERGY

Inputs

- Inputs are the probabilistic data used to represent uncertainty:
  - Probabilities assigned to outcomes for three major uncertainties
    - Energy Prices
    - Capital Costs
    - Discount Rate (and other Economic Indicators)
  - These uncertainties were considered to be both:
    - most significant, and
    - most subject to rapid dramatic change.
  - Uncertainties modeled as independent based on historical data and expert judgment.
  - Each uncertainty modeled with three discrete outcomes per sound analytical principles and common practice.

©2013 Navigant Consulting, Inc.
Confidential and proprietary. Do not distribute or copy.

NAVIGANT
ENERGY

Outputs

- Four outputs show how each alternative performs in a world of uncertainty:
  - Scenario Value
    - the most basic output
    - the NPV for each alternative in each scenario compared to a fixed base
  - Expected Value
    - the most basic probabilistic output
    - the sum of (each scenario NPV) x (the probability of each scenario).
  - Risk
    - NPV quilts, scatter plots, box & whisker plots and S-curves
    - shows the range and likelihood of potential outcomes
  - Value of Optionality
    - the added value of learning and adaptation
    - compares the expected value and risk of flexible pathways with fixed plans

©2013 Navigant Consulting, Inc.
Confidential and proprietary. Do not distribute or copy.

NAVIGANT
ENERGY

FAQ 1: Is it reasonable to use NPV as the primary metric?

- Yes
- Different metrics can be used for different purposes for evaluating resource plans. Economic evaluation is specifically intended to determine the overall value each plan creates. In this context, NPV is the "gold standard."
- As corporate finance experts Ross, Westerfield and Jaffe state:
  - *While we found that the alternatives [payback period, discounted payback period, accounting rate of return, IRR, and profitability index] have some redeeming qualities, when all is said and done, they are not the NPV rule; for those of us in finance, that makes them decidedly second-rate.*

©2013 Navigant Consulting, Inc.
Confidential and proprietary. Do not distribute or copy.

FAQ 2: Is it reasonable to use a 78-year time horizon for NPV?

- Yes
- With NPV, the time horizon should capture the major potential impacts of the investment alternatives over their lives. The 78-year time frame was chosen because of the life of the assets in question. Discounting over this time horizon allows for the appropriate balancing of near-term and long-term impacts. Shortening the time horizon (without adding appropriate residual value) is akin to applying a 100% discount rate or assigning a zero value to long-tem impacts with certainty.

©2013 Navigant Consulting, Inc.
Confidential and proprietary. Do not distribute or copy.

NAVIGANT
ENERGY

FAQ 3: Is it reasonable to treat discount rate as an uncertainty?

- Yes
- In the economic evaluation, the discount rate reflects the return that markets require for the type of investment in question. In many applications involving large-scale and long-term investments, this required market return is not known with certainty and it is accepted practice to treat discount rate as an uncertainty.
- As Harvard Professor Martin Weitzman states:
  - *There are many reasons why the far-distant-future interest rate might be considered to be a… random variable from today's perspective.*

©2013 Navigant Consulting, Inc.
Confidential and proprietary. Do not distribute or copy.

NAVIGANT
ENERGY

FAQ 4: Is the approach to discount rate uncertainty reasonable?

- Yes
- Discount rate uncertainty was addressed by:
  - assigning probabilities to different discount rate outcomes,
  - calculating NPV's given specific outcomes, and
  - calculating the expected NPV (ENPV) across these outcomes.

  In this context, discount rates and interest rates are linked.
- As a team of economists led by Nobel Laureate Dr. Ken Arrow states:
  - *An alternate approach to modeling discount rate uncertainty that is more empirically tractable is the expected net present value (ENPV) approach.*

©2013 Navigant Consulting, Inc.
Confidential and proprietary. Do not distribute or copy.

NAVIGANT
ENERGY

FAQ 5: Is it reasonable to take a "utilitarian" approach to comparing plans?

- Yes
- In the economic evaluation, alternatives are compared based on the value each produces in each scenario compared to a fixed base. Differences reflect actual value gained or lost. This is called the utilitarian or expected utility approach; it has broad and deep analytical foundations, and is widely accepted as a guide to better decision-making. This is the basis of the quilts, scatter plots, box & whisker plots and S-curves.
- As UCLA Professor L. Robin Keller states :
  - *Expected utility is well suited as a prescriptive model of decision-making under risk.*

©2013 Navigant Consulting, Inc.
Confidential and proprietary. Do not distribute or copy.

NAVIGANT ENERGY

FAQ 6: Is it reasonable to take a "regret" approach to comparing plans?

- No, it is a descriptive tool with intuitive appeal, but should not be used formally for evaluating decisions.
- In another approach, alternatives are compared based on the value each produces in a scenario compared to the value produced by a base alternative in that same scenario. Differences reflect disappointment or relief. This is called the regret approach; it is generally viewed as descriptive and is not widely recommended as a guide to better decision-making.
- The regret approach produces what most view as illogical results. For example, the alternative that is chosen as the base appears as riskless because there is no disappointment or relief when compared to itself. Of course, in reality, each alternative has risk.
- As Dr. Bell, a leading author on the regret approach, states:
  - *[This]… paper does not suggest that people ought to make financial tradeoffs to avoid disappointment.*

©2013 Navigant Consulting, Inc.
Confidential and proprietary. Do not distribute or copy.

MISO Pricing Trends and Energy Policy

JOANNE FLYNN
MARCH 10, 2014

Electricity Prices in MISO are Expected to Increase

- Over the forecast horizon, electricity prices in the MISO region are expected to increase due to the following key drivers:
  - Need for additional generation resources
  - Increasing fossil fuel prices
  - Expectation of carbon pricing
- To provide this forecast of future prices in the MISO region, Manitoba Hydro engages a number of expert North American energy analysts to provide their independent views of the range of future price trajectories for electricity and its key drivers.
- Manitoba Hydro's electricity export price forecast capture the expectation of rising prices through the independent views of expert energy analysts.

Need for Additional Generation Resources in MISO

There are a number of factors driving the need for new supply:

- **Retirement of Existing Generation Supply**
  - EPA Regulations – New mercury standard requires costly environmental control technology. Expectations, 60 GW of US coal fleet is expected to retire in the near term (EIA's 2014 Annual Energy Outlook).
  - MISO projecting 12.6 GW of coal retirement or about 20% of existing coal fleet (MISO MTEP 2013).
  - Numerous nuclear plants reaching end of 60 year operating license by mid-2030s.
- **Gradual regional electric load growth**
  - Regional load growth of 0.5-1%/year is forecasted by numerous independent energy analysts, regional utilities and US EIA.
- **Meeting New Generation Needs in MISO**
  - Natural gas generation
  - Renewable and Non-Emitting Generation Resources are Viewed as Preferable

Fuel Prices Are Expected to Increase

- Average cost of fossil fuels has been the most influential determinant of market prices for electricity in the US as conventional thermal generation is dominant in almost all regions.
- Shift in natural gas market
  - Prior to 2008 – high prices, concerns about resource scarcity, LNG import capabilities being developed
  - Post 2008 – economic downturn, commercialization of new extraction process (hydraulic fracturing) resulting in a domestic surplus of natural gas
    - New gas outlook has been incorporated in annual gas and electric forecasts.
- Fuel prices are still expected to grow in real terms
  - Natural Gas: EIA's 2014 Annual Energy Outlook projects real price growth of 3.7%/year between 2012-2040
  - Coal: Delivered coal prices are projected to increase at 1%/year over same horizon

Environmental Policy Trends

U.S. EPA Regulations

- Mercury and Air Toxics Standard (MATS) – Implementation 2016-17. Primarily driver for 60 GW US coal retirements.
- Other regulations add environmental costs but are not as significant as MATS for coal retirements
- Performance Standards to limit CO_2 emissions from new and existing power plants
  - Draft regulation for new power plants released in September 2013, to be finalized in 2014.
    - Effectively ban on new conventional coal (without CCS).
  - Draft regulation for existing power pants expected in June 2014 , to be finalized by June, 2015.

State/Provincial Level

- Cap and Trade – Quebec, California, RGGI states
- Carbon Pricing – BC, Alberta, Manitoba (coal only)
- Some Other States Require Planning For Carbon Price Risk and/or Externalities
  - Minnesota requires utilities to include future cost of carbon regulations of $9, $21.5 & $34/ton of CO2 in resource plans beginning in 2019. (Minnesota Statutes § 216H.06)

Environment Canada Regulations

- Regulations limiting GHG emissions from coal-fired power plants finalized in September, 2012
- Currently discussing performance standards to limit GHG emissions from natural gas-fired power plants.

Expectation of Carbon Pricing

- There are broad expectations for carbon pricing within the next 10 years for the US electricity sector.
  - The timing, magnitude and pricing mechanism are uncertain.

- Manitoba Hydro manages this uncertainty and expected valuation similar to other key inputs into export price forecast.
  - External consultants provide their own, independent expectations for the timing and valuation (if any) of a carbon price under their Reference/Base case as well as for high & low sensitivity cases.

- In 2013, the majority of the consultants included a carbon price in their Base/Reference and high sensitivity cases. While some consultants expect no carbon price in their Base/Reference case through the forecast horizon.

- The Low Case has no carbon price expectations

Price Forecasting Process Relies on a Consensus of External Industry Experts

- Consensus forecasting supported in literature as increasing forecast accuracy over use of a single forecast.

- Manitoba Hydro employs a consensus forecasting approach from at least five of independent market experts.
  - This avoids risk of assigning too much weight to one single view of the future (either optimistic or pessimistic).

- Manitoba Hydro engages price consultants that are well-established, reputable and are active throughout North America in providing expert advice on regulatory, financial and technical issues to electricity industry stakeholders.
  - They utilize sophisticated methodologies and simulation tools to model market operations.

- Three future outlooks provide a range of plausible price futures and support assessing uncertainty in power resource planning
  - For example the low priced case would typically contain (for example) assumptions of abundant domestic natural gas resources, minimal environmental regulations, low economic growth and low electric demand.

- Manitoba Hydro's electricity export price forecast is robust and appropriate for long-term resource planning purposes.

The Brattle Group

Power Price Overview for Manitoba Hydro's Export Market in MISO

Prepared for
Manitoba Hydro's NFAT Hearing

Dean Murphy
The Brattle Group

March 2014

Copyright © 2014 The Brattle Group, Inc.

Primary Drivers of Long-Term MISO Power Prices

Many factors can influence long-term power prices, but a few key factors are the primary drivers

- **Fuel price**
  - Primarily natural gas: prices have fallen in past several years
  - Coal prices can also be important, but tend to be more stable
- **Climate policy** – stringency and form both have an effect
  - CO_2 price (cap, tax) vs. non-price mechanisms (promote renewables, retire coal, efficiency…)
  - Little movement on federal climate policy, but other means are possible
- **Coal retirements**
  - Driven partly by new EPA environmental requirements; also by low gas prices
  - Strict climate policy, if enacted, could trigger many additional retirements

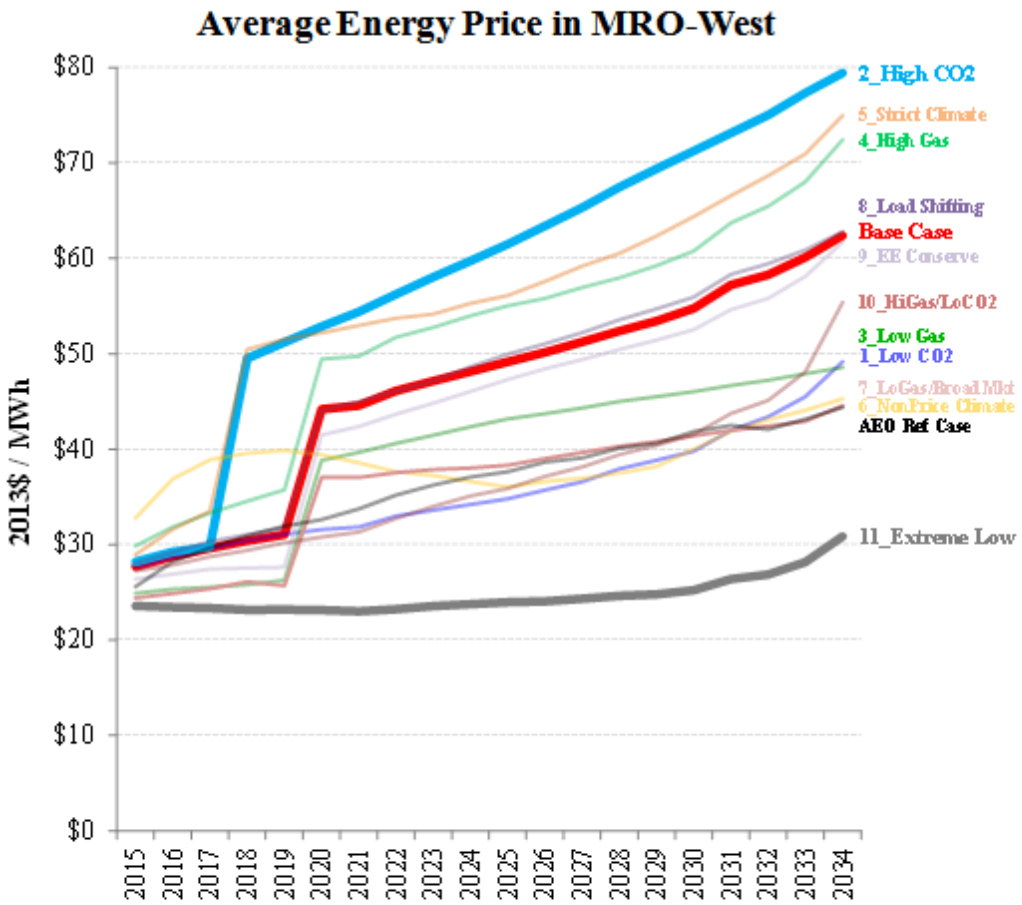
Primary Drivers of Long-Term MISO Power Prices

Somewhat less important factors

- **Load growth**
  - Growth has been very low in the past 5-10 years (vs a few decades ago), and will likely remain low
  - But supply responses (more or less retirements, additions) mean load has a modest long run effect

- **Renewable additions (and transmission expansion)**
  - Driven by state Renewable Portfolio Standard (RPS) requirements and subsidies
  - Large additions also require regional transmission expansion
  - Tend to offset the effects of coal retirements, though offer less capacity value

Range of Power Prices



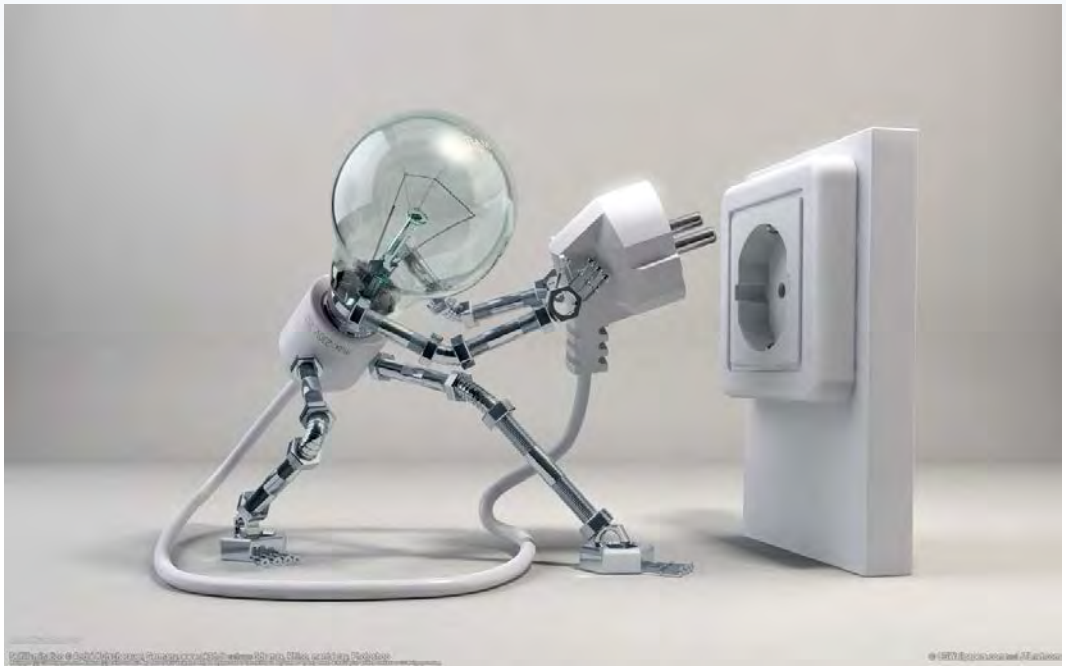
Scenarios evaluated show a broad range of possible future market prices. By 2030, scenarios show energy prices ranging from $25/MWh to $70/MWh.

- CO_2 price drives the extreme values
  - Heavily coal-based regional generation fleet is strongly influenced by CO_2 price
- Gas prices also have a significant effect, though smaller than CO_2
- Coal retirements increase power prices; how much depends on prevailing CO_2 and gas prices
  - More retirements lead to higher prices, and greater gas sensitivity
  - More coal retirement causes slightly higher prices vs. 2012 forecast
- Large renewable additions may push prices down somewhat, but effect is limited if transmission is also expanded, as is likely
- Load levels (including DSM) only modestly affect energy prices
  - Load shifting affects only a few peak hours, but delays capacity needs
  - EE may cut energy price a couple dollars

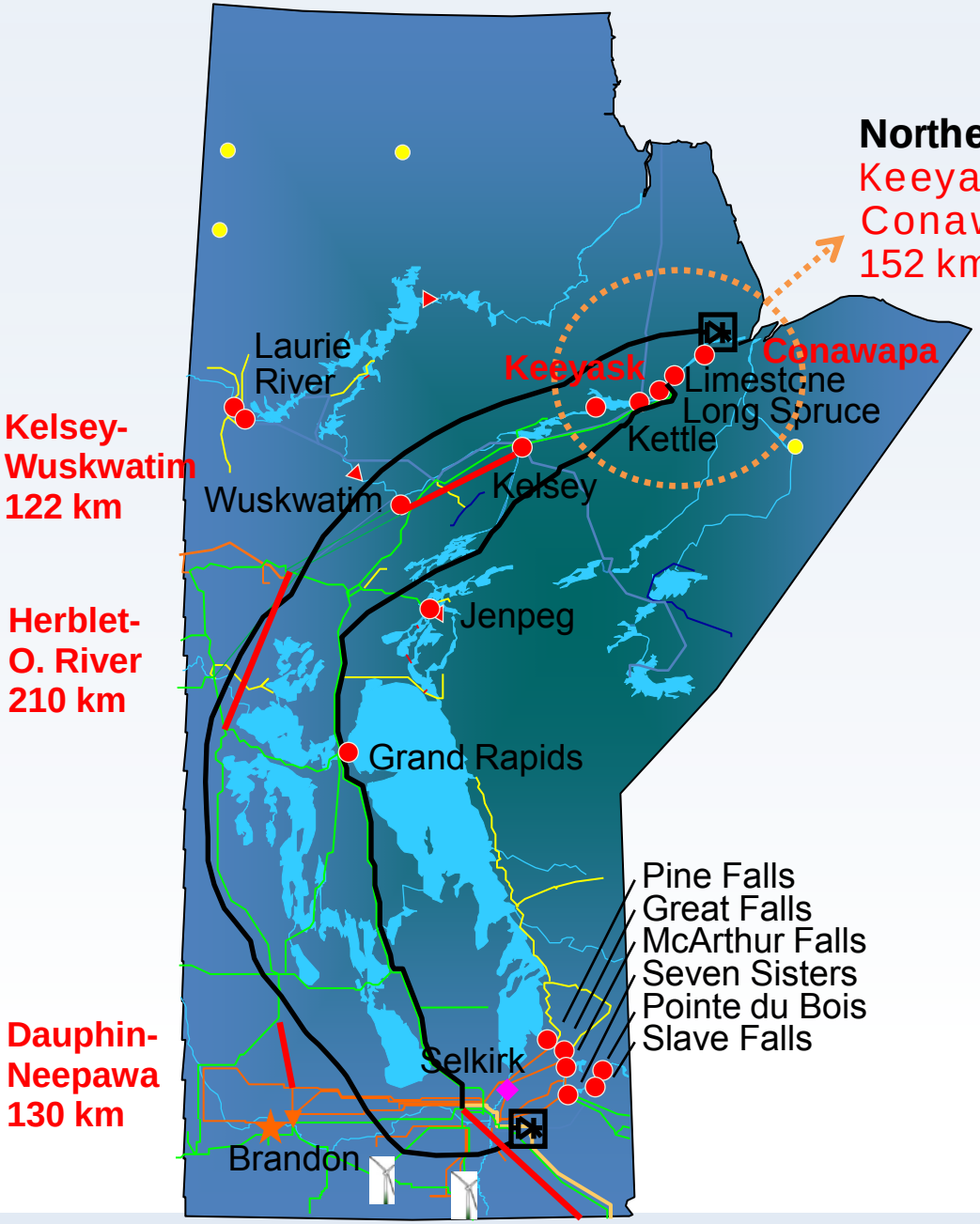
Summary of Factors Affecting Power Price

Factor	Effect on Power Price	Likely Change in Factor
CO_2 price	CO_2 price increases power price directly	Large effect; upside potential only
Gas price	Gas price rise increases power price directly	Up from 2012 lows; expected to increase further (though slowly)
Coal Retirements	Retirements increase power price modestly	Large announced retirements, with additional retirements likely
Load Growth	Growth increases power price modestly, all else equal	Likely low load growth
Renewable Additions	More renewables lowers power price modestly	Continued renewable additions likely (coal retirements mitigate)
Transmission (w/ Renewables)	Large transmission additions could raise Minn Hub price slightly	Some additions likely, especially if there are large renewable additions

Transmission Facilities



DAVID JACOBSON, PH.D., P.ENG.
DATE: MARCH 10, 2014



Northern Collector System (3554 -> 5554 MW)
Keeyask – 630/695 MW;
Conawapa – 1395/1485 MW
152 km new transmission

844 km new transmission

$775M ($2012) or $1065 ($2020)

Kelsey-Wuskwatim 122 km

Herblet-O. River 210 km

Dauphin-Neepawa 130 km

MMTP (230 km)

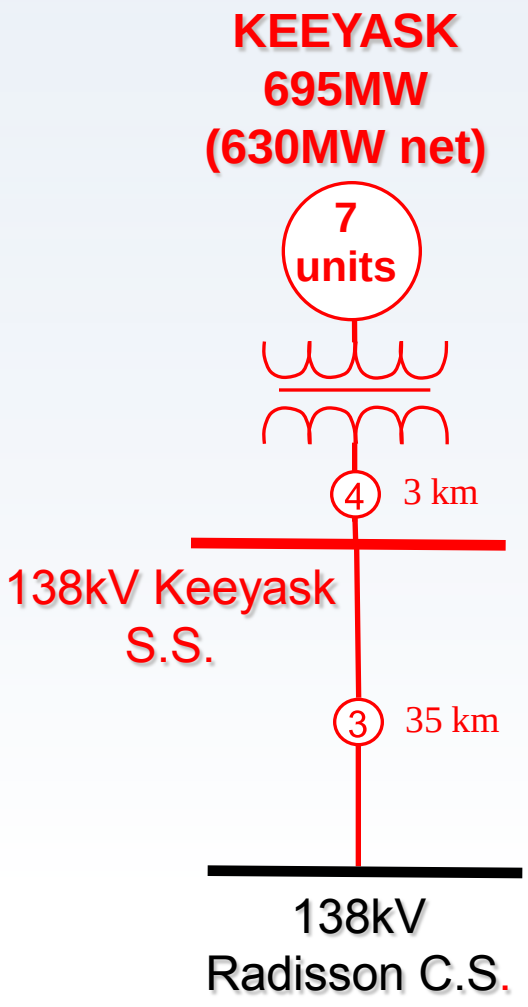
PDP
HVDC
Other Transmission

Selkirk - Gas
Brandon – Coal
Brandon – Gas
Control Structures
Diesel Sites
Hydraulic G.S.'s
Wind plant

Example – 400 MVA Transformer – 195 ton – similar to space shuttle

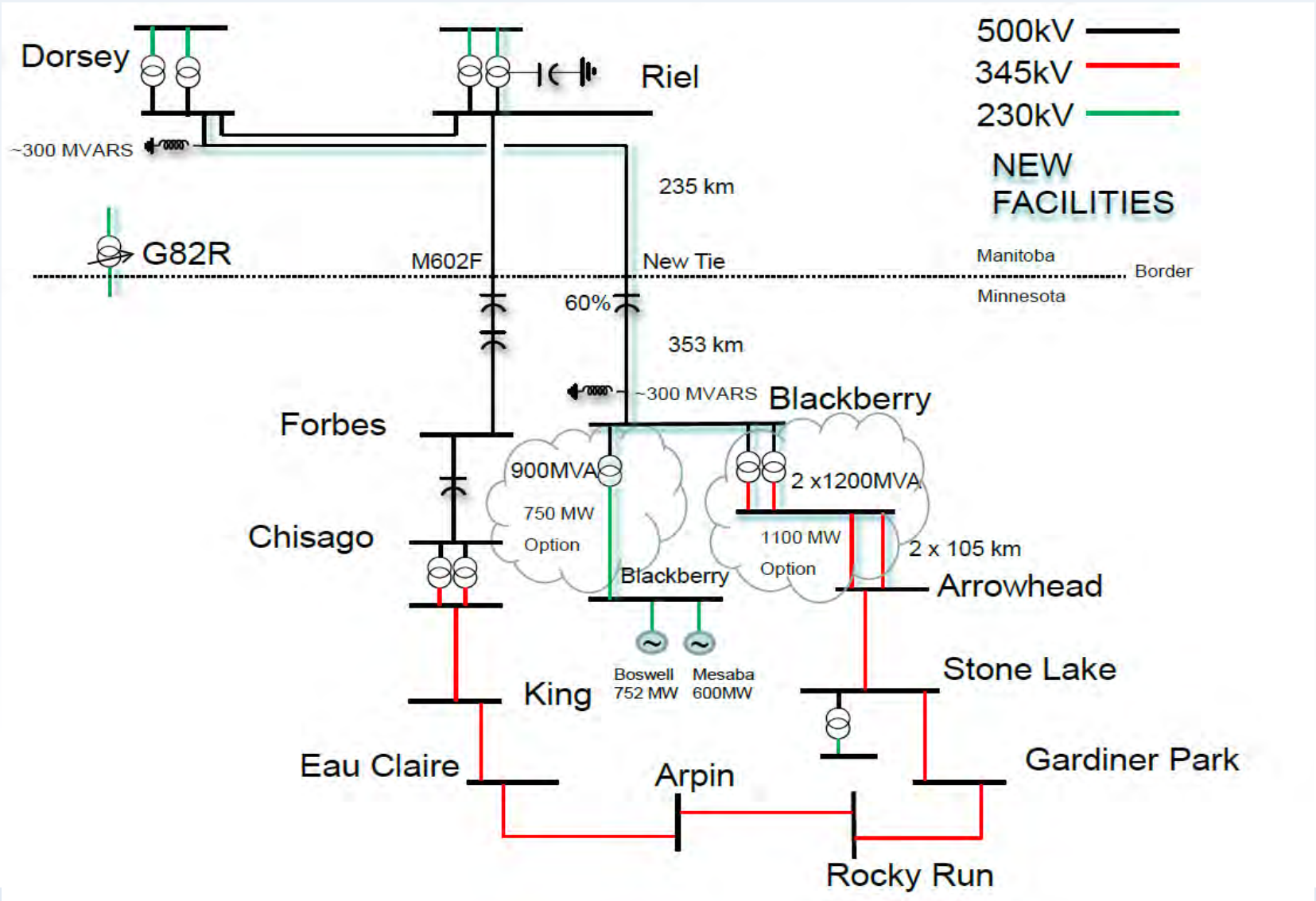


Keeyask Transmission Project



- Four (4) unit lines and three (3) Keeyask-Radisson 138 kV ac lines ($86M - $2012)
- Keeyask Switching Station ($40.3M - $2012)
- Radisson Station Termination circuit breaker replacement (31) due to increased fault levels $30.4M - $2012
- Total: $156.7M ($2012)

500 kV (750 MW) Interconnection



Manitoba Minnesota Transmission Project



- **235 km 500 kV line to US border ($173.6M - $2012)**
- **Dorsey line termination; shunt reactor; Riel 230/500 kV 1200 MVA transformer; 3x73.4 MVAr capacitors ($77.5M - $2012)**
- **Glenboro 300 MVA Phase Shifter $16.5M - $2012**
- **Total: $267.6M ($2012)**
- **Today: $281.4M ($2013)**

Great Northern Transmission Line

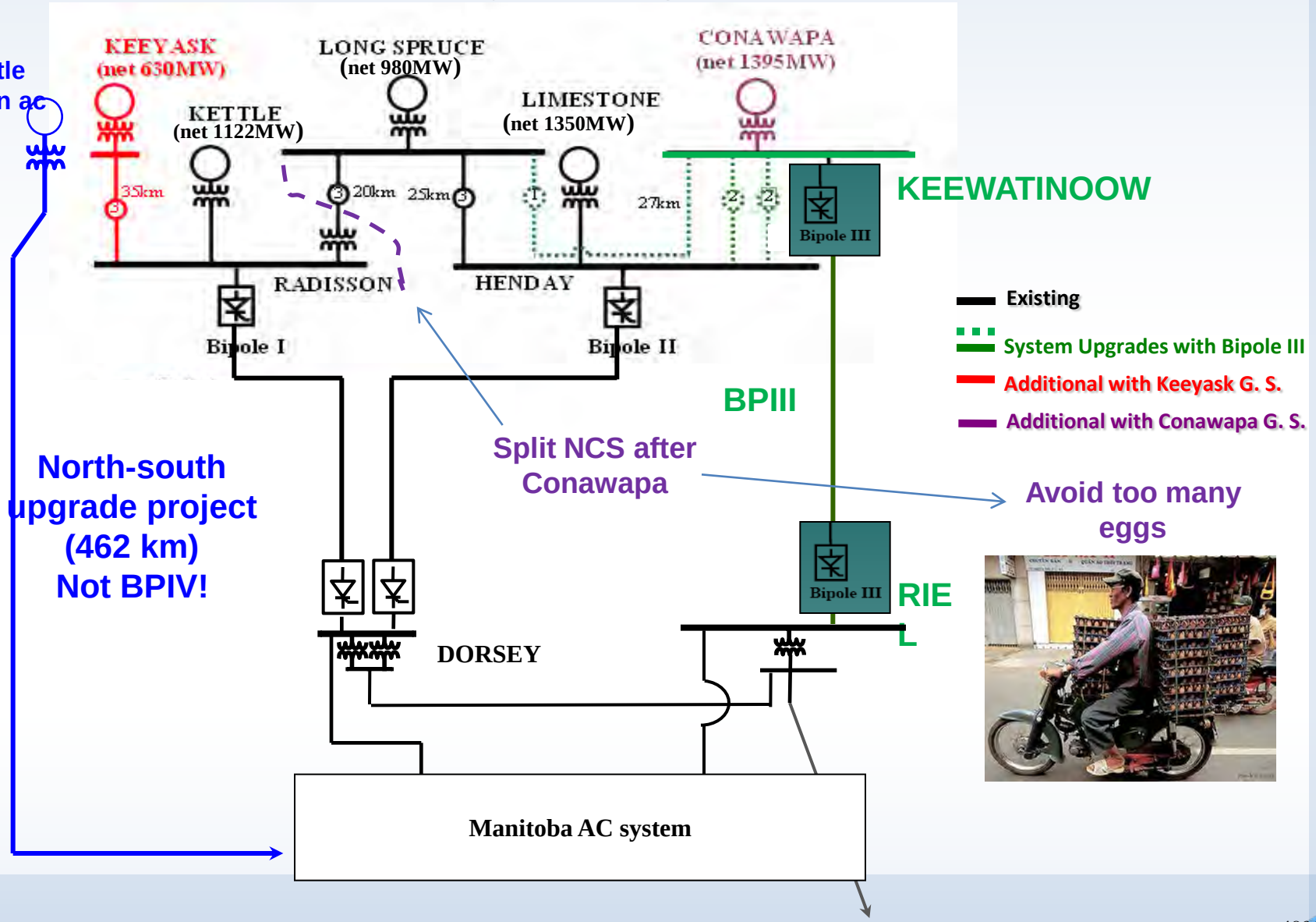


- **240 mile 500 kV line to US border ($524.3M - $2012)**
- **Blackberry station; 300 MVAr shunt reactor; 230/500 kV 900 MVA transformer; 60% series compensation ($54.4M - $2012)**
- **Total: $578.7M ($2012 US)**
- **Today: $507 M ($2013 US)**

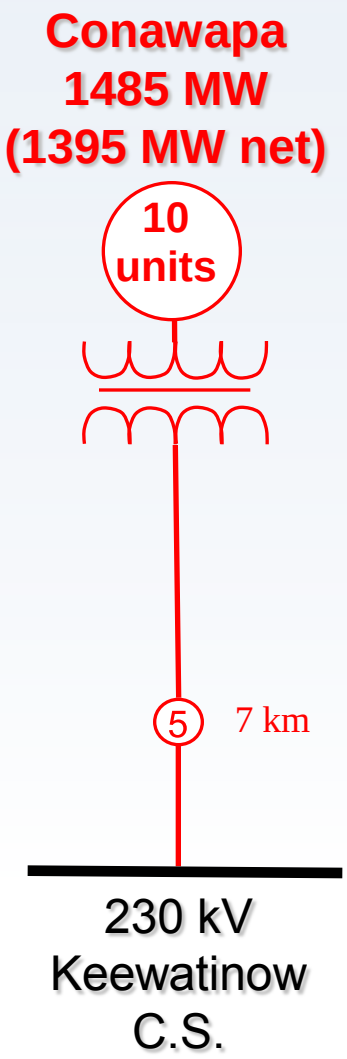
New Interconnection Summary

- Currently finalizing Study Report. Identified 750 MW facilities may be able to transfer 883 MW at no extra cost.
- **Window of Opportunity** – MISO approved $5B in upgrades in MTEP11 to facilitate renewable integrations (Multi-Value Projects). Roughly **$2B** of these facilities increase the Minnesota to Wisconsin transfer capability before 2020. The timing of the Manitoba to WPS export requests capitalize on these investments in MISO. Submitting new requests today would likely require significant additional investment.

Transmission System upgrades – Conawapa



Conawapa Transmission Outlet Project



- **Five (5) unit lines ($3M - $2012)**
- **Keewatinoow Station Termination ($7M - $2012)**
- **Total: $10M ($2012)**

4896

North-South Transmission Upgrade Project

- AC Upgrades ($198 million - $2012)
  - 80 km Kelsey to Birchtree 230 kV line
  - 42 km Birchtree to Wuskwatim 230 kV line
  - 210 km Herblet to Overflowing River 230 kV line
  - 130 km Dauphin to Neepawa 230 kV line
  - Equipment upgrades (50 MVAr SVC, line retensions)
- DC upgrades ($143 million - $2012)
  - Splitting northern collector system; Allow for 3 switchable Kettle units
  - 300 MVAr filter at Radisson
  - 250 MVAr Synchronous Condenser at Riel
  - Circuit breaker replacements
- Total ($340 million - $2012)

Economic Evaluation - Interconnection Assumptions

JOANNE FLYNN
MARCH 10, 2014

Economic Evaluation Assumptions
US Interconnections (250 MW & 750 MW)

- Manitoba Portion of a new US Interconnection
  - Manitoba Hydro responsible for 100% of the capital and operating costs of the Manitoba Portion of any new US interconnection.
- 250 MW US Interconnection (high risk of not being approved)
  - Manitoba Hydro is not responsible for any costs associated with the US portion of the 250MW interconnection
- 750 MW US Interconnection
  - Manitoba Hydro is responsible for a portion of the capital and ongoing operating costs of the US interconnection. This obligation is dependent on whether WPS sale and investment is included in the development plan
    - Plans with WPS Sale – MH portion of capital and ongoing operating costs = 40%
    - Plans without WPS Sale - MH portion of capital and ongoing operating costs = 66%

750 MW Transmission Interconnection

Proportion of Combined Capital & Operating Costs Assumed by Manitoba Hydro for Evaluation Purposes

	MANITOBA Manitoba-Minnesota Transmission Project			US Great Northern Transmission Line		
	%	Capital Cost (2014$)	Ongoing O&M (2014$)	%	Capital Cost (2014$)	Ongoing O&M (2014$)
Plan 5 K19/Gas25/750MW (WPS Sale & Inv)	100%	$277 M	$12 M	40%	$122 M	$499 M
Plan 6 K19/Gas31/750MW	100%	$277 M	$12 M	66%	$304 M	$567 M
Plan 12 K19/C31/750MW	100%	$277 M	$12 M	66%	$304 M	$567 M
Plan 14 K19/C25/750MW (WPS Sale & Inv)	100%	$277 M	$12 M	40%	$122 M	$499 M
Plan 15 K19/C25/750MW	100%	$277 M	$12 M	66%	$304 M	$567 M

Capital Costs
- Thermal and Wind

JOANNE FLYNN
MARCH 10, 2014

Capital Costs - Sources

- Natural Gas-Fired Generation
  - Manitoba Hydro contracted Gryphon International Engineering Services Inc to recommend technology options and provide Manitoba specific costs for natural gas-fired generation.
- Wind Generation
  - Manitoba Hydro contracted GL Garrad Hassan to provide Manitoba Specific costs for wind generation.
  - Manitoba Hydro participates in wind industry organizations keeping current with technology costs, and continually monitors price and technology trends for updates to assumptions used in planning processes for wind technologies.

Capital Costs – Uncertainty and Cost Ranges

- Natural Gas and Wind generation
  - Manitoba Hydro contracted Validation Estimating LLC to conduct an independent, third party review of risk and uncertainty of natural gas and wind generation cost estimates used in the NFAT analysis, including assumed transmission associated with these projects
  - Review by an independent party removes bias by the estimator in terms of Class of estimate and contingency required in the estimate to obtain specific confidence levels in the estimate
  - The uncertainty and risk assessment recognizes modularity and known technology of wind and natural gas-fired resources as factors which reduce uncertainty, as stated in Validation Estimating LLC reports
  - The level of capital cost estimate for wind and natural gas-fired projects used in the NFAT Business Case is a Class 5 estimate which has a higher uncertainty due to the lesser amount of overall engineering completion

Capital Cost Ranges – Thermal & Wind

Resource	Low	Reference	High
		(Millions of 2014$)	
CCGT 357MW	$312	$443	$612
SCGT 245MW	$127	$176	$240
LM6000 55MW	$56	$78	$105
Wind 65MW	$104	$141	$189

Keeyask and Conawapa Estimate Update

Control Budget (CEF/IFF) and NFAT Low, Ref, and High

DAVE BOWEN, P. ENG
DATE: MARCH 10, 2014

Terminology

- Estimate - the calculation of a range of costs to complete the project based on a set of assumptions. Critical assumptions include the project scope/level of definition, schedule, and in-service date.

- Control Budget – is established when the estimate is approved and is the benchmark for measuring project cost performance. It includes a contingency at a P50 value and management reserves for Keeyask and Conawapa. This will then form the basis of the capital expenditure forecast and integrated financial forecast (CEF/IFF).

- NFAT Low, Reference and High – representative range of possible capital costs that could occur that are inclusive of project risks and the labour reserve. These are inputs to the NFAT economic and financial probabilistic analysis. The low, reference and high correspond to P10, P50 and P90 values.

Topics

- Overview
  - Why and What are we updating
    - Control Budget: Reviewed and updated
    - NFAT: Reviewed and updated representative range of possible costs that could occur
  - Recent Estimate History & Methodology
- Part A – Review and Update to Control Budget
- Part B – Review and Update to NFAT Low, Reference and High
- Project Execution

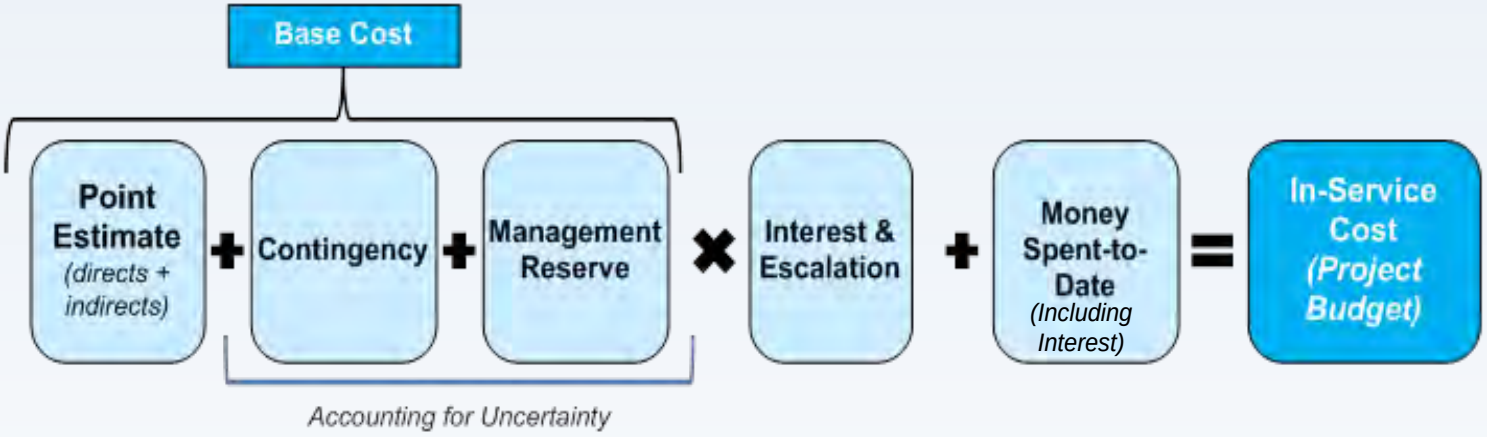
Why has the Keeyask estimate been updated and what has been updated?

- The Keeyask General Civil Contract (GCC) closed in December, 2013
- Since this time, our team has been evaluating the bids, and reviewing both the control budget and NFAT low, reference and high costs.
- The GCC is the largest contract and drives site construction and risks
- As part of on-going management of project, MH continues to review adequacy of estimate and forecast to complete
- Review included main parts of the estimate, contingency and management reserves

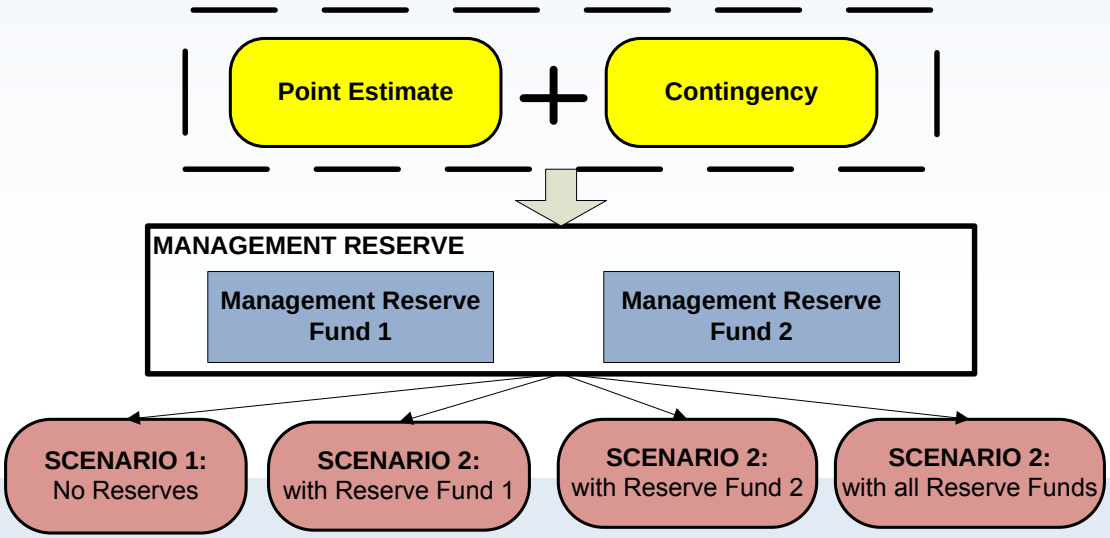


Methodology - Estimate and Budget

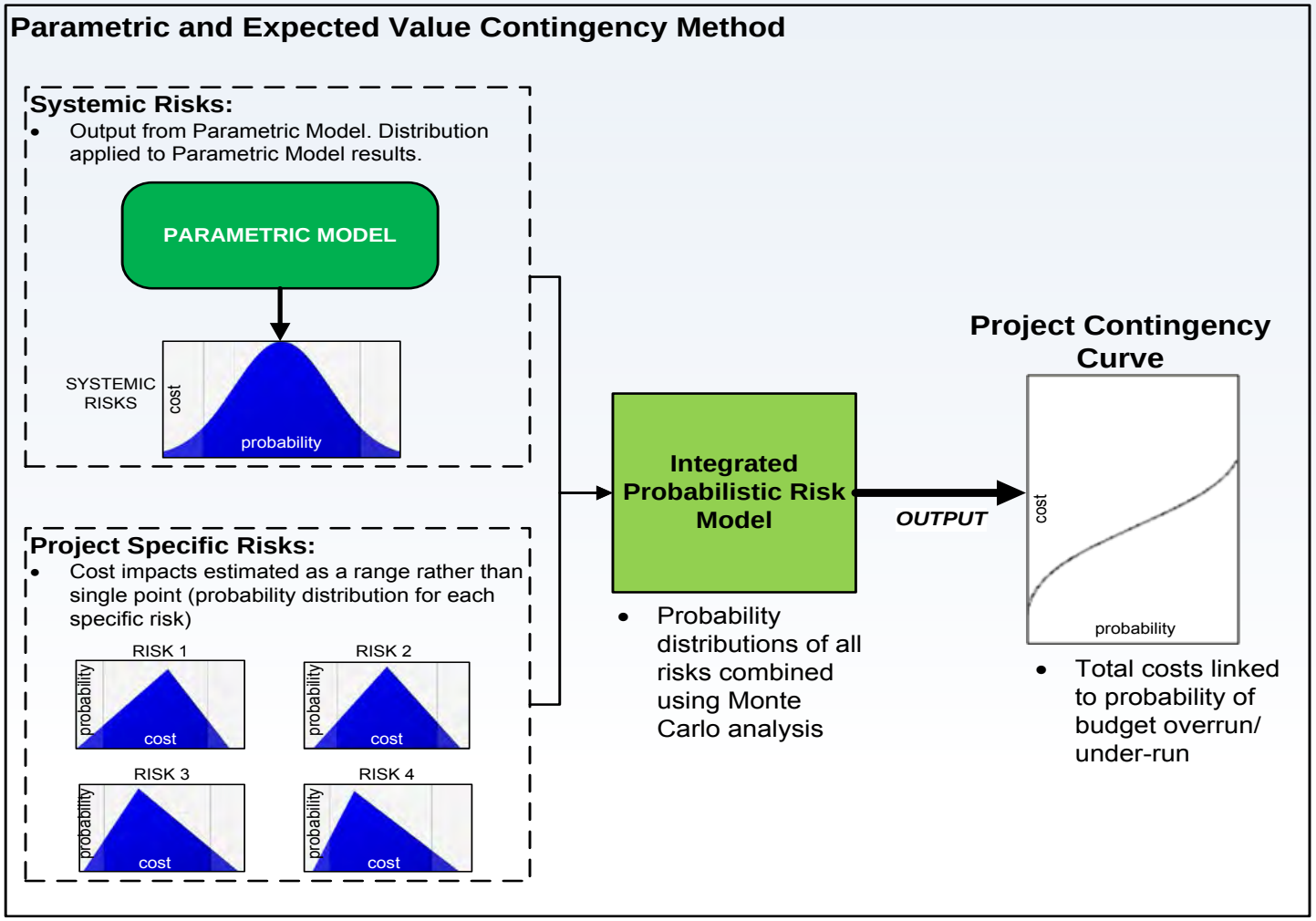
Step 1 – Estimate Development



Step 2 – Budget Scenario Development



Methodology – Contingency Analysis



Part A – Control Budget Results

Summary of Work/Key Findings:

- Examined the adequacy of the Point Estimate, Contingency and Management Reserves.
- Point Estimate updated based on Keeyask General Civil Contract proposals, changes to estimate assumptions, and pricing received for committed contracts to date.
- Contingency analysis re-run testing adequacy to completion.
- Labour risk reviewed and reserve updated.
- Escalation reserve continues to be included for escalation beyond CPI.
- Updates to Conawapa based on Keeyask findings.

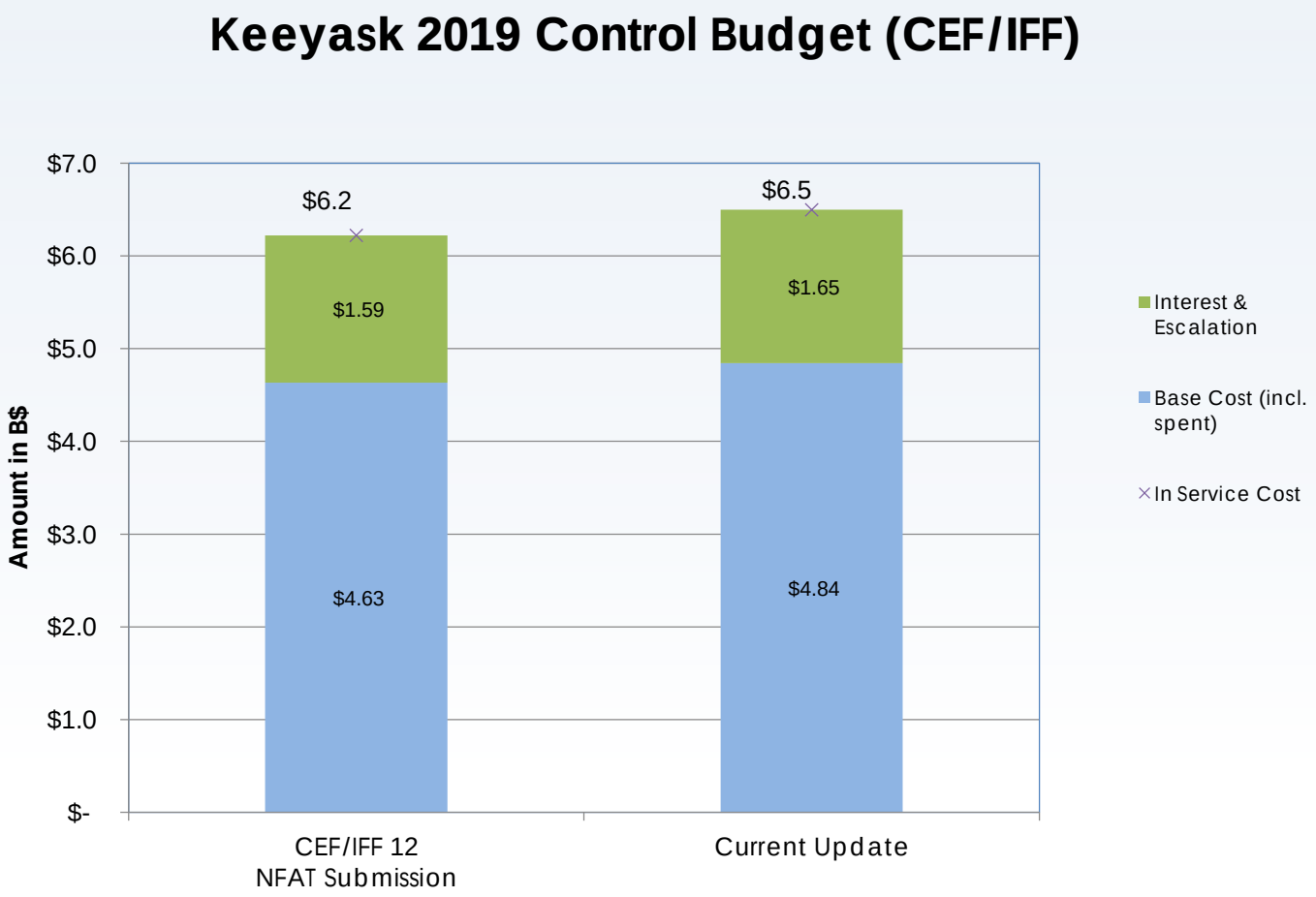
Part A – Keeyask Key Assumptions

Key assumptions:

- Award of GCC in March, 2014
- Subject to all approvals start in-stream construction July, 2014
- First unit in-service November, 2019
- Incorporate results from GCC and all current contracts
- Scope of work to construct Keeyask is the same



Keeyask 2019
Updated Control Budget Variance

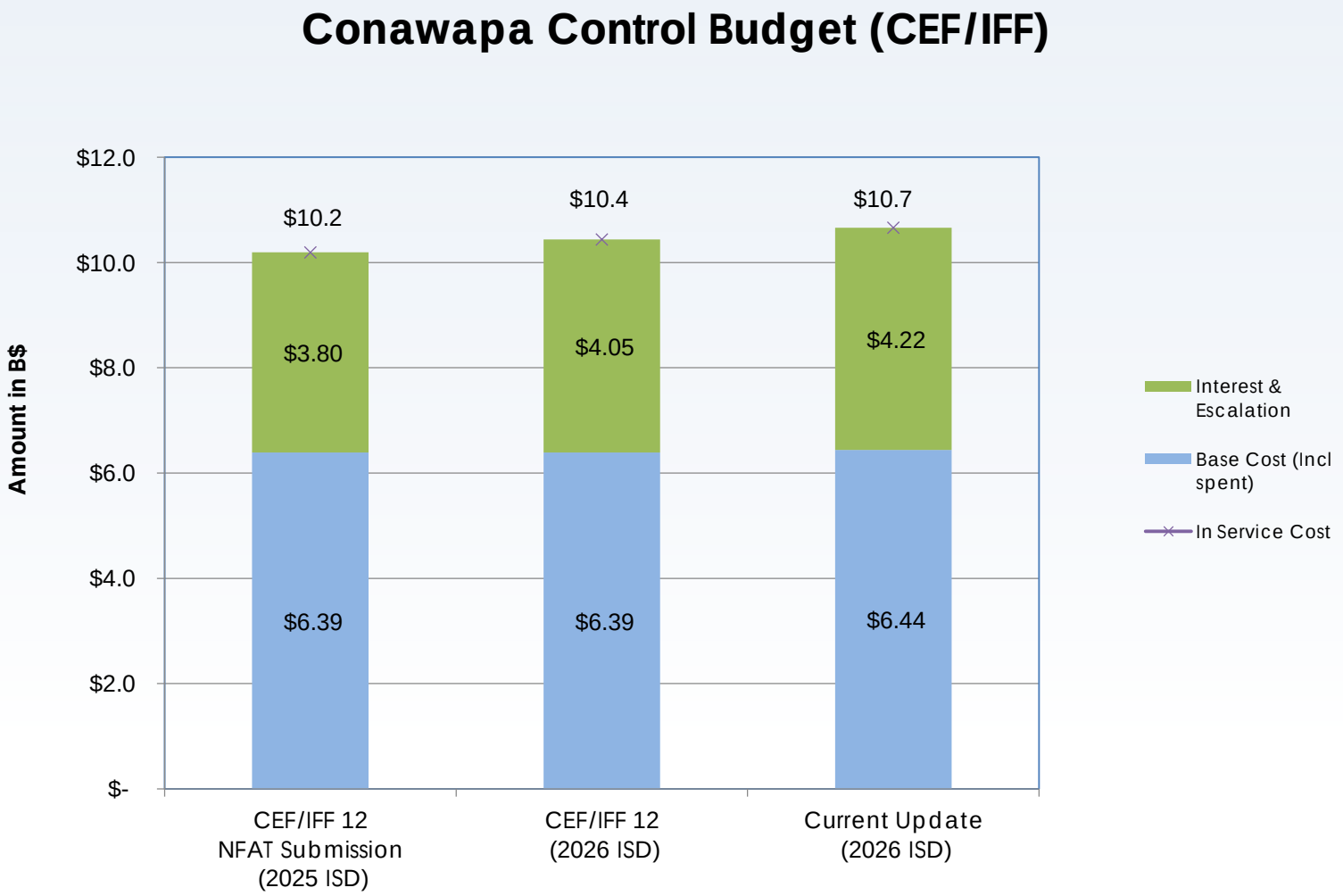


Part A – Conawapa Key Assumptions

Key assumptions:

- Start construction Jan, 2018
- First unit in-service May, 2026
- Incorporate findings from Keeyask GCC and contracts into estimate
- Scope of work to construct Conawapa is the same

Conawapa 2026
Updated Control Budget Variance



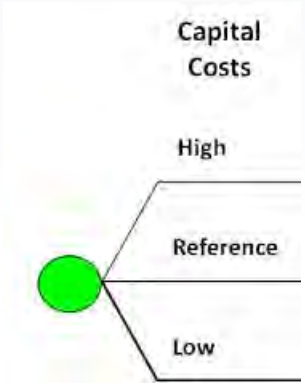
Part A – Control Budget Conclusion

- Updated estimate reflects the most current project information
- Estimate methodology applies industry best practices and addresses risks using contingency and management reserves
- This updated estimates will form the control budget to manage the execution of the project

Part B – NFAT Low, Ref, & High

Summary of Work/Key Findings:

- NFAT low, reference and high are key inputs into the economic and financial probabilistic analysis.
- Original values were based on the stress test contingency curve used to establish the 2012 Control Budgets for Keeyask and Conawapa
- Key variables include contingency, and labour reserve.



Part B – NFAT Low, Ref, & High

Summary of Work/Key Findings:

- Labour reserve has been incorporated into the contingency curve. It was formerly modeled outside of this curve.
- Contingency is based on updated contingency assessment and curve. Range of results now larger.

NFAT Results - Keeyask

	Keeyask 2019/20 (Billions of $)		
Description	**Low**	**Reference**	**High**
A) Key Variables (2014 Update)			
i) Contingency	-0.18	0.31	0.88
ii) Labour Reserve	0.18	0.19	0.19
iii) Escalation Reserve	0.04	0.09	0.14
B) Base Cost (Including Sunk)			
i) 2012 Values (2013$)	4.07	4.39	4.87
ii) 2014 Update (2013$)	4.36	4.95	5.62
Base Cost Difference	**0.29**	**0.56**	**0.75**
C) Total In-Service Costs			
i) 2012 Values	5.31	5.71	6.33
ii) 2014 Update	5.61	6.35	7.18
In-Service Cost Difference	**0.30**	**0.64**	**0.85**

NFAT Results - Conawapa

	Conawapa 2026/27 (Billions of $)		
Description	**Low**	**Reference**	**High**
A) Key Variables (2014 Update)			
i) Contingency	-0.47	0.46	1.56
ii) Labour Reserve	0.35	0.36	0.38
iii) Escalation Reserve	0.13	0.31	0.51
B) Base Cost (Including Sunk)			
i) 2012 Values (2013$ - 2026/27 ISD)	5.40	5.97	6.65
ii) 2014 Update (2013$ - 2026/27 ISD)	5.23	6.36	7.68
Base Cost Difference	**-0.17**	**0.39**	**1.03**
C) Total In-Service Costs			
i) 2012 Values (2026/27 ISD)	8.82	9.70	10.76
ii) 2014 Update (2026/27 ISD)	8.64	10.40	12.48
In-Service Cost Difference	**-0.18**	**0.70**	**1.72**

Project Execution

- Sound Project Delivery Strategy
- Comprehensive Project Schedule
- Project Team
  - World Class Consultants
  - Top Tier Suppliers
- Mitigation Strategy for Labour Risk
- Incorporate Lessons Learned From Wuskwatim and Other Projects



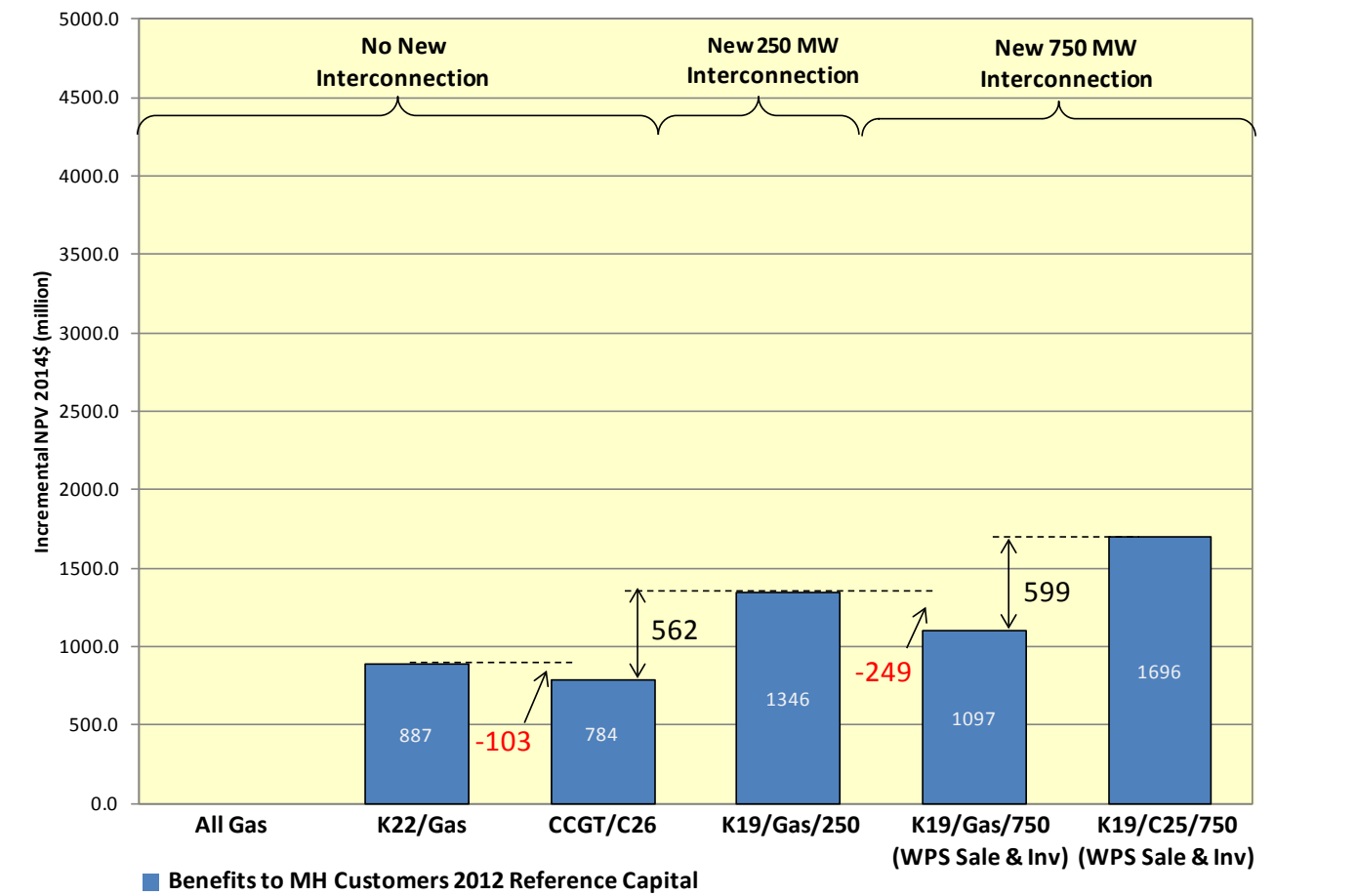


Results from Economic Evaluation

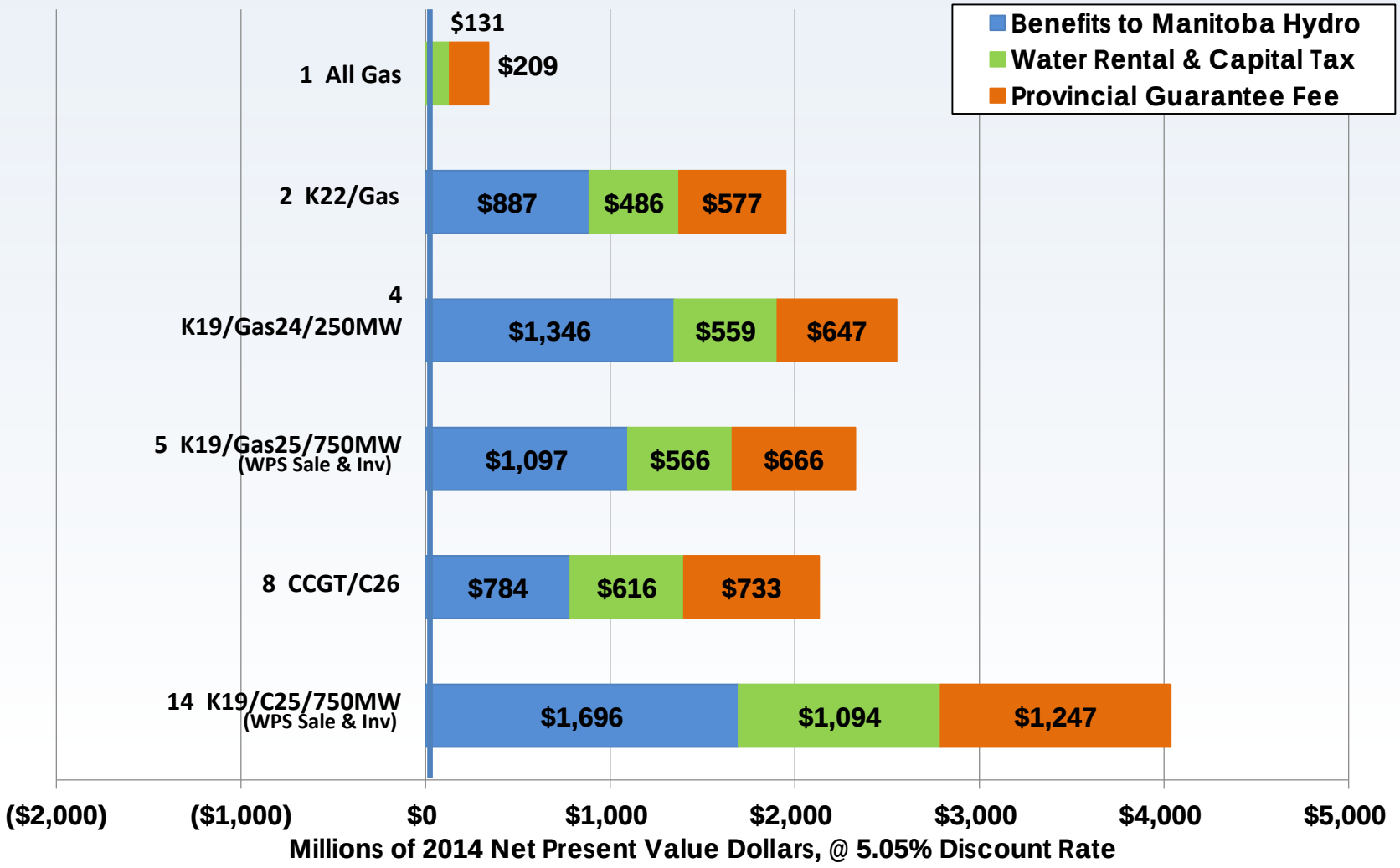
JOANNE FLYNN
MARCH 10, 2014



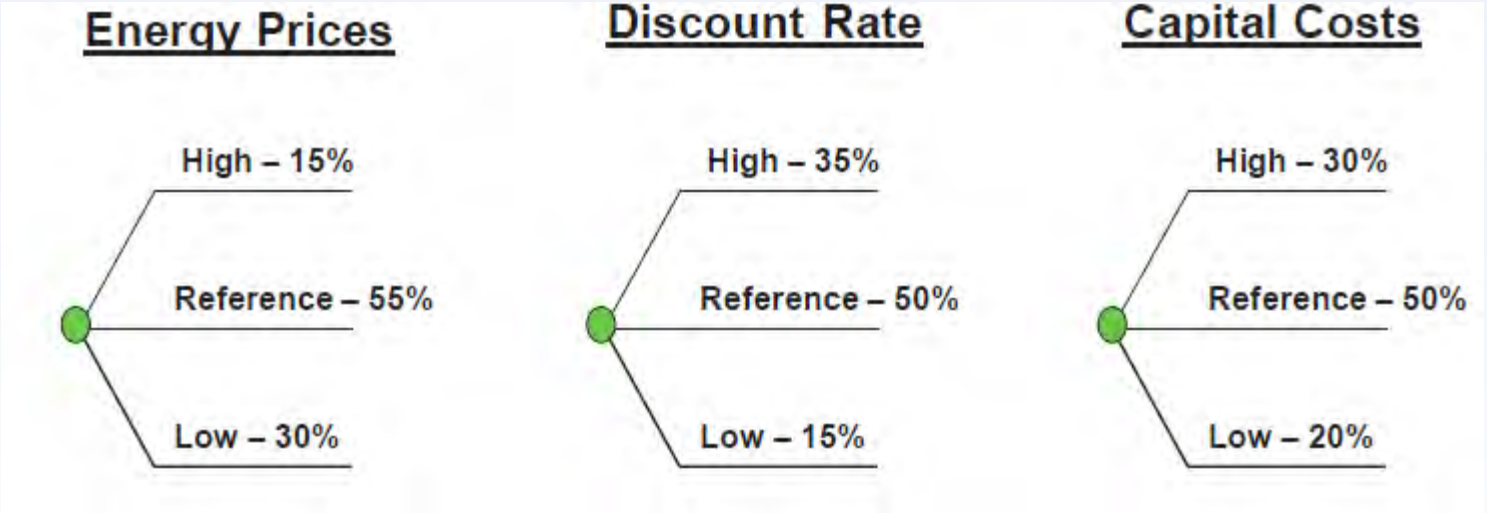
2012 Reference Case (Chapter 9)



2012 Reference Case with Provincial Benefits
(Chapter 9)



2012 Probabilistic Analysis



2012 Probabilistic Analysis – Chapter 10

Quilt – Single Point Base, Incremental Analysis

Development Plan			1	3	7	2	4	13	11	6	15	12	5	14	
			All Gas	Wind/Gas	SCGT/C26	K22/Gas	K19/Gas24 /250Mw	K19/C25 /250MW	K19/C31 /250MW	K19/Gas31 /750MW	K19/C25 /750MW	K19/C31 /750MW	K19/Gas25 /750MW	K19/C25 /750MW	
													WPS Sale & Investment		
Energy Prices	Discount Rates	Capital Costs	Millions of 2014 NPV dollars												Probabilities
Low	Low	H	-4043	-7769	-3309	-3792	-3190	-3459	-3506	-3418	-3642	-3554	-2855	-2841	1.35%
		Ref	-3049	-5403	-2401	-2532	-1877	-2124	-2166	-2130	-2177	-2138	-1616	-1410	2.25%
		L	-2247	-3686	-1655	-1590	-890	-1069	-1099	-1175	-1030	-1022	-703	-292	0.90%
	Ref	H	-463	-3056	-1297	-1212	-911	-2510	-2161	-1191	-2816	-2323	-730	-2155	4.50%
		Ref	208	-1478	-582	-278	95	-1368	-1050	-185	-1559	-1153	257	-929	7.50%
		L	750	-323	6	408	837	-473	-176	548	-585	-243	974	20	3.00%
	High	H	1204	-796	-284	25	117	-2029	-1413	-182	-2383	-1622	203	-1810	3.15%
		Ref	1708	384	323	785	963	-994	-434	679	-1243	-592	1060	-698	5.25%
		L	2114	1245	822	1336	1580	-189	327	1297	-364	201	1674	157	2.10%
Ref	Low	H	-5014	-7167	-1760	-2511	-1796	206	-334	-2041	498	0	-2103	853	2.48%
		Ref	-4020	-4802	-852	-1251	-482	1541	1006	-753	1963	1415	-865	2284	4.13%
		L	-3217	-3064	-107	-309	504	2597	2073	202	3110	2531	49	3402	1.65%
	Ref	H	-671	-2354	23	-46	341	152	104	85	170	190	109	470	8.25%
		Ref	0	-775	738	887	1346	1295	1215	1091	1427	1360	1097	1696	13.75%
		L	542	380	1326	1573	2089	2189	2089	1824	2401	2270	1813	2645	5.50%
	High	H	1308	-82	879	1091	1258	109	391	998	2	366	1041	268	5.78%
		Ref	1812	1098	1487	1851	2104	1144	1370	1859	1143	1396	1898	1380	9.63%
		L	2218	1959	1986	2402	2721	1949	2132	2478	2022	2189	2512	2235	3.85%
High	Low	H	-6435	-6719	-355	-1499	-692	3819	2796	-1006	4455	3410	-1694	4372	0.68%
		Ref	-5441	-4353	552	-239	621	5154	4135	282	5921	4826	-456	5803	1.13%
		L	-4638	-2616	1298	703	1607	6210	5203	1237	7068	5941	458	6922	0.45%
	Ref	H	-1158	-1767	1241	941	1398	2746	2308	1127	2993	2571	713	2940	2.25%
		Ref	-487	-189	1956	1874	2403	3888	3420	2134	4250	3741	1701	4166	3.75%
		L	55	966	2543	2560	3146	4783	4293	2867	5225	4652	2417	5115	1.50%
	High	H	1210	533	1956	2017	2246	2170	2127	1993	2236	2228	1691	2203	1.58%
		Ref	1713	1712	2563	2777	3092	3206	3106	2854	3377	3259	2549	3315	2.63%
		L	2120	2573	3063	3328	3709	4010	3867	3473	4256	4051	3163	4170	1.05%

Colour Legend: < -3000 | 0 | > 3000

Expected Values – Incremental Analysis

Development Plan	1	3	7	2	4	13	11	6	15	12	5	14
	All Gas	Wind/Gas	SCGT/C26	K22/Gas	K19/Gas24 /250Mw	K19/C25 /250MW	K19/C31 /250MW	K19/Gas31 /750MW	K19/C25 /750MW	K19/C31 /750MW	K19/Gas25 /750MW	K19/C25 /750MW
											WPS Sale & Investment	
	Millions of 2014 NPV dollars											
10th Percentile -"Risk"	-3502	-4599	-1217	-1249	-898	-1988	-1362	-1181	-2186	-1594	-828	-1429
25th Percentile	-560	-2200	-297	-248	115	-650	-363	-183	-904	-361	139	-204
75th Percentile	1481	383	1363	1636	2092	1854	2074	1832	2008	2009	1726	2255
90th Percentile - "Reward"	1905	1209	1956	2007	2479	3180	2953	2215	3360	3220	2256	3377
Expected Value	-70	-1084	455	564	971	712	736	706	760	821	772	1085
Ref-Ref-Ref NPV	0	-775	738	887	1346	1295	1215	1091	1427	1360	1097	1696

2013 Update (NFAT Chapter 12)

2013 Development Plan Description	2012 Assumptions	2013 Assumptions
	Incremental NPV Relative to All Gas (Millions of 2014 $)	
2. K23/Gas (2012 - K22/Gas)	$887	$728
4. K19/Gas30/250MW (2012 - K19/Gas24/250MW)	$1,346	$1,133
12. K19/C33/750MW (2012 – K19/C31/750MW)	$1,360	$1,204
14. K19/C26/750MW (WPS Sale & Inv) (2012 – K19/C25/750MW (WPS Sale & Inv))	$1,696	$1,462

Plans 2, 4 and 14
- DSM Sensitivity (1.5x DSM)
- DSM Stress Test (4x DSM)

Sensitivity Analysis

- Determine the effect on the economic value of selected development plans of single high impact variables.
- Sensitivity Analysis was conducted for:
  - In-Service Date Delay
  - Drought
  - Manitoba Load
  - Climate Change

Sensitivity Analysis - Drought

- The risks involved with drought have been either captured directly or studied separately in the various stages of MH's analysis:

Captured Directly in Economic & Financial Analysis

- Supply Risk: by planning for resource needs as per the Generation Planning Criteria
- Financial Risk: through inclusion of revenue projections from all low flow conditions in the overall revenue forecasts for each case studied (the averaging of revenues for all 99 flow cases in the historical record)

Studied Separately

- Financial Risk: sensitivity analysis of a prolonged 5-year drought
- Supply Risk: qualitative and quantitative analysis of emergency energy available

Sensitivity Analysis - Drought

- Duration of drought
  - Five year extended drought is captures the incremental impact between choice of development plans
- Timing of Drought:

  5 year Drought beginning in:
  - 2014/15 - during construction of Keeyask
  - 2021/22 - affecting early revenues from Keeyask and during construction of Conawapa
  - 2027/28 – affecting early revenues from Conawapa
  - 2032/33 – beyond early revenues from Conawapa
- Impact of Energy Prices:
  - High, Reference, Low Energy Prices

Sensitivity Analysis - Drought

Analysis Conclusions:

1. The impact of a severe drought is significant for all plans studied.

2. Development plans with new hydro resources will yield incrementally higher revenues under high flow periods and incrementally lower revenues under low flow periods.

3. Incremental negative impact of drought is greater for plans with increasing amounts of new hydro-electric generation and a larger interconnection due to a proportionally greater loss in flow-related revenue.

4. The All Gas plan has the greatest relative sensitivity to changes in energy prices over the course of a 5–year drought .

Sensitivity Analysis – Manitoba Load

1. Sensitivity analysis based on the 90th percentile and 10th percentile probability bands for energy and capacity 2012 Manitoba load forecasts.
2. Under low and high load sensitivities the economic ranking of the development plans does not change.
3. Load changes have the largest impact on the All Gas Plan.
4. Low load sensitivity – incremental NPV of plans with new hydro and new interconnection decrease relative to the All Gas Plan
5. High load sensitivity – incremental NPV of plans with new hydro and new interconnection increase relative to the All Gas Plan

Sensitivity Analysis – Climate Change

- Manitoba Hydro collaborates with national and international climate change experts to better understand the potential impacts of climate change on Manitoba Hydro's system.
- Impacts of climate change on future water supply
  - Large ensemble of global climate models project a range of future water supply conditions.
  - Most projections show average annual future water supply to increase.
  - Captures large source of climate change uncertainty.
  - Relative changes to average streamflow seasonality are expected to be minimal with respect to the observed inter-annual variability.
  - Low confidence in climate model projections of extremes into the future
  - Currently there is no utility accepted standard to assess potential climate change impacts on extreme system-wide hydrologic drought.
- Incremental NPV analysis favors the Preferred Development Plan under all assessed climate change scenarios.
- Large new interconnection assists in managing extremes.

Economic Results – DSM & Updated Keeyask and Conawapa Capital Costs

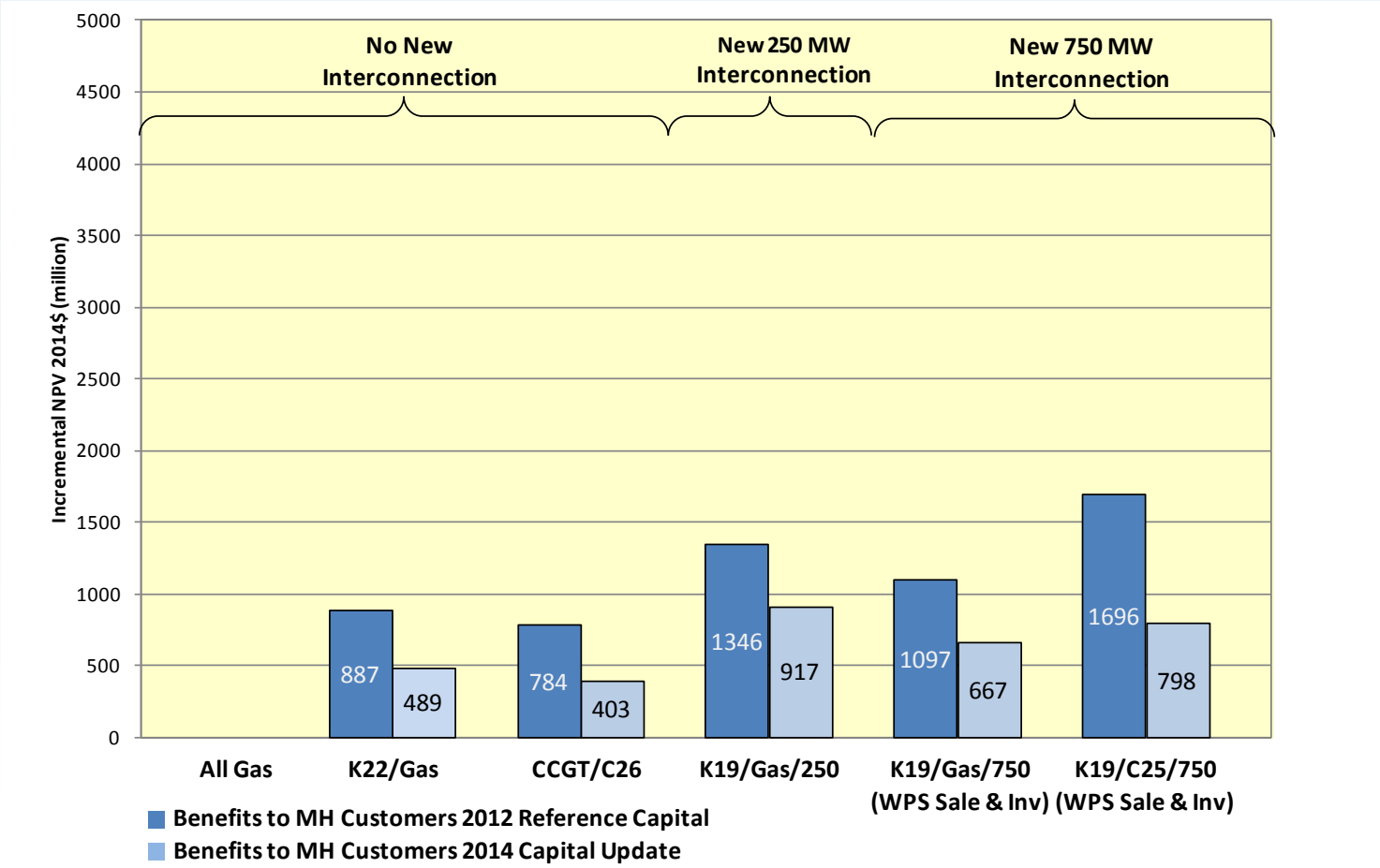
- Probabilistic Analysis - Keeyask & Conawapa Capital Costs

- Reference Case Analysis for higher levels of DSM

Changes to Preferred Development Plan Reference Economics

Planning Assumptions	Incremental NPV over All Gas Plan	Delta	Discount Rate
	Millions of NPV 2014$		
2012 – Chapter 9	$1696	$898	5.05%
2012 With 2014 Cost K&C	$798		5.05%
2013 Update – Chapter 12	$1462		5.40%
2013 Update No WPS Inv	$1245	$871	5.40%
2013 Update No WPS Inv, With 2014 Cost K&C	$374		5.40%

2014 Capital Cost Update – Keeyask and Conawapa Incremental Reference Case NPVs



2012 NFAT Assumptions

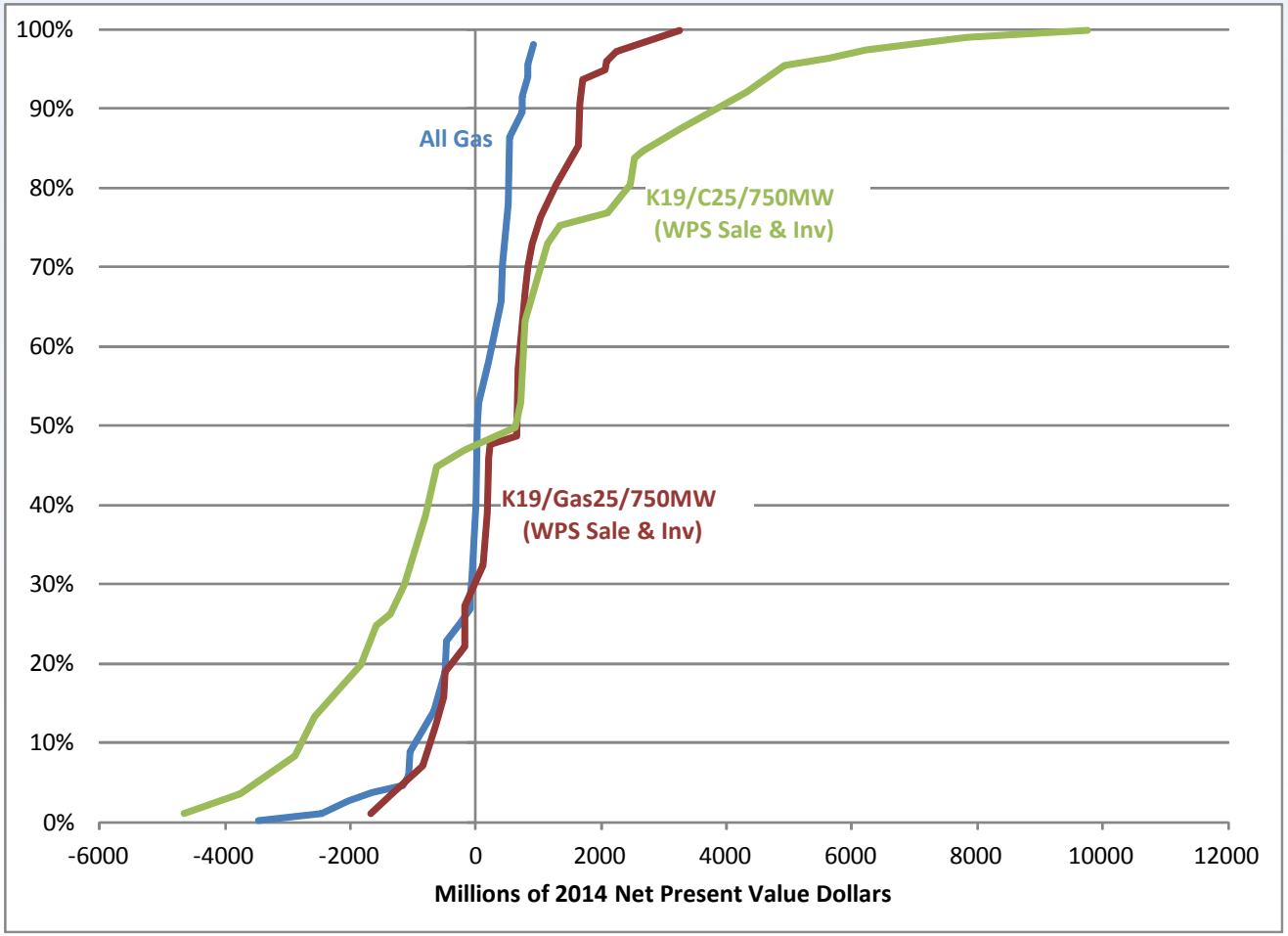
Probabilistic Analysis
Updated Capital Costs – Keeyask and Conawapa

Development Plan			1	2	4	8	5	14
			All Gas	K22/Gas	K19/Gas24 /250MW	CCGT/C26	K19/Gas25 /750MW	K19/C25 /750MW
							WPS Sale & Investment	
Energy Prices	Discount Rates	Capital Costs	Millions of 2014 NPV Dollars					
Low	Low	H	-1062	-1401	-851	-1501	-516	-1583
		Ref	-68	16	646	106	906	632
		L	734	1205	1898	1449	2086	2539
	Ref	H	-463	-1751	-1512	-2398	-1331	-3755
		Ref	208	-677	-334	-1085	-172	-1827
		L	750	232	658	15	795	-167
	High	H	-88	-1782	-1761	-2625	-1675	-4640
		Ref	416	-891	-748	-1480	-651	-2876
		L	823	-133	110	-519	205	-1356
Ref	Low	H	-2033	-120	543	325	236	2111
		Ref	-1039	1296	2040	1932	1658	4326
		L	-237	2486	3292	3275	2837	6233
	Ref	H	-671	-585	-260	-910	-492	-1130
		Ref	0	489	917	403	667	798
		L	542	1397	1910	1503	1634	2458
	High	H	17	-716	-620	-1343	-837	-2562
		Ref	520	175	393	-198	187	-798
		L	927	933	1251	762	1043	722
High	Low	H	-3454	892	1647	2005	645	5631
		Ref	-2460	2309	3143	3612	2066	7846
		L	-1658	3498	4396	4955	3246	9752
	Ref	H	-1158	402	797	469	112	1340
		Ref	-487	1476	1974	1782	1271	3268
		L	55	2384	2967	2882	2238	4928
	High	H	-82	210	368	-156	-186	-627
		Ref	422	1101	1381	989	837	1137
		L	828	1859	2239	1949	1694	2657

2014 Capital Cost Update – Keeyask and Conawapa Expected Values

Development Plan	1	2	4	8	5	14
	All Gas	K22/Gas	K19/Gas24 /250MW	CCGT/C26	K19/Gas25 /750MW	K19/C25 /750MW
					WPS Sale & Investment	
	Millions of 2014 NPV Dollars					
10th Percentile -"Risk"	-953	-862	-727	-1457	-728	-2768
25th Percentile	-244	-622	-290	-980	-178	-1537
75th Percentile	483	1026	1339	916	992	1314
90th Percentile - "Reward"	738	1448	2019	1898	1655	3850
Expected Value	-9	268	651	143	450	303
Ref-Ref-Ref NPV	0	489	917	403	667	798

2014 Capital Cost Update – Keeyask and Conawapa Expected Values



Updated DSM Evaluation

Development Plans
1. All Gas 5. K19/Gas/750MW (WPS Sale) 14. Preferred Development Plan

DSM Levels	2027/28 Energy levels	
2013 DSM	773 GWh	(1x DSM)
Level 1	1,704 GWh	(2x DSM)
Level 2	2,961 GWh	(4x DSM)
Level 2 DSM with Pipeline Load Net Reduction in Load	2,961 GWh -1,478 GWh 1,483 GWh	 (2x DSM)
Level 3 DSM	3,546 GWh	(5x DSM)
Level 3 DSM With Pipeline Load Net Reduction in Load	3,546 GWh -1,478 GWh 2,068 GWh	 (2.7x DSM)

DSM Analysis – 3 Additional Levels

What level of DSM is economic?

	Total Resource Cost Without Pipeline Load Includes all costs and does not account for changes in Domestic revenue [with pipeline load for level 2 to level 3 only] Incremental NPV (millions of 2014$) of implementing higher level of DSM		
	All Gas	K19/Gas/750MW	K19/C/750MW
Base to Level 1	535	497	285
Level 1 to Level 2	816	887	737
Level 2 to Level 3 [with pipeline]	-49 [-60]	-86 [-39]	-102 [-85]

Note: ISD changes with Level of DSM for Conawapa (DSM1:2030, DSM2:2031, DSM3:2033) and All Gas (DSM1:2028, DSM2:2031, DSM3:2033).

Impact of DSM Levels on Development Plan Economics

	Without Pipeline Load [with pipeline load for level 2 and level 3 only] Incremental NPV (millions of 2014)$ Relative to All Gas at specified level of DSM			
	Base DSM	Level 1 DSM	Level 2 DSM	Level 3 DSM
Plan 5 K19/Gas/750MW [Pipeline]	377	339	410 [339]	373 [361]
Plan 14 K19/C/750MW [Pipeline]	374	124	45 [139]	-7 [114]

Equity Return in the real WACC of 5.4% -return on equity above borrowing cost

2013 Base DSM NPV in 2014$ incremental to All Gas Base DSM)

	RWACC 5.4%	Debt Rate 4.65%	(RWACC - Debt Rate) Embedded Return On 25% Equity
K19/C26/750MW	$374M	$1887M	**$1513M**
K19/Gas26/750MW	$377M	$1098M	**$721M**

2014 Level 2 DSM (NPV in 2014$ incremental to All Gas Level 2 DSM)

	RWACC 5.4%	Debt Rate 4.65%	(RWACC - Debt Rate) Embedded Return On 25% Equity
K19/C31/750MW	$45M	$1364M	**$1319M**
K19/Gas31/750MW	$410M	$1152M	**$742M**

- Portion of embedded return on equity required to maintain debt equity ratio 75:25
- Not suggesting replacing WACC in corporate economics but demonstrates return on equity available to Manitoba Hydro, which is embedded in the WACC

Integration of Economics with Other Perspectives

ED WOJCZYNSKI, P. ENG.
MARCH 10, 2014

NFAT TOR Multiple Perspectives

Market Valuation Economics (corporate economics NPV)

MH Domestic Customer

- Reliability
- Energy security
- Rate increases
- Financial targets
- Retained earnings, fixed asset & debt levels

Socio-economic

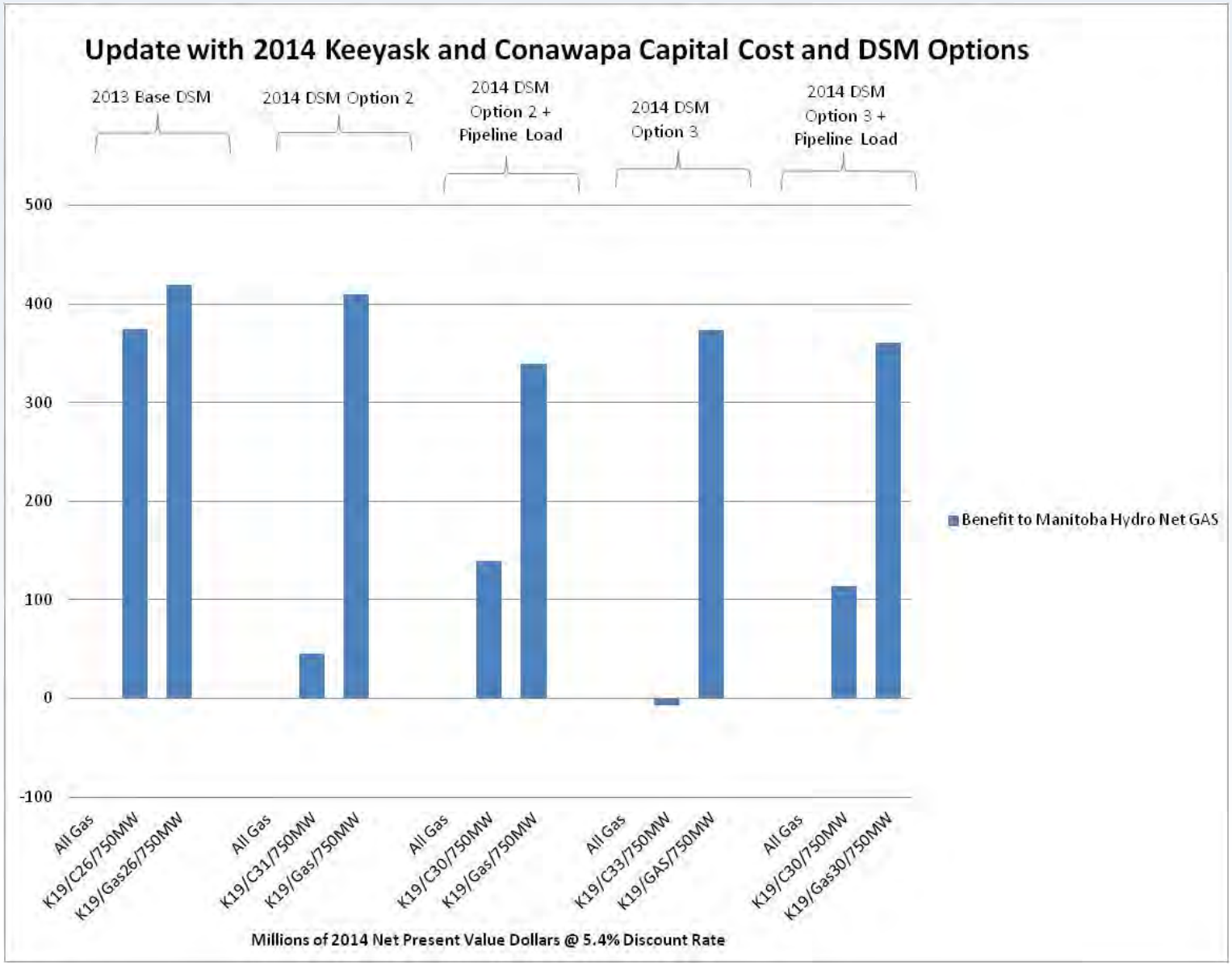
- Manitoba Economy - employment & income
- Training & business opportunities
- Infrastructure, services, personal & family & community life, resource use, heritage resources
- Special focus on Northern & Aboriginal communities

Macro-environmental impacts & benefits

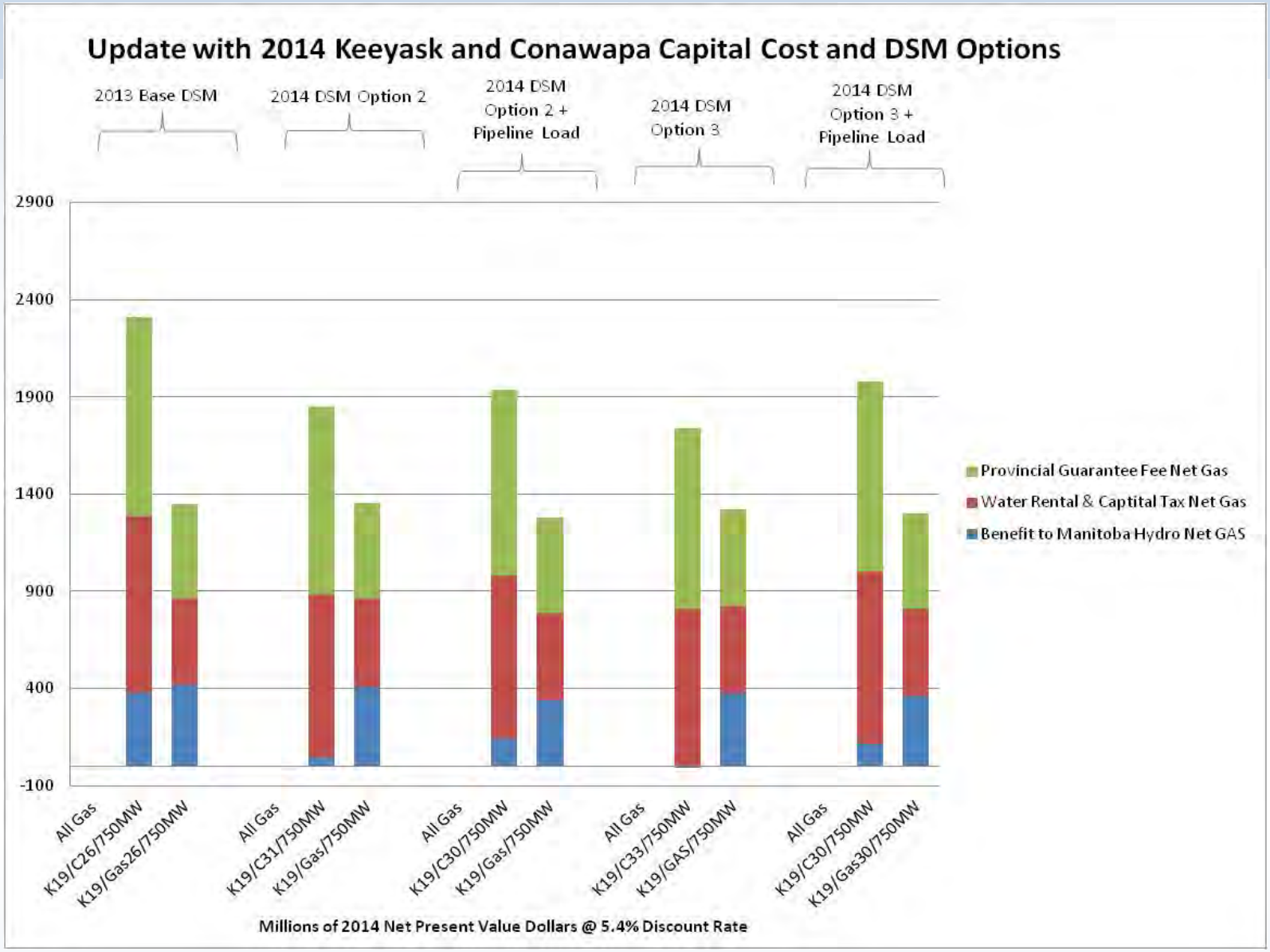
Manitoba Government

- Financial transfers to provincial government
- Alignment to Manitoba Hydro Act, Sustainable Development Act, Climate Change Act, Clean Energy Strategy

Risk & Uncertainty



-2014 reference capital cost estimates for Keeyask and Conawapa
-2013 load forecast and assumptions, MP & WPS sales, no WPS interconnection investment



-2014 reference capital cost estimates for Keeyask and Conawapa
-2013 load forecast and assumptions, MP & WPS sales, no WPS interconnection investment

Manitoba Domestic Customer Bulk System Reliability & Energy Security Analysis

Rolling Blackouts In Alberta Due To Extreme Heat

THE CANADIAN PRESS

CP | By The Canadian Press
Posted: 07/02/2013 7:20 pm EDT | Updated: 07/02/2013 8:51 pm EDT

CALGARY - Soaring temperatures on Tuesday pushed Alberta's demand for electricity beyond what it can deliver, so the power regulator ordered some utility companies to use less, which caused temporary rolling blackouts.

Newfoundland Premier defends energy system on fourth day of blackouts

ST. JOHN'S — The Canadian Press
Published Monday, Jan. 06 2014, 7:47 AM EST

Newfoundland's rolling blackouts expected to end Thursday after cold increases power demand

ST. JOHN'S — The Canadian Press
Published Wednesday, Jan. 08 2014, 4:35 PM EST



Newfoundland Premier Kathy Dunderdale resigns

'ANE TABER
e Globe and Mail
lished Tuesday, Jan. 21 2014, 9:02 PM EST

Big blackout of 2012

A severe thunderstorm rolled through the Prince Albert a

What began as an intense light show er
downpour.

After about 20 minutes of sheets of rain po

Newfoundland Outages: Blackouts Close Schools, As Island Enters Fourth Day Of Blackouts

CP | By Sue Bailey, The Canadian Press Posted: 01/06/2014 7:32 am EST |

Newfoundland in massive blackout after storm wallops Atlantic Canada

NP CANADIAN PRESS | January 4, 2014 | Last Updated: Jan 4 4:37 PM ET
More from Canadian Press



Cause of massive Saskatchewan blackout under investigation

0

By Tim Cook
Wednesday, September 19, 2007 6:41:54 EDT AM

Saskatchewan's government-owned power utility is investigating a series of events that caused a massive blackout, leaving alarm clocks flashing in bedrooms across the province early Tuesday morning.

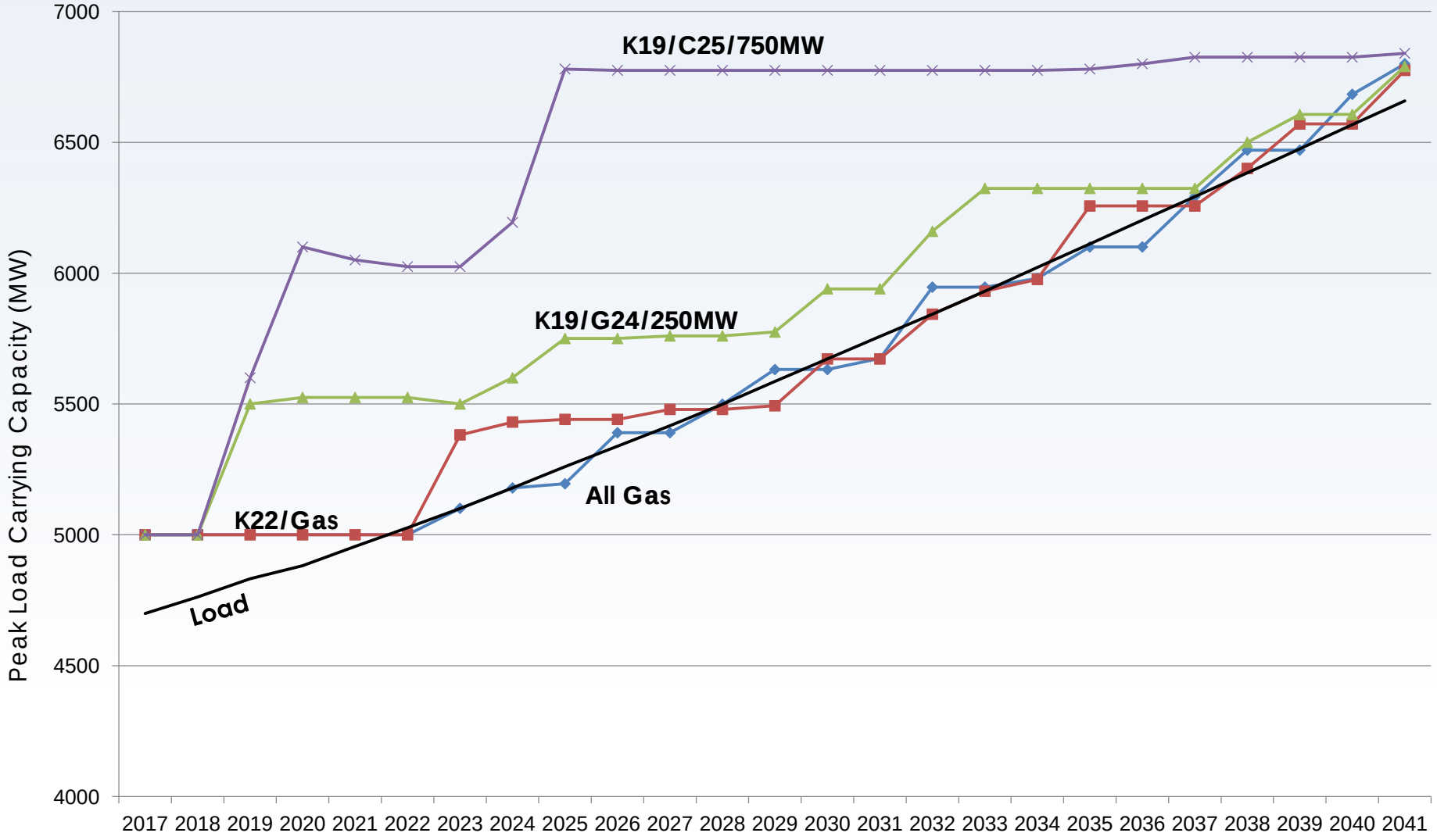
Newfoundlanders asked to save power as cold snap pushes grid to limit

ST. JOHN'S — The Canadian Press
Published Tuesday, Mar. 04 2014, 4:07 PM EST

Reliability Analysis

- Loss of Load Expectation Measure of Reliability
  - Engineering analysis used to compare the reliability of different development plans
  - Analysis of the expectation (probability) that available generation will be insufficient to serve domestic peak load
  - 0.1 day/year is NERC metric to demonstrate resource adequacy (guideline used widely including MH)
  - Not a North American standard yet but results are published annually and industry expected to meet
- Plans with 750 MW Interconnection much more reliable
  - 500 to 1000 MW more ability to carry MB domestic load fro 2020 to 2040
  - compare to Keeyask = 695MW

Bulk System Reliability: Peak Load Carrying Capacity

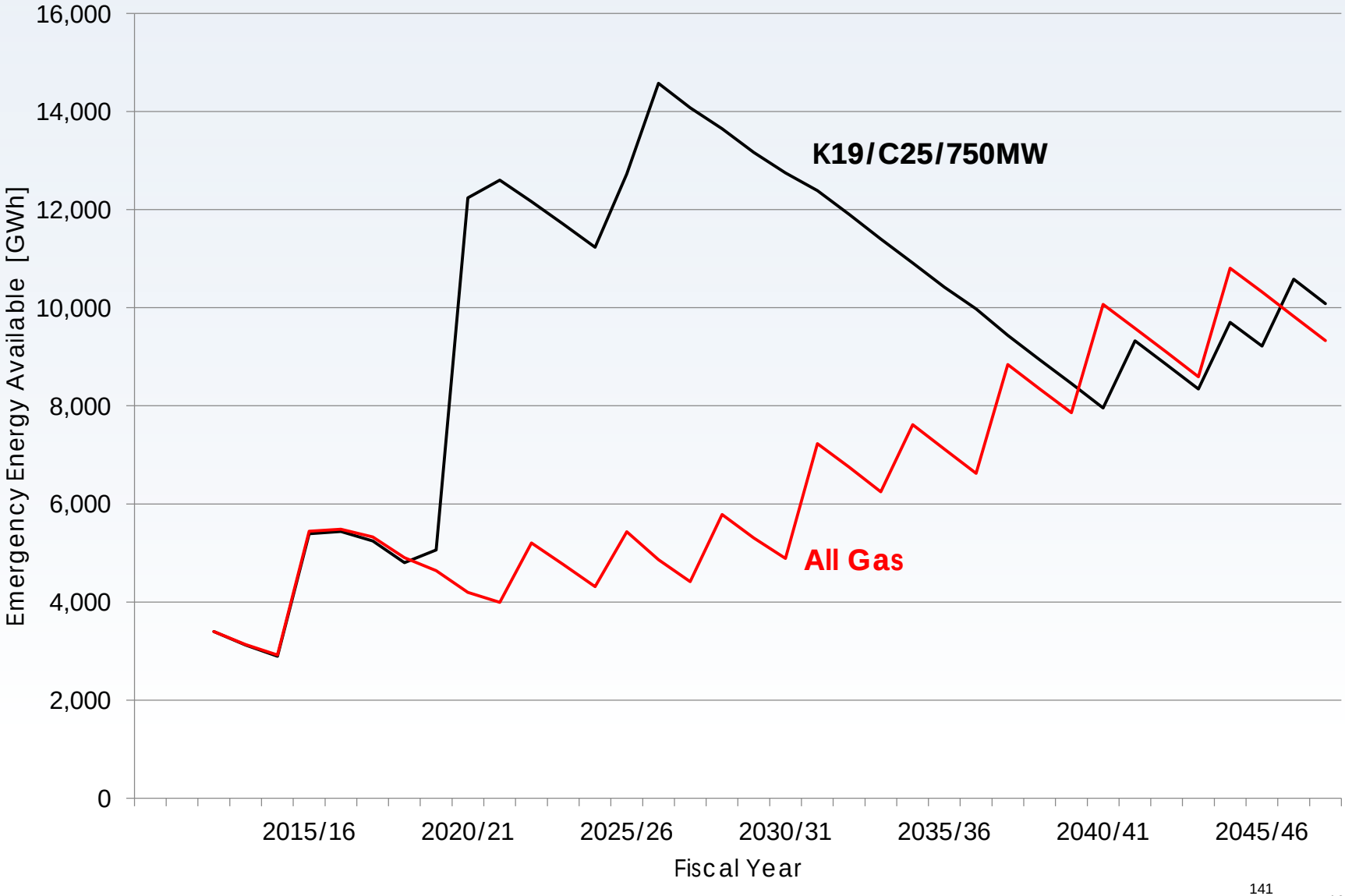


4951

Energy Security Analysis

- Emergency energy available to Manitoba domestic load if:
  - drought more extreme than drought of record or
  - load higher than P50
  - major outages of generation or transmission
  - emerging risk of natural gas delivery infrastructure
- In such emergency :
  - can stop delivery to exports (force majeure)
  - would use all import room on interconnection
- Plans with 750 MW Interconnection much more secure under droughts more extreme than planned for
  - 3000 to 4500 GWh/year more emergency energy for MB domestic load from 2020 to 2040
  - compare to Keeyask = 3003 GWh

Emergency Energy Available
Including Non-Firm On-Peak Imports



NFAT Decisions & Pathways

NFAT Future Electricity Supply Plan Decisions

Fundamental decision: long term Manitoba electrical future

- Should next major electrical supply be hydro or gas?
  - DSM expanded in all plans

Associated decisions if next supply is hydro

- Should interconnection expansion opportunity be pursued?
  - need Keeyask 2019 & 250 MW MP sale
- Should interconnection be 750 MW or 250 MW?
- Should WPS 308 MW sale be pursued?
  - need 750 MW interconnection

Development Plan Implementation Pathways

-All include DSM (& potentially wind, etc.)

1	Gas 2023 only for domestic load	Later gas generation or hydro
2	Keeyask 2023 only for domestic load	Later gas generation or Conawapa
3	Keeyask 2019, 250 MW interconnection, MP 250 MW Sale, 125 MW NSP extension, 100 MW WPS sale	Later Conawapa or gas generation
4	Keeyask 2019, 750 MW Interconnection, MP 250 MW Sale, 125 MW NSP extension, 100 MW WPS sale	Later Conawapa or gas generation
5	Keeyask 2019, 750 MW Interconnection, MP 250 MW Sale, 125 MW NSP extension, 308 MW WPS Sale	Later Conawapa or gas generation

Short List: Three Pathways

1	Gas 2023 only for domestic load	Later gas generation or hydro
2	Keeyask 2023 only for domestic load	Later gas generation or Conawapa
3	Keeyask 2019, 250 MW interconnection, MP 250 MW Sale, 125 MW NSP extension, [illegible]	Later Conawapa or gas generation
4	Keeyask 2019, 750 MW Interconnection, MP 250 MW Sale, 125 MW NSP extension, [illegible]	Later Conawapa or gas generation
5	Keeyask 2019, 750 MW Interconnection, MP 250 MW Sale, 125 MW NSP extension, 308 MW WPS Sale	Later Conawapa or gas generation

250 MW Interconnection now hypothetical, likely not viable

308 MW WPS now signed, clearly beneficial with 750 MW line

Narrows to Two Key Decisions

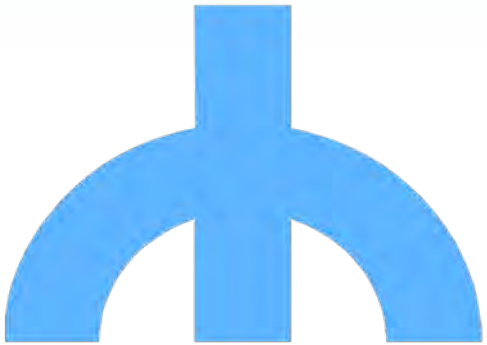
1. Should Keeyask be next supply built for Manitoba Load?
   - NO ► Stay on Pathway 1 (Gas 1st)
   - YES ► Start on Pathway 2 (Keeyask 1st)

2. If yes, should Keeyask be advanced to take advantage of opportunity for interconnection infrastructure and exports?
   - NO ► Stay on Pathway 2 (Keeyask later for MB Load)
   - YES ► 750MW ► Start down Pathway 5 (Keeyask 2019, 750 MW Line)

Overall Conclusions

- Keeyask Gas plan with 750MW line & MP/WPS/NSP
  - Approx $300 to $400M corporate benefits in new scenarios
  - Over $1 Billion including provincial transfers
  - Justified as being economic and by other benefits- rates, reliability, energy security, environment, economy, aboriginal

- Keeyask Conawapa plan with 750MW line & MP/WPS/NSP
  - $ Zero to $400M corporate benefits in new scenarios
  - Over $ 1 ½ Billion including provincial transfers
  - Likely justified as being economic and by other benefits- rates, reliability, energy security, environment, economy, aboriginal
  - Will confirm in future if proceed with Conawapa depending on additional export contracts, gas/export prices forecasts, load growth, DSM, capital costs, interest rates, etc.



Tab 49

REFERENCE:

Coalition/MH I-45a; 2015/16 GRA PUB/MH I-57

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please add two columns to the table in Coalition/MH I-45a: 2013 Forecast and 2013 Forecast with Update reflecting the additional pipeline load contemplated at the NFAT (as seen in the response to 2015/16 GRA PUB/MH I-57).

b) Please identify the specific pipeline loads that are forecast along with their annual energy and capacity requirements.

RATIONALE FOR QUESTION:

RESPONSE:

Public disclosure of the response to this IR (or portions thereof) would result in the release of information considered to be confidential and commercially sensitive. As directed by the PUB, Manitoba Hydro will be filing a motion seeking confidential treatment of the redacted information contained in this response pursuant to Rule 13.

a) The NFAT 2013 update filed as part of the NFAT proceedings was a scenario update to the 2013 Forecast designed to approximately represent emerging information related to new planned pipeline expansions in the Petroleum sector. This scenario update did not specifically increase customer usage within the pipeline sector forecast; but was approximated by advancing 1700 GWh of the forecast Potential Large Industrial Load ("PLIL") into the first four years of PLIL (Years 4 to 8 of the 20 year forecast period) and continuing with 100 GWh per year PLIL growth thereafter.

   The following table presents the forecast for the Pipeline sector under the 2013 Forecast and the 2013 scenario with the adjustment of 1,700 GWh assigned to the

pipeline sector. It should be noted that the values in the response to 2015/16 & 2016/17 Electric General Rate Application PUB/MH I-57 were presented at Generation and the 2013 forecast scenario would present a net increase to the Top Consumers overall of 1,300 GWh as compared to the 2013 Load Forecast.

PIPELINE FORECAST COMPARISON

	2013 Forecast	2013 Forecast Pipeline Scenario	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast
2013/14	1180	1180	810.4	810.4	810.4	810.4
2014/15	1145	1145	1070	1038	1038	1038
2015/16	1295	1295	1310	1130	1154.2	1154.2
2016/17	1315	1740	1485	1353	1353	1327.9
2017/18	1345	2195	1730	1276	1276	1415
2018/19	1445	2720	1800	1258	1258	1425
2019/20	1345	3045	2005	1252	1252	1460
2020/21	1375	3075	2005	1814	1814	1577
2021/22	1385	3085	2005	1806	1806	2007
2022/23	1395	3095	2005	1827	1827	2007
2023/24	1395	3095	2005	1827	1827	2007
2024/25	1395	3095	2005	1833	1833	2007
2025/26	1395	3095	2005	1835	1835	2007
2026/27	1395	3095	2005	1835	1835	2007
2027/28	1395	3095	2005	1835	1835	2007
2028/29	1395	3095	2005	1835	1835	2007
2029/30	1395	3095	2005	1835	1835	2007
2030/31	1395	3095	2005	1835	1835	2007
2031/32	1395	3095	2005	1835	1835	2007
2032/33	1395	3095	2005	1835	1835	2007
2033/34			2005	1835	1835	2007
2034/35				1835	1835	2007
2035/36					1835	2007
2036/37						2007

b) Only annual energy load is forecasted for each pipeline company. Capacity requirements are not forecasted on an annual basis. Below are the customer specific loads as forecast in the 2017 Electric Load Forecast.

	[redacted]
2017/18	
2018/19	
2019/20	
2020/21	
2021/22	
2022/23	
2023/24	
2024/25	
2025/26	
2026/27	
2027/28	
2028/29	
2029/30	
2030/31	
2031/32	
2032/33	
2033/34	
2034/35	
2035/36	
2036/37	
Contract Limit (MV.A.)	
2016/17 Peak	

1a 4b and 8

Tab 50

MANITOBA PUBLIC UTILITIES BOARD

Re: MANITOBA HYDRO
NEEDS FOR AND ALTERNATIVES TO
REVIEW OF MANITOBA HYDRO'S
PREFERRED DEVELOPMENT PLAN

Regis Gosselin - Chairperson
Marilyn Kapitany - Board Member
Larry Soldier - Board Member
Richard Bel - Board Member
Hugh Grant - Board Member

HELD AT:

Public Utilities Board
400, 330 Portage Avenue
Winnipeg, Manitoba
March 6, 2014
Pages 989 to 1254

TSCRIPT.COM Digital Transcription Services
"When You Talk - We Listen!"

APPEARANCES

Bob Peters (np)	)Board Counsel
Sven Hombach	
Patti Ramage	)Manitoba Hydro
Marla Boyd	
Byron Williams	)CAC
William Gange	)GAC
Peter Miller (np)	)
Antoine Hacault	)MIPUG
George Orle	)MKO
Michael Anderson	)
Jessica Saunders (np)	)MMF
Corey Shefman	)
Christian Monnin	)IEC
Michael Weinstein	)

TABLE OF CONTENTS

	Page No.
List Exhibits	992
List of Undertakings	1049
MANITOBA HYDRO PANEL 3 CONTINUED:	
DALE FRIESEN, Previously Affirmed	
LLOYD KUCZEK, Previously Sworn	
LOIS MORRISON, Previously Sworn	
IAN PAGE, Previously Sworn	
INGRID ROHMUND, Previously Sworn	
ED WOJCZYNSKI, Previously Sworn	
Continued Cross-examination by Mr. Antoine Hacault	1051
Cross-examination by Mr. George Orle	1153
Cross-examination by Mr. Corey Shefman	1194
Cross-examination by Mr. Christian Monnin	1224
Discussion	1244
Certificate of Transcript	1254

LIST OF EXHIBITS

EXHIBIT NO.	DESCRIPTION	PAGE NO.
MKO-1	MKO Intervener request form Date: May 14, 2013	
MKO-2	MKO draft budget for NFAT Date: June 28, 2013	
MKO-3	MKO letter to PUB re Participation in NFAT Date: October 1, 2013	
MKO-4	MKO letter to PUB re withdrawal of counsel Date: January 27, 2014	
MKO-5	MKO letter to PUB re Request to expand scope Date: January 29, 2014	
MKO-6	MKO Letter to PUB re additional questions Date: February 2, 2014	
MKO-7	MKO letter to PUB re opinion on socio-economic impacts Date: February 4, 2014	
MKO-8	MKO Desiderata Chymko Cvs Date: February 6, 2014	
MKO-9	MKO letter to PUB re Intervener budget (Pimicikamak Coalition) Date: February 6, 2014	
MKO-10	MKO/Typlan Information Requests Date: February 20, 2014	
	-1 Sustainability criteria	

LIST OF EXHIBITS (Con't)

EXHIBIT NO.	DESCRIPTION	PAGE NO.
MKO-10	-2 Consideration of adverse impacts to Public	
	-3 Consideration of World Bank docs	
	-4 Socio-economic impact review	
	-5 Socio-economic impact review	
	-6 Socio-economic impact review	
	-7 Socio-economic impact review	
	-8 Socio-economic impact review	
	-9 Definition of "rate shock"	
	-10 Socio-economic impact review	
	-11 Socio-economic impact review	
MMF-1	MMF intervener request form Date: May 16, 2013	
MMF-2	MMF letter to PUB response Order 67/13 Date: July 2, 2013	
MMF-3	MMF letter to PUB application to R&V Order 67/13 Date: July 10, 2013	
MMF-4	MMF letter to PUB re new counsel Date: August 27, 2013	
MMF-5	MMF letter to PUB SOW and budget Date: August 30, 2013	

LIST OF EXHIBITS (Con't)

EXHIBIT NO.	DESCRIPTION	PAGE NO.
MMF-6	MMF letter to PUB re Pre-hearing conference Date: September 13, 2013	
MMF-7	MMF letter to PUB re Manitoba Hydro motion Date: September 27, 2013	
MMF-8	MMF/Manitoba Hydro Round 1 Information Requests Date: November 2013	
	-1 Socio-Economic	
	-2 Socio-Economic	
	-3 Socio-Economic; Conawapa	
	-4 Socio-Economic	
	-5 Export markets	
	-6 Economics of Change (Risk)	
	-7 Economics of Change (Risk)	
	-8 Economics of Change (Risk)	
	-9 Solar	
	-10 DSM	
	-11 DSM	
	-12 DSM	
	-13 DSM	
	-14 Economics of Change (Risk)	
	-15 Economics of Change (Risk)	
	-16 Economics of Change (Risk)	
	-17 Economics of Change (Risk)	

LIST OF EXHIBITS (Con't)

EXHIBIT NO.	DESCRIPTION	PAGE NO.
MMF-8	-18	
	-19 DSM	
	-20 DSM	
	-21 DSM	
	-22 DSM	
	-23 DSM	
	-24 Drought (Risk)	
	-25 Export markets	
	-26 Capital costs	
	-27 Price forecasts	
	-28 Environmental impacts	
	-29 Access (Transmission)	
	-30 Socio-economic	
	-31 Socio-economic	
	-32 Resource options	
	-33 Resource options	
	-34 DSM	
	-35 Levelized cost	
	-36 Levelized cost	
	-37 Access (Transmission)	
	-38 Socio-economic	
	-39 Socio-economic	
	-40 NPV	

LIST OF EXHIBITS (Con't)

EXHIBIT NO.	DESCRIPTION	PAGE NO.
MMF-8	-41 Capital costs	
	-42 Economics of Change (Risk)	
	-43 Export markets	
	-44 Dsm	
	-45 Rate impacts	
	-46 Socio-economic	
	-47 Economics of Change (Risk)	
	-48 Macro-environmental	
	-49 Socio-economic	
	-50 Socio-economic	
	-51 Socio-economic	
	-52 Socio-economic	
	-53 Environmental impacts, Cumulative effects	
	-54 NPV	
	-55 Socio-economic	
	-56 Socio-economic	
	-57 Macro-Environmental	
	-58 Macro-Environmental	
	-59 Macro-Environmental	
	-60 Macro-Environmental	
	-61 Macro-Environmental	
	-62 Macro-Environmental	

LIST OF EXHIBITS (Con't)

EXHIBIT NO.	DESCRIPTION	PAGE NO.
MMF-8	-63 Environmental impacts	
	-64 Partnership Agreements	
	-65 Socio-economic	
	-66 Socio-economic	
	-67 Macro-Environmental	
	-68 Environmental impacts	
	-69 Economics of Change (Risk)	
	-70 Economics of Change (Risk)	
	-71 Economics of Change (Risk)	
	-72 Economics of Change (Risk)	
	-73 Rate impacts	
	-74 Solar	
MMF-9	MMF letter to PUB re involvement of Whitfield Russell Date: Nov. 12, 2013	
MMF-10	Schedule A to 11/12/2013 letter qualificaitons of Whitfield Russell Date: November 12, 2013	
MMF-11	MMF/Manitoba Hydro Round 2 Information Requests Date: January 2014	
	- 1 Economic Risk	
	- 2 Economic Risk	
	- 3 Economic Risk	
	- 4 Economic Risk	

LIST OF EXHIBITS (Con't)

EXHIBIT NO.	DESCRIPTION	PAGE NO.
MMF-11	- 5 Economic Risk	
	- 6 Economic Risk	
	- 7 Economic Risk	
	- 8 Economic Risk	
	- 9 Economic Risk	
	- 10 Economic Risk	
	- 11 Economic Risk	
	- 12 Economic Risk	
	- 13 Economic Risk	
	- 14 Economic Risk	
	- 15 Economic Risk	
	- 16 Economic Risk	
	- 17 Economic Risk	
	- 18 Economic Risk	
	- 19 Economic Risk	
	- 20 Economic Risk	
	- 21 Economic Risk	
	- 22 Economic Risk	
	- 23 Economic Risk	
	- 24 Economic Risk	
	- 25 Economic Risk	
	- 26 Economic Risk	
	- 27 Economic Risk	

LIST OF EXHIBITS (Con't)

EXHIBIT NO.	DESCRIPTION	PAGE NO.
MMF-11	- 28 Economic Risk	
	- 29 Economic Risk	
	- 30 Economic Risk	
	- 31 Economic Risk	
	- 32 Economic Risk	
	- 33 Economic Risk	
	- 34 Environmental impacts	
	- 35 Environmental impacts	
	- 36 Socio-economic impacts: Employment	
	- 37 Socio-economic impacts: Business Opportunities	
	- 38 Socio-economic impacts: Infrastructure and Services	
	- 39 Socio-economic impacts: Personal, Family and community life	
	- 40 Socio-economic impacts	
	- 41 Macro-Environmental	
	- 42 Economic Risk	
	- 43 Socio-economic impacts: Employment	
	- 44 Macro-Environmental	
MMF-12	MMF letter to PUB re Proposal of Whitfield Russel, with schedules "A" and "B" Date: January 30, 2014	

LIST OF EXHIBITS (Con't)

EXHIBIT NO.	DESCRIPTION	PAGE NO.
MMF-13	MMF testimony of Rick Hendriks re Socio-economic wind report Date: February 2014	
MMF-14	Report by Whitfield Russell Associates Date: February 12, 2014	
MMF-15	CV of Whitfield Russell Date: February 12, 2014	
MMF-16	CV of Thomas Besich Date: Feb. 12, 2014	
MMF-17	CV of Harrison Clark Date: Feb. 12, 2014	
MMF-18	CV of Geneva Looker Date: Feb. 12, 2014	
MMF-19	CV of Rick Hendriks Date: Feb. 12, 2014	
MMF-20	MMF/Typlan Information Requests Date: February 20, 2014	
	-1 Socio-economic	
	-2 Socio-economic	
	-3 Socio-economic	
	-4 Socio-economic	
	-5 Socio-economic	
	-6 Socio-economic	
	-7 Socio-economic	
	-8 Socio-economic	
	-9 Socio-economic	

LIST OF EXHIBITS (Con't)

EXHIBIT NO.	DESCRIPTION	PAGE NO.
	-10 Socio-economic	
MMF-21	MMF/Elenchus Information Requests	
	Date: February 20, 2014	
	-1 Economic Risk	
	-2 Economic Risk	
	-3 Economic Risk	
MMF-22	MMF/MNP Information Requests	
	Date: February 20, 2014	
	-1 Macro-Environmental	
	-2 Macro-Environmental	
	-3 Macro-Environmental	
	-4 Macro-Environmental	
	-5 Macro-Environmental	
	-6 Macro-Environmental	
	-7 Macro-Environmental	
	-8 Macro-Environmental	
	-9 Macro-Environmental	
	-10 Macro-Environmental	
	-11 Macro-Environmental	
	-12 Macro-Environmental	
MMF-23	MMF/Potomac Economics Information	
	Requests Date: February 20, 2014	
	-1 Economic Risk	

LIST OF EXHIBITS (Con't)

EXHIBIT NO.	DESCRIPTION	PAGE NO.
MMF-23	-2 Economic Risk	
	-3 Economic Risk	
	-4 Economic Risk	
	-5 Economic Risk	
	-6 Economic Risk	
	-7 Economic Risk	
	-8 Economic Risk	
	-9 Economic Risk	
	-10 Economic Risk	
	-11 Economic Risk	
	-12 Economic Risk	
	-13 Economic Risk	
MMF-24	MMF/CAC MIPUG Information Requests	
	Date: February 20, 2014	
	-1 CAC - DSM	
	-2 CAC - DSM	
	-3 CAC - DSM	
	-4 CAC - DSM	
	-5 CAC - DSM	
	-6 CAC - DSM	
	-7 CAC/MIPUG - Macroenvironmental impact	

LIST OF EXHIBITS (Con't)

EXHIBIT NO.	DESCRIPTION	PAGE NO.
MMF-25	MMF/Morrison Park Advisors Information Requests Date: February 20, 2014 -1 Economic Risk -2 Economic Risk -3 Economic Risk -4 Economic Risk -5 Economic Risk	
MMF-26	MMF report Hendriks macro environmental Date: February 20, 2014	
MMF-27	MMF letter to PUB re Manitoba Hydro motion Date: February 21, 2014	
MMF-28	MMF Book of Documents - vol 1 Date: March 3, 2014	
HILL-1	Hill letter to PUB re NFAT Round 1 IRs motion day Date: September 24, 2013	
HILL-2	Hill letter to PUB re Round 1 IR motion day Date: September 27, 2013	
HILL-3	Hill letter to PUB re motion day IRs Date: October 1, 2013	
HILL-4	Hill letter to PUB re IEC status update with schedules A to D Date: Nov 1, 2013	
HILL-5	Hill letter to PUB re status of IEC Round 1 IRs Date: December 13, 2013	

LIST OF EXHIBITS (Con't)

EXHIBIT NO.	DESCRIPTION	PAGE NO.
HILL-6	Hill letter to PUB re Right to cross-examine Date: February 21, 2014	
ERA-1	Elenchus/Manitoba Hydro Round 1 Information Requests Date: Nov. 2013	
	-1 Load forecast	
	-2 Load forecast	
	-3 Load forecast	
	-4 Load forecast	
	-5 Load forecast	
	-6 Load forecast	
	-7 Load forecast	
	-8 Load forecast	
	-9 Load forecast	
	-10 Load forecast	
	-11 Load forecast	
	-12 Load forecast	
	-13 DSM	
	-14 DSM	
	-15 DSM	
	-16 DSM	
	-17 DSM	
	-18 DSM	
	-19 DSM	

LIST OF EXHIBITS (Con't)

EXHIBIT NO.	DESCRIPTION	PAGE NO.
ERA-1	-20 DSM	
	-21 DSM	
	-22 DSM	
	-23 DSM	
	-24 DSM	
	-25 DSM	
	-26 DSM	
	-27 DSM	
	-28 DSM	
	-29 DSM	
	-30 DSM	
	-31 DSM	
	-32 DSM	
	-33 DSM	
	-34 DSM	
	-35 DSM	
	-36 DSM	
	-37 Load forecast	
	-38 Load forecast	
	-39 Load forecast	
	-40 Load forecast	
	-41 Load forecast	
	-42 Load forecast	

LIST OF EXHIBITS (Con't)

EXHIBIT NO.	DESCRIPTION	PAGE NO.
ERA-1	-43 Load forecast	
	-44 Load forecast	
	-45 Load forecast	
ERA-2	Elenchus review of Manitoba Hydro's DSM plan Date: January 2014	
ERA-3	Elenchus Review of Manitoba Hydro's Load forecast Date: January 2014	
LCA-1	La Capra/Manitoba Hydro Round 1 Information Requests Date: Nov 2013	
	-1 Load forecast; new scenarios	
	-2 New scenarios	
	-3 New scenarios	
	-4 New scenarios	
	-5 New scenarios	
	-6 New scenarios	
	-7 New scenarios	
	-8 Export contract	
	-9 Export contract	
	-10 Export contract	
	-11 Export contract	
	-12 Export contract	
	-13 Long term contracts	
	-14 Long term contracts	

LIST OF EXHIBITS (Con't)

EXHIBIT NO.	DESCRIPTION	PAGE NO.
LCA-1	-15 Long term contracts	
	-16 Long term contracts	
	-17 Export Contract	
	-18 Export contract	
	-19 Export contract; Mitigation of Adverse Effects	
	-20 Export contract; Mitigation of Adverse Effects	
	-21 Export contract; Mitigation of Adverse Effects	
	-22 Export contract; Mitigation of Adverse Effects	
	-23 Export contract; Mitigation of Adverse Effects	
	-24 Export contract; Mitigation of Adverse Effects	
	-25 Long term contracts; Export contract	
	-26 Long term contracts;Export contract	
	-27 Long term contract; short term contract	
	-28 Long term contracts	
	-29 Export contract	

LIST OF EXHIBITS (Con't)

EXHIBIT NO.	DESCRIPTION	PAGE NO.
LCA-1	-30 Export contract	
	-31 Export contract	
	-32 Export contract	
	-33 Export contract	
	-34 Export contract	
	-35 Minnesota-Manitoba Transmission line	
	-36 Minnesota-Manitoba Transmission line	
	-37 Minnesota-Manitoba Transmission line	
	-38 Minnesota-Manitoba Transmission line	
	-39 Minnesota-Manitoba Transmission line	
	-40 Minnesota-Manitoba Transmission line	
	-41 Price forecasts	
	-42 Price forecasts	
	-43 Price forecasts	
	-44 Price forecasts	
	-45 Price forecasts	
	-46 Price forecasts	

LIST OF EXHIBITS (Con't)

EXHIBIT NO.	DESCRIPTION	PAGE NO.
LCA-1	-47 Price forecasts	
	-48 Price forecasts	
	-49 Price forecasts	
	-50 Price forecasts	
	-51 Price forecasts	
	-52 Price forecasts	
	-53 Price forecasts	
	-54 Price forecasts	
	-55 Price forecasts	
	-56 Price forecasts	
	-57 Price forecasts	
	-58 Drought (Risk); Export contract; mitigation of adverse effects	
	-59 Drought (Risk); Export contract; mitigation of adverse effects	
	-60 Drought (Risk); Export contract; mitigation of adverse effects	
	-61 Minnesota-Manitoba Transmission line	
	-62 Minnesota-Manitoba Transmission line	
	-63 Drought (Risk); Mitigation of Adverse Effects	

LIST OF EXHIBITS (Con't)

EXHIBIT NO.	DESCRIPTION	PAGE NO.
LCA-1	-64 Drought (Risk); Mitigation of Adverse Effects	
	-65 SPLASH; Power System Economic Analysis	
	-66 SPLASH; Transmission availability; power system economic analysis	
	-67 SPLASH: Power System Economic Analysis	
	-68 SPLASH: Power System Economic Analysis	
	-69 SPLASH: Power System Economic Analysis	
	-70 SPLASH: Power System Economic Analysis	
	-71 SPLASH: Power System Economic Analysis; Load forecast	
	-72 SPLASH: Power System Economic Analysis; DSM	
	-73 SPLASH: Power System Economic Analysis; Export contract	
	-74 SPLASH: Power System Economic Analysis	

LIST OF EXHIBITS (Con't)

EXHIBIT NO.	DESCRIPTION	PAGE
LCA-1	-75 SPLASH: Power System Economic Analysis	
	-76 SPLASH: Power System Economic Analysis	
	-77 SPLASH: Power System Economic Analysis	
	-78 SPLASH: Power System Economic Analysis	
	-79 SPLASH: Power System Economic Analysis	
	-80 SPLASH: Power System Economic Analysis	
	-81 SPLASH: Power System Economic Analysis	
	-82 SPLASH: Power System Economic Analysis	
	-83 SPLASH: Power System Economic Analysis	
	-84 SPLASH: Power System Economic Analysis	
	-85 SPLASH: Power System Economic Analysis	

LIST OF EXHIBITS (Con't)

EXHIBIT NO.	DESCRIPTION	PAGE
LCA-1	-86 SPLASH: Power System Economic Analysis	
	-87 SPLASH: Power System Economic Analysis	
	-88 SPLASH: Power System Economic Analysis	
	-89 SPLASH: Power System Economic Analysis	
	-90 SPLASH: Power System Economic Analysis	
	-91 SPLASH: Power System Economic Analysis	
	-92 SPLASH: Power System Economic Analysis	
	-93 SPLASH: Power System Economic Analysis	
	-94 SPLASH: Power System Economic Analysis	
	-95 SPLASH: Power System Economic Analysis	
	-96 SPLASH: Power System Economic Analysis	

LIST OF EXHIBITS (Con't)

EXHIBIT NO.	DESCRIPTION	PAGE
LCA-1	-97 SPLASH: Power System Economic Analysis	
	-98 SPLASH: Power System Economic Analysis	
	-99 SPLASH: Power System Economic Analysis	
	-100 SPLASH: Power System Economic Analysis	
	-101 SPLASH: Power System Economic Analysis	
	-102 SPLASH: Power System Economic Analysis	
	-103 SPLASH: Power System Economic Analysis	
	-104 SPLASH; Power System Economic Analysis	
	-105 SPLASH mode	
	-106 SPLASH: Power System Economic Analysis	
	-107 SPLASH: Power System Economic Analysis	
	-108 SPLASH: Power System Economic Analysis	

LIST OF EXHIBITS (Con't)

EXHIBIT NO.	DESCRIPTION	PAGE
LCA-1	-109 SPLASH: Power System Economic Analysis	
	-110 SPLASH: Power System Economic Analysis	
	-111 Climate change	
	-112 Climate change	
	-113 Water Supply; hydrology	
	-114 Water Supply; Generation supply	
	-115 Hydrology; Keeyask; Conawapa	
	-116 Drought (Risk); Sensitivity Analysis; stress test	
	-117 Drought (Risk); Sensitivity Analysis; water system	
	-118 Drought (Risk); Sensitivity Analysis; water system	
	-119 Climate change; water supply; streamflow; SPLASH	
	-120 Climate change; water supply; runoff; streamflow; SPLASH	
	-121 Climate change; water supply; runoff	
	-122 Climate change; water supply; streamflow; SPLASH	

LIST OF EXHIBITS (Con't)

EXHIBIT NO.	DESCRIPTION	PAGE
LCA-1	-123 WATFLOOD; Streamflows; hydrological models; climate change	
	-124 WATFLOOD; streamflows; hydrological models; climate change	
	-125 WATFLOOD; streamflows; hydrological models; climate change	
	-126 WATFLOOD; streamflows; hydrological models; climate change	
	-127 WATFLOOD; streamflows; hydrological models; climate change	
	-128 WATFLOOD; streamflows; hydrological models; climate change	
	-129 WATFLOOD; streamflows; hydrological models; climate change	
	-130 WATFLOOD; streamflows; hydrological models; climate change	
	-131 WATFLOOD; streamflows; hydrological models; climate change	
	-132 Water supply	

LIST OF EXHIBITS (Con't)

EXHIBIT NO.	DESCRIPTION	PAGE
LCA-1	-133 SPLASH; production cost modeling; system operation	
	-134 Carbon/GHG Emissions; export markets	
	-135 Carbon/GHG Emissions	
	-136 Carbon/GHG Emissions	
	-137 Carbon/GHG Emissions	
	-138 Transmission investment; Minnesota-Manitoba Transmission line	
	-139 Transmission investment; Capital costs	
	-140 Transmission investment; Capital costs	
	-141 Transmission investment; Capital costs	
	-142 Bipole II	
	-143 Transmission investment; Minnesota-Manitoba Transmission Line	
	-144 Transmission investment; Minnesota-Manitoba Transmission Line	
	-145 Transmission investment; Minnesota-Manitoba Transmission Line; wind synergy	

LIST OF EXHIBITS (Con't)

EXHIBIT NO.	DESCRIPTION	PAGE
LCA-1	-146 Transmission investment; Minnesota-Manitoba Transmission Line; wind synergy	
	-147 Transmission Transfer Limits	
	-148 Transmission Transfer Limits	
	-149 Transmission Transfer Limits	
	-150 Transmission Transfer Limits	
	-151 Transmission Assessment Report	
	-152 Transmission Investment; Capital costs; Keeyask	
	-153 Transmission Investment; Capital costs; Conawapa	
	-154 Transmission investment; Capital costs	
	-155 Transmission investment; Capital costs; Minnesota-Manitoba Transmission line	
	-156 Transmission investment; Capital cost	
	-157 Natural Gas	
	-158 Natural Gas	
	-159 Natural Gas	
	-160 Natural Gas	

LIST OF EXHIBITS (Con't)

EXHIBIT NO.	DESCRIPTION	PAGE
LCA-1	-161 Natural Gas	
	-162 Natural Gas	
	-163 Natural Gas	
	-164 Natural Gas	
	-165 Natural Gas	
	-166 Natural Gas	
	-167 Natural Gas	
	-168 Natural Gas; oil supply	
	-169 Natural Gas; oil supply	
	-170 Natural Gas	
	-171 Natural Gas	
	-172 Natural Gas	
	-173 Natural Gas	
	-174 Natural Gas	
	-175 Natural Gas	
	-176 Natural Gas	
	-177 Natural Gas	
	-178 Natural Gas	
	-179 Natural Gas	
	-180 Natural Gas	
	-181 Natural Gas	
	-182 Natural Gas	
	-183 Natural Gas	

LIST OF EXHIBITS (Con't)

EXHIBIT NO.	DESCRIPTION	PAGE
LCA-1	-184 Natural Gas	
	-185 Natural Gas	
	-186 Natural Gas	
	-187 Natural Gas	
	-188 NPV	
	-189 NPV	
	-190 NPV	
	-191 NPV	
	-192 Debt-equity ratio	
	-193 Debt-equity ratio	
	-194 Debt-equity ratio	
	-195 Economic of Change (Risk)	
	-196 Economic of Change (Risk)	
	-197 Capital costs	
	-198 NPV	
	-199 NPV	
	-200 NPV	
	-201 IRR	
	-202 IRR	
	-203 Capital costs	
	-204 Capital costs	
	-205 NPV	
	-206 NPV	

LIST OF EXHIBITS (Con't)

EXHIBIT NO.	DESCRIPTION	PAGE
LCA-1	-207 NPV	
	-208 NPV	
	-209 NPV	
	-210 NPV	
	-211 NPV	
	-212 NPV	
	-213 NPV	
	-214 NPV	
	-215 NPV	
	-216 NPV	
	-217 Debt-Equity ratio	
	-218 NPV	
	-219 Rate impacts	
	-220 Debt-Equity ratio	
	-221 NPV	
	-222 Rate impacts	
	-223 NPV	
	-224 Rate impacts	
	-225 NPV	
	-226 NPV	
	-227 NPV	
	-228 NPV	
	-229 NPV	

LIST OF EXHIBITS (Con't)

EXHIBIT NO.	DESCRIPTION	PAGE
LCA-1	-230 NPV	
	-231 Rate impacts	
	-232 Rate impacts	
	-233 Debt-Equity ratio	
	-234 Debt-Equity ratio	
	-235 Debt-Equity ratio	
	-236 Rate impacts	
	-237 Load forecast	
	-238 Imports	
	-239 Imports, exports	
	-240 Imports, exports	
	-241 Imports	
	-242 Imports	
	-243 Imports	
	-244 Imports	
	-245 Imports	
	-246 Resource Need	
	-247 Imports	
	-248 Imports	
	-249 DSM	
	-250 Keeyask; Conawapa	
	-251 Imports	
	-252 Project Licensing	

LIST OF EXHIBITS (Con't)

EXHIBIT NO.	DESCRIPTION	PAGE
LCA-1	-253 Keeyask	
	-254 Keeyask	
	-255 Export contract	
	-256 Project Licensing	
	-257 Transmission transfer limits	
	-258 Sunk costs	
	-259 Export contract	
	-260 Keeyask	
	-261 Environment impacts	
	-262 Environment impacts	
	-263 Environment impacts	
	-264 Environment impacts	
	-265 Keeyask	
	-266 Risks	
	-267 Imports	
	-268 Power Resource Plan	
	-269 Resource Option Screening	
	-270 Resource Option Screening; wind	
	-271 Resource Option Screening	
	-272 Resource Option Screening	
	-273 Resource Option Screening	
	-274 Resource Option Screening	
	-275 Resource Option Screening	

LIST OF EXHIBITS (Con't)

EXHIBIT NO.	DESCRIPTION	PAGE
LCA-1	-276 Resource Option Screening	
	-277 Resource Option Screening	
	-278 Resource Option Screening	
	-279 Resource Option Screening	
	-280 Resource Option Screening; levelized cost	
	-281 Resource Option Screening; levelized cost	
	-282 Resource Option Screening; levelized cost	
	-283 Resource Option Screening; levelized cost	
	-284 Resource Option Screening; levelized cost	
	-285 Resource Option Screening; levelized cost	
	-286 Resource Option Screening; levelized cost	
	-287 Resource Option Screening; levelized cost	
	-288 Resource Option Screening; levelized cost	

LIST OF EXHIBITS (Con't)

EXHIBIT NO.	DESCRIPTION	PAGE
LCA-1	-289 Resource Option Screening; carbon/ GHG emissions	
	-290 Resource Option Screening; nuclear	
	-291 Resource Option Screening	
	-292 Resource Option Screening	
	-293 Resource Option Screening	
	-294 Resource Option Screening	
	-295 Resource Option Screening; wind	
	-296 Resource Option Screening; wind	
	-297 Resource Option Screening; wind	
	-298 Resource Option Screening; wind	
	-299 Wind	
	-300 Wind	
	-301 Resource Option Screening; wind	
	-302 Resource Option Screening; wind	
	-303 Resource Option Screening; wind	
	-304 Resource Option Screening; wind	
	-305 Resource Option Screening; wind	
	-306 Resource Option Screening	
	-307 Resource Option Screening	
	-308 Resource Option Screening; levelized cost	
	-309 Resource Option Screening	

LIST OF EXHIBITS (Con't)

EXHIBIT NO.	DESCRIPTION	PAGE
LCA-1	-310 Resource Option Screening; levelized cost	
	-311 Resource Option Screening; levelized cost; wind	
	-312 Resource Option Screening; levelized cost; wind	
	-313 Merchant generation	
	-314 Resource Option Screening; levelized cost	
	-315 Resource Option Screening	
	-316 Resource Option Screening	
	-317 Resource Option Screening; wind	
	-318 Resource Option Screening	
	-319 Resource Option Screening	
	-320 Resource Option Screening	
	-321 Resource Option Screening; emerging energies	
	-322 Resource Option Screening; emerging energies	
	-323 Resource Option Screening; emerging energies	
	-324 Resource Option Screening; emerging energies	

LIST OF EXHIBITS (Con't)

EXHIBIT NO.	DESCRIPTION	PAGE
LCA-1	-325 Resource Option Screening; emerging energies	
	-326 Resource Option Screening; emerging energies	
	-327 Resource Option Screening; emerging energies	
	-328 Resource Option Screening; emerging energies	
	-329 Resource Option Screening; emerging energies	
	-330 Resource Option Screening; emerging energies	
	-331 Development plans	
	-332 Development plans	
	-333 Development plans	
	-334 Development Plans	
	-335 Wind	
	-336 Development Plans	
	-337 Wind	
	-338 Load forecast	
	-339 Resource Need	
	-340 Power System Economic Analysis	
	-341 DSM	

LIST OF EXHIBITS (Con't)

EXHIBIT NO.	DESCRIPTION	PAGE
LCA-1	-342 Power Systems Economic Analysis; DSM	
	-343 Power Systems Economic Analysis; DSM	
	-344 Power Systems Economic Analysis	
	-345 Price forecasts	
	-346 Discount Rate	
	-347 Conawapa	
	-348 Export Contract	
	-349 NPV	
	-350 NPV	
	-351 Economics of Change (Risk)	
	-352 Load forecast; economics of change (Risk)	
	-353 Climate change;economics of change (Risk)	
	-354 Water supply; Economics of change (Risk)	
	-355 Water supply; drought risk	
	-356 Water supply; drought risk	
	-357 Water supply; drought risk	
	-358 Drought risk	
	-359 Drought risk	

LIST OF EXHIBITS (Con't)

EXHIBIT NO.	DESCRIPTION	PAGE
LCA-1	-360 Load forecast; Economics of change (Risk)	
	-361 Load forecast; Economics of change (Risk)	
	-362 Load forecast; Economics of change (Risk)	
	-363 Reliability	
	-364 Reliability	
	-365 Reliability	
	-366 Reliability	
	-367 Reliability	
	-368 Reliability	
	-369 Price forecasts	
	-370 Export markets	
	-371 Export markets	
	-372 Export markets	
	-373 Capital costs	
	-374 Ancillary services; Export markets	
	-375 Ancillary services; Export markets	
	-376 Ancillary services; Export markets	
	-377 Ancillary services; Keeyask	
	-378 Ancillary services; Conawapa	
	-379 Ancillary services; Export markets	

LIST OF EXHIBITS (Con't)

EXHIBIT NO.	DESCRIPTION	PAGE
LCA-1	-380 Capacity market; Export markets	
	-381 Capacity market; Export markets	
	-382 Capacity market; Export markets	
	-383 Capacity market; Keeyask	
	-384 Capacity market; Conawapa	
	-385 Capacity market; Export markets	
	-386 Capacity market; Export markets	
	-387 Capital costs	
	-388 NPV	
	-389 NPV	
	-390 NPV	
	-391 NPV	
	-392 Capital costs	
	-393 Economics of change (Risk)	
	-394 NPV	
	-395 NPV	
	-396 NPV	
	-397 NPV	
	-398 Rate impacts	
	-399 Keeyask	
	-400 Keeyask	
	-401 Environment impacts	
	-402 Environment impacts	

LIST OF EXHIBITS (Con't)

EXHIBIT NO.	DESCRIPTION	PAGE
LCA-1	-403 Capital costs	
	-404 Power Resource Plan	
	-405 Power Resource Plan	
	-406 Power Resource Plan	
	-407 Power Resource Plan	
	-408 Wind	
	-409 Wind	
	-410 Imports	
	-411 Imports	
	-412 Imports	
	-413 Power Resource Plan	
	-414 Power Resource Plan	
	-415 Power Resource Plan	
	-416 Power Resource Plan	
	-417 Power Resource Plan	
	-418 Power Resource Plan	
	-419 Power Resource Plan	
	-420 Power Resource Plan	
	-421 Power Resource Plan	
	-422 Power Resource Plan	
	-423 Power Resource Plan	
	-424 Power Resource Plan	
	-425 Power Resource Plan	

LIST OF EXHIBITS (Con't)

EXHIBIT NO.	DESCRIPTION	PAGE
LCA-1	-426 Power Resource Plan	
	-427 Power Resource Plan	
	-428 Export contract	
	-429 Export contract	
	-430 Export contract	
	-431 Export contract	
	-432 Export contract	
	-433 Export contract	
	-434 Export contract	
	-435 Export contract	
	-436 Export contract	
	-437 Export contract	
	-438 Export contract	
	-439 Export contract	
	-440 Export contract	
	-441 Export contract	
	-442 Export contract	
	-443 Export contract	
	-444 Export contract	
	-445 Export contract	
	-446 Export contract	
	-447 Export contract	
	-448 Export contract	

LIST OF EXHIBITS (Con't)

EXHIBIT NO.	DESCRIPTION	PAGE
LCA-1	-449 Export contract	
	-450 Export contract	
	-451 Export contract	
	-452 Power Market Trading contracts	
LCA-2	La Capra/Manitoba Hydro Round 2 Information Requests Date: January 2014	
	-453 SPLASH: Dependable energy	
	-454 SPLASH; Transmission cost	
	-455 SPLASH	
	-456 Salvage value; NPV	
	-457 Capital cost; Keeyask; Conawapa; NPV	
	-458 Capital cost; Keeyask; Conawapa; NPV	
	-459 Long-term contracts; Export contracts; contract risk	
	-460 Dependable energy; exportable surplus; firm exports	
	-461 Reservoir operation; drought impacts	
	-462 Drought Impact; MISO	
	-463 Drought impact; MISO	
	-464 Drought impacts	

LIST OF EXHIBITS (Con't)

EXHIBIT NO.	DESCRIPTION	PAGE
LCA-2	-465 Drought impacts	
	-466 Drought impacts	
	-467 Reservoir operation	
	-468 Reservoir operation; opportunity sales	
	-469 New cases	
	-470 New cases	
	-471 SPLASH; export market prices	
	-472 Natural Gas Price; coal price	
	-473 Natural Gas Price; coal price	
	-474 Natural Gas Price; carbon price	
	-475 Natural Gas Price	
	-476 Natural Gas Price	
	-477 Natural Gas Price	
	-478 Natural Gas Price	
	-479 Natural Gas Price	
	-480 Natural Gas Price	
	-481 Natural Gas Price	
	-482 Natural Gas Price; gas turbine assumptions	
	-483 Financial analysis; drought risk	
	-484 Export contracts; export market policies	

LIST OF EXHIBITS (Con't)

EXHIBIT NO.	DESCRIPTION	PAGE
LCA-2	-485 Export contracts; export market policies	
	-486 Export contracts; export market policies	
	-487 Export contracts; export market policies	
	-488 Export contracts; export market policies	
	-489 Export contracts; export market policies	
	-490 SPLASH	
	-491 SPLASH	
	-492 Drought impacts; climate change	
	-493 Transmission Economics	
	-494 Transmission Economics	
	-495 Transmission Economics	
	-496 Transmission Economics	
	-497 Transmission Economics	
	-498 Transmission Economics	
	-499 Transmission Economics	
	-500 Transmission Economics	
	-501 Transmission Economics	
	-502 Transmission Economics	

LIST OF EXHIBITS (Con't)

EXHIBIT NO.	DESCRIPTION	PAGE
LCA-2	-503 Transmission Economics	
	-504 Transmission Economics	
	-505 Transmission Economics	
	-506 MISO; Opportunity exports	
	-507 MISO; Opportunity exports	
LCA-3	La Capra Associates Main Report Date: January 24, 2014	
LCA-4	Technical appendix 1 - resource planning Date: January 24, 2014	
LCA-5	Technical appendix 2 - generation alternatives Date: January 24, 2014	
LCA-6	Technical appendix 3 - Alternative resource Plans Date: January 24, 2014	
LCA-7	Technical appendix 4 - Environmental Issues and policy Date: Jan 24, 2014	
LCA-8	Technical appendix 5 - Hydrological risk (not yet filed) Date: Jan 24, 2014	
LCA-9	Technical appendix 6 - Export markets Date: January 24, 2014	
LCA-10	Technical appendix 7 - Export contracts Date: January 24, 2014	

LIST OF EXHIBITS (Con't)

EXHIBIT NO.	DESCRIPTION	PAGE
LCA-11	Technical appendix 8 - Transmission Date: January 24, 2014	
LCA-12	Technical appendix 9 - Economic Analysis Date: January 24, 2014	
LCA-13	Technical appendix 10 - Financial analysis Date: January 24, 2014	
LCA-14	Incremental CPV Bar charts, break even years Date: January 24, 2014	
LCA-15	Total capital expenditures Date: January 24, 2014	
LCA-16	Worksheet - cash flows and cumulative incremental CF for P 4, 5, 6 and 14 Date: January 24, 2014	
LCA-17	Summary of expected economic value Date: January 24, 2014	
LCA-18	S-curves of selected plans, 78 years sensitivity Date: January 24, 2014	
LCA-19	S-curves of Plan 14 and Plan 5 Date: January 24, 2014	
LCA-20	S-curves of selected plans, 10 percent higher Capital costs for Hydro Date: January 24, 2014	

LIST OF EXHIBITS (Con't)

EXHIBIT NO.	DESCRIPTION	PAGE
LCA-21	S-curves of selected plans, all higher Capital costs for Hydro Date: January 24, 2014	
LCA-22	Resource plan economic benefits to the Province of Manitoba Date: Jan 24, 2014	
LCA-23	S-curves of selected plan, Province of Manitoba Perspective Date: Jan 24, 2014	
LCA-24	Probabilities distributions Date: January 24, 2014	
LCA-25	Probabilities Distributions - LCA Sensitivity Discount Rates Date: January 24, 2014	
LCA-26	Probability Distributions - 10 percent higher Capital costs for Hydro Date: January 24, 2014	
LCA-27	Probability Distributions - higher Capital costs for Hydros all scenarios Date: January 24, 2014	
LCA-28	Probability Distributions - variation in high and low capital for thermal and wind Date: January 24, 2014	

LIST OF EXHIBITS (Con't)

EXHIBIT NO.	DESCRIPTION	PAGE
LCA-29	Probability Distributions - no variation in high and low capital for thermal and wind Date: January 24, 2014	
LCA-30	Probability Distributions, Province of Manitoba perspective Date: Jan. 24,2014	
LCA-31	Figure 6-03 - exports before/after Keeyask Date: January 24, 2014	
LCA-32	Figures 6-09, 6-11, 6-13, 6-14 - energy mix charts Date: January 24, 2014	
LCA-33	Figures 6-15, 6-18 - MHEB historical LMPs with charts Date: January 24, 2014	
LCA-34	Figure 6-19 - MISO MP history charts Date: January 24, 2014	
LCA-35	Figure 6-40 - MISO fuel mix Date: January 24, 2014	
LCA-36	Figures 4-4, 4-5 NPV impact of Climate change cases Date: January 24, 2014	
LCD-37	Figure 8-30 - transmission cost exposure of development plan that include the Conawapa GS Date: January 24, 2014	
LCD-38	La Capra Associates - Dynamic rates model - Ref case Date: January 24, 2014	

1	LCD-39	La Capra Associates - POE quilt model
2		(App. 11.3) Date: January 24, 2014
3	LCD-40	La Capra Associates - rate quilt model
4		(App 11.4) Date: January 24, 2014
5	LCD-41	La Capra Associates - Tech appendix 10
6		- Figures Date: January 24, 2014
7	LCD-42	La Capra Associates - Revenue LCOE
8		quilt model (App. 11.4) Date: January
9		24, 2014
10	LCD-43	TA1 Resource Planning Figures
11	KP-1	Knight Piesold/Manitoba Hydro Round 1
12		Information Requests Date: Nov 2013
13		-1 Capital costs
14		-2 Levelized cost
15		-3 Levelized cost
16		-4 Solar
17		-5 Solar
18		-6 Solar
19		-7 Solar
20	KP-1	-8 Combined cycle combustion turbine
21		-9 Capital costs
22		-10 Capital costs
23		-11 O and M costs
24		-12 O and M costs
25		-13 O and M costs

LIST OF EXHIBITS (Con't)

EXHIBIT NO.	DESCRIPTION	PAGE
KP-1	-14 Keeyask	
	-15 Capital costs	
	-16 Capital costs	
	-17 Capital costs	
	-18 Capital costs	
	-19 Capital costs	
	-20 Capital costs	
	-21 Capital costs	
	-22 Capital costs	
	-23 Capital costs	
	-24 Capital costs	
	-25 ?	
KP-2	Knight Piesold/Manitoba Hydro Round 2 Information Requests Date: January 2014	
	-26 Contingency	
	-27 CEF Breakdown	
KP-3	Knight Piesold review of Keeyask and Conawapa GS Date January 23, 2014	
MNP-1	MNP/Manitoba Hydro Round 1 Information Requests Date: November 2013	
	-1 Aboriginal relations	
	-2 Mitigation of adverse effects	
	-3 Environment impacts	

LIST OF EXHIBITS (Con't)

EXHIBIT NO.	DESCRIPTION	PAGE
MNP-1	-4 Macro-environmental	
	-5 Macro-environmental	
	-6 Macro-environmental	
	-7 Environmental Protection Plans	
	-8 Macro-environmental	
	-9 Macro-environmental	
	-10 Macro-environmental	
	-11 Macro-environmental	
	-12 Macro-environmental	
	-13 Keeyask	
	-14 Environment impacts	
	-15 Macro-environmental	
	-16 Mitigation of Adverse Effects	
	-17 Macro-environmental	
	-18 Mitigation of Adverse Effects	
	-19 Mitigation of Adverse Effects	
	-20 Mitigation of Adverse Effects	
	-21 Mitigation of Adverse Effects	
	-22 Mitigation of Adverse Effects	
	-23 Mitigation of Adverse Effects	
	-24 Mitigation of Adverse Effects	
	-25 Project benefits	
	-26 Mitigation of Adverse Effects	

LIST OF EXHIBITS (Con't)

EXHIBIT NO.	DESCRIPTION	PAGE
MNP-1	-27 Mitigation of Adverse Effects	
	-28 Mitigation of Adverse Effects	
	-29 Mitigation of Adverse Effects	
	-30 Macro-environmental	
	-31 Macro-environmental	
	-32 Macro-environmental	
	-33 Macro-environmental	
	-34 Macro-environmental	
	-35 Conawapa	
	-36 Caribou	
	-37 Macro-environmental	
	-38 Caribou	
	-39 Mitigation of Adverse Effects; Conawapa	
	-40 Mitigation of Adverse Effects	
	-41 Mitigation of Adverse Effects	
	-42 Sturgeon	
	-43 Sturgeon	
	-44 Sturgeon	
	-45 Sturgeon	
	-46 Sturgeon	
	-47 Sturgeon	
	-48 Sturgeon	

LIST OF EXHIBITS (Con't)

EXHIBIT NO.	DESCRIPTION	PAGE
MNP-1	-49 Sturgeon	
	-50 Sturgeon	
	-51 Socio-economic; emerging energies	
	-52 Keeyask;Conawapa	
	-53 Socio-economic; emerging energies	
	-54 Environment impacts	
	-55 Long term contracts	
	-56 Access (Transmission)	
	-57 Mitgation of adverse effects	
	-58 Wind	
	-59 Climate change	
	-60 Carbon/GHG Emissions	
	-61 Carbon/GHG Emissions	
	-62 Carbon/GHG Emissions	
	-63 Carbon/GHG Emissions	
	-64 Carbon/GHG Emissions	
	-65 Carbon/GHG Emissions	
	-66 Carbon/GHG Emissions	
	-67 Carbon/GHG Emissions	
	-68 Carbon/GHG Emissions	
	-69 Economics of change (Risk)	
	-70 Economics of Change (Risk)	
	-71 Access (Transmission)	

LIST OF EXHIBITS (Con't)

EXHIBIT NO.	DESCRIPTION	PAGE
MNP-1	-72 Drought (Risk)	
	-73 Carbon/GHG Emissions	
	-74 Carbon/GHG Emissions	
	-75 Mitigation of Adverse effects	
	-76 Carbon/GHG Emissions	
	-77 Carbon/GHG Emissions	
	-78 Carbon/GHG Emissions	
	-79 Mitigation of Adverse effects	
	-80 Sturgeon; Economics of change (Risk)	
	-81 Carbon/GHG Emissions	
	-82 Carbon/GHG Emissions	
	-83 Carbon/GHG Emissions	
	-84 Macro-environmental	
	-85 Macro-environmental	
	-86 Macro-environmental	
	-87 Macro-environmental; access (Transmission)	
	-88 Mitigation Adverse Effects	
	-89 Caribou	
	-90 Environment impacts; Socio-economic	
	-91 Environment impacts; Socio-economic	
	-92 Mitigation of Adverse Effects	

LIST OF EXHIBITS (Con't)

EXHIBIT NO.	DESCRIPTION	PAGE
MNP-1	-93 Environment impacts	
	-94 Macro-environmental	
	-95 Mitigation of Adverse Effects	
MNP-2	MNP report re Macro-environmental considerations Date: January 13, 2014	
MNP-3	MNP letter to PUB re IRs Date: February 6, 2014	
MNP-4	Errata summary Date: February 14, 2014	
MNP-5	MNP report re Macro-environmental considerations - UPDATED Date: February 14, 2014	
MPA-1	Morrison Park Advisors/Manitoba Hydro Round 1 Information Requests Date: November 2013	
	-1 NPV	
	-2 NPV	
	-3 NPV	
	-4 NPV	
	-5 NPV	
	-6 Customers	
	-7 Capital Plans	
	-8 Debt guarantee	
	-9 Debt guarantee	

LIST OF EXHIBITS (Con't)

EXHIBIT NO.	DESCRIPTION	PAGE
MPA-1	-10 Drought	
	-11 Debt Ratio	
	-12 Decision conditions	
	-13 Export Agreements	
	-14 Relative weight of decision factors	
	-15 US transmission asset ownership	
	-16 IRRs	
	-17 Distribution of Burden of Risk	
MPA-2	Morrison Park Advisors/Manitoba Hydro Round 2 Information Requests Date: January 2014	
MPA-3	Morrison Park Advisors Commercial evaluation of Manitoba Hydro PDP business case Date: January 2014	
PE-1	Power Engineers/Manitoba Hydro Round 1 Information Requests Date: Nov 2013	
	-1 Trans. line	
	-2 Trans. line	
	-3 Trans. line	
	-4 Trans. line	
	-5 Trans. line	
	-6 Transmission Reliability	
	-7 Transmission Reliability	

LIST OF EXHIBITS (Con't)

EXHIBIT NO.	DESCRIPTION	PAGE
PE-1	-8 Transmission Reliability	
	-9 Economics of Change (Risk)	
	-10 Transmission Reliability	
	-11 Transmission Reliability	
	-12 Transmission Reliability	
	-13 Economics of change (Risk)	
	-14 Economics of change (Risk)	
PE-2	Power Engineers/Manitoba Hydro Round 2	
	Information Requests Date: January 2014	
	-15 Trans. line	
	-16 Trans. line	
	-17 Transmission Reliability	
	-18 Transmission Reliability	
	-19 Transmission Reliability	
	-20 Economics of change (Risk)	
PE-3	Power Engineers Transmission Line	
	Construction and Management Report	
	Date: January 24, 2014	
POT-1	Potomac Economics/Manitoba HydroRound 1	
	Information Requests Date: Nov 2014	
	-1 MISO; MISO Price Forecast; Export	
	Price Forecast	

LIST OF EXHIBITS (Con't)

EXHIBIT NO.	DESCRIPTION	PAGE
POT-1	-2 MISO; MISO Price Forecast; Export Price Forecast	
	-3 MISO; MISO Price Forecast; Export Price Forecast	
	-4 MISO; MISO Price Forecast; Export Price Forecast	
	-5 MISO; MISO Price Forecast; Export Price Forecast	
POT-2	Potomac Economics Report on export prices and revenues Date: Jan. 15, 2014	
TyP-1	Typlan Independent Review of Socio-economic Benefits Date: January 6, 2014	
MH-91	Response to Undertakings 5 and 6	1143
MH-92	CVs for MH panel 4	1144
MH-93	Response to Undertaking 13	1187
HILLCO-7	Book of documents	1244
MH-94	Response to Undertaking 16	1245

LIST OF UNDERTAKINGS

NO.	DESCRIPTION	PAGE
19	Manitoba Hydro to provide a revised Table 33 shown at page 16 of the MIPUG book of documents but with respect to the 5 percent and 95 percent probability metric, as well as the 2.5 and 97.5 percent and at the 0.1 percent and the 99.9 percent	1086
20	Manitoba Hydro to provide an update on the number of First Nations homes insulated along with the measures that have been installed	1165
21	Manitoba Hydro to provide a brief description of the methodology used to select or to canvass candidates to participate in focus group testing, and provide a summary of the demographics	1223

--- Upon commencing at 9:05 a.m.

THE CHAIRPERSON: Good morning. I believe that we're ready to commence today's proceedings. I will turn over the microphone to Mr. Hombach. Good morning, Mr. Hombach.

MR. SVEN HOMBACH: Good morning, Mr. Chairman and members of the Board. I'm advised that there aren't any administrative matters from counsel. Before we do get started and continue the public cross-examination of Manitoba Hydro's load forecast and DSM panel, I would like to remind everyone that this afternoon there will be an in-camera session for the Board where commercially sensitive information will be discussed.

At that point, the audio feeds to the other rooms will be cut and the doors will be locked. I anticipate at this point that that session will take place after lunch, but that depends on how long Intervenor counsel need this morning.

My Friend, Ms. Boyd, has advised me that there currently aren't any undertakings by Manitoba Hydro to address, so I would suggest that the panel call upon M. Hacault to continue he examination. Thank you.

THE CHAIRPERSON: Bonjour, M. Hacault.

MANITOBA HYDRO PANEL 3 CONTINUED:

DALE FRIESEN, Previously Affirmed

LLOYD KUCZEK, Previously Sworn

LOIS MORRISON, Previously Sworn

IAN PAGE, Previously Sworn

INGRID ROHMUND, Previously Sworn

ED WOJCZYNSKI, Previously Sworn

CONTINUED CROSS-EXAMINATION BY MR. ANTOINE HACAULT:

MR. ANTOINE HACAULT: Bonjour, good member -- good morning, members of the panel. Perhaps, if appropriate, I'll just start with where I'm intending on going today. I'm going to be asking some questions -- further questions with respect to DSM. I will also be asking some questions with respect to the parameters of, let me see, the stress tests that was touched upon in the presentation, and some short issues, such as the curtailable program which affects part of the MIPUG group.

So those are the general subject areas. And I'll be notifying the panel of Hydro and of this Board as and when I get into these different issues.

As a recap for yesterday, I'd ask -- and it hasn't been -- I think it's being brought upon the screen, it's at Tab 1. For some reason, that -- it's -- it should be up a couple pages. It's the beginning of the Power Smart section of Tab 1. That's where all the metrics were. And there's a summary -- at least it's -- it's page 5, sorry. I misstated the page for the person who's doing this.

So am I correct, Mr. Wojczynski, that this is from your document, Manitoba Hydro's document, what I'm putting up on the screen, firstly?

MS. MARLA BOYD: Sorry, Mr. Hacault, I'm having a bit of trouble locating it. Was it -- were you referring to pa -- page 5 in your book of documents?

MR. ANTOINE HACAULT: Page 5, Volume II of our book of documents.

MS. MARLA BOYD: I have the wrong volume. Do you have the volume?

MS. LOIS MORRISON: Yes, this is a section from our Power Smart plan.

CONTINUED BY MR. ANTOINE HACAULT:

MR. ANTOINE HACAULT: Okay. And yesterday I was making a valiant attempt, I don't know

if I managed to, to compare some of the metrics that Hydro has listed in its Power Smart Program.

Do you recall my valiant attempt?

MR. LLOYD KUCZEK: Yes.

MR. ANTOINE HACAULT: So for the integrated metric, am I right in understanding that this takes into account, if we look at our example, not only the cost to the Utility, but the cost to the customer?

MR. LLOYD KUCZEK: That's correct.

MR. ANTOINE HACAULT: Okay. So when we're looking at that metric, we've got to be careful because if we're focussing on the cost to the Utility, any of the ones listed under 'integrated metrics' includes costs in addition to those incurred by the Utility, correct?

MR. LLOYD KUCZEK: Correct. And as I mentioned -- I -- I am repeating myself, but I think it's always important to keep in mind that it's -- it's that cost, that's the most important because customers pay that cost --

MR. ANTOINE HACAULT: Okay.

MR. LLOYD KUCZEK: -- at the end of the day.

MR. ANTOINE HACAULT: And in effect to

a certain extent, if you're using that metric, you're making a decision as to what the customer might or might not want to do with respect to that extra cost, correct?

MR. LLOYD KUCZEK: It's more to do with it's a relevant cost to look at from the perspective of a resource option. So when you're looking at a generation option, the customers pay the whole cost; an alternative is DSM options, so the relevant cost is the total cost.

MR. ANTOINE HACAULT: Correct. And in the example that we went over, we went through a second category of metrics which you've categorized as 'utility metrics', correct?

MR. LLOYD KUCZEK: Correct.

MR. ANTOINE HACAULT: And two (2) of those were firstly the -- the first one listed under that heading is a rate impact measure cost, correct?

MR. LLOYD KUCZEK: Correct.

MR. ANTOINE HACAULT: And we had also, I believe, looked at the levelized utility cost.

MR. LLOYD KUCZEK: Correct.

MR. ANTOINE HACAULT: And then finally you list another metric. It's at the bottom of the page. It's on the screen. It's the one that focusses

on the effect of the particular program on the consumer, the consumer metrics.

MR. LLOYD KUCZEK: Correct.

MR. ANTOINE HACAULT: So your initial slide had shown a base case of seven (7) cents as a rate. When -- this was part of the presentation, correct?

MR. LLOYD KUCZEK: Correct.

MR. ANTOINE HACAULT: And what you were trying to illustrate is if we had a hundred gigawatts of generation built at ten (10) cents, that would bring our cost to the Utility and ratepayers at seven point two seven (7.27) so -- compared to the base case, correct?

MR. LLOYD KUCZEK: Correct. As a rate impact, you do it on new generation.

MR. ANTOINE HACAULT: But the math you wanted to illustrate didn't automatically follow that if you -- if DSM cost you ten (10) cents, that wouldn't lead you to a rate of seven point two seven (7.27).

MR. LLOYD KUCZEK: That's correct.

MR. ANTOINE HACAULT: So do I take it that we have to be careful -- if we're talking about spending ten (10) cents on new generation and ten (10)

cents on DSM for the same gigawatt hours, we don't necessarily get the same results mathematically?

MR. LLOYD KUCZEK: You don't, but that's where the fairness issue comes into play. If you didn't care about the fairness issue, you could spend up to that because the total customer bills in aggregate are the same as measured by the cust -- or the Utility's revenues.

But as I pointed out, the fairness issue deals with -- or -- or the point being not all customers are impacted the same way. Now, you create an argument about all customers have access to programs but, you know, you get into all sorts of issues about customers have already participated in the Power Smart Programs. And, so it's -- it's a consideration that we think is important to take into account in designing programs.

MR. ANTOINE HACAULT: Yes. So if you had 5 percent of the population that was benefiting from a program that costs ten (10) cents, it would be the remaining portion of the population that would be subsidizing, in effect, the people who are benefiting from the higher-cost DSM?

MR. LLOYD KUCZEK: Yes.

MR. ANTOINE HACAULT: And the last

alternative was actually spending less on DSM with an effect that nobody would be paying a higher rate than the generation option.

MR. LLOYD KUCZEK: That's correct.

MR. ANTOINE HACAULT: But to achieve that we had to downscale the DSM mathematically to -- from ten (10) cents down to two point seven (2.7) cents, correct.

MR. LLOYD KUCZEK: From a utility perspective. But from an -- an integrated perspective the customer -- the DSM still costs the same as -- as the example in my mind that I was contemplating when I drafted that example. So the DSM cost didn't change. It was just the -- the question of sharing.

And so when I talk about program designs, that's one (1) of the -- one (1) of the considerations you need to think about, is how to share that cost. And at the same time you've got to think about the program being effective, in terms of achieving the results, so.

MR. ANTOINE HACAULT: Understood.

MR. LLOYD KUCZEK: And -- and so when I -- I do want to point out when you -- when I provided that example it wasn't to suggest that that's how we do things. We still take each program and

assess it individually and --

MR. ANTOINE HACAULT: Just --

MR. LLOYD KUCZEK: -- we're willing to go above that line, and have customers subsidize other customers to a reasonable degree.

MR. ANTOINE HACAULT: Thank you very much. Again, when I'm asking questions, I'll repeat the same caveat that coun -- Board counsel said. If I get anywhere close to CSI, just let me know. I don't think any questions will. And whoever deems it appropriate to answer my question most certainly can -- can answer it.

The -- I'm going to be getting into the stress test area with respect to how we're approaching evaluating some of the alternatives. Let me start with a little bit of introduction to that.

It's my understand that if we took simply a needs-based approach, that we wouldn't be building Keeyask as early as we're now proposing based on the opportunity that's being created as a result of certain circumstances for export and other reasons, correct?

MR. ED WOJCZYNSKI: Correct.

MR. ANTOINE HACAULT: So that -- I would suggest that with respect to the needs

perspective, if we were just looking at that, we'd be looking at, from what I understood, more a 2023 perspective than a 2019 perspective.

MR. ED WOJCZYNSKI: With the 2013 load forecast and 2013 IFF assumptions, the -- the date would be 2023. As I indicated in -- in some -- in -- in Exhibit 90 yesterday, that date would vary depending on -- on the -- in the future on diff -- other assumptions. But the -- the 2013 IFF information is 2023, yes.

MR. ANTOINE HACAULT: And there's some information as proceeding suggesting that if you're ramping up the DSM, it might actually push out that date further for Keeyask, correct?

MR. ED WOJCZYNSKI: It would push it out later than 2023, yes.

MR. ANTOINE HACAULT: And I would suggest that this puts some pressure from -- if you're looking at a needs perspective, to make sure that if we're advancing something that we've got our stress tests right to take into account what might happen if we took a needs approach as opposed to an opportunity approach.

MR. ED WOJCZYNSKI: Yes. Yes.

MR. ANTOINE HACAULT: At Tab 3 of our

book of documents we've got certain load forecasts. And I'm going to take whoever is appropriate through some of these documents to best understand how the NFAT material is being presented now, how it relates to the experience that you've put in your slides, and how it relates to previous approaches by Manitoba Hydro. That's where I'm going.

So if I look at Tab 5 of our book of documents, which is page 23, I believe, you had taken us through the forecast accuracy of Manitoba Hydro using this table.

Was I correct in understanding that?

MS. LOIS MORRISON: That is correct.

MR. ANTOINE HACAULT: Okay. Now, I just want to understand how this slide works. I think I know, but I'm not too sure. If I look in 1992, I see a darker bar which goes somewhat over the 5 percent.

Do you see that?

MS. LOIS MORRISON: Yes.

MR. ANTOINE HACAULT: Okay. And am I correct in understanding that the forecast for that bar would have been made in 1982, ten (10) years before?

MS. LOIS MORRISON: That is correct.

MR. ANTOINE HACAULT: Okay. And there's a practically imperceptible bar. So that time, you were bang on for the five (5) year accuracy. So that would have been a forecast that would have made -- been made five (5) prior to that.

And that would have been, I think, 1987?

MS. LOIS MORRISON: That is correct.

MR. ANTOINE HACAULT: Okay. So we've got two (2) metrics here that we're looking at over a twenty (20) year time period. Did Hydro believe that this sampling was something that was representative of what it -- what might happen with the forecasting? Is that why it put this twenty (20) year graph? Because you could have chosen ten (10) years. You could have chosen fifteen (15). You could have chosen thirty (30). 2 50

Why did you choose twenty (20)?

MS. LOIS MORRISON: We -- you're correct. We could have used ten (10) years. We could have used fifteen (15) years. We could have used five (5) years. What we do is we're -- we're showing back twenty (20) years only to demonstrate that, as with all forecasting, you're looking at a longer period of time.

And if we did look at the five (5) years we would probably be limiting our -- the -- the -- it would be limiting your view of how the economy cycles when you're -- and it would pro -- it would -- it may disproportionately show the influence of past economic changes on a shorter period of time.

So we look at the twenty (20) year horizon so that we can better demonstrate the cycles that occur within over time and to show that forecasting can -- will vary over time due to cycles. And so what we're trying to demonstrate is how accurate our -- or how well our -- our forecasts have performed compared to what's actually occurring in the marketplace over a longer period of time.

MR. ANTOINE HACAULT: Now, did the forecasting methodology change significantly, or was it sufficiently the same, to use this example, throughout the twenty (20) year time period?

MS. LOIS MORRISON: There have been adjustments to the forecast over this time period. We're looking at more than twenty (20) years of data, given that, as you -- as you mentioned, in 19 -- the -- the information presented for 1992 would have been ten (10) years prior to that.

So now we're looking at -- sorry, it is

a twenty (20) year horizon. So there has been some adjustments to our forecasting over that period of time where we've made improvements and adjustments. But the adjustments, we feel, have added to the value of the forecasting and have not, I believe, materially impacted the performance of our forecasting.

MR. ANTOINE HACAULT: Okay. Do you know about when you put those enhancements that you're talking about? Although they don't materially impact the forecasting, when did they occur?

Just, like, when did you start making these enhancements?

MR. LLOYD KUCZEK: If -- if you go back to the '70s, there was quite a difference back then. So this only includes from 1982 and -- and onwards. And that's going back to when employees were in place thirty (30) years ago, and I honestly, as well as Ms. Morrison, don't -- don't recall what methodologies were employed.

But I do know in that time frame in the early '80s we did start undertaking more sophisticated forecasting methodologies. And I don't recall, and I'm not familiar with, how those changed over time. But I know those refinements always -- continuously being made as we moved into the future

MR. ANTOINE HACAULT: Thank you. I just wanted to get some sense as to whether we're talking apples and oranges. Sometimes you've introduced certain computer models or certain metrics that change significantly.

But based on what I've understood right now, there hasn't been any significant changes in the metrics for forecasting -- this forecasting, correct?

MR. LLOYD KUCZEK: I would suggest nothing significant. The significant change occurred from the '70s to somewheres -- either late '70s or early '80s. And prior to that, my understanding was it was a pretty crude forecasting methodology that was used.

MR. ANTOINE HACAULT: Thank you. Now, the one thing I'm not absolutely sure I understand is if we go back to the 1992 bar, the dark blue one, which was the ten (10) year forecast, the bar goes above the 5 percent. Is that an indication that the forecast was too optimistic?

In other words, you talk -- thought in 1982 that your load was going to be higher than it actually was in 1992.

MS. LOIS MORRISON: Yes. It means in 1992 our forecast was five (5) -- was -- was that

degree higher than the actual.

MR. ANTOINE HACAULT: Okay. So conversely if we go in the range of 2007, the forecast was too low. You thought that the load was going to grow at a certain rate, but in fact it didn't grow that quickly. It was at a lower load.

MS. LOIS MORRISON: Yes. During that period of time the actual consumption was greater than what we had forecast.

MR. ANTOINE HACAULT: Okay. Now, it was explained, and it's in the rebuttal also, that if Manitoba's -- Hydro's goal, as I understand it, for the ten (10) year metric is to achieve 10 percent accuracy, and -- and that would be what you can reasonably expect to achieve for a ten (1) year forecast.

Did I understand that correct?

MS. LOIS MORRISON: Yes. We believe that the forecast is -- is reasonably performing if we are within 10 percent.

MR. ANTOINE HACAULT: So I would suggest to you that if -- if that's the standard and your expectation that you can achieve that accuracy, that an appropriate stress test level going forward would be whether or not we're, I'm going to call it,

in that cone of a 10 percent range in a ten (10) year time frame.

Do you agree with that?

MS. LOIS MORRISON: Yes.

MR. ANTOINE HACAULT: Okay.

THE CHAIRPERSON: Just so I -- just to make sure I understand. So your fore -- your five (5) year forecast -- sorry, your forecast five (5) years out is inaccurate to the percentage that's shown there, but you're only taking the one (1) year.

So for example, if you're looking at the year that we're talking about, 1994, you were, say, 7 percent out five (5) years prior to that, for that one (1) year alone.

MS. LOIS MORRISON: Yes, if you -- if we're looking at the 1994 forecast, what we do is we go -- if we're looking -- what we look at is the 1994 year. Then we say, What did we forecast five (5) years ago for that year, and are we within 5 percent of that? And so we look at each forecast for all those years. We look back to the forecast for that year, five (5) years prior, and for ten (10) years prior.

THE CHAIRPERSON: But you can't infer from that that -- so, for example, looking at the most

recent year, the -- the latest year for which there is 9 percent accuracy over -- over estimate, you can't assume, then, that -- I guess what I'm getting at is that you would be looking at a -- a range of years in -- in assessing your forecast. And all this is telling you is that you're out one (1) year by 8 percent. But it doesn't tell me what the rest of the time savings is like.

In other words, when you do your forecast you don't -- you don't just do five (5) years out. You're doing twenty (20) years out. And what I'm trying to understand is this tells me that you're ten (10) -- your 8 percent out five (5) years forward. How much are you out for the rest of the years?

Because, I mean, you're -- you're now saying to us: We're going to build a dam. We're projecting fifteen (15) years from now, we're -- we're projecting a need.

Not fifteen (15) years, but say eleven (11) years out. And all this is telling me is that five (5) years from now you're going to be anywhere from minus ten (10) to minus -- plus ten (10) out.

How -- you know, how much out are you going to be eleven (11) years from now, which is probably a more germane figure?

MS. LOIS MORRISON: In our work with Elenchus we did provide them with detail about the forecast accuracy for fifteen (15) and twenty (20) years also. It -- it's more so we present -- we could present that also. It's just for the purposes of discussion we generally present the five (5) and ten (10) year, because we can provide more in -- more information. If we go to fifteen (15) years, obviously, there'll be less bars. If we go to twenty (20) years there's, again, less bars.

So this was more so to demonstrate the impact of cycling and -- and to show that there's going to be periods of what appears to be over-forecasting and under-forecasting. That's the -- that's the purpose of this -- this chart and that it's not necessarily that the -- that the forecast is consistently over forecasting or consistently under forecasting. It was more so to demonstrate that perspective. But we -- we do have the data to look at, the fifteen (15) year and the twenty (20) year performance also.

MR. LLOYD KUCZEK: I -- I should add that we -- we don't just provide this for external parties, too. We -- it's an -- it's an internal tool as well for us just to have some sense of what -- how

the load forecasting has been performing, in terms of accuracy in the past. We do know that -- and -- and it's understood that the forecast will always be wrong. So it's just -- it's the only metric that we could come up with for looking back and just how is it doing.

CONTINUED BY MR. ANTOINE HACAULT:

MR. ANTOINE HACAULT: Hopefully some of my subsequent questions will help clarify the question of the Board Chair. Now, there's two (2) things that I understand are being done with the load forecasts.

The first is you readjust your load forecast each year, correct?

MS. LOIS MORRISON: That is correct.

MR. ANTOINE HACAULT: Okay. The second thing is that you weather adjust your load forecast.

So if you've had an unusually high flow or an unusually -- sorry, unusually cold weather, you would weather adjust the load forecast, correct?

MS. LOIS MORRISON: That is correct. We weather adjust the year to ensure that we're working from a normal weather point.

MR. ANTOINE HACAULT: Okay. So if we look at the last three (3) years of the five (5) year accuracy, in each of those years, if I've understood correctly, the forecast was too high?

MS. LOIS MORRISON: For the last four (4) years, the five (5) year accuracy would demonstrate that we forecast greater energy use than what was consumed. But that's also a period that reflects the economic downturn, and it reflects a forecast that would have been prepared at a time just before the beginning of the economic downturn.

MR. ANTOINE HACAULT: Thank you. And that's why it was useful, because we see how the effect of economic cycles and that uncertainty in economic cycles -- and we'll be talking about that in the hearing, with respect to a number of other factors -- can affect the load forecast accuracy, correct?

MS. LOIS MORRISON: Yes, that is correct.

MR. ANTOINE HACAULT: Okay. Now, I'll want to next go to one of the -- I'm going to call graphs that are used in the NFAT proceeding to kind of see how the stress testing is comparing to the metric of your forecast accuracy.

So if we could turn to page 16 of the

book of documents. That's Tab 3, page 16.

(BRIEF PAUSE)

MR. ANTOINE HACAULT: As I understand this graph, we've got the dark blue line that we see being actuals.

Is that correct?

MS. LOIS MORRISON: The dark blue line represents our weather-adjusted actuals.

MR. ANTOINE HACAULT: Okay.

MS. LOIS MORRISON: The blue dots represent the actual consumption.

MR. ANTOINE HACAULT: Okay. And if we're going out ten (10) years, so that's the ten (10) year metric, and it should be highlighted on everybody's screen and in the document, we would go out to 2022 and 2023.

Do you see that?

MS. LOIS MORRISON: Yes, I do. Thank you.

MR. ANTOINE HACAULT: Okay. And I believe we've established that would be about the date if we approach this on a needs basis that we would anticipate, at least for the time being, requiring

Keeyask, correct?

MS. LOIS MORRISON: As Mr. Wojczynski said, based upon the filing of the '13 Resource Plan and the '13 IFF.

MR. ANTOINE HACAULT: Okay. And what I've also included, it's a couple pages in, it's page 19, is taking those figures. And you'll see it's Table 1.

Has anybody at Hydro had the opportunity to check to see whether we've properly transcribed numbers and made the calculations correctly?

MS. LOIS MORRISON: Yes, they appear to be correct.

MR. ANTOINE HACAULT: Okay. So midway through the table there's a heading, "2013-2014 Forecast." And we had just looked at the table for 2022/2023, which was the tenth year out, correct?

MS. LOIS MORRISON: That is correct.

MR. ANTOINE HACAULT: And if we do the mathematical calculation, Manitoba Hydro, in its NFAT stress test, is suggesting a 5 percent bandwidth for the stress test, correct?

MS. LOIS MORRISON: That is correct, based upon the information provided in the 2013

forecast.

MR. ANTOINE HACAULT: Yes. And if we flipped back we would see that if we go twenty (20) years out, the stress test being suggested by Hydro is a margin of 7.6 percent either to the positive or the negative, correct?

MS. LOIS MORRISON: That is correct.

MR. ANTOINE HACAULT: So the Chairperson had asked a question. And this is the way the information is being presented as far as what might be the best outcome or the worst outcome with respect to forecasting in Hydro's filing for this proceeding as of those time periods?

MS. LOIS MORRISON: Yes, that is correct.

MR. ANTOINE HACAULT: Okay. And the calculation for the ten (10) year time period that -- I didn't put the number which was mathematically derived by -- in the column 2022 to 2023, the base year is twenty-eight thousand six-o-five (28,605), and Hydro is saying, Well it might go on the probabilities to 10 percent down to twenty-seven (27) -- or only increase to twenty-seven thousand sixty-five (27,065), correct?

MS. LOIS MORRISON: That is correct.

MR. ANTOINE HACAULT: So that's a little bit over 1,500 gigawatts, and if we had increased that to the 10 percent metric for ten (10) years as we've just reviewed, the bandwidth would actually be over -- about 3,000 gigawatts?

MS. LOIS MORRISON: That is correct.

MR. ANTOINE HACAULT: Okay. And 3,000 gigawatts is approximately a Keeyask?

MS. LOIS MORRISON: That is correct.

MR. ANTOINE HACAULT: So for the NFAT material, we're showing about half a Keeyask stress test at the ten (10) year time period, but if we use the 10 percent metric we actually end up having a full Keeyask of variability at the ten (10) year time period, correct?

MS. LOIS MORRISON: That is correct.

MR. ANTOINE HACAULT: Now, if we could go back to the actual experience of Manitoba Hydro over a ten (10) year time period -- and that was at Tab 5, I believe, page 23.

(BRIEF PAUSE)

MR. ANTOINE HACAULT: If we go and look at actuals, and we were just looking at a ten

(10) year metric, and the stress test being proposed by Manitoba is 5.4 percent, would 1992 for example meet the stress test which Hydro is proposing?

MS. LOIS MORRISON: It would be just slightly higher.

MR. ANTOINE HACAULT: Okay. And we see one (1) bar about the fourth year in which is over 10 percent, so that clearly wouldn't meet the stress test that Manitoba Hydro is proposing for the ten (10) year metric?

MS. LOIS MORRISON: That is correct.

MR. ANTOINE HACAULT: And the same thing for the next year; it seems not too far off, but probably doesn't meet that metric either?

MS. LOIS MORRISON: That is correct.

MR. ANTOINE HACAULT: And if we continue down the next one might be pretty close. That -- I don't know if that ends up being 1998 or 1999, correct?

MS. LOIS MORRISON: That is correct.

MR. ANTOINE HACAULT: And then we've got two (2) that don't meet that metric that follow, correct?

MS. LOIS MORRISON: That is correct.

MR. ANTOINE HACAULT: They're at 10

percent approximately, correct?

MS. LOIS MORRISON: That is correct.

MR. ANTOINE HACAULT: And then if we go further on into the graph we see also, I would suggest, probably another five (5) years where the metric's not met, the five point four (5.4) metric?

MS. LOIS MORRISON: After the two (2) that don't meet that are --

MR. ANTOINE HACAULT: After the two (2) --

MS. LOIS MORRISON: -- 10 percent?

MR. ANTOINE HACAULT: -- year 2002.

MS. LOIS MORRISON: Oh, after the 2002. Yes.

MR. ANTOINE HACAULT: And going forward to 2012, there appears to be at least five (5) clear indications there that the stress test would not be met at five point four (5.4).

MS. LOIS MORRISON: That is correct.

MR. ANTOINE HACAULT: Yeah. Okay. So that it appears that, for the first sector, where we're too optimistic, there may be -- although I don't have the exact data points, one (1), two (2), three (3), four (4), five (5), six (6), probably, that don't meet the 5.4 percent stress test. And then another

five (5) in the years that follow for approximately eleven (11) times out of this twenty (20) year time period where the stress test is not met, correct?

MS. LOIS MORRISON: I -- I don't think we would necessarily characterize this as a stress test, as more so a feedback metric as to how well we've been performing.

MR. ANTOINE HACAULT: Okay. Thank you for that clarification, but at one (1) point in time going forward, and even today somebody's making some estimates on which to base the NFAT decisions, correct?

MS. LOIS MORRISON: That is correct.

MR. ANTOINE HACAULT: And it appears that, at least based on the five point four (5.4) metric that's shown in that cone that we looked at, if we use that as a reference point approximately half the time Manitoba Hydro might be meeting that, and the other half of the time it might not be meeting it based on actual experience shown on this graph.

MS. LOIS MORRISON: If you're using the 5.4 percent that you included, yes.

MR. ANTOINE HACAULT: Yes. Thank you. Now, the other thing that I wanted to compare, I indicated that I would compare, is Manitoba Hydro's

approach to stress test metrics prior to its adopting the 90 percent and 10 percent approach for this filing. And that was found at page 18 of our materials. It doesn't have a title, but in the index we'll see that it's a -- oh, sorry, 2004/2005 load forecast.

Do you see that?

MS. LOIS MORRISON: Yes. Thank you.

MR. ANTOINE HACAULT: Okay. And if we go down that particular slide there should be, again, the 10 percent and the 20 percent years as far as time-frames.

Do you see those highlighted?

MS. LOIS MORRISON: Yes. Thank you.

MR. ANTOINE HACAULT: Okay. And if we go back to -- a little bit higher on this page, we see the cone widens quicker when compared to the NFAT filing cone, correct?

MS. LOIS MORRISON: That is correct.

MR. ANTOINE HACAULT: And, again, I would take you to the mathematical calculations which follow this at page 19. I think it's the next page. And with respect to the ten (10) year metric, Hydro in its previous forecasting metrics, at least on this particular year, was varying from a 9 percent to

approximately 13 percent variation depending on what kind of metrics we used; whether it was a 95 percent lower confidence, or we did the medium-low scenario at 10 percent probability, correct?

MS. LOIS MORRISON: That is correct.

MR. ANTOINE HACAULT: And for the twenty (20) years out, the metrics that were used by Manitoba Hydro depending on whether it was 95 percent approach or a 10 percent to 90 percent approach, varied from approximately 11.9 percent up to 15.8 percent.

That was the variation, correct?

MS. LOIS MORRISON: That is correct.

(BRIEF PAUSE)

MR. ANTOINE HACAULT: Just to clarify the table, if we look at the actual forecasts, when we have the title, looking at the top, there's 95 percent lower confidence interval. We'll see that in the 2004 and 2005 forecast and we will also see something that's called 'medium-low scenario.' That relates to the 2004/2005 forecast.

The next metric that's shown, 10 percent probability point, relates to the new

forecast. And you'll see that in the new forecast, 2013/2014. Correct?

MS. LOIS MORRISON: That is correct.

(BRIEF PAUSE)

MR. ANTOINE HACAULT: Now, did I understand -- and this was the discussion I think Mr. Wojczynski had -- if we show a higher load directionally, this makes Hydro projects look better?

MR. ED WOJCZYNSKI: Generally, yes.

MR. ANTOINE HACAULT: Okay. And is the reverse true? Because it doesn't always follow.

MR. ED WOJCZYNSKI: Generally, yes, but not to the same degree as the -- the high benefits. And this may be an appropriate time to comment on resource planning for new generation, whether it's in Manitoba or any other jurisdiction in North America, or elsewhere, for that matter, that no one is ever going to get a perfect forecast, a load forecast, and there's always, always going to be uncertainty on what was that -- what would have been the perfect date when you would exactly meet your criteria. No one ever claims they can get that perfect. And so one (1) of the considerations

planners always have, and -- and decision makers, when deciding on putting in additional resources is to recognize that uncertainty.

We have in our 12 percent reserve criteria a little bit of space for a load which is higher than you forecast, 'cause you could have higher -- a very cold winter that takes us out of the normal range. You might have a spurt of load growth tha -- that year some -- that wasn't expected, but there isn't a lot of room for that.

And if you have these cycles in the -- in the economy that are fundamental that are always going to be there and you have -- you can have larger industrial type of loads come in in relatively short notice, there's al -- there's always a significant risk. Your load can be higher than you were forecasting. Conversely, it can be lower.

It's easier, generally, in planning, again, whether it's Manitoba or somewhere else, to have over-planned than under-planned. The concept is the -- the risk on having the load higher than lower is -- is worse than the risk that your load is -- is lower than you forecast.

Or to put it differently, if you -- if you try and get it perfectly right, you have a bigger

risk that the load is -- is too high and you have to play catchup. That's a bigger risk than you tried to get it perfectly, and then the load was too low and you have surpluses.

And there had been studies years ago. It's a fundamental done by EPRI on that; it's called 'Over/Under Capacity Planning.' It doesn't -- the exact name, but it's -- it's a general concept that resource planners have been aware of and -- and are very conscious of when we do our planning. And I think that's part of perhaps the context when we're looking at these things.

They're -- we can have significantly higher load forecast than the ones we're using in our sensitivities. We -- we recognize that, and we're aware of that. And that's one of the reasons we talk about one of the criteria we apply, and I talked about the first day in the -- in the evening or the end of the day, that there's this energy security and capa -- and reliability benefit going above the criteria because of those kind of uncertainties.

And so certain plans are better able to withstand errors in load growth than other plans. And we argue that the plans for the 750 megawatt tie-line and advanced hydro are better able to deal with that

uncertainty than -- than some of the other plans.

MR. ANTOINE HACAULT: Thank you very much for that explanation, Mr. Wojczynski. I think the focus of my questions were: Did we go high enough, and did we go low enough. And -- and it's just trying to understand what metrics, as far as did we go high enough and did we go low enough, that I'm exploring.

So we've explored the 10 percent desire on accuracy, and we've explored how the metrics used to be wider, and how for this filing the metrics perhaps don't give that flexibility that you talked about to handle the higher loads that might be coming with either a big industrial or unforeseen circumstances to properly test.

But we'll get into the alternatives. I just wanted to set out the metrics that were being used; and I think you're going to have a separate panel on the alternatives, correct?

MR. ED WOJCZYNSKI: Yes. And you just laid out a certain kind of conclusion about the metrics. And I would, as a resource planner, agree with what you said.

MR. ANTOINE HACAULT: The one thing that hasn't been filed, and I don't know if it's -- it

exists and is readily filed, we saw in -- in the previous forecasts that there was actually the wider metric of 95 percent confidence level up and down. For this filing, it's been narrowed to 90 and -- 90 percent and 10 percent.

Does Hydro maintain the 95 percent confidence level data with respect to, for example, what's being presented now?

MS. LOIS MORRISON: It's not that we don't include it. It's in the -- the way we've presented it within the load forecast, I believe on page -- it's actually in your book of documents, page 15 of your book of documents.

What we've -- we've done is we have basically outlined -- there's -- you can calculate the 95 percent based on the information that's provided there, and what we present is the 90/10. So if -- if an individual or an organza -- if we wanted to look at beyond -- if we wanted to look at 20 percent/80 percent probability projections, or if we wanted to look at the 95 -- 95/5 percent, we could -- oh, I apologize, we're missing the 95/90 (sic). We could provide that.

MR. ANTOINE HACAULT: Okay. Well, then if you could provide the table that is set out on

the following page, I'd like an undertaking to provide that table, but with the 95 percent metric as opposed to the -- sorry. Well, firstly we'll deal with that one.

Would it be possible to provide that same table that's found on the next page of our book of documents with the 95 percent metric?

MS. LOIS MORRISON: Yes, we can provide that.

MS. MARLA BOYD: I believe it's Table 33 from page 16 of the MIPUG book of documents, is that correct?

MR. ANTOINE HACAULT: Okay. So the undertaking is to provide a revised Table 33 shown at page 16 of our book of documents but with respect to the 5 percent and 95 percent probability metric.

Is that correct?

MS. LOIS MORRISON: Yes, that is correct.

(BRIEF PAUSE)

MR. ANTOINE HACAULT: Would it be very difficult to also provide the same table, but with the other two (2) metrics at the other ranges shown on

page 15 of our book of documents, the 1 percent and the 2.5 percent? Because I don't know exactly what the 5 percent metric will give us at a ten (10) year range, whether it -- it will lead to a 10 percent bandwidth in the ten (10) year time frame or not.

MS. LOIS MORRISON: So you would like us, just so I'm clear, to provide you with the table -- a repeat of that same Table 33 at the 2.5 and 97.5 percent and at the 0.1 percent and the 99.9 percent?

MR. ANTOINE HACAULT: Correct.

MS. LOIS MORRISON: Okay. Yes, we can do that.

MR. ANTOINE HACAULT: Does the court reporter need that repeated for an undertaking? It can be dealt with as one (1) undertaking, if that's okay.

--- UNDERTAKING NO. 19: Manitoba Hydro to provide a revised Table 33 shown at page 16 of the MIPUG book of documents but with respect to the 5 percent and 95 percent probability metric, as well as the 2.5 and 97.5 percent and at

the 0.1 percent and the 99.9 percent

CONTINUED BY MR. ANTOINE HACAULT:

MR. ANTOINE HACAULT: The next subject matter I'm getting into will be a very short item, and it still deals with load forecast. But we've discussed getting load forecast information from top consumers. I don't know who might be best to an -- answer this, but I would suggest that these top consumers are very concerned about the confidentiality of their load forecasts.

Is that fair?

MR. DANIEL FRIESEN: That would be fair.

MR. ANTOINE HACAULT: Okay. And to date, has Hydro been able to secure on a voluntary -- or -- basis some load forecast information from its top consumers?

MR. DANIEL FRIESEN: Yes, we have.

MR. ANTOINE HACAULT: And can you indicate the level of, I'm going to say, concern that top consumers might have with respect to keeping that information private?

For example, would you have situations

where the companies would insist that it not be the same Manitoba Hydro representative that gets the information?

MR. DANIEL FRIESEN: I can speak to that in -- in a couple of different ways. I think, first of all, we have to recognize that the top consumer group, like Manitoba Hydro, make substantial investments in infrastructure. And those investments are recovered over long periods of time. And they're very dependent on market conditions, market opportunities, et cetera.

They're not competing in a local market. They're completing (sic) in a national, interna -- gl -- continental, and international market. So there's a certain degree of positioning that needs to occur for them to take the best advantages of the opportunities that they see. So confidentiality is extremely important to them, and I think all of us can easily recognize that.

So the -- the challenge sometimes arises in situations where we have two (2) large players in the same industry located within Manitoba. And they're in a competitive business. And so we have had instances where we have had companies in the same industry sector request from us specifically that not

only do we have their representative be different, they also be in different departments reporting through different managers. And they have relied on us to respect those lines and relied on us not to share information back and forth between those individuals. And we have, to the best of our ability, always respected that request.

MR. ANTOINE HACAULT: Thank you. The next subject matter which I'll deal with relates to some of the information Ms. Rohmund -- hopefully I've pronounced that correctly -- provided to us.

You had -- in one (1) of your slides, we don't need to go to it, but it was Slide 42, you had sourced something from the American Council for an Energy-Efficient Economy. And we've extracted what we understand to be that document at Tab 6, starting at page 38; so Tab 6, page 38.

(BRIEF PAUSE)

MR. ANTOINE HACAULT: First, is this document so -- or something similar to it -- have you had a chance to review it?

MS. INGRID ROHMUND: Yes.

MR. ANTOINE HACAULT: Okay. And it --

could you explain your understanding of this document? What does it outline?

MS. INGRID ROHMUND: This document, to the best of my knowledge, describes the status of the individual states in the United States with respect to whether or not they have energy efficiency standards and renewable energy standards.

MR. ANTOINE HACAULT: Okay. And am I correct in understanding -- or is it your understanding that several of these states have targets imposed by elected bodies?

MS. INGRID ROHMUND: That is correct.

MR. ANTOINE HACAULT: Okay. I would suggest then that these policy decisions made by elected bodies are things that these utilities have to follow to the extent that they can?

MS. INGRID ROHMUND: Yes.

MR. ANTOINE HACAULT: So that -- would it be fair to say that it wouldn't always be appropriate to just apply to Manitoba policy decisions that are made by elected bodies in other states? There may be, in Manitoba, a different policy decision. We haven't seen one yet through the legislature.

But there may be different policy

considerations by this government?

MS. INGRID ROHMUND: I -- I should comment on that. I don't feel that I have the -- that I should do that.

MR. LLOYD KUCZEK: But -- but just to point something out. We do have legislation that requires us to consult with the Minister responsible for Manitoba Hydro. So that's the process that we're going to use in Manitoba, and we have to now.

MR. ANTOINE HACAULT: Yeah, understood. So if there's a new policy that might be discussed or implemented by this government through that consultation process, and being mindful of your counsel's comments not to get into those, but that might be something that Manitoba Hydro is required to follow if there is such a directive by this government?

MR. LLOYD KUCZEK: In the end, the Power Smart energy efficiency plans will be developed in consultations with the government. And -- and if they have policies, that'll be part of the considerations, I'm sure, as -- as part of those consultations.

MR. ANTOINE HACAULT: Thank you.

(BRIEF PAUSE)

MR. ANTOINE HACAULT: The next area which I want to understand with respect to stress tests is for DSM, have we chosen the appropriate outer boundaries. And to understand that a bit better, I think we've put it at Tab 2, page 14.

(BRIEF PAUSE)

MR. ANTOINE HACAULT: Some of the DSM options. And I'm not going to get into the debate as to whether it should be a separate alternative or it should be integrated.

But, as I understand it, these options represent Manitoba Hydro's effort to try and, much the same as the load forecast, set out might be an outer limit for a stress test on the new projects that are being considered?

MR. LLOYD KUCZEK: I -- I wouldn't consider this a stress test. We develop these options to undertake some sensitivity analysis, that Mr. Wojczynski could talk about, but the -- the options themselves were, as I mentioned before, developed at a high level. They won't necessarily be options that we

have to follow as outlined within each particular option. We will be assessing the -- the individual components within each option to develop an overall energy efficiency or demand-side management plan going forward.

MR. ED WOJCZYNSKI: Yeah. And -- and, as Mr. Kuczek was just saying, we're -- these were high-level concepts for the DSM to do an evaluation, preliminary evaluation, of what kind of level of DSM on -- on the -- on the spectrum of possibilities would -- would make sense. And then more refined work would happen to land on the specific programs and the exact specific level.

But it's also meant, this exercise with these evaluations and levels of DSM, to -- to test what the impact would be on the Alternative Development Plans. So it's -- it's -- this is serving two (2) purposes at the same time.

MR. ANTOINE HACAULT: And thank you for that. I maybe used the wrong word when I said "a stress test." But it -- I understood it to be a test, because if we flip to page 28 of our book of documents, as part of a presentation, we saw where the baseline was and what the different options on DSM would do to the energy consumption. Hydro tried to

model that, correct?

(BRIEF PAUSE)

MS. LOIS MORRISON: The -- the graph that's being presented there, the -- I think as Ms. Rohmund pointed out -- the two (2) lines that would be more so applicable would be the achievable potential and the market potential.

The economic potential and the technical potential that are presented here for demonstration purposes are merely theoretical levels of potential, and are not what would deem to be achievable in this marketplace, or any marketplace that's undertaking a DSM potential study. It's -- it's merely setting comparison points, and as part of the process that Ms. Rohmund outlined, to get to the point where you can start putting some parameters around what might be achievable in a marketplace, you have to have an understanding of what's technically available, what's economically available, and then being to talk about what influence you might be able to have within a marketplace.

So that would then be looking at the -- what is denoted here as the achievable potential and

the market potential.

MR. ANTOINE HACAULT: Thank you. And that is a nice segue to the line of questioning I was going to get a little bit of clarification.

With respect to what's referenced as market potential, Mr. Byron Williams yesterday had taken Ms. Rohmund to -- through some other reports, and as I understood the evidence -- and perhaps we can bring up -- could we bring up CAC book of documents yesterday at page 120 and 121.

(BRIEF PAUSE)

MR. ANTOINE HACAULT: Yes, that's -- that's the correct page. So in this particular analysis, Ms. Rohmund, you had, for this particular utility, broken down what -- okay, let's break this down a little bit.

The RAP here is equivalent to what in your Hydro study?

MS. INGRID ROHMUND: RAP stands for realistic achievable potential, and that is the -- analogous to the achievable potential in the Manitoba Hydro study.

MR. ANTOINE HACAULT: Okay. So

although Hydro didn't ask you to do this, this other utility within the achievable category requested three (3) subsets of that achievable category.

Am I understanding that correct?

MS. INGRID ROHMUND: Yes, that's correct. The -- in this study, which was for Consolidated Edison of New York, we developed -- the primary metrics we developed were the maximum achievable potential and the realistic achievable potential. And at the very end of the study they said, We want a -- a range around the realistic achievable. And they gave us the parameters for that. It was a plus or minus percentage amount that I don't recall. I think 10 or 15 percent, something like that.

MR. ANTOINE HACAULT: Okay. So I just want to take it one (1) step at a time. When Hydro shows its achievable through your study, part of that achievable would be an upper boundary based on a -- and I'm reading from the number 1 on the screen:

> "Based on an optimistic assessment of measure-specific assumptions about market availability and access."

Now, part of that 'achievable' category

would be comprised of that subset, correct?

(BRIEF PAUSE)

MS. INGRID ROHMUND: So the -- as I said, the work that we did in the study was to estimate the maximum achievable potential and the mid-level realistic achievable potential. That's where all of the parameters fed those two (2) forecasts of potential. So the mid-level realistic achievable potential here would be analogous to the achievable potential in the Manitoba Hydro study. And the high and the low RAP that the client wanted to show was a fairly arbitrary distinction, along with their definitions of how they wanted to reflect those.

MR. ANTOINE HACAULT: Thank you. That's what I was trying to clarify. I wasn't too sure when we -- for the Manitoba Hydro categorization of achievable, and then there's the next metric, the market, whether or not the achievable really was a compilation of numbers 2 and 3 of what we see on this page.

So when we talk about Manitoba Hydro achievable, does it represent the mid-level estimate of realistic achievable potential:

"Based on reasonable estimates of future customer acceptance, drawing on the experience of other utilities and organizations with existing energy efficient programs."

Is that the upper bound of the 'achievable' category that you've used for Manitoba Hydro?

(BRIEF PAUSE)

MS. INGRID ROHMUND: So the -- the Manitoba Hydro study uses a different definition of 'achievable potential', slightly different, as is the case with every study. Every client wants to characterize the achievable potential in language that they feel comfortable that they can meet. So the -- the language you see here is Con Edison's language, and Manitoba Hydro's definition of 'achievable' is their definition. But the -- reading the words here and recalling how he did the study, then the -- the definition of 'mid-level RAP' here is analogous to Manitoba Hydro's achievable.

MR. ANTOINE HACAULT: Thank you. I wanted to get that clarification because I was

starting to get confused when Mr. Williams was asking questions and -- and were saying his -- this RAP was the same as the achievable. And I'm saying, well, does the high RAP really fit in Manitoba Hydro's definition. Now you've helped clarify that. Thank you.

So with respect to the market portion, that would be in Manitoba Hydro definition. And we -- if we can flip back to our graph at page 28, we see the baseline at the top which hits about 25,000 gigawatt hours.

Is that correct?

MS. INGRID ROHMUND: Correct.

MR. ANTOINE HACAULT: And the achievable potential, we've just gone through that, is somewhere down from there; and then, finally, the market potential. That's the more tenuous, say, results or objectives.

They're not as sure as the achievable ones?

MS. INGRID ROHMUND: That's definitely true, yes. That is the upper bound of ach -- of what can be achieved.

MR. ANTOINE HACAULT: Okay. And the economic and technical potentials, those were

theoretical, as I understand?

MS. INGRID ROHMUND: Correct.

(BRIEF PAUSE)

MR. ANTOINE HACAULT: Now, I just want to get a little bit more clarification. We had looked at the -- like the max RAP and we read that definition.

Is the market potential even more tenuous than that definition?

MS. INGRID ROHMUND: The market potential that we estimated for Manitoba Hydro is analogous to the maximum achievable potential that we developed in the Con Edison study.

So their maximum achievable and market potential are both theoretical -- theoreticor -- theoretical upper limits on what can be achieved in the marketplace. You need to have ideal circumstances in order to achieve that in terms of regulatory utility programs, perfect information, all the things that facilitate the adoption of energy efficiency.

MR. ANTOINE HACAULT: Thank you.

(BRIEF PAUSE)

MR. ANTOINE HACAULT: So as I recall your numbers, the market potential more or less corresponds with -- if we flip back to page 19, and you can perhaps check your number, page 19 of -- or sorry, 14 of our book of documents.

Can you tell us, if we're looking at the options that were set out on this table, which option does your market potential for 2027/2028 energy levels correspond to?

(BRIEF PAUSE)

MR. ANTOINE HACAULT: Actually, I think if you -- if the document management people go to the rebuttal evidence at page 29, we did include that in our book of documents.

But page 29 of your rebuttal evidence, there is some graphing of those numbers?

MS. LOIS MORRISON: Yes. Mis -- what is presented in the table of page 14 of your evidence and cor -- information that's somewhat similar that's presented on page 29 of the rebuttal evidence, we have to recognize that the DSM Potential Study that Ms. Rohmund assisted us with focussed on energy conservation initiatives, and did not include items

such as load displacement and fuel switching, and did not specifically speak to conservation rates, although those are one of the tools that can be used to help -- help us move towards that market achievable, or market potential.

And those are items that are included within these levels of DSM that are being presented in -- both on page 14 and in -- on page 29 of the rebuttal evidence.

If you're looking solely just at gigawatt hours and the equivalency, the Level 3 DSM is in the range of what was presented as market potential. But again we didn't model market potential in our analysis for Level 3. There's -- there's -- Level 3 DSM includes enhanced energy efficiency programming, plus it also includes the items that I just mentioned: load displacement, energy conservation rates, and fuel switching from natural -- from electricity to natural gas.

MR. ANTOINE HACAULT: Thank you very much. Now, Ms. Rohmund, looking at page 29 of the rebuttal evidence, is it your opinion then based on what you've been able to determine that the Level 1 DSM is a little bit higher than what your conclusion was on what Hydro could reasonably achieve?

(BRIEF PAUSE)

MS. INGRID ROHMUND: So I think I want to distinguish between what we did in the potential study and what is shown as the plan options here. So we did the analysis and identified measures and sectors and -- and aggregated all that up to get our achievable potential, which is identified here in words on the -- on the -- and -- and the lines on the chart.

Manitoba Hydro took that information and has developed its plan. And it has taken some -- I'm sure taken some elements from the study but also taken its own history and experience to develop that plan. So the numbers are comparable but what is underlying those numbers are -- are different things, as they -- as they typically are.

Our -- our study provides guidance to the development of the plans.

MS. LOIS MORRISON: I believe Mr. Kuczek, in his introductory statement, did characterize that the DSM potential study is there to help us frame our future efforts, and it was a starting point. It's a high-level projection. And we took that information to then help better form other

initiatives that we may pursue, and it's from there.

And then also as he's mentioned, this is -- again these are more high-level programming. The Level 1 will include some detailed program where, as he's mentioned, we've launched those programs, or those enhanced initiatives. But there's also some components within that programming that are a little bit -- still require some fine tuning and more detailed analysis.

MR. ANTOINE HACAULT: Thank you. I was --

MR. LLOYD KUCZEK: Excuse me, just -- just to add some clarity. These are options. They're not our plan. We developed these options as an interim step for the purpose of doing sensitivity analysis. So just -- Ms. Rohmund used the word 'plan' -- 'our plan'. These aren't our plans. We're currently finalizing our plans.

MR. ANTOINE HACAULT: Yeah. Thank you for that. So am I to take from that that I can't just automatically look at the conclusions of -- of -- I'm not going to say EnerROC (sic), because I don't want to take Byron's thunder away, but EnerNOC, I can't just take those conclusions and say, Well, listen, Hydro can achieve -- this is a market potential, and -

- and we can achieve that. We -- I can't just jump to that conclusion?

MS. INGRID ROHMUND: That is correct.

MR. ANTOINE HACAULT: Okay. Now, there's a lot of material; and I apologize if it's in the material.

Is there something that tells us how Manitoba Hydro comes up with the Level 2 savings at twenty-nine sixty-one (2,961)?

In other words, what programs are added, and what is the quantity of additional cumulative savings attributed to each of those programs that would meet -- or bring us up to the Level 2?

(BRIEF PAUSE)

MS. MARLA BOYD: We're just getting things lined up here. Patti and I have had an exchange with Mr. Williams this morning, trying to clarify their arm wrestling match. And I'm not sure it's actually going to come down to arm wrestling, but we have an undertaking in the works with CAC that I suspect will address the question that you're asking. So while we can't provide it to you instantly, we will

be able to provide that description in the context of the response to the undertaking.

CONTINUED BY MR. ANTOINE HACAULT:

MR. ANTOINE HACAULT: Okay. So I'll just repeat what I'm trying to determine. There must be some numbers and some calculations and some programs that bring us from Level 1 at 1,704 gigawatts up to 2,961 gigawatts.

I'd like to know what those programs and numbers are that back up the graph. So --

MR. LLOYD KUCZEK: I -- I could provide you with that now, because Level 2 involv -- it -- it's composed of three (3) initiatives. One (1) is the energy conservation rates, one (1) is the load displacement initiative, and one (1) is the fuel-switching initiative.

So our high-level estimates of what potentially could be achieved -- and this is very high level, with each one (1) being somewhat different. But the conservation rate's approximately 400 gigawatt hours -- three ninety (390) is on my page here. I'll give you the specific numbers. Two eighty-five (285) for fuel choice, and four fifty (450) for the load displacement.

MR. ANTOINE HACAULT: Thank you very much. And is that as of 2027/2028?

MR. LLOYD KUCZEK: '27/'28, and -- and we'll confirm those numbers. Mr. Friesen's suggesting one (1) of them might be slightly different. I'm not -- a work in progress, again, but in that range.

MR. ANTOINE HACAULT: And none of those were specifically in EnerNOC's scope of work.

Is that correct?

MR. LLOYD KUCZEK: That's correct.

MR. ANTOINE HACAULT: Thank you. Now, I probably have about twenty (20) minutes left, fifteen (15) to twenty (20) minutes. I don't know what the Board's wishes is.

THE CHAIRPERSON: Let's con -- let's continue.

CONTINUED BY MR. ANTOINE HACAULT:

MR. ANTOINE HACAULT: Thank you. Now, could I ask the document manager to go to page 1 of our book of documents -- or, sorry, page 2. And what I'd like to have expanded is the very bottom right corner, the very bottom right corner.

(BRIEF PAUSE)

MR. ANTOINE HACAULT: Now, this column which leads to the bottom right corner, at the top has the year 2027. We don't need to go there; for the document manager. And on the left-hand side at the very bottom indicates, "total gigawatts at generation."

Do I have that right so far?

MS. LOIS MORRISON: That is correct.

MS. MARLA BOYD: Are we to be looking at page 1 or page 2 of your book of documents?

MR. ANTOINE HACAULT: Page 2 of the book of documents.

MS. MARLA BOYD: Thank you.

CONTINUED BY MR. ANTOINE HACAULT:

MR. ANTOINE HACAULT: And -- yeah, that was the same thing, just like -- it's small numbers. You're testing my eyes for sure.

MS. LOIS MORRISON: We actually had smaller ones.

MR. ANTOINE HACAULT: But -- but this comes from Hydro's 2013 to 2016 Power Smart Plan, showing the annual energy savings projected in that plan, correct?

MS. LOIS MORRISON: That is correct.

MR. ANTOINE HACAULT: And if I look at the bottom number, we've been talking -- so this would be at generation, there's about three thousand (3,000) -- and it says 113 gigawatts total at generation to 2027/'28, correct?

MS. LOIS MORRISON: That is correct.

MR. ANTOINE HACAULT: So we're basically saying that the current Power Smart Plan, if it works out as forecasted, would be generating, is it annual savings compared to the baseline of about a Keeyask?

MS. LOIS MORRISON: The number you're referring to includes savings to date. So by the time we reach '27/'28, including all activity to date, we will have created a virtual dam the size of approximately Keeyask.

MR. ANTOINE HACAULT: Okay. So I had done a hearing way long ago in Limestone that's probably -- nobody fer -- remembers, and DSM was a big issue. We got Ed shaking his head.

DSM was -- was kind of a new subject. And so from the time these programs have been put into place, some of them are of shorter duration, but the total continued expected savings will be roughly a Keeyask?

MS. LOIS MORRISON: Including all of the efforts undertaken in the area of energy efficiency, which includes programs that you're more familiar with, incentive-based programs, and codes and standards.

MR. ANTOINE HACAULT: Okay. Thank you for that clarification.

Now, there was some discussion about industry DSM, and I'd just like to get a handle on some of those numbers. So if we go to page 4.

(BRIEF PAUSE)

MR. ANTOINE HACAULT: It's even smaller numbers. But there should be a highlighted line there that hopefully we can expand. It's under the heading, "Industrial".

So the heading of that sheet, if I can read the small writing correctly, says:

"2013/2016 Power Smart Plan annual energy savings, gigawatt hours, for the time period going up to 2012/'13."

Do I have that right?

MS. LOIS MORRISON: Yes, that would re

-- represent the savings to date.

MR. ANTOINE HACAULT: So this is not the projection; this is the historical part of what we were talking about, correct?

MS. LOIS MORRISON: That is correct.

MR. ANTOINE HACAULT: So if we move across the line we see that at the start of this period under the industrial heading, "Performance Optimization Program," initially there doesn't appear to have been a program because we zeros, correct?

MS. LOIS MORRISON: That is correct. This timeline projects is based upon the -- when we first launched our initiatives. And so we had initiatives that were launched as early as 1989.

MR. ANTOINE HACAULT: Okay. And if the document person could scroll to the right, we see, over the years, the various amounts that have been achieved, and if we continue to the right -- I'd rather have the numbers, but we'll look at the -- the headings.

There's -- three (3) columns to the left, there's a number of three hundred and eighty point zero four (380.04) that's highlighted.

Has everybody found that?

(BRIEF PAUSE)

MR. ANTOINE HACAULT: There, it's bigger. Have you found it?

MS. LOIS MORRISON: Yes, thank you.

MR. ANTOINE HACAULT: Okay. And you -- can you confirm what heading that is?

MS. LOIS MORRISON: That's the interim estimate of the savings as of 2012/'13 for the initiative to-date.

MR. ANTOINE HACAULT: Okay. And then there are headings -- or there's another column next to it which says -- has the number two hundred and fifty-six-o-six (256.06)

What's that number intended to reflect?

MS. LOIS MORRISON: That reflects the savings as of the benchmark year '27/'28.

MR. ANTOINE HACAULT: So what is involved in the thought process in concluding that this program as of that time-frame would go down in effectiveness to two hundred and fifty-six (256)?

MS. LOIS MORRISON: What's being presented here is more so -- it -- it's the end of certain initiatives come -- it's -- certain initiatives coming to the end of their lives, and it's

a persistence of savings going forward. We recognize, and are making corrections to, how our initiatives are tracking savings. And so in future initiative -- further reporting you'll see that those savings will be continuing forward.

This is presented solely for the purposes of economic analysis in our shop, and we recognize that those savings will be continuing on into the future.

MR. ANTOINE HACAULT: And finally, the extreme right column at two ninety-nine point eight five (299.85) still under the heading "Industrial". Is that just increased to give you added generation numbers?

MS. LOIS MORRISON: Yes, that is correct.

MR. ANTOINE HACAULT: Okay. And if we go up to the residential analysis -- I don't know -- if you scroll up the page, document management person, I'll -- where residential total, you just had it in the middle. Whoa. You're going -- yeah, and if you bring us to the right again for the last three (3) numbers.

So what we've done, we've brought up on the screen the residential total, the two forty-six

ninety-nine (246.99) is what again?

MS. LOIS MORRISON: That's the interim estimate of savings to-date for all activity to-date.

MR. ANTOINE HACAULT: Okay. And if we go to the next column, that again is the expected, I'll call it, 'staying power of those programs', it goes down from two forty-six (246) to one-o-three (103).

Is that correct?

MS. LOIS MORRISON: It's recognizing the end-of-life for certain technologies and, so there is a diminishing amount. However, we recognize that those energy savings are continuing into the future whether or not they're -- they're reinvested on -- by Manitoba Hydro or by the customer.

So there is -- there is a slight decline that will be corrected -- that has been corrected in our future programming.

MR. ANTOINE HACAULT: Okay. So I know we're talking generalities, but roughly the staying power of the industry DSM with respect to the categories that we've looked at, is roughly two and a half (2 1/2) times that of the residential total shown on this particular table.

But we exclude codes in that, correct?

MR. DANIEL FRIESEN: To kind of address what you're saying there in a -- in a generic sense, when we look at industrial loads a lot of the measures that we support result in fundamental changes to processes. And when that technology reaches the end of its useful life, it's highly unlikely in most cases that the customer is going to revert to an older technology. The process has been changed. So at the minimum they'll reinvest in the technology that was present at end-of-life. So, in general, we assume persistence of most industrial measures to be quite -- quite strong.

Now, as Lois pointed out, we -- you know, we're examining persistence in quite a bit of detail in the midst of our current -- developing a better understanding of what our future savings are going to be. And that covers all categories from residential right through to industrial.

And we're -- we're in -- in a big picture way, we're assuming that those savings will carry forward into the future. How we record them, I think is a little bit of an issue right now, and we're working to clarify that.

MR. ANTOINE HACAULT: Thank you very much. But the numbers as you present them today show

the staying power of the industrials, for the reasons that you've explained, to be a bit higher than the staying power of the residential numbers?

MS. LOIS MORRISON: I -- I don't think we would make that characterization. What this is more representing is how we looked at it from an economic perspective. But when we look at it from an actual impact to our system, we're recognizing that when -- on the residential sector, when a customer goes and, say, installs their -- or purchases a new appliance, when they to repurchase a -- that appliance when it comes to its end-of-life, they're not going to go back and replace it with something that is less efficient than what they've purchased to date.

And so -- although this number is showing a diminishment, it's not what's -- this number was presented based on an economic analysis of the program per se for our -- for our investment purposes. It was not based on recognizing that that savings will continue on into the future. And it is something that we have addressed in IRs that we will be -- that is -- that will be adjusted and has been adjusted in the 2000 and -- in the level 1s, 2s, and 3s that we've investigated, and it is being adjusted in our -- in our Power Smart planning that is being undertaken

right now.

And -- but the degree of that influence is very minor overall. You can see that the drop in the residential sector, although you are characterizing it as 2:1 ratio, the -- the drop in terms of an actual absolute value is quite small.

MR. ANTOINE HACAULT: Thank you. And -- and the chart speaks for itself. But the industrials were expected, for 2012/2013, to have an impact of about 380 gigawatt hours, correct?

MS. LOIS MORRISON: That is correct.

MR. ANTOINE HACAULT: And the residential sector was ex -- was expected to have an impact of about 246 gigawatt hours, so some 130 odd gigawatt hours less impact, correct?

MS. LOIS MORRISON: Yes, that is a correct comparison.

MR. ANTOINE HACAULT: If we could go to page 2 of our book of documents.

MS. LOIS MORRISON: I should probably characterize, before we move on, that -- that drop, or that -- that change that we were talking about, in terms of the -- the difference between the interim estimate and what's presented in the plan. Because it's savings to date it's actual activity; it does not

affect our load forecast. I -- I do want to get that on the record, because our load forecast takes our actual consumption to-date and forecasts forward from there.

So this difference that you're looking at, in terms of the 2012 year and the comparison at benchmark, is not -- it has -- has been captured and -- and is appropriately reflected in our load forecast, because we don't drop the savings. The savings don't diminish in our load forecast, they are continued forward.

MR. ANTOINE HACAULT: Thank you for that clarification.

Going to page 2, if we could zoom in on the residential, the right-hand side of the table. This is part of the 2013/2016 Power Smart Plan, correct? This is annual energy savings?

MS. LOIS MORRISON: This is correct.

MR. ANTOINE HACAULT: And if we could go to the extreme right of this table, please, document manager. With respect to how this has been categorized, there's two (2) numbers that are recorded. One (1) is an incentive-based total as of 2027/'28 of 22.1 gigawatt hours, correct?

MS. LOIS MORRISON: That is correct.

MR. ANTOINE HACAULT: And we see the increase that's been previously talked about to give us at -- an at-generation number as of 2027 to 2028 of 25.2 gigawatt hours, correct?

MS. LOIS MORRISON: That is correct.

MR. ANTOINE HACAULT: So that's one (1) component. That's the incentive-based. And then there's another category called, "Customer Service Initiatives," and that gives us a different number of thirty point seven (30.7) as of '27 -- 2027/2028, correct?

MS. LOIS MORRISON: That is correct.

MR. ANTOINE HACAULT: And again, that amount, however, is increased at a slightly higher rate, 4 percent, to give us at-generation, correct?

MS. LOIS MORRISON: No, it's not multiplied by the 4 percent.

MR. ANTOINE HACAULT: Increased?

MS. LOIS MORRISON: No, it's -- the 4 -- the 4 percent of what it represents of the overall total --

MR. ANTOINE HACAULT: Ah, okay.

MS. LOIS MORRISON: -- energy savings. It's not a multiplication by.

So -- so what we're doing is we're

converting the energy projection of '27/'28 to generation. And that factor is a factor of 14 percent, which represents transmission and distribution losses that we -- we recognize is the difference between the -- what the generation is -- the en -- the -- the energy at generation versus the energy at the meter.

MR. ANTOINE HACAULT: Okay. And there's a fairly big number in this last component, twenty-two point one (22.1), of the customer service initiatives.

Am I right in understanding that that would be geothermal?

MS. LOIS MORRISON: Yes, that is our geothermal residential energy earth power loan, which represents primarily geothermal energy.

MR. ANTOINE HACAULT: So it's the hope of the Corporation that that program will have a fair amount of success?

MS. LOIS MORRISON: Yes.

MR. ANTOINE HACAULT: Okay. Fair enough. So we've seen a total of about 7 percent. You -- thank you for that explanation.

So 3 percent plus the 4 percent relates to residential, correct?

MS. LOIS MORRISON: Represents those residential initiatives, yes.

MR. ANTOINE HACAULT: Yes. But there would be, in addition to that, code impacts, et cetera, and those are dealt with later on in the table, correct?

MS. LOIS MORRISON: That is correct.

MR. ANTOINE HACAULT: Now if the document manager could go down there should be some highlight that pops up. And we see the number of one ninety-three point five (193.5); that relates to the: "Industrial Optimization Program;" is the heading.

What's that about?

MS. LOIS MORRISON: Are you asking us to explain the Performance Optimization Program?

MR. ANTOINE HACAULT: Just so we can understand. You know, just briefly. I -- I don't --

MS. LOIS MORRISON: Yeah.

MR. ANTOINE HACAULT: -- need a large explanation. But really I don't think the Board understands.

MR. DALE FRIESEN: Yeah. So one of the challenges you are faced with in the industrial sector is that a lot of the measures -- and individual measures might be an air compressor, might be an

electric motor, might be a particular segment of a process system -- are very inter -- interrelated.

So when you change one (1) component of that process or that system, you end up impacting other components of that system. And there are also decisions that are made with respect to sizing of equipment, that it can -- upstream and downstream implications for the energy performance of that equipment.

So what the Performance Optimization Program does is it draws a boundary around a particular process, and looks at that process within the context of that boundary, and examines the energy performance as a system versus an individual measure. And that allows us -- it's more appropriate for the industrial sector in the way the industrial sector plans and operates equipment.

MR. ANTOINE HACAULT: Thank you -- thank you for that clarification. Now, Mr. Friesen, would you have an idea of what the load of the industrial group would be?

MR. DALE FRIESEN: It's in the range of about 7,500 gigawatt hours.

MR. ANTOINE HACAULT: So that represents approximately what if we do the math on the

--

MR. DALE FRIESEN: Roughly a third, give or take a little bit, of the domestic consumption.

MR. ANTOINE HACAULT: Okay. And with respect to the residential load, is that approximately what of the...

MR. DALE FRIESEN: Yeah, we -- we had a slide in Mr. Kuczek's presentation that provided that segmentation. It's not quite in a correct -- if you look at Slide 2 of Mr. Kuczek's presentation...

MR. ANTOINE HACAULT: Yes.

MR. DALE FRIESEN: That's not a full representation of the industrial load. The 22.8 percent you see on that slide is the top consumer load, which is predominantly industrial load. But the red portion, the 34.4 percent general service mass market, also includes a fairly substantial component of industrial load.

So when you -- when you break out industrial load separately, as you saw in the DSM Potential Study, that number works out to approximately one-third (1/3) of the total domestic load.

MR. ANTOINE HACAULT: Okay. Thank

you. So we were looking at 28 percent participation or effectiveness in this Power Smart Program with respect to that particular heading under the industrial.

And that relates to approximately their profile as a load profile in Manitoba?

MR. DALE FRIESEN: It's reasonably close.

MR. ANTOINE HACAULT: Okay.

MR. DALE FRIESEN: One of the advantages that we do have in the -- in the industrial sector is that industrial users have a tendency to make a very conscious decision about their costs and the measures that will address those costs.

They're used to undertaking economic evaluations. They're used to understanding payback -- they understand paybacks. They understand rates of return. And therefore, they make more conscious decisions about energy efficiency. And that's helpful in -- in penetrating those markets.

MR. ANTOINE HACAULT: And thanks. That leads quite nicely to what I wanted to do, is have some sense of the residential load and the annual energy savings of that particular sector.

So is it fair to say that the

residential, as shown on this graph, is about 30 percent of the load profile of Manitoba?

MR. DALE FRIESEN: That's reasonable, yes.

MR. ANTOINE HACAULT: Okay. And when we looked at the graph and compare that to the industrial participation, we've got 28 percent for about a third of the industrials, but if we go up -- back up to the top of the graph on residential there are challenges to getting the residential group above -- or at that level on programs?

We just have about 7 percent total?

MS. LOIS MORRISON: There's a different approach. I -- I think it would probably be more appropriate for us to -- to represent how Manitoba Hydro working with provincial and federal government is working towards improving efficiency in the different sectors.

Codes and standards are generally much more effective in the residential market, and much more influencing the residential. So a substantial amount of the code impact that we are projecting is in the residential market. And so -- and codes and standards are a very effective and cost-effective mechanism for creating energy efficiency improvements.

And so it's probably not necessarily an accurate representation to say that we're only projecting or anticipating getting 7 percent of our savings through the residential sector. We're actually anticipating getting a substantial amount, but a -- a large proportion of that comes through effective codes and standards.

MR. DANIEL FRIESEN: Yeah. To give you just a little bit of understanding how codes and standards differ from sector to sector, when you look at the measures and the activities across Canada and the United States that are related to codes and standard initiatives, in general, codes and standards initiatives related to residential and commercial measures are quite prescriptive in nature. They -- they set minimum energy performance levels for equipment that are then regulated at some point by a provincial or federal authority. It impacts the buying decision that the -- the purchaser makes.

In the industrial sector our codes and standards are more process based. They're designed to help the industrial user make a better decision about how they use their energy. It's very difficult to put a prescriptive regulation in place for an industrial process, because they differ. The mining sector uses

equipment differently than the pulp and paper sector, et cetera.

And so the -- the measures are different. As a result, it's much harder to physically ascribe codes and standards savings to industrial measures than it is to residential measures. So the point Ms. Morris (sic) makes is very, very important, that when you look at the codes and standards contribution in -- in -- that's tabulated towards the bottom of this page, a large portion of that is residential and commercial use. So that should always be kept in mind.

MR. ANTOINE HACAULT: Thank you. So then I -- I think that ties in nicely with some of the questions I asked of Ms. Rohmund on policy. Because codes, you would agree with me, are legislated through the Building and Mo -- well, you might not know that it's through the Building and Mobile Homes Act. But it is a legislated requirement which, when a builder builds, he can't build a house like I have with R12. He needs to comply with the new standards.

And it's prescriptive and it doesn't cost Manitoba Hydro any money to make those people comply with the codes, correct?

MS. LOIS MORRISON: Well, I -- I would

-- I would say that Manitoba Hydro, particularly in regards to Part 9 of the building code requirements, was instrumental in and -- and invested in getting those building codes in place. So we did actually engage and invest in that to -- to achieve that code change.

MR. DANIEL FRIESEN: Manitoba Hydro invests quite heavily in codes and standards development. I think if you would speak nationally, we are considered to be one (1) of the leaders with NRCan, BC Hydro, the Ontario Ministry of Energy, as funders of activities to develop new standards that are implemented in the future within federal and provincial regulations, energy efficiency regulations. So Manitoba Hydro does have a considerable investment in codes and standards. We work closely with provincial authorities. We work with federal authorities on many levels to achieve those.

MS. LOIS MORRISON: And -- and I might add to the discussion that it's particularly -- again, going back to the Part 9 code improvements, it's only recently that -- it -- it's as a result of Manitoba Hydro's involvement that we actually have energy components in the building code. The Part 9 code that was enacted recently is a representation of what was

previously our Power Smart new homes standards.

And it was that program, and our investment in our program, and working with builders that we were able to come to a point where the code community, which is separate from and is -- is governed by the Office of the Fire Commissioner, was able to bring that code in place. As we all know, if we were to simply show up with a new code without public consultation, without public support, without support of the builders and -- and the building industry, it would not be well received and there would be push back.

And so it's these types of investments that the Corporation makes working with home builders, bringing programs out, and moving forward we're -- with the government, that we're able to bring these codes in and bring them in so that the capacity is in the marketplace to deliver what the code is requiring. The builders know how to build to that standard, and they have the -- the mechanisms in place and their processes in place to deliver that. So we would -- would -- we do invest heavily in this area.

MR. ANTOINE HACAULT: So is it fair to suggest that these are viewed by the Corporation as very good, high return investments with respect to

energy savings?

MR. LLOYD KUCZEK: Just to give you an example, we have travel constraints on, but when it comes to an individual attending one (1) of the code meetings, I don't have to think too much about it: the person always attends.

MR. ANTOINE HACAULT: Thank you.

THE CHAIRPERSON: M. Hacault, are you getting --

MR. GEORGE ORLE: Excuse me, Mr. Chair, we -- we didn't hear that last answer at all back here. If it could be repeated either by the transcriptor or the -- the person making the answer.

MR. LLOYD KUCZEK: I'll -- I'll repeat it, and I might not use the same exact words.

But I -- I was just trying to provide an example of how important this is to Manitoba Hydro in terms of our Power Smart efforts. And I -- what I stated was that we have travel constraints on within the company, but when I get travel requests related to our staff participating in initiatives to try to influence codes and standards, I -- I don't think too much about it, those -- those travel requests are always approved.

MR. ANTOINE HACAULT: Mr. Chair, I

really apologize, because there's answers that were quite a bit -- they were very useful, but they were quite a big lengthier. There's just one (1) page I'd like to refer to on -- in our book of documents to complete this illustration or line of questioning. Page 26, please.

The reason why I took the witnesses through some of this information was to contrast it with part of the presentation that was made with respect to the ind -- industrial potential summary. You see on this slide that shows that they were not projecting 28 percent of the baseline projection, but only 2.7 percent in this particular slide.

There's just one (1) other explanation. I would suggest that we take a break, because I -- that I want the panel to give a bit of information -- or to the PUB. It's on the Curtailable DSM Program. I have a couple of questions which would seek to have this panel explain, because there's some lack of clarity in the material.

(BRIEF PAUSE)

THE CHAIRPERSON: Forge ahead.

MR. ANTOINE HACAULT: Okay.

(BRIEF PAUSE)

THE CHAIRPERSON: I'll take that back. Let's -- fifteen (15) minutes.

--- Upon recessing at 11:06 a.m.

--- Upon resuming at 11:26 a.m.

THE CHAIRPERSON: Okay. I believe that we're ready to resume the proceedings once everybody is in position.

MS. MARLA BOYD: Could I just have a moment, just to take care of a couple of items? I have a list from -- so, first off, if I could ask Mr. Wojczynski, please, to comment with respect to a undertaking made yesterday and responded to as Exhibit Number 90. There was one (1) item that needed to be added. It was discussed at transcript page 986. If he could just have a moment to add an additional item.

MR. ED WOJCZYNSKI: Yes, I -- I think a -- a clarification to add to what I said in terms of Undertaking 11 yesterday. Undertaking 11 was asking about the financials for the five (5) plans, and when we were going to update them; the five (5) plans being the five (5) key development plans. And what I said

was we were not going to be doing an updated financial analysis on those. We were -- it was the other ones that we talked about in the -- in the Undertaking 10.

But I think what would probably have been helpful for me to indicate that probably where some people might have had the impression we were going to update the financials for those five (5), is that I'd indicated, I believe it was in day 1, that we were going to update the analysis on five (5) of the key plans. And by -- and I was referring to the economic analysis, and that would be provided on the Monday.

So where we had -- in Chapter 10 we had fifteen (15) plans we worked on. We're taking actually the six (6) most key plans, including the 250 megawatt plan that Mr. Williams was interested in, and we're going to provide a partial update to what we did there to account for the higher capital cost, and we'll be doing that on the -- on the upcoming Monday. So that's just a bit of extra information.

Secondly, when -- there was the questioning this morning on the possibility of a higher or a lower load forecast, and I -- and there was question about the implications of that for Manitoba Hydro. And this will be dealt with more

extensively next week, but as -- given that we've got the load forecast panel here I thought it would be appropriate to mention that, as a resource planner and as the operators, an example of the kind of thing that we have to deal with is that this year the peak load forecast -- we all know this is an exceptionally cold winter, so obviously that drives the load.

In January -- January 6th, I think it was, and -- that we had a peak load, a net peak load, which was -- an actual load of -- which was 4,719 megawatts which was a new record peak for us. And the previous record peak from previous years had been actually the year before, and as a -- and, sorry, it was 184 megawatts higher than the previous years peak. That's almost the size of Wuskwatim. The -- the peak grew from one (1) year to the next, in terms of -- the record peak by about almost the size of Wuskwatim.

If you take the peak that happened this year, and not weather adjusted, just the actual peak, and compare it to the forecast peak, it was 143 megawatts higher than the forecast peak.

Now, we expect those kind of variations and -- and we put it in to our reserves, and we put it into our planning. That's -- that's probably mostly weather related. But it -- it's the kind of

uncertainty we -- we have to provide for with our criteria, with the reserves, and -- and if you have underlying load growth that happens faster, then that becomes even more of a problem. But I just thought the example this year of how much the peak jumped was quite pertinent to this discussion of load forecast uncertainty.

The third issue that Ms. Morrison asked me to comment on was there was a bit of discussion on -- we are using 90/10 -- a 90 percent and 10 percent confidence intervals on the -- on the load forecast, and -- and we used to use 95/5. And -- and one of the reasons we did that was that the resource planning side of things, when we are setting up our scenarios and setting up the sensitivities we're doing, and the -- the -- that what we are looking for is values which were not really extreme but something which had a medium level of occurrence.

That's why we used for capital costs a P90 and a P10, 90 percent probability, 10 percent probability on the -- on the capital costs. And we are trying to achieve that -- something like that on the other factors, and that was one of the reasons we went to a 90/10 on the load forecast.

But the fact you can have a 95 percent

or 99 percent, and they hap -- they will happen at some point, that's obviously still very critical. It's just for the analyses we were using something which was a more moderate range.

MS. MARLA BOYD: Just to follow up perhaps with Mr. Wojczynski's comments regarding uncertainty, Mr. Friesen needs to add an item of information related to the load forecast, as well.

MR. DALE FRIESEN: Over the course of the last number of days there have been several discussions about perspective or projected pipeline load growth put forward in both Mr. Thomson's opening comments and in subsequent presentations by both Mr. Wojczynski and Mr. Kuczek.

I'd like to place some information on the public record with respect to what Manitoba Hydro knows of that load growth. Most of what I will be speaking to is on the public record. There are some aspects of that discussion that I would not be comfortable speaking with outside of the con -- the CSI sessions that we have planned for later to -- later today.

But in -- in summary, we have two (2) major pipeline companies that operate within Manitoba, those being Enbridge and TransCanada. And I'll speak

to each one individually so that you have a little bit of an understanding of what we see and what they see going forward over the course of the next -- about the next six (6) -- five (5) or six (6) years.

I'll start with Enbridge. Enbridge has seven (7) pumping stations located in Manitoba. Oil enters the Mani -- enters Manitoba at the Saskatchewan border, and then exits Manit -- Manitoba near the Cana -- near Gretna, the get -- the Canada-US border.

They have, over the course of the last number of years, discussed several enhance -- enhancements and upgrades to their pumping infrastructure, the first of which received NEB approval. The Alberta Clipper Phase 1 project received NEB approval in 2013 and is expected to become -- to go into service sometime in the latter half of 2014.

That involved an upgrade in pumping capacity, not new pipeline, to increase flows from about four hundred and fifty thousand (450,000) barrels per day to five hundred and seventy thousand (570,000) barrels per day, and that's a matter of public record.

In addition to that Phase 1 improvement there has -- Enbridge has announced a Phase 2

improvement to that same pipeline, the Alberta Clipper pipeline, that will increase flows from five hundred and seventy thousand (570,000) barrels per day to eight hundred thousand (800,000) barrels per day. That application received NEB approval about a month ago, on February 10th, and it is now subject to various provincial approvals on a variety of different aspects of that project.

The company anticipates that once they've completed all of their approvals, the in-service date will be about fifteen (15) months after that. So we're looking potentially at that load coming into service sometime in 2015, probably around the middle of 2015.

In addition, Enbridge announced this week that they're undertaking a mainline enhancement, basically, a rehabilitation of Line 3, which is one (1) of their old -- the older pipelines in their system. And that enhancement will result in a capacity increase from the current pumping level of about three hundred and ninety thousand (390,000) barrels per day to seven hundred and sixty thousand (760,000) barrels per day. Again, that will require some additional pumping stations, and it will require some additional work in Manitoba, and the projected

in-service date of that is in and around 2017.

It's -- in respect to our load forecast, if you look at the Phase 1 and Phase 2 expansions, or upgrades of the Alberta Clipper line, some of that load is already represented in the Manitoba Hydro forecast. I can't give you the specific amount, but some of that expansion or upgrade is already included in our 2014 -- or sorry, 2013 forecast as was filed with this proceeding.

And Enbridge is still working through some of their hydraulics analysis. And they have provided us with information, but I would not be prepared to discuss that in this forum, and that was something we could address in the CSI forum later today.

The second major pipeline, as I mentioned, is TransCanada Pipeline. In the instance of TransCanada, we essentially have three (3) distinct operating regimes that impact Manitoba Hydro. The -- the longest standing operation of TransCanada in Manitoba has been their natural gas pipeline which carries natural gas from Alberta through to eastern markets in both Canada and the United States.

That operation involves five (5) compression stations within Manitoba. One (1) of

those has the option to use either gas or electric as a pumping -- a source of energy for pumping. As has been documented quite publically over the last number of years. TransCanada has experienced a significant decline in natural gas volumes in that main line, primarily due to shale gas development in Eastern -- in Central North America. And that's challenged the business model of that pipeline significantly. It's also resulted in some reductions in the amount of energy that they consume as supplied by Manitoba Hydro.

In and around 2008 and '09, TransCanada undertook a project to convert a portion of the natural gas pipeline from Alberta to Manitoba to oil through a company called TransCanada Energy, and then build new line into the US. That resulted in the construction of six (6) oil pumping stations in Manitoba. It's been referred to as the Keystone Project. That should not be confused with the Keystone XL Project in the US that's receiving considerable public attention. The Keystone Project has been in operation since 2010 and is recognized in our 2013 load forecast.

The -- the third project, or the third significant undertaking by TransCanada, is the Energy

East Project. TransCanada made a public announcement in April of 2013 that they would be entering an open season to establish commitments for use of this pipeline. And they indicated broadly that the pipeline would consist of conversion of about 3,000 kilometres of existing natural gas pipeline and the construction of about 1,400 kilometres of new construction. They estimated that that pipeline would carry about eight hundred and fifty thousand (850,000) barrels per day.

In two thou -- August of 2013, they announced that the results of their open season and indicated that their estimated increase to 1.1 million barrels per day and that they were planning to invest about $12 billion in the project across Canada.

The expansions, in terms of the impacts to Manitoba, there'll be expansions at four (4) existing oil pumping stations, and there will be addition of four (4) new electric pumping stations within Manitoba.

Last week -- sorry, maybe this week actually, Enbridge filed their initial filing for the -- the Energy East Project with the National Energy Board. That filing is publicly available and it includes a little bit more information about the

pumping locations within Manitoba. There will be eight (8) stations in total. The expected in-service date is 2019. I can't give you an exact time frame as to when in 2019, but it will result in expansions to four (4) existing stations and four (4) new stations, like I mentioned.

One (1) of the key aspects of projects like this, and it's not exclusive to the pipeline industry, is that MIPUG raised the issue of customers voluntarily sharing load information with us. It is -- it is really in the best interests of our top consumers to share that information with us. And that relates to the whole process of providing them with service. Energy is a critical component to most of the -- most of the operations that our top consumers engage in, and facilitating service can be a rather time-consuming process.

A new transmission service in Manitoba presently has a fairly long lead time. We're talking a process that can take from three (3) to five (5) years. And that may be well in advance of when a company is willing to make a public pronouncement about a particular project, for a variety of reasons: shareholder reasons, regulatory reasons, et cetera.

So we commonly find that our top

consumers are quite willing and eager to share information with us, but stress the confidentiality of sharing that information; and are quite concerned that that information will become public, which is one (1) of the reasons that Manitoba Hydro has gone to considerable lengths to establish the confidentiality of -- of our customers' information. Thank you.

MS. MARLA BOYD: Thank you. I also have available the response to Manitoba Hydro's Undertakings number 5 and 6, which were taken from transcript pages 261 and 263. My colleague is circulating those at the moment. I believe they would be Manitoba Hydro Exhibit number 91. Am I correct, Mr. Simonsen?

--- EXHIBIT NO. MH-91: Response to Undertakings 5 and 6

MS. MARLA BOYD: I can also advise the Board that Manitoba Hydro filed electronically this morning the CVs for the upcoming panel, so I believe that could be assigned an exhibit number, as well. I do not have paper copies at the moment, but they were filed electronically at 10:00 this morning, and we'll make them available later. And I would suggest that

those CVs be marked as Manitoba Hydro Exhibit number 92.

--- EXHIBIT NO. MH-92: CVs for MH panel 4

MS. MARLA BOYD: And one final matter. I spoke with my friend, Mr. Monnin, this morning. He brought to my attention page 7 of Manitoba Hydro's rebuttal evidence. At line 19 of that evidence in a description of position in response -- or in respect of Elenchus's report, Manitoba Hydro has used the word, "as advocated by Elenchus."

I have with Mr. Monnin discussed that, and we agree that that word should be substituted to be, "as assumed by Elenchus." So if I could ask the record just to reflect that, please?

(BRIEF PAUSE)

MS. MARLA BOYD: Thank you for your indulgence. I -- I'm finished.

CONTINUED BY MR. ANTOINE HACAULT:

MR. ANTOINE HACAULT: Thank you very much. If our document management person could bring

up the screen? She's bringing up page 3 of our book of documents. It's -- perhaps, Ms. Morrison, you can confirm, this is a different table than what we were looking at.

We were looking at energy tables and now we've switched to a capacity table?

MS. LOIS MORRISON: Yes, that is correct.

MR. ANTOINE HACAULT: And this is still part of your 2013/2016 Power Smart Plan, correct?

MS. LOIS MORRISON: Yes, that is correct.

MR. ANTOINE HACAULT: And it's for the time period ending in 2012 to 2013, correct?

MS. LOIS MORRISON: Sorry, I thought you were on the future projections. You're on which page, could you --

MR. ANTOINE HACAULT: Page 3 of our book of documents.

MS. LOIS MORRISON: Yes, that is for savings to date.

MR. ANTOINE HACAULT: Okay. So the document management person has brought up on our screens the industrial total, and there should be a

highlight on everybody's copy for the Curtailable Rate Program. So we start with that program being at zero. And if we could move to the right, it has some variations in it going forward. Continue, please, document manager. Not quite that far. That's okay, we can stop there.

A couple years out this program had a capacity on a DSM perspective of around 180 megawatts, correct?

MR. DALE FRIESEN: That is correct.

MR. ANTOINE HACAULT: Okay. And we just heard Mr. Wojczynski say that a hundred and eighty-four (184) was practically the size of Wuskwatim.

So this particular program in that particular year was practically the same size as the additional peak demand in this current year, correct?

MR. DALE FRIESEN: That is correct, with one (1) slight caveat. We have to recognize that the dependable energy available from Wuskwatim is very different than the amount of energy that we would be able to release through the Curtailable Rates Program.

MR. ANTOINE HACAULT: Thank you for that clarification. Now, this is program -- the subject matter of possible being -- possibly being

capped. Now, we see going further right before we hit the zero-zero (00), a hundred and forty-six point four three (146.43).

What's that number?

MS. LOIS MORRISON: The one forty-six point forty-three (146.43) represents the interim estimate of savings as of 2012/'13.

MR. ANTOINE HACAULT: Now, if we can perhaps go to Tab 4, pages 20 to 21, could someone from the panel please help us understand this DSM program and what it does for Hydro operations?

MR. DALE FRIESEN: I can address that. The -- the intent and the purpose behind the Curtailab -- Curtailable Rates Program has been the subject of some confusion in some of the evidence that was presented to this -- to this proceeding. And we attempt to clarify that on page 46 of the Manitoba Hydro rebuttal evidence under their Section 3.9, 'Curtailable Rates Program'.

And I'll just read through that paragraph to bring it into the public record, but --

MR. ANTOINE HACAULT: Sorry, just to interrupt. So our document manager can go to page 20 of our --

MR. DALE FRIESEN: Sorry.

MR. ANTOINE HACAULT: -- book of documents, please.

MR. DALE FRIESEN: So --

MR. ANTOINE HACAULT: This is from your rebuttal, sir?

MR. DALE FRIESEN: Yeah. So I won't read it. As my legal counsel informs me, I don't need to be wordy. But the -- the purpose -- the intent and the purpose of the -- of the Curtailable Rates Program is articulated, I believe, quite well in our rebuttal.

MR. ANTOINE HACAULT: So if --

MR. DALE FRIESEN: Sorry. I'll -- I'll take a step backwards. And we'll excuse my inexperience on this, hopefully. The -- the intent is really to support our generation operations. So we use the Curtailable Rates Program to minimize disruptions to our firm customers in the event that we have a loss -- unexpected loss of transmission or generation or an unexpected increase -- and by, "increase," I mean a very short duration increase -- in firm load.

And it also enables us to fill our -- fulfill our specific level of planning reserves and operating reserves that re -- required as part of our ob -- reliability obligations --

MR. ANTOINE HACAULT: Can I stop you right there? Could you --

MR. DALE FRIESEN: -- within the power pool.

MR. ANTOINE HACAULT: Could you give us an example of a short-term unexpected increase in firm load where you would use that -- am I right in saying resource or capacity?

MR. DALE FRIESEN: That's correct. A good example this past summer occurred when we lost one (1) of our bipoles for a short period of time. And so it was, I believe, a fairly warm period of time or a very fairly high temperatures. We have fairly high peak loading in our system at that time. And we used the curtailable load to manage our system peak load within the province while we rectified the situation with the bipole.

So that would be a typical example; unexpected, and it provided us with a very rapid short-term response. And by, "rapid," I mean about a five (5) minute response.

MR. ANTOINE HACAULT: Thank you. Please continue.

MR. DALE FRIESEN: So the -- an important aspect of the Curtailable Rates Program is

that we have a series of options which customers can subscribe to, and those options dictate response time. They dictate the frequency of the interruptions that we can impose upon the customer and the duration of those interruptions.

So they're clearly laid out in a contractual document that's been filed with the Public Utilities Board previously at various GRAs.

MR. ANTOINE HACAULT: Thank you very much. And I won't make the witness go through the particular part, but there's some parts that are highlighted in this. And if the panel has any questions to clarify --

THE CHAIRPERSON: Mr. Friesen, I would if you couldn't take us through the basics of describing the Curtailable Rate Program for the new members of the panel, please.

MR. DALE FRIESEN: Sorry, could you repeat that?

THE CHAIRPERSON: Could you give us a more -- a more basic explanation of the Curtailable Rate Program, defining it a little bit more granular?

MR. DALE FRIESEN: Yeah, I'll give you a little bit of a practical example. So what the Curtailable Rate Program does is it allows customers

to subscribe blocks of load that they are willing to interrupt in exchange for some type of compensation. And the value of that compensation is determined by the value to Manitoba Hydro of that response mechanism.

So we have different options for responding to different types of events. We could build a peaking plant. We could build -- we could have energy in storage. We could build more firm capacity. We -- there are many different options that are available to respond to events within the system that may cause sudden increases in load or may result as a result of equipment failing or equipment going out of service suddenly.

Our program requires customers to subscribe a minimum of a 5 megawatt block, so that precludes, at this point, smaller customers from participating in that program. It's primarily our larger customers that can participate in this program.

And they -- what they have done, it -- particular customers that have processes that can be shut down very quickly with minimal disruption and restarted quite quickly with minimal dis -- disruption. There are many industries where you cannot do this. An interruption of this type would

result in an eight (8) -- six (6) to eight (8), ten (10), twelve (12) hour recovery period. But in certain in -- industries, it's possible to very rapidly turn down load and then very rapidly turn up load when the event has -- has passed.

So at present we have four (4) customers enrolled in this program, all in our top consumer group. And they provide us with these services in exchange for both a standby payment, depending on the option they choose, and a -- in some cases it's a -- a payment that occurs when we actually physically curtail them.

MR. ANTOINE HACAULT: Thank you very much. Those are all my questions in the areas that I intended to canvass with this panel.

MR. DANIEL FRIESEN: Thank you.

MR. SVEN HOMBACH: Mr. Chairman, I was advised by Mr. Orle earlier that he expected to be about half an hour with his cross-examination. Considering that it's currently about ten (10) minutes to noon, it would help if the panel could let me know if we should continue with one (1) more presenter or break for lunch right now.

THE CHAIRPERSON: Yes, let's continue, please. Mr. Orle...?

CROSS-EXAMINATION BY MR. GEORGE ORLE:

MR. GEORGE ORLE: Thank you, Mr. Chair, members of the panel, and members of the Hydro panel. I don't have the familiarity that my colleagues here have with the Manitoba Hydro. I may get your names mixed up. I'm sorry. I may even forget what your name is.

So some of these questions will be sent out as a lob. Whichever one of you wants to hit it back, I'll accept that answer.

My questions are going to be limited to the demand-side management. It won't be dealing with the forecast whatsoever. And my first question will be to the EnerNOC representative.

And I'm just going to repeat what I believe was your evidence on March the 3rd, and that was that in speaking of the residential sector, Maniti -- Manitoba Hydro had recently done a saturation survey and had extensive information about its customer segments.

Do you recall saying that?

MS. INGRID ROHMUND: Yes, that's correct.

MR. GEORGE ORLE: Okay. Can you please confirm that the demand-side management

assessment for the residential sector began with and is essentially based on the Manitoba Hydro saturation survey?

MS. INGRID ROHMUND: The saturation survey was a very important input into the analysis and we used it extensively. It was all -- it was, however, supplemented with other sources of information.

MR. GEORGE ORLE: Okay. And what other sources of information would that be?

MS. INGRID ROHMUND: Manitoba Hydro billing data, secondary sources -- other projects that we've done, other Canada-specific sources. I'd have to go into the report to read off the specifics. It's in Chapter 2.

MR. GEORGE ORLE: Okay. But the saturation survey would have been the primary tool that you used?

MS. INGRID ROHMUND: For some of the data elements, yes.

MR. GEORGE ORLE: Okay. And do you have a copy of that Hydro saturation survey available?

And -- and, forgive me, I'm -- I'm new here. I don't know if it's been filed before. I came

in after the requests were available.

MS. LOIS MORRISON: Perhaps I can help. The -- a copy of the 2009 Residential Energy Use Survey was filed by Elenchus in response to one (1) of the Public Utility Board interrogatories. If you give me one (1) brief minute, I can find it.

MR. GEORGE ORLE: Thank you.

(BRIEF PAUSE)

MS. LOIS MORRISON: The interrogatory I'm referring to is the response by Elenchus to PUB/Elenchus-1 -- oh, sorry, PUB-Elenchus -- sorry, PUB/Elenchus-2. I apologize.

MR. GEORGE ORLE: Okay.

MS. LOIS MORRISON: That's where -- there includes a copy of the 2009 Residential Energy Use Survey.

MR. GEORGE ORLE: Thank you. Ms. Rohmund, does -- also part of your testimony you indicated that you analyzed separately twenty-nine (29) customer segments, and I believe that those are set out on page 29 of Manitoba Hydro Exhibit, I believe it's, 87. If the document manager could please put that -- thank you. It's there already.

The twenty-nine (29) customer segments that you spoke of in your testimony, those are the segments shown on the right-hand side of that page?

MS. LOIS MORRISON: That is correct.

MR. GEORGE ORLE: Were residential customers and First Nations communities in general identified in any of these twenty-nine (29) categories?

MS. LOIS MORRISON: Yes, they were. They would be identified as -- going down the list here, single family electric non-gas reserve. Then going down further down the list there was -- which -- which is represented by, MF electric non-gas reserve, would be the multi-family electric non-gas reserve.

And I believe that was it. We don't -- didn't have apartments for those communities.

MR. GEORGE ORLE: And those are specifically to reserves?

MS. LOIS MORRISON: Yes.

MR. GEORGE ORLE: Okay. And was there any differentiation made between southern reserves, northern reserves?

MS. LOIS MORRISON: Not within the study, no.

(BRIEF PAUSE)

MR. GEORGE ORLE: In the commercial sector, I believe you've got eighteen (18) segments. Are any of those segments commercial buildings on reserve?

(BRIEF PAUSE)

MS. INGRID ROHMUND: The commercial buildings that were included in the study included commercial buildings on reserves. However, they were not isolated as separate segments.

MR. GEORGE ORLE: Okay. You have the segments set out for residential. Do you have a list of the -- the segments that were used for commercial?

MS. INGRID ROHMUND: Yes.

MR. GEORGE ORLE: And where would I find that?

MS. INGRID ROHMUND: I'll look it up for you in the report.

(BRIEF PAUSE)

MS. INGRID ROHMUND: Page 312 of the

DSM Potential Study Report.

MR. GEORGE ORLE: Thank you. And are you able to segregate southern and northern reserve commercial institutions?

MS. INGRID ROHMUND: No, we were not.

MR. GEORGE ORLE: I'm not sure if I asked this: Are you able to do that for residential; differentiate between northern and southern reserves?

MS. LOIS MORRISON: The study that was undertaken by EnerNOC we did not differentiate within that. However, within our residential energy-use survey we are able to differentiate between northern areas and southern areas.

MR. GEORGE ORLE: Okay. If you refer to page 31 of the same exhibit.

(BRIEF PAUSE)

MR. GEORGE ORLE: Pardon me. When we take a look at page 31 there's a sample of -- of twenty (20) key residential measures and a comparison of a levelized cost of eighteen (18) residential and commercial measures on page 69.

Where would I find a complete list in the exhibit or in the filings of all residential and

commercial measures that were considered in Manitoba Hydro's assessment of DSM potential for residential and commercial sectors?

MS. INGRID ROHMUND: In Chapter 5 of the DSM potential study report we identify the measures that we considered in the study.

MR. GEORGE ORLE: Looking at the list of twenty (20) key residential measures on page 31, which of those measures are presently available to all First Nation communities?

MS. LOIS MORRISON: I -- I think we need -- could you please clarify your question. These measures are not specifically aligned with programs being offered now, although a number of these measures are covered by existing programs.

So I guess I'm -- I -- I would like to know, are you asking program specific or are you asking in terms of this particular study? In this particular study, the majority of these init -- these measures may be present within any of the First Nation homes. It was focussed around insulation, interior lighting, housing construction, geothermal heat pumps, infiltration control, which is air sealing, low-flow showerhead, refrigerators, appliances, electronics.

The majority of these, I would expect,

are very -- are consistently available in most of the housing across the province.

MR. GEORGE ORLE: Okay. And that includes housing on reserves. The programs that you have, these measures included in all of those programs would be available and householders on reserves would be eligible to apply for those programs?

MS. LOIS MORRISON: Yes, they are.

MR. GEORGE ORLE: Okay. Has Manitoba Hydro or EnerNOC made an assessment of the actual penetration of these key residential measures in the programs in the First Nation communities?

(BRIEF PAUSE)

MS. LOIS MORRISON: Are you asking about whether we keep track of the actual penetration of our existing programs in First Nation communities?

MR. GEORGE ORLE: Yes.

MS. LOIS MORRISON: Yes, we do.

MR. GEORGE ORLE: Okay. And where would I find that information?

MS. LOIS MORRISON: We have quite a bit of information on the record to date regarding participation by individuals and working in the First

Nation programs. We -- as part of this filing specifically, we did not file specific information about participation in specific programs unless it was requested under an interrogatory.

If you would like information, Mr. Kuczek and I both have quite a bit of information related to those programs. But as I mentioned, that has been provided under the past electric GRAs. We've given statuses or updates as to the -- the uptake of the pro -- of the initiatives that we work with in those communities.

MR. GEORGE ORLE: And could I ask you as an undertaking to provide that information?

MS. LOIS MORRISON: Could you be a little more specific about what particular information you're looking for? That's a very broad request.

MR. GEORGE ORLE: Well, the -- the -- I gather the programs that are available to First Nations are the ones that they're actually taking an active part in as to what amount or -- or how much of the community actually takes it up.

And -- and what I'm looking for is, essentially, a comparison as to -- to how well these programs are being delivered to the First Nations communities as opposed to the outside or reserve

communities.

MS. LOIS MORRISON: Well, we do have a ver -- we have a program that is specifically targeted to First Nation communities, working with the bands and the councillors specifically, where we actually help -- work with them to identify -- they identify housing which requires insulation upgrades. And we work with the community to install those insulation upgrades at no cost to the community. We provide the materials and pay for the labour and shipping of those materials.

We have worked with, I believe, the vast majority -- and Mr. Kuczek can give a better update on the specifics of those details, because that program actually reports directly to his office because of the priority of that program.

In addition to that, we have initiatives where we are working with, or attempting to contact, the band offices to provide walkthrough audits or walkthrough energy assessments for the commercial facilities in those communities. So it's -- it's an area that we've got quite a few undertakings with.

And so if you'd like a status update on our First Nations Energy Efficiency Program, in terms

of the number of houses that we have improved the energy efficiency of, the types of measures that we've included in those upgrades, we could provide that.

MR. GEORGE ORLE: Thank you. I -- I'd like that.

MR. LLOYD KUCZEK: I can just add a little bit more information. We've taken a different approach with the First Nation communities. And -- and the pace of progress is really dependent on each community or First Nation that we're working with. But our approach is to work with each one, and as Ms. Morrison pointed out, work with the individual communities. And it's usually the housing manager that we work with.

And we're -- we're trying to clean up, certainly, all of the residential homes that re -- that can use additional insulation. So we've retrofitted over a thousand in over -- I believe it's about thirty-seven (37) First Nation communities. Some First Nation communities still haven't participated yet, but that's their choice. We're certainly willing to work with any First Nation community that's willing to participate with us.

And on the geothermal side, I mentioned earlier in the hearing that we're working with two (2)

First Nation communities, and we have installed over a hundred geothermal systems in -- we haven't, they have actually, have installed over a hundred geothermal systems in those communities. And there's discussions with four (4) additional First Nation communities to potentially do the same thing there.

So the approach is somewhat different with the First Nation communities, and -- and in some -- in some ways much more successful when they're willing to participate and work with us on implementing these measures. Because if they're on board in terms of doing it, certainly with the residential side there's no cost to them. The geothermal side we're -- would be homes that are eligible in terms of being economic. There's no cost as well. So it's -- it's turned out to be successful to that degree.

MR. GEORGE ORLE: Are these delivered under a...

(BRIEF PAUSE)

MR. GEORGE ORLE: Okay. I believe that the undertaking was for you to provide us with a -- either the results or the -- the success of the

programs that you've -- you've had so far with -- with the First Nations communities.

Am I right in that?

MS. LOIS MORRISON: Yes, we have committed to provide you with an update as to the number of homes that we've insulated, along with the measures that have been installed.

--- UNDERTAKING NO. 20: Manitoba Hydro to provide an update on the number of First Nations homes insulated along with the measures that have been installed

CONTINUED BY MR. GEORGE ORLE:

MR. GEORGE ORLE: And would I be able to tell from -- from those figures the -- the ratio of how well these programs are being delivered to the general population as opposed to the reserve communities?

MR. LLOYD KUCZEK: That's difficult to answer. So it depends on each First Nation community. So there's three (3) communities that we've totally retrofitted all the homes that fall into the category

of being eligible. In other words, they -- they require insulation.

So we've done all the homes in those communities, so if we compared those communities to the general population of Manitoba, we're doing much better. If you compare it to communities that have been signed up or are working with us -- 'signed up' is the wrong term for it, but that currently are not participating in the programs, it -- clearly not as good as the general population in Manitoba. So it varies by community.

MR. GEORGE ORLE: Okay. So what you're saying is that if a community wants to bring these programs in, they can have as much penetration as they want or as much as the program allows.

And this is the basis of who asks as opposed to where it's being delivered to?

MR. LLOYD KUCZEK: It's actually -- we -- we are approaching the communities, so it's a question of them responding. And -- and sometimes that takes time for them to understand what's all involved. But there's -- there's no limitations of participation. It's -- it's more to do with, as I mentioned earlier, the pace of the First Nations community -- communities' willingness to participate.

MR. GEORGE ORLE: Okay. If you'd refer to -- to page 69, and I'm just going to ask -- this is a general question again.

The -- the programs that are shown on page 69, again, are all of those available to the First Nations communities?

MS. LOIS MORRISON: Yes.

MR. GEORGE ORLE: Okay.

(BRIEF PAUSE)

MR. GEORGE ORLE: And on page 83 of that same exhibit, the new programs that are being proposed, again, and just a general question: Are -- are these new programs all -- all three (3) available to First Nations communities?

MS. LOIS MORRISON: Yes.

MR. GEORGE ORLE: Okay.

(BRIEF PAUSE)

MS. LOIS MORRISON: We should state though that as Mr. Kuczek noted, one of the programs has not yet been approved. It's potentially going to be -- it's still under review, and subject to approval

--

MR. GEORGE ORLE: Okay.

MS. LOIS MORRISON: -- and that was the LED lighting program.

MR. GEORGE ORLE: And as you go into consideration of new programs or enhancing programs, do you have any -- any policy in terms of consultation with First Nations communities in regards to what new programs might be available, or what programs might be available that the First Nations would -- would appreciate receiving, as opposed to the ones that you're already delivering?

(BRIEF PAUSE)

MS. LOIS MORRISON: In terms of our program design, we -- all of the opportunities that we pursue where -- particularly where it's geared to a market that's served by electric heat -- electric space and water heating, is to the benefit of, we would assume, First Nation communities also.

It's more so on the lines of the delivery of how do we get that measure or that opportunity to the First Nation communities, or the members of the First Nation community. And we get

information through our interactions with the communities, so we take their thoughts.

And the ones that we're working with, they provide us with insight as the best way to deliver those types of programs to -- to their members.

MR. GEORGE ORLE: Okay, is there a specific policy in how you deal with that? You -- you talk about talking to the communities. Is it -- is it a matter of a formal consultation? Is it just word of mouth, things that you may hear from -- from the communities?

I'm just wondering whether you have a process in place to -- to have these consultations.

MR. LLOYD KUCZEK: There isn't formal consultations, per se. The opportunities within a First Nation community are generally the same opportunities that are available to outside the communities.

What we have in place is we have an individual that's dedicated just to working with the communities. And so that individual works with the housing manager and explores opportunities.

Right now, the focus is primarily on the residential sector, but discussions are ongoing as

far as expanding that to the commercial, as well. And -- and this is something that has evolved over time. I'm not sure if we put it in place four (4) years ago or thereabouts, but prior to that, participation wasn't as good in the First Nation communities.

And so we're -- we've found that this is working quite well for us, actually, as well as the First Nation community, so it's a big improvement.

MR. GEORGE ORLE: Does Manitoba Hydro have a First Nation Power Smart program?

MR. LLOYD KUCZEK: We -- we call it that, but it's essentially the same program as the Affordable Energy Program. It -- it -- the only difference would be the delivery, where we have the individual working with the First Nation community, and usually he's working directly with the housing manager --

MR. GEORGE ORLE: Okay.

MR. LLOYD KUCZEK: -- in the community.

MR. GEORGE ORLE: I didn't see it mentioned in any one of the -- the programs available here. So is it just a title that's given to the manner of delivery as opposed to a program of its own?

MR. LLOYD KUCZEK: That's correct.

(BRIEF PAUSE)

MR. LLOYD KUCZEK: And just to add a bit more to that, we -- we track progress separately with -- but it's a subset of the overall Affordable Energy Program.

(BRIEF PAUSE)

MR. GEORGE ORLE: Are any of the programs specifically designated under the First Nations Smart Program?

I had earlier asked you whether it was just a name for the delivery of the services there, but are there any programs within that that are -- are different than the programs available under the general programs you've set out already?

MR. LLOYD KUCZEK: They -- they are different from the sense that they're a community -- they're -- they're the same programs, but they're a community approach. So the geothermal community initiative that we have in place, the only two (2) participants currently are two (2) First Nation communities.

And again, it works very well when the communities are interested and -- in participating because the delivery -- or the effort on our part is -- - is minimized and the -- the participation is substantial given our effort because the First Nation community ends up delivering the program within their community. And we provide resources as well as -- well, technical and financial support to implement those opportunities.

So that fall -- that -- that is the case both with the community Geothermal Program as well as our Affordable Energy Program, which is primarily focussed on insulation, but it includes some low -- lower cost opportunities as well.

MR. GEORGE ORLE: Thank you.

MS. LOIS MORRISON: Maybe a way to -- to characterize it would be that, as you know, we have a Home Insulation Program. We have a Water and Energy Saver Program specifically noted here. They ha -- they -- they address certain measures.

We also have, as Mr. Kuczek mentioned, the Affordable Energy Program of which we are specifically targeting. There are components that have different program mechanisms that help us target specific sectors of the marketplace and -- and

increase our reach and increase our penetration.

But they're, essentially, taking the Home Insulation Program and measures from the Water and Energy Saver Program, rebundling them, repackaging them and offering additional services, such as the -- as paying for the labour in the Affordable Energy Program. And in the First Nations sector, specifically targeting the First Nations sector, we work with the -- the community -- with the Band, the housing manager, to actually pay for the labour to -- we pay them to have them install the measures.

It's -- it's a different repackaging to specifically get those measures that we see as benefiting the individuals into those homes. So when we were talking about being a special program, or a specific program, it's -- it's takin -- it's repackaging things that are offered in other areas and, specifically, developing a program delivery mechanism that helps us get greater reach in those communities.

MR. GEORGE ORLE: Thank you. I -- I appreciate those answers. And it gives me a better understanding of -- of what the delivery and the models are that are being used here. And, again, I apologize if this is material that's already been

presented. There's been a -- a lot of material to try to go through. Thank you. I appreciate.

Ms. Rohmund, I'll direct another question to you. In -- in the process of determining the segments for the residential customers, are demographics of these customers, such as income, household age, household preferences, developed as part of that?

(BRIEF PAUSE)

MS. INGRID ROHMUND: The characteristics that we used to segment the residential sector were the heating fuel, gas or electric, whether gas is available or not; and -- and geographic region, where we could, north and south; and reserve; and the age of the home, so built before 2000, or from 2000 forward; and then income level were the variables that we used.

MS. LOIS MORRISON: And this is all detailed on page -- on -- in Table 3-1 of the report, how we identified or broke out the segments and characterized them.

MS. INGRID ROHMUND: As well as the number of customers in each segment and their energy -

- their electricity use in 2010/'11.

MR. GEORGE ORLE: Okay. Thank you. I won't refer specifically to the document. I think you may remember it. It -- it was your Ameren Illinois study. And in that you included a development of residential attitudinal segment distribution.

Was that something that was asked of you in -- in this particular study by Manitoba Hydro? Did you develop any of that?

MS. INGRID ROHMUND: No, we did not. I should add that -- that Ameren -- unt -- until this year, Ameren is the only client that we've worked with that has taken that approach. They are -- there's one (1) person at Ameren who is responsible for all three (3) studies that we did who believes strongly in that approach and is able to get the funding to support that level of research as well. The other utilities, the other thirty (30) plus studies that we've done, use a similar approach to what we used with Manitoba Hydro.

MR. GEORGE ORLE: Okay. I hate to say anything is a given when I start a question, because so often it turns out that I'm the one that's wrong on it.

But would it be fair to say that a unit

of electricity saved, whether it comes from the north or whether it comes from the south, has the same value?

MR. ED WOJCZYNSKI: Nearly. The -- the difference is --

MR. GEORGE ORLE: Well, that's halfway. I'm happy with that. Thank you.

Maybe you could just explain to me what -- what the difference might be.

MR. ED WOJCZYNSKI: Load in the south requires transmission from the north to the south, which has its capital cost, but including things like Bipole III, which -- and -- and any other similar north-south. So to the degree reductions in load in the south can prevent or defer those north-south enhancements, the northern load doesn't tend to provide quite the same big deferals. On the other hand, the northern loads, some of them tend to be in more remote areas where there are smaller amounts of load for a significant amount of -- of transmission investment. So it -- it would actually depend a little bit on where that northern load is and what type it is.

If you're referring to the type that are in some of the First Nations, some of them would

have fairly high transmission upgrade costs down the road if load were to grow, so you'd have to do a very specific study to really get a good answer on that.

MR. GEORGE ORLE: Okay.

MR. ED WOJCZYNSKI: So I -- I guess it's nearly, and it depends.

MR. GEORGE ORLE: Then in -- in terms of the value of the programs that you put together, there would be -- I think if you were looking at it on a -- on a cost-effective basis, a program delivered to the south would probably be of -- of more value to Manitoba Hydro than -- than ones delivered to the north?

MS. LOIS MORRISON: We don't characterize it that way when we're developing our programs. Our programs, we -- we develop them based on one (1) overall value assigned to the -- to -- to the province, is how we assess our investment in programming.

MR. GEORGE ORLE: Okay. And I'd just like to ask another question related to -- to an aside made on -- on Monday, and that's in regards to: When putting these plans together you -- you take a look at whether or not they make economic sense. And ,I believe, Mr. Kuczek, you were talking about that in

terms of sending your people back when they brought you a program that made no sense. But that's not the case in every one of your programs.

When I -- I recall that you were talking about a program, a lower-income program, where essentially the -- the benefits to the customer were being given to them for, I believe you said, almost free.

MR. LLOYD KUCZEK: So -- so that's the Affordable Energy Program. And so that's the same program that the First Nation communities are participating in as well, and so there's no cost to the First Nation communities.

And you mentioned income before, so it might be of interest to you, a well, to know that what we do with the First Nation communities is we don't -- with the Affordable Energy Fund -- Program, not fund, but the Energy Affordable Program throughout Manitoba, there is a income eligibility component to that that customers have to meet to be eligible for that program and participate. With First Nation communities we don't look at income. If there's a residential building within that community, First Nation community, they're eligible.

MR. GEORGE ORLE: Okay. And I would

assume that the -- the basis for that is that you don't always look at cost. There's a -- there's an equitable factor that comes into play occasionally in dealing with these programs?

MR. LLOYD KUCZEK: That -- that is true. With -- with the First Nation communities, we realized that there is a number of -- there'd be challenges getting income levels, and we talked about it outside the First Nation communities as well, one (1) neighbourhood in Winnipeg, whether we should take the same approach and not worry about the income of those individuals. And the reason you do that I because it just may be a more effective way of achieving what you're -- you're attempting to achieve through the Power Smart programs, and that's capture cost-effective energy efficient opportunities. And some of those sometimes are not, as I mentioned when we talked about our different options. Embedded in a package could be some stuff that on the increment is not cost-effective.

But we do not require through the Affordable -- or the Affordable Energy Fund Program which includes the First Nations program, it does not have to meet those cost-effective tests. This program is supported through the affordable energy fund, and

the -- that fund is established through legislation as well. And it's directed -- or part of the -- one of the primary objectives is to ensure that those in a lower income and those that live in Northern Manitoba have access to the same programs as other Manitobans.

MR. GEORGE ORLE: Okay. Has there ever been any thought of -- of enhancing the programs that are available to -- to low income or -- or northern communities to -- to offset what -- what I would characterize as -- as a better ability on the part of consumers in the southern part of the province to -- to take the benefit of -- of certain savings?

(BRIEF PAUSE)

MR. LLOYD KUCZEK: We -- we effectively think we're achieving that through that Affordable Energy Program, and the First Nations component within that program.

MR. GEORGE ORLE: Okay. Maybe I might do this better as an example. I find that my mind works better with practical examples rather than philosophical questions. But I'm going to refer to the -- the brochure that -- that we talked about. That's Exhibit Number 88.

And -- and I'm going to use, as an example, the difference between someone in the south part of the province, and -- and someone living in, say, an area like Island Lakes. I used to use just an ordinary citizen from River Heights, but I kept getting badgered about the fact that I shouldn't use people from River Heights, as every one (1) of my examples. So I now just use myself, and it makes it a lot easier.

In my home, I have an electric water heater. When I saw this brochure, I realized that that's probably not the best decision for me to make. I can switch over and, in effect, I get myself a fifteen hundred dollar ($1,500) benefit. That's worth a considerable amount of money to me.

I have a neighbour that's just a few doors down, and his house is heated with gas and also has a gas water heater. When I go to the second side of the brochure, there's a -- a fifteen thousand dollar ($15,000) saving that my neighbour could get. That's a -- a significant saving, and I believe that we were told that this is based upon current rates, not if -- if the proposal is accepted in the rates that we've been talking about. Those aren't even included in these savings.

Am I -- am I right on that?

MS. LOIS MORRISON: You are correct. These are based upon current rates.

MR. GEORGE ORLE: Okay. So I'll -- I'll take, as an example, one (1) of my friends, and I -- I do have friends in Island Lake so I can use this and I -- I'll make a composite name, a common first name, a common last name in several of the communities, Steven Harper.

My friend Steven Harper has a house heated by gas -- I'm sorry, by electricity. Water is heated by electricity. He pays the current Hydro rates. He does not have an option to switch over to natural gas. He foregoes a significant saving in rates. More importantly, he'll be paying the new rates that are going to come in, if this is approved, for the next twenty (20) years.

On the other hand, myself, who has now divested myself of anything running on electricity to heat my home, or to heat my water, will not have to pay those high rates for the next twenty (20) years. There seems to be a -- a level of inequity in that, in terms of if programs are set up and a benefit is -- or the programs are all equally available, that if one (1) area of the province can obtain a significant

benefit from a program that perhaps there should be resources put into the other areas that would match that or would be equivalent.

I don't know how much goes into the -- the low income programs, but would it be close to the types of savings that would be available to just a regular, middle-class homeowner in -- in Winnipeg?

MR. LLOYD KUCZEK: The savings that you achieve through participating in the Affordable Energy Fund Program vary by each -- each customer that participates, because it's dependent on the measures that are implemented. So it's the starting level of the insulation, for example, to the finishing level.

You could easily save five hundred dollars ($500) if your -- if your -- your base home didn't have the basement insulated, for example, and the attic insulated very well. So you -- you could save in the range of five hundred dollars ($500). So you're not going to get the savings that customers have -- to the same degree as customers have in terms of fuel choice. But fuel choice and the access to natural gas is not something that influence us as -- influences us in terms of what we offer customers on an individual measure basis. We assess those based on the economics.

So those measures which you're bringing into the discussion is the issue of whether or not there's -- or -- and how you deal with this -- the -- the economics of bringing -- bringing natural gas to --

MR. GEORGE ORLE: Yeah.

MR. LLOYD KUCZEK: -- areas that currently don't have access to it.

MR. GEORGE ORLE: And I'm sure we'll get into this later on in the -- in the hearing, but the -- the other corollary of that example that I used is that, after I've avoided the twenty (20) years of increased rates, I'm still eligible for the dividend if it's going to come at the end of those twenty (20) years.

When I say "dividend," I'm talking about what we're talking about as a benefit to -- to all Manitobans at the end of that year from the payment of the rates and delivery of the new -- new dams. We're all going to be benefiting from that. And even though I haven't paid anything towards the increased rates, I'll be entitled to that -- that as I call dividend the same as anyone else would be.

I -- I think that's more of an aside. I -- I'm not asking for --

MR. LLOYD KUCZEK: You lost me there. I'm sorry.

MR. GEORGE ORLE: All right. Thank you.

THE CHAIRPERSON: Mr. Orle, are you -- are you done? Are you -- I'm sorry to interrupt.

MR. GEORGE ORLE: Yeah.

THE CHAIRPERSON: Thank you.

MR. GEORGE ORLE: Those are all my questions. Thank you very much to the panel. Thank you to the Board.

THE CHAIRPERSON: I wonder if -- before we break for -- for lunch, I wonder if I could ask the Manitoba Hydro to undertake to explain to the panel the rates that are actually paid by First Nations communities in Northern Manitoba.

And the reason I'm asking you this is because we heard from some presenters on Thursday last that First Nations people living in the shadow of some of those dams were paying far more for their electricity than somebody located in -- in southern Manitoba.

So I wonder if you could undertake to inform the -- the panel just how rates for First Nations communities in northern Manitoba are

calculated and paid. So we want an understanding of -- we want to understand if there was any -- if the statements that we heard were -- were factual or not.

MS. LOIS MORRISON: I -- I think we can address that right now. Manitoba has uniform rate legislation which requires us to, essentially, charge everyone the same set of rates, with the exception of those individuals in the diesel-served communities.

But for residential customers, everyone is charged the same rate, even those individuals leaving -- living in the diesel-served communities. They are paying the same basic monthly charge, they pay the same uniform rate per kilowatt hour.

And I -- I -- the individuals who were here and presented from the community were -- are being paid -- are being charged the same rate per kilowatt hour and the same basic monthly charge across Manitoba.

THE CHAIRPERSON: Thank you. Let's -- let's adjourn for lunch. And I would suggest that we return here at 1:15.

MS. LOIS MORRISON: I could offer you one (1) more item, Mr. Chair --

THE CHAIRPERSON: Okay.

MS. MARLA BOYD: -- for your lunchtime

reading pleasure, if you -- if you like. Manitoba Hydro is in a position to file its response to Undertaking Number 13, which included any late 2013 external population forecasts and the 2014 economic outlook. It's available here, and we have copies being circulated.

I believe it would be Exhibit Number 93. Thank you.

--- EXHIBIT NO. MH-93: Response to Undertaking 13

THE CHAIRPERSON: Ms. Boyd, does that give you enough time for your team to have lunch if we resume at 1:15?

MS. MARLA BOYD: Could we perhaps go to 1:30? Thank you.

THE CHAIRPERSON: Let's do 1:30. Thank you.

--- Upon recessing at 12:42 p.m.
--- Upon resuming at 1:37 p.m.

THE CHAIRPERSON: Good afternoon. The -- we'll restart the proceedings.

MR. SVEN HOMBACH: Yes. Thank you,

Mr. Chairman. Before we proceed, just a few administrative matters.

First of all there are three (3) sessions left this afternoon. The lawyer for MMF will be examining next followed by counsel for the Independent -- Independent Expert Consultants. I anticipate that this will take about an hour.

After that, as I advised this morning and yesterday, there will be a closed in camera session where members of the public will be included, where commercially sensitive information will be discussed. At that point, the audio and video feed out of this room will be disconnected, as well. I would likely call for a ten (10) minute break before that session so that the necessary technical arrangements can be made.

I've also been advised by My Friend Ms. Ramage that Manitoba Hydro has a few administrative matters to address, so perhaps I can turn it over to Ms. Ramage.

MS. PATTI RAMAGE: Thank you. My administrative matters actually don't deal with this panel so much as the next panel. Next week we'll be putting up a different panel. It's a fairly large panel and it's a complex subject matter.

It'll be -- that's when we're going to be dealing with the economic analysis, and -- and uncertainty. And included in those materials are -- when we review is discount rates, and I don't know about the rest of the room but I find it really, really hard to understand.

And so what I asked our people to do was put together a package of recommending reading, and we've done this for the room, so everyone can have it. We've picked out what we though were some of the key IRs on discount rates, and some of the academic articles that were referenced in our IR responses.

And we have to admit when we looked at them one (1) of the things we found was a couple of them, when you clicked on the link, you found that you had to pay to get to read it. So Manitoba Hydro has gone in and we have bought those articles for people in the room and we have a package.

So that when we get to our tough sledding next week I think it'll really help if people will have read these materials ahead of time, so that we're hopefully a little further down the path in terms of getting there. So our folks upstairs are just putting the final touches on making sure there's copies.

(BRIEF PAUSE)

MS. PATTI RAMAGE: Oh, they're amazing. Ms. Fernandes has them and they're available. We will be distributing them throughout the room. So it's your recommended reading. It's already all on the record, but we thought it would help move things along next week.

THE CHAIRPERSON: So the day of recess tomorrow is we have homework assigned, is what you're saying?

MS. PATTI RAMAGE: That is exactly correct.

MR. KURT SIMONSEN: Is that going to be an exhibit, Patti?

MS. PATTI RAMAGE: I wasn't planning on making it an exhibit, simply because it's all material on the record. We've com -- we've -- we've just compiled it for reading. If that's something we decide we want to do, I -- maybe after parties have addressed it, and if they would like it to be made as an exhibit, we can do that then, but...

MR. SVEN HOMBACH: Ms. Ramage, I would expect that probably at least one (1) of the parties will refer to those articles. If they're going to

refer them on the record, it might be a benefit to have them as exhibits. Now, would the copyright restrictions allow that to have them made exhibits, or does Manitoba Hydro have any concerns?

MS. PATTI RAMAGE: That's a good point, Mr. Hombach. What we did with the articles that had to be paid for, we only have permission to make twenty-five (25) copies. And so those articles cannot go on the record of the proceeding per se, in terms of on the website. They have to be limited to what we produce in the room. That is the permissions we were able to -- to purchase.

THE CHAIRPERSON: So could I suggest that maybe on Monday we have a document which can go on the record and that becomes the exhibit.

MS. PATTI RAMAGE: We can do that, but that would be the actual -- the IR response that's already there, and that's why I was thinking --

THE CHAIRPERSON: Oh, I see. Okay.

MS. PATTI RAMAGE: -- it didn't necessarily have to be an exhibit, because if you look it could be -- and it's not the first one in this package -- but it could be IR PUB/Manitoba Hydro First Round 151c. That's when the article is referred to and it's footnoted. We've just attached the actual

article now.

So if people wanted to refer to it, they already have that reference. That's why I was thinking it didn't need an exhibit number 'cause there's nothing new here. It's already on the record.

(BRIEF PAUSE)

MS. PATTI RAMAGE: Ms. Boyd just suggested maybe we could provide a list of what's there that could go on the record just in one (1) document to show what the -- the package was.

MR. SVEN HOMBACH: That might be helpful. Thank you.

MS. PATTI RAMAGE: Okay. And I'm going to turn the chair back over to Ms. Boyd now.

THE CHAIRPERSON: I will turn the microphone over to Mr. Corey Shefman, acting on behalf of the Manitoba Metis Federation. Mr. Shefman, please.

MR. BYRON WILLIAMS: Mr. Chair, if -- it's Byron Williams here, if I might. Sorry, Mr. Shefman.

I think I -- I will not suggest that any arm wrestling took place, but I think we have an

agreement with the help of Mr. Kuczek, Wojczynski, Boyd, and Ramage in terms of the undertaking about DSM. And I'll -- I'll try and state it accurately. And then Hydro will correct me.

Manitoba Hydro is undertaking to provide the projected savings per program aggregate over fifteen (15) years as represented in the Power Smart program, the 2013 program, as well as scenario 1, scenario 2, and scenario 3. In addition to that, they will provide the levelized utility cost for each program for each scenario.

As long as Hydro confirms that, I think that's what we've got. And the levelized utility cost was by program.

MS. MARLA BOYD: In the benchmark year, correct?

MR. LLOYD KUCZEK: Correct. And the scenarios being the DSM option 1, 2, and 3, as we referred to earlier.

MR. BYRON WILLIAMS: In the benchmark year.

MR. LLOYD KUCZEK: Correct.

THE CHAIRPERSON: Could I suggest to Mr. Kuczek and Mr. Wojczynski, please, if you could move your microphone over to the -- to the other side

of your -- where you're sitting so that you're facing immediately -- you're facing the microphone when you're answering questions in that direction. I think it would be more helpful for me, at least.

CROSS-EXAMINATION BY MR. COREY SHEFMAN:

MR. COREY SHEFMAN: Thank you, Mr. Chair. Most of my questions today are going to be for -- I believe for Mr. Kuczek, but you're welcome to pass it on, as the case may be.

I'm going to start by looking at this slide from your presentation the other day. It's slide 83. In discussing the levelized resource cost comparison from your presentation you discussed, in particular, the success of the Community Geothermal Program. And that's come up a number of times throughout this panel.

Can you confirm that this is the program you were referring to when you made mention of the programs that Manitoba Hydro is working on with Fisher River and Peguis?

MR. LLOYD KUCZEK: That's correct.

MR. COREY SHEFMAN: And although we -- I know we've gone over the fact that these numbers, for 2014 in particular, aren't finalized.

Is the level of funding or price per kilowatt hour generally in the range of where it should be, that -- in that it's higher than most of the other programs on this chart?

MR. LLOYD KUCZEK: The levelized resource cost is -- is higher than most of the programs for geothermal, generally speaking, and that it would be the case with this opportunity, as well.

MR. COREY SHEFMAN: Thank you. When you spoke of this program, in particular, and when we were having that discussion about Peguis and Fisher River, you indicated that Manitoba Hydro would be looking to pursue similar opportunities in other communities.

Is that correct?

MR. LLOYD KUCZEK: That's correct.

MR. COREY SHEFMAN: Is that desire specific to the Community Geothermal Program or does it include other programs that engage in -- engage communities in DSM-related power generation?

MR. LLOYD KUCZEK: It goes beyond the geothermal. The other -- the other program is -- the Affordable Energy Fund Program is certainly something that we've discussed and we were exploring and interested in working with other communities to

achieve more energy savings on a more cost-effective basis through that program where it makes sense, and so we're interested in that.

MR. COREY SHEFMAN: Can you describe in a little bit more detail what kind of power generation is -- comes out of the program?

MR. LLOYD KUCZEK: The -- it's the energy savings and the measures. The -- the big measures in that program -- well, there's two (2) big measures: One (1) is natural gas furnaces if they're standard efficient furnaces, so there's significant savings there. But that would only apply to those that have natural gas, of course.

The other measures are the -- that's significant is the insulation. And then we offer a number of little things like a -- six (6) CFLs usually goes with the package -- some pipe wrap, and -- and so those opportunities as well. But the energy savings associated with those aren't as significant.

MR. COREY SHEFMAN: I'm sorry, to clarify when I was talking about the geothermal -- geo -- geothermal, and correct me if I'm wrong, but my understanding is that the Geothermal Program is actually generating new power for these communities?

MR. LLOYD KUCZEK: No.

MR. COREY SHEFMAN: Okay.

MR. LLOYD KUCZEK: It's -- a geothermal is a -- a replacement for a heating system which is -- it's still an electric -- it uses electricity for a heat source, but it also uses -- captures the heat from either the ground, it could be the water, but another heat sink, and supplements that. So you end up, effectively, heating a home for about a third of the -- the amount that you would require otherwise with an electric furnace.

But an elect -- a geothermal system has an electric furnace, effectively, in it. If -- if you just visualize a box that looks like a furnace in your house, you still have that box. If you open it up, you'll see an electric heater, actually, as a component of that. That only comes on when the geothermal system that's drawing the heat out of the ground, for example, can't -- can't maintain the heat within the home.

So I have a geothermal system. So on my second box already, and the first one (1) used -- it was a -- a larger unit, so it used to not -- the backup didn't kick in until it was about minus twenty-seven (27). So this time I put a smaller system in, but it kicks in at minus seventeen (17), roughly.

MR. COREY SHEFMAN: Right. So you don't appear to have mentioned biomass programs in -- when we're -- when you're talking about these community DSM programs, efforts to reduce to -- to encourage generation of other sorts.

Can you tell us why you haven't discussed them?

MR. LLOYD KUCZEK: We actually are discussing that opportunity right now. What we're looking at doing as doing a feasibility study to see if it makes sense to do something like that. The -- the obvious and -- and the most simplest way of doing that would just be a -- have a wood stove in your house. But we're looking at something a little broader than that right now. But we're -- we're going to start with a feasibility study.

MR. COREY SHEFMAN: And you'll have to excuse me, I'm new to this process, but is the feasibility study just a -- an in-office thing, or are -- are you actually taking it out into communities? And if so, where -- where is the study taking place?

MR. LLOYD KUCZEK: It would be an academic study. It wouldn't be a practical study where you're actually doing a pilot or a demonstration project.

MR. COREY SHEFMAN: Do you have a timeline for moving on to a pilot project for biomass generally, or for wood stoves in particular?

MR. LLOYD KUCZEK: No, the -- that decision is usually made after you do a feasibility study. So the reason for doing a feasibility study is to assess whether or not it makes any sense to go to the next stage.

MR. COREY SHEFMAN: Okay. We're going to return to this a little bit later in my questions, but one (1) of the other things you mentioned in your presentation in or around this chart, was that fuel switching generally was a topic of discussion at Hydro, more perhaps than it has been in the past. And that some discussions were being contemplated with the government to put more emphasis on fuel switching.

Can you indicate to us what programs or what type of fuel switching might be on the table for discussion between Hydro and the government?

MR. LLOYD KUCZEK: Well, maybe I'll break that into two (2) components. One (1) is we -- we effectively have a fuel switching initiative through our Affordable Energy Fund Program currently. So if a customer is -- comes to us and they have propane and oil we will -- we have a program to help

them convert to electricity, or natural gas, or geothermal if -- if that made sense.

But, generally speaking, if they have access to natural gas we would look at that opportunity first and help them out. If they were in an Affordable Energy Fund Program, they're just eligible for the program just as if they had a standard efficient furnace. And they can convert to an electric furnace if they propane or oil as well.

With the -- the fuel switching that generally was spoken about earlier, that's all related to space heating and the choice between natural gas and electricity at this point.

MR. COREY SHEFMAN: So in Hydro's opinion, there isn't any real alternative to natural gas on the one (1) hand or electricity on the other for space heating or water heating at this point?

MR. LLOYD KUCZEK: Geothermal's an option, as well.

MR. COREY SHEFMAN: Okay. So we've established through the -- through your testimony over the last few days that gas -- and again, correct me if I'm wrong -- that ga -- natural gas is the preferred method in terms of -- from the consumers' end for water and space heating.

Is that correct? Is that a fair assessment?

MR. LLOYD KUCZEK: With space heating, if you have your choice, it makes -- it makes sense to do that. For water heating, it depends on the particular situation. So when you -- from -- and from which perspective.

And Ms. Morrison is actually more familiar with the different scenarios, but it's more costly to install a natural gas furnace -- or a hot water tank than it is an electric hot water tank.

MR. COREY SHEFMAN: So let's talk then just -- for the sake of this discussion, just about space heating. We've established as well that natural gas isn't available or isn't a viable option in northern Manitoba.

Is that correct?

MR. LLOYD KUCZEK: And other areas in southern Mani -- certain areas in southern Manitoba as well.

MR. COREY SHEFMAN: Right. And in previous testimony, the panel spoke about how geothermal isn't a real -- at this point, isn't a realistic, broadly implementable alternative; mainly due to costs, but I'm sure there are other issues as

well.

Is that correct?

MR. LLOYD KUCZEK: Cost is the big issue. Usual -- usually you can -- if -- if you didn't care about costs, usually you can install a geothermal system. It's just much more costly if you have to drill into bedrock, for example.

MR. COREY SHEFMAN: Sure. And in the panel's response to MKO's questions a short time ago, the panel acknowledged that individuals in the North, generally speaking, in addition to not being able to benefit from fuel switching, are more reliant on electri -- or because they can't be -- benefit from natural gas fuel switching, they are more reliant on electricity.

So my question is: Why isn't Hydro putting more emphasis or paying more attention to other and more diverse fuel-switching initiatives that might give those in the North more options when it comes to this arm of DSM?

(BRIEF PAUSE)

MR. DALE FRIESEN: Sorry. Could you repeat the question?

MR. COREY SHEFMAN: Absolutely. Given what we've established, in -- in particular that individuals in the North can't at present benefit from fuel switching in the same way that those in Winnipeg and other parts of southern Manitoba can benefit, why isn't Hydro paying -- or spending more effort and energy to promote other alternatives in the North or to -- to provide fuel-switching alternatives to northern Manitobans?

MR. DALE FRIESEN: I think in many instances the base case for switching to other forms of fuel such as biomass, for instance, or solar or small wind, et cetera, hasn't been established to our satisfaction, so that we feel comfortable that the technology is suitable for the installation. We're currently doing a fair amount of work in a few areas, bio-energy being one (1) of them, where we're examining biomass-to-energy pathways. We're undertaking a series of five (5) demonstrations with funding from the -- from the Canadian Federal Government through the Clean Energy Fund.

We're taking the lessons learned from those five (5) demonstration projects and we're examining each of those technologies as a possible solution for remote communities, and northern

communities in general. And from that, we're establishing a sixth demonstration possibility that, if we aren't able to physically locate it in the North, it will at least give us the ability to simulate the conditions of the North in a southern demonstration that we can keep our hands on a little better and maintain a little better control of.

And we're hoping the outcome of those demonstrations will be one (1) or two (2), potentially three (3) options, that we can pursue in on-site demonstrations in the North that will hopefully eventually lead to -- to an option that provides for a more carbon-neutral and lower cost solution, and potentially one that's better suited to the resource -- energy resource availability in the -- in the area, such as biomass, for instance.

MR. CORY SHEFMAN: Thank you. Following up on your answer, you mentioned solar and small wind. What work is Hydro currently doing to make these alternatives more viable for those in the North?

MR. DALE FRIESEN: I'll speak to solar specifically. We've undertaken a demonstration with the -- with Red River College here in Winnipeg to examine the feasibility of solar parabolic technology.

Instead of going the PB route where you take the sun's energy and convert it to electricity, we're looking at redu -- improving the efficiency by going directly from the sun's energy to thermal -- to thermal -- let me rephrase that.

We want to direct the -- the sun's energy in a way that focusses it -- allows us to collect it as thermal energy which we can then use to directly heat. So that -- that project has got a little bit more than a year under it's belt right now. We're continuing to examine different ways. The first stage was just looking at the collection technology itself. The next stage will actually be using that energy to physically heat a building. But that's a technology that has some promise. It still wouldn't be cost effective in the North, given the intermittency of the sun's hours, but it's a technology we're looking at in the solar world.

There's plenty of experience, I believe, with small wind. The challenge we have with small wind is that when you combine the intermittency and the very high cost of small wind, it's -- generally doesn't -- the economics doesn't work out favourably for it.

MR. CORY SHEFMAN: Moving to a kind of

related area, it's just -- in particular Hydro's efforts to promote DSM and promote its adoption, in Mr. Hombach's examination or cross-examination yesterday, or earlier anyways, on the matter of Hydro's fuel-switching initiative you indicated that Hydro has an extensive advertising and education campaign.

In your explanation of Hydro's efforts in this regard it was suggested that the campaign was targeted specifically to the southern areas of Manitoba where gas is available, where natural gas is available; that the customers who are receiving this education and promotion are generally homeowners or home builders; and that involved a particular focus on the actual building of the homes.

Do we recall that -- that discussion?

MS. LOIS MORRISON: Yes, we do.

MR. CORY SHEFMAN: Perfect. The flyer that was distributed yesterday, is that part of that strategy?

MS. LOIS MORRISON: That's part of the heating education campaign. That's not part of our overriding Power Smart campaign.

MR. CORY SHEFMAN: Okay. What is Hydro's strategy to educate customers in northern

areas who rely more heavily on electric heat?

What kind of material has been made available, or what promotion has been done to educate northern consumers as to all of their options like we see on the screen?

MS. LOIS MORRISON: Well, first off, Manitoba Hydro has had a long-standing overriding initiative to promote Power Smart itself. We've been -- we've been promoting the Power Smart brand since 1992 across the province. And so we -- what we do is we -- we've created an overriding strategy to just generally promote brand awareness of Power Smart.

Then individually for each program we have individual promotion strategies to educate and encourage customers to participate that's targeted to each of those different sectors.

Now, to bring it to -- to your area of concern specifically, and I -- and I understand -- I'm -- and I'm -- I'm taking from your -- your question that you're interested in our efforts to promote energy conservation in the North to residential customers.

MR. CORY SHEFMAN: M-hm.

MS. LOIS MORRISON: And so building on that, we've actually in the past -- since we launched

our home insulation program, to use that as an example, what we've done is we specifically target those areas that have a high penetration of electric heat. And so we will do specific advertising and radio communication in -- in those areas.

So we've done specific advertising in the Northern newspapers, in community newspapers, and in the -- the community radio stations. We've done, in addition to that, specifically in the North -- we did an oil and propane conversion program to offer up assistance through the Affordable Energy Fund that Mr. Kuczek referred to earlier to help customers, if they were heating with oil and propane, to convert to -- either to electricity, which is more economic than heating with oil or propane; or, if they chose to, to convert to at least a high-efficiency propane.

In addition to that, for each of our programs we -- we set out a strategy to try and target areas that we can get greater penetration. We also look at our markets and say, If we're not getting the penetration we expected to in that region, we'll do additional concerted efforts to -- to promote in those regions.

So that's kind of broadly what we do. And we've been doing that approach since the early

'90s.

MR. COREY SHEFMAN: Does Hydro track penetration data in Aboriginal communities, in terms of adoption of these programs?

MS. LOIS MORRISON: As Mr. Kuczek alluded to earlier, we have -- we have specific data on our efforts in the First Nation communities that are targeted under the Afford -- under our First Nation community program. We also have tracked specifically uptake -- program uptake, in terms of what was previously our Power Smart New Home Program. And we also track the number of projects undertaken in our commercial buildings in First Nation communities.

And as I mentioned earlier, we have been approaching First Nation communities to offer up the services of -- for -- for their band buildings, the band-owned buildings or the band-operated buildings, to have energy assessments.

And basically what we do at the end of that is we provide a report that explains what opportunities -- energy-efficient opportunities there might be and what incentives might be there to support the implementation of those energy efficiency oppor -- opportunities in those buildings.

MR. COREY SHEFMAN: Thank you. Moving

on a little bit to load shifting. In your previous presentation it was explained that one (1) of the challenges of load shifting, especially given that 50 percent of our -- and correct me if that statistic is wrong -- of Manitoba's energy is consumed for heat.

One (1) of the challenges of load shifting is that curtailing the use of electricity for heat for one (1) period has to be -- has to be made up at another time.

And so was that -- is that correct, generally speaking?

MS. LOIS MORRISON: That is correct.

MR. COREY SHEFMAN: So then programs in -- into reducing the use of electric heat, period, would -- are important to pursue?

MS. LOIS MORRISON: At this point, we focus -- and I believe Mr. Friesen referred to that earlier in our testimony. That our pro -- programs are primarily focussed on saving energy. And with that saving energy is a corresponding reduction to demand or peak.

But, yes, what we -- what we look at is there's additional benefit -- or we focus, obviously, on elec -- reducing the electric heat consumption because that has added benefit to our system of

reducing both energy because we're ver -- we're concerned about energy constraints, and peak.

MR. COREY SHEFMAN: And I acce -- I -- I understand now and that you have a study ongoing on these wood stoves.

No feasibility study?

MR. LLOYD KUCZEK: No, there's no feasibility study on wood stoves. Per -- the feasibility study is -- that we're looking at undertaking is whether or not -- on a community-based initiative, whether or not they're -- it makes sense to have a bioenergy system in place --

MR. COREY SHEFMAN: Okay.

MR. LLOYD KUCZEK: -- which might be a district system --

MR. COREY SHEFMAN: Okay.

MR. LLOYD KUCZEK: -- as opposed to the stoves. But the stoves that exist today, there's high-efficient stoves -- high-efficient stoves that are combined with electric heat. And Dale's probably more familiar with those, but...

MR. DALE FRIESEN: So to sort of build on what Mr. Kuczek said, we are looking at district heating systems as being one (1) option. The -- the advantage you gain with district heating systems is

that your energy source, whatever you're using for heating, can be managed in a more economical fashion, and it creates better economics for alternative fuels.

So that's -- that's one (1) of the driving factors behind that. And those -- those off set some of those costs that go along with distributing that energy throughout a community. It also makes implementation and maintenance of the systems over the long-term easier because you have that more centrally located. There are challenges though.

And currently probably one (1) of the biggest challenges we face in Manitoba with bioenergy is a lack of refined biomass fuel. We have a lot of raw biomass fuel in Manitoba, but we don't have sufficient refining capacity to produce it into a form that we can use effectively. And that's -- that's one (1) of our challenges, and one (1) of the areas we're looking at, is how do we refine biomass into a usable fuel?

MR. COREY SHEFMAN: But is it not the case -- I -- I take your points, but is it not the case that when consumers use wood stoves and potentially only use wood stoves to heat their homes -- and I'm just using wood stoves as an example here --

that the reduced load would contribute positively to the -- the goal that we've been discussing of reducing load from the infrastructure?

MR. DANIEL FRIESEN: Yes, it would reduce -- it would reduce the -- the infrastructure requirement for electricity, for instance, if electric heat was the option -- other option, yes.

MR. COREY SHEFMAN: Thank you. And you're aware that there are a number of communities currently in northern Manitoba -- currently in northern Manitoba that utilize wood stoves for heat during the winter?

MR. DANIEL FRIESEN: Yes.

MR. COREY SHEFMAN: Now, you may be aware that a number of my client's community members use wood stoves as a matter of preference, because it's something they've done for many years.

Am I correct in my understanding that this sort of program is accomplishing exactly the sort of thing that Manitoba Hydro is trying to do in the south by freeing up load?

MR. DANIEL FRIESEN: In a -- in a big picture way, yes. It -- it is displacing electric -- it -- you know, it is displacing heat that might otherwise come from an electric source. So in that

sense, you're correct.

MR. COREY SHEFMAN: Thank you.

MR. DANIEL FRIESEN: It's not an initiative that is being driven per se by Manitoba Hydro in the -- in the same manner, but I understand what you're saying, yes.

MR. COREY SHEFMAN: So Manitoba Hydro is not providing the people that are using wood stoves -- as, again, as an example -- with information as to what the benefits are of them doing so, or to continuing to do so?

MR. DANIEL FRIESEN: Yeah, we -- we don't have any information.

MS. LOIS MORRISON: At this time I don't believe we traditionally produce that information. It's not publicly available on our website, the benefits of heating with wood stove versus natural gas, or biomass, or any of the other options. You are correct, we don't have that on our website at this point --

MR. DANIEL FRIESEN: And -- and sort of to -- to build on that a little bit: We aren't offering incentives per se for people to use wood stoves in southern Manitoba either. What our -- the way our program is -- the Bio-Energy Program is

designed is, we look at -- we're looking for carbon-neutral, or low cost, or no cost fuel sources to use in biomass to energy pathways. And that energy may be thermal for heat, or it may be electricity.

And we're looking at the resource cost of that pathway, and then addressing appropriately if there's a situation where that makes economic sense. So we're not per se paying -- like, our -- our objective isn't purely to look at using wood in wood stoves. That's the -- that's not a primary focus of -- - of that Bio-Energy Program. It is -- it isn't intended to subsidize heating with wood. That -- that's not -- not the intention of the program.

MR. COREY SHEFMAN: And my purpose for asking this question is because it is an example of a -- let's call it a 'made in the North' solution -- to these sorts of issues.

Has Hydro -- or does Hydro see a place for these sorts of community solutions, or made in the North solutions, to the problems that we're discussing here?

MR. LLOYD KUCZEK: We -- we've actually had some discussions about that, but would be similar to natural gas and us offering incentives to use natural gas. And so we don't offer customers to

use -- an incentive to use natural gas right now, too. But in the broader context of a fuel- switching program, one would have to think about it from the provincial perspective in the North, for those that don't have natural gas, and it doesn't make sense. And you get into the free ridership issue and what not. But that -- from the overall fuel-switching persp -- perspective, you really should assess that.

MR. COREY SHEFMAN: Okay. Ms. Morrison, I believe it was you who said during the initial evidence that it's best to ask the customer what's important to them, and provide them with the information that they need to make decisions which meet their needs when we're talking about moving away from reliance on electric heat.

Has Manitoba Hydro done this specifically in the North, and specifically with the Metis community?

MS. LOIS MORRISON: I believe my -- my analogy was that if someone were to ask me --

MR. COREY SHEFMAN: M-hm.

MS. LOIS MORRISON: -- what the prefer -- preference would be for hea -- their fuel source, that I would ask them what was important to them at that time. That was more in line with the question

that was asked of Mr. Thomson as to whether he would recommend natural gas over electric -- electricity for heat.

We have not specifically gone out and asked anyone in the province what their specific preferences are and what they want in terms of heat. So to say, Have I specifically excluded anyone in the -- in the Metis communities? No. We've -- we've generally asked through our broad-based customer residential energy survey, through our general surveys across the province, what people are interested in and what their thoughts are and what their preferences are.

So the surveying that we've done, or the information gathering that we've done, has been at the provincial level and not specifically isolating any one (1) particular community.

MR. COREY SHEFMAN: Thank you. I just have one (1) more area I'd like to discuss with the panel. In your -- in the panel's answer -- and I'm not -- I'm sorry, I'm not sure who it was specifically that gave the answer -- on the subject of the benefits of DSM programs -- and I believe it was panel member Grant that asked the question -- it was indicated that customers -- even customers who are well informed of

the programs weren't taking them up. There was not as much use of Hydro's DSM programs as we perhaps would like there to be. And a mention was made of a focus group that was convened on the subject, and I'd like to talk a little bit about that focus group.

My first question is: What was the -- what was the purpose of the focus group? What question -- what was the broad theme or question that was asked?

MR. LLOYD KUCZEK: We don't have a -- we just undertook that focus group session, and I -- I sat through a couple of them, but we didn't -- I don't recall the specific question, per se. But it was along the lines of, you know, What would it take for cus -- you to implement a measure in terms of payback?

And so there was a question asked along those regards. And the -- the moderator was trying to get some sort of sense of whether they would willing -- be willing to invest if it was a 5 percent return, 10 percent return. But the general just -- just the message that I got back -- and again, I'd have to see the report and what the report's going to say -- was that a lot of the participants at the sessions that I was at were more concerned about the waste element of it, of just disposing of something that was still

useful yet.

And certainly a payback of -- it was either five (5)-- I think it was 10 percent, it just wasn't enough. Like, you know, 10 percent investment might be okay when you're investing in a financial instrument, but it didn't seem to work with them in terms of the Power Smart initiatives. And -- and they drew on the fact that they're disposing of something that was still useful.

MR. COREY SHEFMAN: Sure.

MR. LLOYD KUCZEK: And just to add to that, we were doing focus group sessions in Winnipeg, Brandon, and as well as the North, so we recognize that there's differences throughout Manitoba.

MR. COREY SHEFMAN: Perfect. And that was going to be -- my next question is: Where were they held? And so thank you for -- for anticipating that.

In addition to where they were held, I'm also interested in some of the demographics of the focus groups. Can you tell me whether there was any First Nation representation in the focus groups?

MS. LOIS MORRISON: There was Aboriginal representation in the focus groups.

MR. COREY SHEFMAN: Can you tell me

whether there was any First Nations and whether there was any Metis representation?

MS. LOIS MORRISON: They didn't delineate it specifically based on status versus non-status Aboriginals. We classified them simply Aboriginal background. Either they self-identified as Aboriginal or they did not self-identify as Aboriginal.

MR. COREY SHEFMAN: Okay. Sorry, can I have a moment? Thank you.

(BRIEF PAUSE)

MR. COREY SHEFMAN: All right. My last question then would be the -- with respect to the focus groups that were held, and I guess I'm particularly interested in the one that was held in the North, or ones I suppose if there were more than one (1), how is that data -- where is that data being fed into? How is that data being used to help Hydro improve its outcomes when we're talking about adoption of DSM programming?

MS. LOIS MORRISON: The purpose of the focus groups was to help us better brand Power Smart. We had initiated them to get a better understanding as

to what messaging would resonate with people and actually get them to adopt or -- or think that, This is something that I should be interested in.

It's -- it's -- what messaging would drive them to -- to take that call to action to contact Manitoba Hydro, find out more about what they need to do to make their homes more energy efficient.

And so the purpose of the -- the focus group testing was to test a number of different messages around Power Smart and about ener -- around energy efficiency, and which ones resinated. So, as Mr. Kuczek mentioned, there was a return on investment message. Is that what you need to hear in order to get you to -- to motivate you to -- to take action?

So all of the messaging -- so -- so the purpose of the focus groups was to test messaging, and that's why we wanted to test in different jurisdictions, because we recognize that people in Winnipeg are different from people in rural southern Manitoba, and from northern Manitoba. And, so that information that was test -- collected through those focus groups is going to feedback to help us in -- in determining how do we structure our next advertising campaign. What messages are really going to resinate with our customers best?

MR. CORY SHEFMAN: I'm wondering if we could have Hydro take an undertaking on the question of the makeup of those focus groups? Who was participating? How those people were selected? And -- and unfortunately it doesn't appear that you've broken down the demographics quite as clearly as we'd like, but as far -- as broken down as we can get them?

(BRIEF PAUSE)

MS. LOIS MORRISON: Okay. The -- we don't have the report yet, as Mr. Kuczek mentioned. What we -- and -- and working within what the ad agency and the -- the research firm is allowed to provide us with, in terms of the breakdown of the groups, but we -- yes, we can provide -- once we have the information, we can provide a identification of, say, the demographic of the individuals that were at -- were selected for the focus group.

MR. CORY SHEFMAN: And as well as how they were selected?

MS. LOIS MORRISON: Yes, we can provide the -- a brief description of the methodology for which they were selected by.

MR. CORY SHEFMAN: Thank you.

MS. LOIS MORRISON: The undertaking is that Manitoba Hydro will provide a brief description of the methodology used to select or to canvass can -- candidates to participate in a -- in a focus group test -- in our focus group testing, and we will also provide a summary of the demographics.

--- UNDERTAKING NO. 21: Manitoba Hydro to provide a brief description of the methodology used to select or to canvass candidates to participate in focus group testing, and provide a summary of the demographics

MR. CORY SHEFMAN: And with that, Mr. Chair, I am finished with our questions.

THE CHAIRPERSON: Thank you, Mr. Shefman. I now turn over the microphone to Me. Monnin.

MR. SVEN HOMBACH: Mr. Chairman, I wonder if Ms. -- if Mr. Monnin would prefer to sit in the front, if we should take a one (1) minute break, to allow parties to switch so that his face can be

seen?

MR. CHRISTIAN MONNIN: I will accept the complimentary Air Canada bump up to first class.

(BRIEF PAUSE)

CROSS-EXAMINATION BY MR. CHRISTIAN MONNIN:

MR. CHRISTIAN MONNIN: Merci, Mr. President. And just to be clear, my earlier comment wasn't a critique of the -- what I've been referring to as the Statler and -- and Waldorf section of the -- of the PUB. A bit more context on that. Those are the two curmudgeons and Muppets who were back on the -- the balcony. It's quite comfortable back there. I look forward to going back.

The questions that I'll be asking today are not levelled at anyone in particular, and so, to the extent that anyone on the Board or in this panel, rather, is in a position to answer, please do so. And as most of My Learned Friends have said, if the questions that I ask to elicit CSI, please advise, and we'll -- we'll deal with that accordingly.

For the purposes of this cross-examination, which will be a short one, I assure you, we've prepared a book of documents with nine (9) tabs

in -- in that book of documents. There's an index in the book of documents just to -- to -- if -- if you can pull that up, please, to just indicate that there is method to our madness.

You'll see, for example, Tab 1, page 3, is page 3 of the book of documents, and then MH-85 is the exhibit; it refers to Manitoba Hydro rebuttal evidence page 14. In reality, that's -- that's she -- 7 of the rebuttal, but because MH-85 has some introductory documents, it's the 14th page of that exhibit. So when I'm referring to page 7 of -- which we referred to earlier with Madam Boyd, it comes up as 14 in the exhibit. And that's just to explain how -- how this index works.

If we can turn to Tab number 2, page 5, of our book of documents. And I just want to ask you a few questions on -- on load forecast at this point in time, and specifically line 10 and 11 of that page. The purpose of load forecast is to present the best estimate of long-term future energy requirements for Manitoba. And -- and I just want to ask some questions of this panel with respect to -- to that.

And do I understand correctly that the long-term -- or the load forecast for NFAT is not the same as one that would be prepared for a GRA?

MS. LOIS MORRISON: The load forecast used in the NFAT is the same load forecast that Manitoba Hydro uses for all forecasting purposes.

MR. CHRISTIAN MONNIN: And as my wife would say, I never miss an opportunity to demonstrate how ill-informed I am. Are -- so are there no distinctions between the methodology used for the NFAT load forecast and GRA load forecast?

Do I have that correct?

MS. LOIS MORRISON: No, I don't believe there are any differences --

MR. CHRISTIAN MONNIN: Okay.

MS. LOIS MORRISON: -- subject to check, but...

MR. CHRISTIAN MONNIN: In -- in that regard, still along the same lines, but a broader question and broader scope, would -- would you agree with the statement that a longer-term view, for example, here the NFAT, which I understand is seventy-eight (78) years, implies a greater uncertainty and, therefore, must concern long-term risks that ought -- that need not to be considered in short-term?

Would you agree with the statement -- that statement?

MR. ED WOJCZYNSKI: Sorry, could you

repeat the question.

MR. CHRISTIAN MONNIN: Absolutely. A longer-term view, for example, here we're using obviously the NFAT, implies a greater uncertainty and, therefore, must concern long-term risks that need not be considered in the short term?

MR. ED WOJCZYNSKI: Yeah.

MR. CHRISTIAN MONNIN: Okay. And then going back to it, a view from another angle, for example, in the GRA context, a load forecast is used to set rates until the next GRA.

Do I understand that correctly?

MR. LLOYD KUCZEK: We don't have a -- we -- we don't undertake a GRA every year, but we do produce a load forecast every year for planning purposes. So if there is a GRA, we will use the most current load forecast, which is produced every year, so. And it was the same thing with the NFAT process. Whatever the most current forecast was at the time, that's what's used.

(BRIEF PAUSE)

MR. COREY SHEFMAN: And -- and in -- in the context of a -- a longer torm -- term forecast

like the NFAT, am I correct to -- to -- when I state that there would be a greater risk of a fundamental shift in electricity use, so I'll refer to it as a structural change, for example, due to grid parity over the seventy-eight (78) year time frame than there would be in a GRA context?

MR. ED WOJCZYNSKI: I'm not going to -- my part of the answer is going to deal with going from thirty-five (35) years or the twenty (20) years at the end of the forecast to seventy-eight (78) years. My colleagues can comment on the earlier part of that. That is, the first twenty (20) or thirty-five (35) years.

As we were discussing somewhat earlier in these proceedings, the analysis that Manitoba Hydro does to go out to -- from the thirty (30) -- the end of the thirty-five (35) years to seventy-eight (78) years is not an economic analysis that -- that is reliant on having a precise forecast. It is an estimate of what the residual value is.

And as we discussed the other day, we freeze the -- the load amount -- the load forecast at the -- the year -- at the end of the thirty-five (35) year period and fix various assumptions so we get an estimate of what the value of the residual asset is.

And whether the load growth after that is somewhat higher or somewhat lower, is -- is not -- is not mat - - particularly material to that estimate.

It's simply a way to deal with the fact that we have an asset life of sixty-seven (67) years, which is longer than the study period which we're using the -- the detailed load forecast for. So it -- - so going beyond thirty-five (35) or twenty (20) years, I think I dealt with that. For your question for the earlier years, I think I'd have to look -- look to our load forecast people.

MR. CHRISTIAN MONNIN: Thank you.

MR. DANIEL FRIESEN: The question of disruptive technologies, as they've been referred to in some evidence, going forward into the future is something that we see as being something we would capture in the technical potential of our studies, both current and future, that may -- that may occur as we move forward and move towards those dates when some of those technologies become economic.

That same uncertainty you specify with respect to glo -- load growth, I think also exists with respect to those technologies. There's a considerable degree of uncertainty as to when that grid parity moment will happen. And as we discussed,

grid parity is just an indicator of the start of a transition. It's not as though we would expect to see a step change occur at the date of grid -- grid parity.

And all of these conspire together to allow Manitoba Hydro, and our process which forecasts on an annual basis, to adapt, to adjust. And as we've spoken in various parts in this proceeding, we're not inflexible to -- to adapting to the future. We -- we adapt our DSM programs, we dava -- adapt our development plans as information becomes clearer. So there are some pathways to -- to adapt built into our structure and our process.

MR. CHRISTIAN MONNIN: Okay. Can you please go to Tab 3, page 7 of our book of documents, then? And -- and if I just look at -- for example, I -- I believe we've included four (4) graphs in our book of documents. And based on what -- what Mr. Wojczynski just said, what I think I understand is you -- you cap it around the thirty (30) year period.

And -- and are these just really linear extrapolations of what occurred in the past and that's really the best that we can do, and that's why you just see a gradual line going through the years?

Do I have that correctly?

MS. LOIS MORRISON: Are you referring to our forecast methodology for the first twenty (20) years, or are you referring to the thirty (30) -- to the period after the twenty (20) years?

MR. CHRISTIAN MONNIN: Yes, after the twenty (20) years. And -- and so -- and if you go to the next frame as well it's just -- I'm not getting down into the substance of these particulars frames. It's just they all, from my perspective, seem to show the same linear extrapolation on a continual basis.

And -- and can -- the takeaway that I get from these graphs is simply that Hydro was saying that nothing is really going to change on a going-forward basis as we go through the evolution of this -- - the -- the seventy-eight (78) years of the -- the NFAT.

MS. LOIS MORRISON: I -- I think that the forecast that you're looking at here is not merely an extrapolation of the past historical energy consumption. What the forecast represents,, as we mentioned before, is the projection of the population growth, along with the average use of energy for -- per customer.

Now, if the population growth is higher or lower, the slope of that line changes. It may

mimic what we've seen in the past, or it may not mimic what we've seen in the past. It may be higher or lower. Based upon that, for -- for the majority of our -- of our population forecasts, as -- as Mr. Kuczek mentioned in his presentation, we forecast for the residential sector, the commercial sector, and the top consumers.

Now, what you see here -- depicted here is the twenty (20) year horizon going forward. And that's influenced, as we mentioned, before by a population forecast which is growing at an average rate of 1.1 percent in the 2013 forecast, plus we are seeing an average -- an increase in the average use per customer, and that's resulting in the 1.5 percent. This is also prior to adjustments for our DSM initiatives.

As Mr. Kuczek mentioned earlier, under the 2013 forecast, that was -- would reduce it to 1.4 percent. As we spoke to, I believe, yesterday in terms of the Level 1, 2, and 3, that growth can change. We are awaiting -- we will be publishing the updated Power Smart Plan and releasing it in -- at the end of March, as Mr. Kuczek also mentioned.

So there are a number of things that -- to simply state that we are anticipating that to

continue at that rate just because it happened in the past is an inaccurate statement.

MR. CHRISTIAN MONNIN: Well, in that -- that regard, is -- is -- in its forecasting, is Hydro taken into account the possibility of low probability, high impact events?

And if so, in what nature are they doing that?

(BRIEF PAUSE)

MS. LOIS MORRISON: We do include in the forecast examples of what the impact of unexpected high growth or high -- or a load loss, so an unexpected increase in, say, electric vehicles, or an unexpected loss of a -- of a large consumer are reflected as possible events and what those -- what those events might look like if they were to occur on our system.

We also prepared for -- for analysis we prepare a projection of high and low load growth for -- for the analysis of risk for planning. But as -- as we've outlined on page 50 of our 2013 load forecast, we do recognize that there are occurrences that can happen in the marketplace that can have substantial

change on our forecasts.

We don't arbi -- we don't arbitrarily assign a probability of those types of occurrences coming because we don't know. We don't know if there's going to be say a 70 -- say -- say we were to go to the point where 70 percent of our -- our automobiles and -- and transportation vehicles were to be electric car -- plug-in electric vehicles. We -- we look at that as to say, Well, what kind of impact would we see on our system if that were to occur? But we're not going to arbitrarily put that into our forecast and say, What would ha -- you know, are we going to plan for that now? No. But are we -- we recognize it is something that may happen.

Is that likely to happen? We -- we can't assign a probability to that event, and so we don't attempt to.

MR. ED WOJCZYNSKI: I -- I might add to that, that when you're talking about low probability, high impact events, do we plan for that, there's one (1) aspect there in the load forecast itself. Obviously, it's true in other elements of our planning, as well. But -- oh, sorry.

The -- I think some -- maybe some of the events that you're thinking of are what some

people term Black Swan events, where they're the unexpected things that you can't plan for because you don't know they're going to happen.

And -- and in -- in that, you want -- well, a terms that's also used, anti-fragility, so that you can respond to uncertain future events like the ones you're talking about. And our argument is that one (1) of the best ways for electrical systems to do that is to be strongly interconnected across all of North America so that we -- we all are much more able to respond to changes and -- that we're not expecting.

MR. CHRISTIAN MONNIN: I think in --

MR. ED WOJCZYNSKI: So that's the other part, maybe, to your question.

MR. CHRISTIAN MONNIN: Thank you. I think in the spirit of these -- these proceedings I'll refer to them as the blackout events. And -- and your considerations, I -- I think I know the answer, but I just want to throw these out there.

In some of the -- the risk analysis that Hydro took upon itself when -- going through this process, has -- has there been -- have the following been considered: a risk that an unexpected demand growth could result in a blackout.

Has that been considered in -- in your deliberations?

MR. ED WOJCZYNSKI: Yes, and that's why we talk about having increased energy security and increased capacity liability benefits from the Preferred Plan compared to some of the other plans, and that -- but that will be dealt with in more detail next week.

MR. CHRISTIAN MONNIN: Okay. And I suspect maybe the following will be dealt with, as well. But is there consideration of the risk that the projected escalation of Hydro rates will -- will change consumer expectations in the coming years and the perception of electricity is cheap in Manitoba will change?

Has that been considered?

MR. ED WOJCZYNSKI: Yeah, the load forecasting people, I'm sure, will want to answer as well, but that's why, right in the submission, we -- there's a whole number of reasons why we might have low load growth as opposed to high load growth.

And -- and so that's why we did a stress test using low load growth and -- in our -- in our work as well, as high levels of DSM. But I'm sure the load forecasting people might want to add to that.

MS. LOIS MORRISON: Actually, Mi -- Mr. Wojczynski, you -- you handled that very well. I was going to mention that, although we -- we did note that we will be looking at the issue of price elasticity in more detail as we go forward, there is -- there is the -- as we mentioned, we do look at a high/low scenario, and there is the op -- there is the potential that that could be encapsulated within the load -- the -- the low scenario.

MR. CHRISTIAN MONNIN: And on the issue of low domestic demand, do I understand correctly that the primary protection against risk related to low domestic demand is the fact that power can be exported instead?

Does that statement make sense?

MR. ED WOJCZYNSKI: That's one of the ways. The other is in our plan we have -- as Mr. Thomson discussed the first day here, that whereas the plan has Keeyask '19 and Conawapa '26, if we see load growth dipping or -- or something else happening that ca -- like higher DSM, then we always have the option of pushing back Conawapa's in-service date in the next four (4) years.

And even once we've started on Conawapa, there's a number of years before we have to

commit to the general civil contract, so it's longer. It's probably six (6) years in that order that we have to -- to start seeing a surprising drop in load growth. So that would be a very effective way to respond to it as well.

MR. CHRISTIAN MONNIN: Okay. And -- and I think that answer that you've just provided will apply to this next question that I'm -- I'm going to put forward is -- is that, in that regard, the real risk related to the load forecast is the risk that the export price will be below the price needed to recover the full cost of Keeyask and Conawapa.

MR. ED WOJCZYNSKI: As I just indicated, in the case of Conawapa, what we would do is defer it. In the case of Keeyask, that -- if all -- if we started building Keeyask and all of a sudden load growth stopped and we had no more load growth, then -- then Keeyask would be subject to the export -- the economics of Keeyask in that case would be subject purely what we could obtain on the export market.

But as Mr. Thomson indicated, with the contracts on the opportunity market, we're always going to be exposed to uncertainty in that price. We have long-term firm contracts where the price is already fixed, and that will be just the -- the

quantum of that will be discussed in the CSI portion. But those contracts have prices which are quite favourable.

I -- I should add as well, as -- as Mr. Thomson indicated, we -- the Keeyask is -- is the majority of the dependable output for Keeyask is being sold under contract -- well, not forever, but certainly for the front end -- with the three (3) sales we have -- that we have signed contracts for. And that's the MP 250, the WPS 308, and the NSP 125.

MR. CHRISTIAN MONNIN: I just have a few questions with respect to top consumers. And if we could go to page 17 of our book of documents. Looking firstly at line 3 through 5, which reads as follows:

> "Give the risks associated with the shortfall of a suitable energy supply, it is in the best interests of consumers -- [sorry] customers to provide Manitoba Hydro with accurate information regarding their future energy needs."

Keeping that in mind, I understand that the top consumer would run the risk of Hydro being unable to supply the power that they require if the

top consumers were to underestimate future demand.

Is that correct?

MR. DALE FRIESEN: Sorry. Could you just repeat your question, please?

MR. CHRISTIAN MONNIN: Absolutely. I understand that the top consumers would run the risk of Hydro being unable to supply the power they require if they, the top consumers, were to underestimate the future demand.

Is that correct?

MR. DALE FRIESEN: That's correct. And --

MR. CHRISTIAN MONNIN: From --

MR. DALE FRIESEN: Sorry. And to add to that, that extends beyond generation. That extends to transmission and distribution capability as well.

MR. CHRISTIAN MONNIN: So keeping that in mind, there -- there's a strong incentive on top consumers to avoid underestimating.

MR. DALE FRIESEN: Of course.

MR. CHRISTIAN MONNIN: Now, keeping that in mind, if -- if a top consumer is uncertain of its future demand, wouldn't it be prudent, from a top consumers' perspective, to provide the highest potential electricity demand?

MR. DALE FRIESEN: It would appear obvious that that would be a risk that we would face when customers provide -- provide that information to us. And that is why, when we go forward and we seek information from customers, we don't focus purely on demand.

We recognize that their capacity numbers will be such that they can accommodate future load growth or future expansion plans that they may have beyond their initial -- their initial projection.

We also press them for information related to their energy consumption and their load factor and how they foresee that to change over time. And we have found that, in general, most of our top consumers are quite open to discuss that and -- and share what they see as their future. And when we ask them to support that, they're generally willing to do that as well.

MR. CHRISTIAN MONNIN: In a scenario where top consumers have an incentive to overestimate their -- their demand, would -- would that have any impact on over-forecasting?

MR. DANIEL FRIESEN: Our forecast is weighted towards energy, in terms of the information that we provide from the top consumers. The capacity

requirement probably intra -- impacts the transmission and distribution facilities that we provide to a -- to a greater degree. And since our top consumers fund, directly, a large portion of the capacity improvements that are required to serve them, it's really not in their best interest to wildly exaggerate the capacity numbers that they give us, because they'll have to pay for that infrastructure directly.

MR. CHRISTIAN MONNIN: I -- I don't think it's in anyone interest to wildly exaggerate, but over -- you would agree with me that there's a distinction between wildly exaggerating and overestimating?

MR. DANIEL FRIESEN: I agree that -- I agree with your premise, yes.

MR. CHRISTIAN MONNIN: Okay. You'll be pleased to note that I'm -- I'm almost done. If you could just turn to page 22 of our book of documents, please. And just a -- a quick question -- a few questions with respect to Section 8.2.2.2, starting at page 22 -- sorry, line 22. Elenchus, in their report titled, "NFAT Review":

> "Review of Manitoba Hydro's Demand-side Management Plan recommends that ecological footprint analysis is

required to assess all alternatives, including demand-side management options."

And going further down, line 28 and 29, it's -- the closed notes version of it is that:

"Opting for a -- an ecological footprint analysis is misguided."

And I just have a few questions with respect to that.

MS. LOIS MORRISON: I -- I -- this section is actually better handled by a subsequent panel --

MR. CHRISTIAN MONNIN: Okay.

MS. LOIS MORRISON: -- related to the GHG components of our filing.

MR. CHRISTIAN MONNIN: Very well.

MS. LOIS MORRISON: So --

MR. CHRISTIAN MONNIN: Well, you've managed to sort -- short-circuit the remainder of my cross-examination.

MS. LOIS MORRISON: Not intentionally.

MR. CHRISTIAN MONNIN: That's fine. That's fine. A la prochaine fois. Thank you, M. -- M. President.

MR. SVEN HOMBACH: Thank you, Mr.

Monnin. The Board counsel book of document, would you like that introduced as an exhibit?

MR. CHRISTIAN MONNIN: Yes, please. Number 1, I believe.

MR. SVEN HOMBACH: It's, I believe, Hillco Exhibit Number 7, Mr. Simonsen?

MR. KURT SIMONSEN: Correct.

--- EXHIBIT NO. HILLCO-7: Book of documents

DISCUSSION:

MR. SVEN HOMBACH: Now, Mr. Chairman, that concludes the public examination of this particular panel. Next on the agenda is the closed in camera session with respect to commercially sensitive information. I would suggest we take a five (5) minute break to allow the parties to set up. At this point I would ask anybody that has not signed a non-disclosure agreement or undertaking to excuse themselves while they -- from the hearing room. That would include members of the public, and I believe that includes, at this point, all Intervenor counsel as well.

MS. MARLA BOYD: Just before we do that, Mr. Chair -- sorry. Oh, Marla Boyd. I do have

one (1) more undertaking that could be filed. It is Manitoba Hydro's response to Undertaking number 16. We can circulate copies. I believe it should be Exhibit number 94.

--- EXHIBIT NO. MH-94: Response to Undertaking 16

MS. MARLA BOYD: I would also ask your permission that not all of our panel is actually required for the CSI portion of this hearing. So if I could ask that you would excuse Ms. Rohmund and Mr. Page from the panel, we'll carry on from there.

THE CHAIRPERSON: That's fine. Thank you. So we will recess for approximately ten (10) minutes. I'm sorry? Oh, go ahead. M. Hacault, go ahead.

MR. ANTOINE HACAULT: This may be a little bit more technical, but there's some ongoing decisions to be made with respect to CSI undertakings and what's going to happen. And we're just stating for the record, and we won't repeat it, but that our clients are reserving their rights with respect to those issues. So that we -- our silence isn't interpreted as agreeing to the process proceeding without those things being dealt with.

And the second part is, and I've spoken to Board counsel about this, we don't know, because we won't be there whether there's some questions that are truly not CSI questions or some responses that go beyond CSI information.

And we had asked Board counsel to consider whether or not it might be appropriate to also consider putting a redacted transcript, to the extent that that is feasible or necessary, to ensure that any questions that go beyond specific CSI would be made available, as far as the questions and answers, because I could see us just asking general questions. You may have to sometimes to go further afield than specific CSI. So we had made that request, that that be considered as to whether or not we could have that part of the transcript that's not truly CSI disclosed to us.

And finally, we just repeat our previous encouragement to this Board that as much as possible, and we've seen some correspondence on that, that we keep the most information available to the public and to members of the public, including us. So that if we could continue to be mindful of that.

I know in the past there was some pretty innovative ways to deal with things. For

example, if we didn't want to put specific numbers, we -- we put ranges, or we had statements like Mr. Wojczynski just indicated, you know, the prices generally are favourable.

So if there's ways to deal with it so that the public has some kind of general sense, that would also be appreciated. Thank you.

MR. BYRON WILLIAMS: Mr. Chair, I'll be less technical than My Friend Mr. Hacault. Our client has been concerned that their ability to make meaningful representations is materially impaired by the CSI process in place, particularly with the undertaking as currently framed.

And so we'll just be registering our objection to this process. And rather than repeating my objection every time the panel goes into CSI, please take this as an ongoing objection to the process on the basis of our concern that it is impairing our ability to make meaningful representations and that the undertaking as currently framed effectively prevents our client from participating. Thank you.

THE CHAIRPERSON: Okay. Mr. Shefman...?

MR. CORY SHEFMAN: Thank you. For the

record, my client has the same concerns as just described by counsel for the CAC, and just for the record we wanted that to be said.

MR. GEORGE ORLE: Mr. Chairman, also I -- on behalf of my client I -- I repeat the same concerns raised but I -- I have an additional one. And that is based upon the opinion that we have received from the Law Society of Manitoba, counsel is precluded as a matter of ethics from signing the confidentiality agreements that have been prepared on behalf of the Board.

So it's not a matter of just indicating that we can't sign. We will be in breach of our obligations to the Law Society. And the -- the manner in which it's been put forward prevents us from actually even taking any part in -- in signing or signing anything close to what's been prepared by the Board.

THE CHAIRPERSON: Thank you for your comments and objections. They've been noted. Some of the issues that have been raised will be addressed in due course by the panel. Thank you very much. So we're recessed --

MS. PATTI RAMAGE: Mr. Chair, before we --

THE CHAIRPERSON: I'm sorry.

MS. PATTI RAMAGE: -- recess -- and I don't intend to respond to the various comments that were made with respect to the -- the objections to CSI. There are motions on the record, and you have Manitoba Hydro's position.

I would clarify that I don't believe there's a Law Society opinion that -- there was some preim -- some preliminary comments. But that wasn't actually the reason I wanted to get on the mic.

I ran down here because the people upstairs said they've locked the door. So I'm a little out of breath. I was trying to get in. Because there is another CSI matter I wanted to deal with. I thought we'd be dealing with it once the room had cleared, but it's not necessary to clear -- to clear the room for this, as it turns out.

As -- as the panel will know, last Friday they issued a letter to Manitoba Hydro requesting that Manitoba Hydro do two (2) things. One (1) was to justify the CSI, the -- the -- I -- I believe it was the Board advisors went through the redactions Manitoba Hydro had made and put in their comments, whether they agreed or disagreed.

Manitoba wa -- Hydro was to file by

tomorrow its response to those redactions. We ran into a roadblock this week. Our people, as it turned out, were chasing their tails a bit because they couldn't figure out the redactions. And it turned out there was an inadvertent error and the redactions that had been proposed in some case were not ones that had been made by Manitoba Hydro and they were working -- the PUB staff, Mr. Hombach can clarify, were -- had provided redactio -- had comments on redactions that Manitoba Hydro hadn't asked for.

And it was -- it took our people a little bit of time to figure out what was going on. And what it's done is put us behind. And today, PUB counsel provided us with their comments on the actual redacted reports according to the redactions that were in fact made by Manitoba Hydro.

I believe -- and I don't want to speak for others because I don't know for sure where the reports... I believe some the IECs had -- had proposed redactions, and that's what the comments were made on instead of the actual report. So that's now been clarified. Mr. Hombach gave us that today, but it means we will not be able to file our comments tomorrow. Our goal at this point is to file them on Wednesday to -- to catch up.

The other thing that the Board had asked was that we file redacted IRs on any CSI IRs. That is a real issue for our people, because the same people who have to deal with the redactions are the people who are in front of you now and next week.

And so what we've asked our staff to do, and we want to keep the Board apprised because we're making our best efforts in doing everything we can, is to start working on it, but they can't be in two (2) places at once. And so they're going to start. And we will file as we -- as we get those redacted IRs with the goal to be completed by the end of March, but we simply -- they can't get them done by the end of the next. And particularly, this hiccup has really thrown a wrench into things, in terms of getting those redactions done.

So with all of that, I have to tell you that the wind just got taken right out of me when I heard that we're going to be asked to redact transcripts. I just don't know where the time's going to come. And that's -- people can't testify and redact at the same time, and we just don't have the -- the ability to do that.

And I look at my notes and there's one (1) other comment I have. I said Wednesday for the

redactions. There are two (2) reports that deal with transmission. We're going to need longer to deal with those transmission reports. That's the power engineers and the section of LCA. The redactions there are different from what I think PUB advisors thought they were. They were looking at them from a financial point of view.

My understanding is the redactions there deal with something called, what we would look at as our criteria, critical infrastructure prote -- protection under NERC standards and critical energy infrastructure information under US Federal Power Act.

And those are the type of things that we'd be looking for in a transmission report. And our transmission people are going to be on the stand on Monday. So we're going to need more time for them to go through that because that's not something that our finance and economics people can help with. It's a very specialized area where they're looking for -- and that goes to the physical security of the system.

And that's not what this group deals with, but that's protecting our system from -- from acts of terrorism, that sort of thing. And they take -- they look at -- at the information to see if it releases any -- any soft points, that sort of thing.

And that's required under other legislation. So it wouldn't be -- have necessarily been redacted under the terms of reference, per se, although it certainly has financial consequences if -- if something like that happened.

So we're relying on someone else to do that, and we run into the same problem. So I just wanted to keep the Board apprised of what's going on with that.

MR. SVEN HOMBACH: Mr. Chairman, perhaps I can suggest that during the break I'll have a fre -- chat with Ms. Ramage and we can see whether the timing of the issue can be resolved. And we'll regroup on ten (10) minutes.

THE CHAIRPERSON: Okay. So again, all those comments have been noted and will be considered in due course. And I must say that we will try to make this a priority because we understand that we need to address these promptly. So that will certainly be a priority of the panel.

Thank you very much. So for those of you who are leaving us, having a good evening. And we will recess for ten (10) minutes.

(PANEL STANDS DOWN)

--- Upon adjourning at 3:02 p.m.

Certified Correct,

_____

Cheryl Lavigne, Ms.

$

$1,500 1181:14

$12 1141:15

$15,000 1181:20

$500 1183:15,18

0

0.1 1049:9 1086:9 1087:1

00 1147:2

09 1140:12

1

1 992:8,25 994:7,9 997:22 1000:17 1001:6,11,25 1002:17 1003:5,14,16,18,21,23,25 1004:5,7 1006:10,12 1035:10 1039:11,13 1040:21,23 1045:15,17 1046:17,19 1047:21,23 1052:3,5 1057:16 1065:15 1066:10,14 1067:6 1072:8 1075:7 1076:23 1077:9 1080:25 1086:1,15 1089:12 1096:17,20 1102:23 1104:4 1106:8,14,15,16,20 1107:5,20 1108:10 1118:23 1119:7 1122:3 1128:10 1130:4 1131:3,14 1132:17 1133:8 1134:16 1137:14,24 1138:18 1139:3,25 1142:7 1143:4 1146:19 1149:11 1152:22 1155:5,6 1175:14 1177:17 1179:10 1181:7 1182:5,25 1186:23 1189:14 1190:24 1192:11 1193:9,18 1196:10 1197:21 1199:11,21 1200:16 1203:17 1204:9 1210:2,6,8 1211:24 1212:4,12,18 1217:17,19 1220:19 1223:24 1225:5 1232:20 1234:21 1235:8 1244:4 1245:1 1249:21 1251:25

1,400 1141:7

1,500 1074:2

1,704 1106:8

1.1 1141:13 1232:12

1.4 1232:18

1.5 1232:14

1/2 1114:23

1/3 1123:23

1:15 1186:21 1187:14

1:30 1187:16,17

1:37 1187:21

10 993:13,20 994:18 998:8 1001:3,20 1002:11 1004:16 1006:21 1036:8,23 1037:15 1039:5,22 1041:9 1046:3 1047:5 1055:11,19,25 1056:20 1057:7 1060:23 1061:15,20 1062:24 1064:18 1065:13,20 1066:1,22 1067:13,22 1068:7 1071:15 1073:17,22 1074:3,12,13,14,19 1075:1,8,9,25 1076:11 1078:2,11,23 1079:4,9,24 1083:9 1084:5 1086:3,4,5 1096:14 1133:3,13 1135:10,20 1152:2,20 1188:14 1218:20 1219:3,4 1225:18 1245:14 1253:14,23

10:00 1143:24

100 1013:9

101 1013:11

102 1013:13

103 1013:15 1114:8

104 1013:17

1049 991:4

105 1013:19

1051 991:14

106 1013:20

107 1013:22

108 1013:24

1086 1049:10

109 1014:3

10th 1138:6

11 993:14 994:19 998:9 1001:21 1002:12 1004:17 1006:22 1039:23 1041:10 1046:4 1047:6 1067:20,24 1077:2 1132:22 1225:18

11.3 1039:2

11.4 1039:4,8

11.9 1079:10

11/12/2013 997:17

11:06 1132:6

11:26 1132:7

110 1014:5

111 1014:7

112 1014:8

113 1014:9 1109:4

114 1014:10

1143 1048:15

1144 1048:16

115 1014:11

1153 991:15

116 1014:12

1165 1049:14

117 1014:14

118 1014:16

1187 1048:17

119 1014:18

1194 991:16

12 994:20 997:16,19 998:10 1000:7,9,10,11,13,14 1001:22 1002:13 1004:18 1006:23 1039:24 1041:11 1046:5 1047:7 1081:4 1152:2

12:42 1187:20

120 1014:20 1095:10

121 1014:22

1095:10
122 1014:24
1223 1049:20
1224 991:17
123 1015:3
124 1015:5
1244 991:19
1048:18
1245 1048:19
125 1015:7
1239:10
1254 989:25
991:21
126 1015:10
127 1015:13
128 1015:16
129 1015:18
13 994:4,21
998:11
1002:14
1003:25
1004:19
1006:24
1039:25
1041:12
1045:7
1046:6
1047:8
1048:17
1072:3,4
1079:1
1187:3,10
130 1015:20
1117:14
131 1015:22
132 1015:24
133 1016:3
134 1016:5
135 1016:7
136 1016:8
137 1016:9
138 1016:10
139 1016:12
14 992:4
994:22
998:12
1004:20
1006:25
1036:15,21
1040:3
1041:13
1045:10,13
1046:7
1047:9
1092:7
1101:5,20
1102:8
1120:2
1225:8,13
140 1016:14
141 1016:16
142 1016:18
143 1016:19
1134:20
144 1016:21
145 1016:23
146 1017:3
146.43
1147:3,6
147 1017:6
148 1017:7
149 1017:8
14th 1225:10
15 994:23
998:13
1004:21
1007:3
1040:4
1041:14
1046:8
1047:12
1048:12
1061:16,21
1067:17,19
1068:3,8,20 1084:13
1086:1
1096:14
1107:13
1132:4
1133:14
1138:11
1193:7
15.8 1079:10
150 1017:9
151 1017:10
151c 1191:24
152 1017:11
153 1017:13
154 1017:15
155 1017:17
156 1017:20
157 1017:22
158 1017:23
159 1017:24
16 993:16
994:24
998:14
1004:22
1007:4
1040:5
1041:15
1046:9
1047:13
1048:19
1049:4
1070:25
1071:1
1085:11,15
1086:20
1245:2,6
160 1017:25
161 1018:3
162 1018:4
163 1018:5
164 1018:6
165 1018:7
166 1018:8
167 1018:9
168 1018:10
169 1018:11
17 994:25
998:15
1004:23
1007:5
1040:6
1041:16
1046:10
1047:14
1197:25
1239:13
170 1018:12
171 1018:13
172 1018:14
173 1018:15
174 1018:16
175 1018:17
176 1018:18
177 1018:19
178 1018:20
179 1018:21
18 995:3
998:16
1004:24
1007:6
1040:7
1041:17
1047:15
1078:3
1157:4
1158:22
180 1018:22
1146:8
181 1018:23
182 1018:24
183 1018:25
184 1019:3
1134:14
1146:13
185 1019:4
186 1019:5
187 1019:6
188 1019:7
189 1019:8
19 995:4
998:17
1004:25
1007:7
1040:8
1041:18
1047:16
1049:3
1062:22
1072:7
1078:22
1086:18
1101:3,4
1144:9
1237:19
190 1019:9
191 1019:10
192 1019:11
193 1019:12
193.5
1121:11
194 1019:13
195 1019:14
196 1019:15
197 1019:16
198 1019:17
1982 1060:23
1063:15
1064:22
1987 1061:7
1989 1111:14
199 1019:18
1992 1060:16
1062:23
1064:17,23,25 1075:2
1207:10
1994
1066:12,16,17
1998 1075:18
1999 1075:19
1s 1116:23

2

2 992:14
993:4,18
994:10
997:20,23

1000:18
1001:7,12
1002:3,18
1003:6
1004:8
1006:13
1032:7
1035:13
1039:14
1040:15,24
1045:18
1046:12,20
1047:10
1048:3
1054:16
1061:10,17
1069:11
1075:22
1076:7,10,23 1085:25
1088:21
1092:7
1093:18
1094:7
1097:9,21
1105:8,14
1106:13
1107:21
1108:10,11
1114:23
1117:19
1118:14,22
1123:11
1136:23
1137:25
1139:3
1154:15
1163:25
1171:23,24
1193:9,18
1196:9
1199:21
1204:9
1225:15
1232:20
1249:20
1251:10
1252:1

2,961 1105:9
1106:9

2.5 1049:8
1086:2,8,24

2.7 1057:7
1131:13

2:1 1117:5

20 992:24
995:5
998:18
1000:16
1001:5,10,24 1002:16
1003:4,11
1005:3
1007:9
1040:9
1041:19
1047:17
1049:11
1061:11,14,18,23
1062:7,18,21 1063:1
1067:11
1068:3,10,20 1073:3
1077:2
1078:11
1079:7
1084:19
1107:12,13
1147:9,23
1158:21
1159:8
1165:9
1182:17,21
1184:12,14
1228:9,12
1229:8
1231:2,4,6
1232:9

200 1019:19

2000 1116:23
1174:18

2002
1076:12,14

2004 1079:20

2004/2005
1078:5
1079:23

2005 1079:21

2007 1065:3

2008 1140:12

2009
1155:3,17

201 1019:20

2010 1140:22

2010/'11
1175:1

2012 1076:16
1118:6
1145:15

2012/'13
1110:23
1112:9
1147:7

2012/2013
1117:9

2013
992:4,6,8
993:16,18,20,22,24
994:4,6,8
997:16,19
1003:17,19,21,23,25
1004:6
1006:11
1039:12
1040:22
1045:16
1046:18
1059:4,5,9
1072:25
1108:22
1137:15
1139:8
1140:23
1141:2,11
1145:15
1187:3
1193:8
1232:12,18
1233:23

2013/2014
1080:2

2013/2016
1110:20
1118:16
1145:10

2013-2014
1072:16

2014 989:24
992:10,12,14,17,19,22,24
997:21
999:25
1000:5,7,9,10,12,13,14,16
1001:5,10,24 1002:16
1003:4,11,13,15
1004:4
1006:7,9
1032:8
1035:9,12,14,16,18,20,22,24
1036:4,7,9,11,13,16,18,20,22,25
1037:5,7,9,11,14,17,20,23
1038:5,9,11,13,15,17,19,23,25
1039:2,4,6,9
1040:16,20
1045:7,9,10,13
1046:13,16
1047:11,20,22
1048:12,14
1137:17
1139:8
1187:4
1194:25

2015
1138:13,14

2016 1108:22

2017 1139:1

2019 1059:3
1142:3,4

202 1019:21

2022 1071:18
1073:19

2022/2023
1072:18

2023
1059:2,6,10,16
1071:18
1073:19

2027 1108:3
1119:3

2027/2028
1101:8
1107:2
1119:10

2027/'28
1109:5
1118:24

2028 1119:3

203 1019:22

204 1019:23

205 1019:24

206 1019:25

207 1020:3

208 1020:4

209 1020:5

21 995:6
998:19
1003:13
1004:4
1005:4
1007:11
1040:10
1041:20
1049:15
1147:9
1223:8

210 1020:6

211 1020:7

212 1020:8

213 1020:9

214 1020:10

215 1020:11

216 1020:12
217 1020:13
218 1020:14
219 1020:15
22 995:7 998:20 1005:5 1007:13 1040:11 1041:21 1242:18,21
22.1 1118:24 1120:10
22.8 1123:14
220 1020:16
221 1020:17
222 1020:18
223 1020:19
224 1020:20
225 1020:21
226 1020:22
227 1020:23
228 1020:24
229 1020:25
23 995:8 998:21 1005:6 1007:15 1040:12,20 1041:22 1060:9 1074:20
230 1021:3
231 1021:4
232 1021:5
233 1021:6
234 1021:7
235 1021:8
236 1021:9
237 1021:10
238 1021:11
239 1021:12
24 995:9 998:22 1003:17 1005:7 1007:17 1035:9,12,14,16,18,20,22,24 1036:4,7,9,11,13,16,18,20,22,25 1037:5,7,9,11,14,17,20,23 1038:5,9,11,13,15,17,19,23,25 1039:2,4,6,9 1040:13 1041:23 1047:20
24,2014 1038:7
240 1021:13
241 1021:14
242 1021:15
243 1021:16
244 1021:17
245 1021:18
246 1021:19 1114:7 1117:14
246.99 1114:1
247 1021:20
248 1021:21
249 1021:22
25 995:10 998:23 1005:8 1007:19 1040:14 1041:24 1191:8
25,000 1099:10
25.2 1119:4
250 1021:23 1133:15 1239:10
251 1021:24
252 1021:25
253 1022:3
254 1022:4
255 1022:5
256 1022:6 1112:21
256.06 1112:14
257 1022:7
258 1022:8
259 1022:9
26 995:11 998:24 1005:9 1007:21 1040:17 1041:25 1131:6 1237:19
260 1022:10
261 1022:11 1143:11
262 1022:12
263 1022:13 1143:11
264 1022:14
265 1022:15
266 1022:16
267 1022:17
268 1022:18
269 1022:19
27 992:10 993:22 994:6 995:12 998:25 1003:19 1005:10 1007:22 1040:18 1042:3 1073:22 1119:10 1197:24
27,065 1073:23
27/'28 1107:3 1109:14 1112:17 1120:1
270 1022:20
271 1022:21
272 1022:22
273 1022:23
274 1022:24
275 1022:25
276 1023:3
277 1023:4
278 1023:5
279 1023:6
28 992:6 995:13 999:3 1005:11 1007:24 1042:4 1093:22 1099:9 1124:1 1125:7 1131:12 1243:4
28,605 1073:20
280 1023:7
281 1023:9
282 1023:11
283 1023:13
284 1023:15
285 1023:17 1106:23
286 1023:19
287 1023:21
288 1023:23
289 1024:3
29 992:12 995:14 999:4 1005:12 1007:25 1042:5 1101:15,17,22 1102:8,21 1155:22,23 1156:1,7 1243:4
290 1024:5
291 1024:6
292 1024:7
293 1024:8
294 1024:9
295 1024:10
296 1024:11
297 1024:12
298 1024:13
299 1024:14
299.85 1113:12
2s 1116:23

3

3 991:6 993:6 994:11 997:24 1000:19 1001:8,13 1002:4,19 1003:7,15 1004:9 1006:14 1035:15 1039:15 1040:25 1045:19 1046:21

1048:5
1051:4
1059:25
1070:2
1071:1
1076:24
1096:3
1097:21
1102:11,14
,15
1106:14
1111:21
1113:22
1120:24
1138:17
1139:18
1142:20
1145:1,19
1165:24
1167:15
1175:15
1188:3
1193:9,18
1204:10
1225:5,6
1230:15
1232:20
1239:8,14

3,000
1074:5,7
1109:3
1141:5

3.9 1147:18

3:02 1254:1

30 993:24
995:15
999:5,25
1005:13
1008:3
1042:6
1061:17
1063:17
1125:1
1175:18
1228:16
1230:20
1231:3

30.7 1119:10

300 1024:15

301 1024:16

302 1024:17

303 1024:18

304 1024:19

305 1024:20

306 1024:21

307 1024:22

308 1024:23
1239:10

309 1024:25

31 995:16
999:6
1005:14
1008:4
1042:7
1158:15,20
1159:8

3-1 1174:21

310 1025:3

311 1025:5

312 1025:7
1157:25

313 1025:9

314 1025:10

315 1025:12

316 1025:13

317 1025:14

318 1025:15

319 1025:16

32 995:17
999:7
1005:15
1008:5
1042:8

320 1025:17

321 1025:18

322 1025:20

323 1025:22

324 1025:24

325 1026:3

326 1026:5

327 1026:7

328 1026:9

329 1026:11

33 995:18
999:8
1005:16
1008:6
1042:9
1049:4
1085:11,14
1086:8,19

330 989:22
1026:13

331 1026:15

332 1026:16

333 1026:17

334 1026:18

335 1026:19

336 1026:20

337 1026:21

338 1026:22

339 1026:23

34 995:19
999:9
1005:17
1008:7
1042:10

34.4 1123:17

340 1026:24

341 1026:25

342 1027:3

343 1027:5

344 1027:7

345 1027:8

346 1027:9

347 1027:10

348 1027:11

349 1027:12

35 995:20
999:10
1005:18
1008:8
1042:11
1228:9,13,
17,23
1229:8

350 1027:13

351 1027:14

352 1027:15

353 1027:17

354 1027:19

355 1027:21

356 1027:22

357 1027:23

358 1027:24

359 1027:25

36 995:21
999:11
1005:19
1008:10
1042:12

360 1028:3

361 1028:5

362 1028:7

363 1028:9

364 1028:10

365 1028:11

366 1028:12

367 1028:13

368 1028:14

369 1028:15

37 995:22
999:12
1005:20
1008:12
1042:13
1163:19

370 1028:16

371 1028:17

372 1028:18

373 1028:19

374 1028:20

375 1028:21

376 1028:22

377 1028:23

378 1028:24

379 1028:25

38 995:23
999:14
1005:21
1008:14
1042:14
1089:17

380 1029:3
1117:10

380.04
1111:23

381 1029:4

382 1029:5

383 1029:6

384 1029:7

385 1029:8

386 1029:9

387 1029:10

388 1029:11

389 1029:12

39 995:24
999:16
1005:22
1008:16
1042:15

390 1029:13
1106:22

390,000
1138:21

391 1029:14

392 1029:15

393 1029:16

394 1029:17

395 1029:18

396 1029:19

397 1029:20

398 1029:21

399 1029:22

3rd 1153:16

3s 1116:23

4

4 992:16
993:7
994:12
997:25
1000:20
1001:14
1002:5,20
1003:8
1004:10
1006:15
1035:17
1036:15
1039:16
1041:3
1045:20
1046:22
1048:7,16
1070:6
1076:24
1110:10
1119:15,17
,19,20
1120:24
1141:17,19
1142:5
1144:4
1147:9
1152:6
1164:5
1170:3
1230:17
1237:23

4,719
1134:10

40 995:25
999:18
1005:23
1008:18
1042:17

400 989:22
1029:23
1106:21

401 1029:24

402 1029:25

403 1030:3

404 1030:4

405 1030:5

406 1030:6

407 1030:7

408 1030:8

409 1030:9

41 996:3
999:19
1005:24
1008:20
1042:18

410 1030:10

411 1030:11

412 1030:12

413 1030:13

414 1030:14

415 1030:15

416 1030:16

417 1030:17

418 1030:18

419 1030:19

42 996:4
999:20
1005:25
1008:21
1042:19
1089:13

420 1030:20

421 1030:21

422 1030:22

423 1030:23

424 1030:24

425 1030:25

426 1031:3

427 1031:4

428 1031:5

429 1031:6

43 996:5
999:21
1006:3
1008:22
1042:20

430 1031:7

431 1031:8

432 1031:9

433 1031:10

434 1031:11

435 1031:12

436 1031:13

437 1031:14

438 1031:15

439 1031:16

44 996:6
999:22
1006:4
1008:23
1042:21

4-4 1038:18

440 1031:17

441 1031:18

442 1031:19

443 1031:20

444 1031:21

445 1031:22

446 1031:23

447 1031:24

448 1031:25

449 1032:3

45 996:7
1006:5
1008:24
1042:22

4-5 1038:18

450 1032:4
1106:24

450,000
1137:20

451 1032:5

452 1032:6

453 1032:9

454 1032:10

455 1032:11

456 1032:12

457 1032:13

458 1032:15

459 1032:17

46 996:8
1008:25
1042:23
1147:17

460 1032:19

461 1032:21

462 1032:23

463 1032:24

464 1032:25

465 1033:3

466 1033:4

467 1033:5

468 1033:6

469 1033:8

47 996:9
1009:3
1042:24

470 1033:9

471 1033:10

472 1033:11

473 1033:12

474 1033:13

475 1033:14

476 1033:15

477 1033:16

478 1033:17

479 1033:18

48 996:10
1009:4
1042:25

480 1033:19

481 1033:20

482 1033:21

483 1033:23

484 1033:24

485 1034:3

486 1034:5

487 1034:7

488 1034:9

489 1034:11

49 996:11
1009:5
1043:3

490 1034:13

491 1034:14

492 1034:15

493 1034:16

494 1034:17

495 1034:18

496 1034:19

497 1034:20

498 1034:21

499 1034:22

5

5 993:8
994:13
998:3
1000:21
1001:15
1002:6,21
1003:9
1004:11
1006:16
1035:19
1036:15,21
1039:17
1041:4
1045:21
1046:23
1048:9,15
1049:6
1052:7,14,
16 1056:19
1060:8,17
1061:3,5,2
2 1062:1
1064:19,25
1066:7,8,1
3,18,19,22
1067:10,13
,21 1068:6

1070:2,6
1072:22
1074:20
1076:5,16,
24 1077:1
1085:16
1086:3,22
1132:23,24
,25
1133:7,9
1137:4
1139:24
1142:20
1143:10,16
1149:21
1151:16
1159:4
1203:19,23
1218:19
1219:3
1225:15
1239:14
1244:16

5.4 1075:2
1076:6,18,
25
1077:15,22

50 996:12
1009:6
1043:4
1061:17
1210:3
1233:23

500 1034:23

501 1034:24

502 1034:25

503 1035:3

504 1035:4

505 1035:5

506 1035:6

507 1035:7

51 996:13
1009:7
1043:5

52 996:14
1009:8
1043:6

53 996:15
1009:9
1043:7

54 996:17
1009:10
1043:8

55 996:18
1009:11
1043:9

56 996:19
1009:12
1043:10

57 996:20
1009:13
1043:11

570,000
1137:22
1138:3

58 996:21
1009:14
1043:12

59 996:22
1009:16
1043:13

6

6 989:24
992:19,22
993:9
994:14
998:4
1000:22
1001:16
1002:7,22
1004:12
1006:17
1035:21
1036:15
1039:18
1041:5
1045:9,22
1046:24
1048:14,15
1076:24
1089:16,17
1133:15
1137:4
1140:17
1143:10,17
1152:1
1196:16
1238:2

60 996:23
1009:18
1043:14

6-03 1038:8

6-09 1038:10

61 996:24
1009:20
1043:15

6-11 1038:10

6-13 1038:10

6-14 1038:10

6-15 1038:12

6-18 1038:12

6-19 1038:14

62 996:25
1009:22
1043:16

63 997:3
1009:24
1043:17

64 997:4
1010:3
1043:18

6-40 1038:16

65 997:5
1010:5
1043:19

66 997:6
1010:7
1043:20

67 997:7
1010:9
1043:21
1229:5

67/13
993:17,20

68 997:8
1010:11
1043:22

69 997:9
1010:13
1043:23
1158:23
1167:2,5

6th 1134:8

7

7 993:10
994:15
998:5
1000:23
1001:17
1002:8,23
1004:13
1006:18
1035:23
1039:19
1041:6
1045:23
1046:25
1055:5
1066:13
1120:22
1125:12
1126:3
1137:6
1144:8
1225:9,11
1230:15
1244:6

7,500
1122:23

7.27
1055:13,21

7.6 1073:5

70 997:10
1010:15
1043:24
1234:5,6

70s 1063:14
1064:11

71 997:11
1010:17
1043:25

72 997:12
1010:19
1044:3

73 997:13
1010:21
1044:4

74 997:14
1010:23
1044:5

75 1011:3
1044:6

750 1082:24

76 1011:5
1044:7

760,000
1138:23

77 1011:7
1044:8

78 1011:9
1036:19
1044:9
1226:20
1228:5,10,
17 1231:15

79 1011:11
1044:10

8

8 993:11
994:16
998:6
1000:24
1001:18
1002:9
1004:14
1006:19
1036:3
1039:20
1041:7
1045:24
1047:3
1067:6,13
1142:2
1152:1

8.2.2.2
1242:20

80 1011:13
1044:11

800,000
1138:4

80s 1063:21
1064:12

81 1011:15
1044:13

82 1011:17
1044:14

83 1011:19
1044:15
1167:12
1194:13

8-30 1038:20

84 1011:21
1044:16

85 1011:23
1044:17

850,000
1141:9

86 1012:3
1044:18

87 1012:5
1044:19
1155:24

88 1012:7
1044:21
1180:25

89 1012:9
1044:22

9

9 993:12
994:17
998:7
1000:25
1001:19
1002:10
1004:15
1006:20
1036:5
1039:21
1041:8
1045:25
1047:4
1067:2
1078:25
1128:2,21,
24 1224:25

9:05 1050:1

90 1012:11
1044:23
1059:7
1078:2
1079:9
1084:4
1132:17
1135:10,20

90/10
1084:17
1135:10,24

90s 1209:1

91 1012:13
1044:24
1143:13

92 1012:15
1044:25
1144:2

93 1012:17
1045:3
1187:8

94 1012:19
1045:4
1245:4

95 1012:21
1045:5
1049:7
1079:2,8,1
9
1084:3,6,1
6,21
1085:2,7,1
6 1086:23
1135:25

95/5 1084:21
1135:12

95/90
1084:22

96 1012:23

97 1013:3

97.5 1049:8
1086:8,25

98 1013:5

986 1132:18

989 989:25

99 1013:7
1136:1

99.9 1049:10
1086:9
1087:2

992 991:3

A

a.m 1050:1
1132:6,7

ability
1089:6
1180:10
1204:4
1247:10,19
1251:23

able
1082:22,25
1087:17
1094:22
1102:23
1106:1
1129:4,7,1
6 1146:22
1158:3,7,1
2 1165:17
1175:16
1191:12
1202:11
1204:3
1235:11
1250:23

Aboriginal
1040:23
1209:3
1219:24
1220:6,7,8

Aboriginals
1220:5

absolute
1117:6

absolutely
1064:16
1203:1
1227:2
1240:5

academic
1189:11
1198:23

acce 1211:3

accept
1153:10
1224:2

acceptance
1098:2

accepted
1181:23

access
995:14,22
1043:10,25
1044:19
1056:12
1096:24
1180:5
1183:21
1184:8
1200:4

accommodate
1241:8

accomplishin
g 1213:19

according
1250:15

accordingly
1224:22

account
1053:7
1056:17
1059:21
1133:18
1233:5

accuracy
1060:10
1061:3
1065:14,23
1067:2
1068:3
1069:2
1070:3,6,1
7,24
1083:10

accurate
1062:12
1126:2
1239:20

accurately
1193:3

ach 1099:22

achievable
1094:8,14,
19,25
1095:22,23
1096:2,3,9
,12,18,19,
25
1097:7,8,1
0,11,19,20
,24,25
1098:7,14,
16,19,23
1099:3,15,
19
1100:14,16
1102:4
1103:8

achieve
1057:5
1065:13,15
,23
1100:20
1102:25
1104:25
1105:1
1128:5,18
1135:22
1179:14
1183:9
1196:1

achieved
1099:23
1100:18
1106:19
1111:18

achieving
1057:20
1179:14
1180:17

acknowledged
1202:10

across
1111:7
1126:11
1141:15
1160:2
1186:17
1207:10
1217:11
1235:9

Act 1127:18
1252:12

acting
1192:18

action
1221:5,14

active
1161:20

activities
1126:11
1128:12

activity
1109:14
1114:3
1117:25

acts 1252:23

actual
1065:1,8
1071:13
1074:18
1077:20
1079:18
1116:8
1117:6,25
1118:3
1134:10,19
1160:10,17
1191:17,25
1206:15
1250:14,21

actually
1057:1
1059:13
1062:13
1064:23
1074:5,13
1084:2,12
1101:13
1105:22
1108:19
1126:5
1128:4,23
1133:15
1134:13
1141:22
1152:11
1161:19,21
1162:5,15
1164:3
1166:18
1170:7
1173:10
1176:21
1185:15
1188:22
1196:24
1197:15
1198:8,20,24 1201:8
1205:13
1207:25
1215:23
1221:2
1237:1
1243:11
1245:9
1248:16
1249:10

actuals
1071:7,10
1074:25

ad 1222:13

adapt
1230:7,10,12

adapting
1230:9

add 1068:22
1104:13
1128:20
1132:19,21
1136:7
1163:6
1171:4
1175:11
1219:11
1234:18
1236:25
1239:4
1240:14

added 1063:4
1105:11
1113:13
1132:18
1210:25

addition
1053:15
1121:4
1137:24
1138:15
1141:19
1162:17
1193:9
1202:11
1208:9,17
1219:19

additional
992:13
1081:2
1105:11
1132:19
1138:24,25
1146:17
1163:17
1164:5
1173:5
1208:22
1210:23
1248:6

address
1050:23
1105:24
1115:2
1124:14
1139:14
1147:12
1172:20
1186:5
1188:19
1253:19

addressed
1116:21
1190:21
1248:21

addressing
1215:6

adjourn
1186:20

adjourning
1254:1

adjust
1069:18,22,24 1230:7

adjusted
1116:22,24
1134:19

adjustments
1062:20
1063:2,3,4
1232:15

administrative 1050:9
1188:2,18,22

admit
1189:13

adopt 1221:2

adopting
1078:1

adoption
1100:22
1206:2
1209:4
1220:21

advance
1142:21

advanced
1082:25

advancing
1059:20

advantage
1211:25

advantages
1088:17
1124:11

adverse
993:4
1007:8,10,12,14,16,18
1009:15,17,19,25
1010:4
1040:24
1041:15,17,18,19,20,21,22,23,25
1042:3,4,5,15,17,18
1043:11
1044:6,10,21,25
1045:5

advertising
1206:6
1208:4,6
1221:23

advise
1143:19
1224:21

advised
1050:8,21
1152:18
1188:8,17

advisors
1003:3
1046:14
1249:22
1252:5

Advisors/ Manitoba
1045:14
1046:11

advocated
1144:12

affect
1070:17
1118:1

affects
1051:22

Affirmed
991:7
1051:5

Afford
1209:8

affordable
1170:13
1171:6
1172:12,22
1173:6
1178:10,17,18
1179:22,25
1180:18
1183:9
1195:23
1199:23
1200:6
1208:11

afield
1246:14

afternoon
1050:13
1187:23
1188:4

against
1237:12

age
1174:7,17

agency
1222:14

agenda
1244:14

aggregate
1056:7
1193:6

aggregated
1103:7

ago 1063:17
1066:19
1082:5
1109:18
1138:6
1170:3
1202:9

agreed
1249:24

agreeing
1245:24

agreement
1193:1
1244:19

agreements
997:4
1046:6
1248:10

Ah 1119:22

ahead
1131:24
1189:21
1245:15,16

air 1121:25
1159:23
1224:3

al 1081:15

Alberta
1137:14
1138:1
1139:4,22
1140:14

aligned
1159:13

allow 1191:3
1223:25
1230:6
1244:17

allowed
1222:14

allows
1122:15
1150:25
1166:15
1205:7

alluded
1209:6

alone
1066:14

already
1056:14
1139:5,8
1155:25
1168:12
1171:18
1173:25
1190:7
1191:18
1192:3,5
1197:21
1238:25

alternative
1035:15
1054:9
1057:1
1092:13
1093:16
1200:15
1201:24
1212:3

alternatives
989:8
1035:14
1058:15
1083:16,19
1203:7,8
1204:20
1243:1

am 1052:9
1053:6,18
1060:21
1090:8
1096:4
1104:20
1120:12
1143:13
1149:7
1165:3
1182:1
1213:18
1223:18
1226:6
1228:1

amazing
1190:4

Ameren
1175:4,11,12,14

America
1080:19
1140:7
1235:10

American
1089:14

amount
1096:13
1114:12
1119:14
1120:19
1125:22
1126:5
1139:7
1140:9
1146:21
1161:20
1176:20
1181:15
1197:9
1203:16
1228:22

amounts
1111:17
1176:19

analogous
1095:23
1097:11
1098:22
1100:14

analogy
1216:20

analyses
1136:3

analysis
1010:6,8,10,12,14,16,18,20,22,24
1011:4,6,8,10,12,14,16,18,20,2
2,24
1012:4,6,8,10,12,14,16,18,20,2
2,24
1013:4,6,8,10,12,14,16,18,21,2
3,25
1014:4,6,13,15,17
1026:24
1027:3,5,7
1033:23
1036:6,9
1092:22
1095:16
1102:14
1103:6
1104:9,16
1113:7,18
1116:17
1133:2,9,11 1139:11
1154:5
1189:2
1228:15,18
1233:20,22
1235:21
1242:25
1243:7

analyzed
1155:21

Ancillary
1028:20,21,22,23,24,25

Anderson
990:16

angle 1227:9

announced
1137:25
1138:15
1141:12

announcement
1141:1

annual
1108:23
1109:10
1110:20
1118:17
1124:23
1230:7

answer
1058:11,12
1087:10
1130:11,13
1153:10
1165:23
1177:3
1204:18
1217:20,22
1224:19
1228:8
1235:19
1236:18
1238:7

answering
1194:3

answers
1131:1
1173:22
1246:12

anticipate
1050:18
1071:25
1188:7

anticipates
1138:9

anticipating
1126:3,5
1219:17
1232:25

anti-fragility
1235:5

Antoine
990:13
991:14
1051:12,13
1052:16,23,24
1053:5,11,22,25
1054:11,16,20,23
1055:4,9,17,23
1056:18,25
1057:5,21
1058:2,6,2

4
1059:11,17,25
1060:14,21
1061:1,9
1062:15
1063:7
1064:1,15
1065:2,10,21 1066:5
1069:8,9,17
1070:1,12,20
1071:5,11,14,22
1072:5,15,20
1073:2,8,16
1074:1,7,10,17,24
1075:6,12,16,21,25
1076:3,9,12,15,20
1077:8,14,23
1078:9,15,20
1079:6,17
1080:7,12
1083:2,24
1084:24
1085:13,23
1086:10,13
1087:4,5,16,21
1089:8,21,25
1090:8,13,18
1091:10,24
1092:3,11
1093:19
1095:2,14,25 1096:16
1097:16
1098:24
1099:14,24
1100:6,23
1101:1,13
1102:20
1104:10,19
1105:4
1106:4,5
1107:1,7,11,18,19
1108:1,11,15,16,21
1109:1,7,17
1110:6,14
1111:2,6,15
1112:3,6,11,18
1113:10,17
1114:4,19
1115:24
1117:7,12,18
1118:12,19
1119:1,6,13,18,22
1120:8,17,21
1121:3,8,16,19
1122:18,24
1123:5,12,25
1124:9,21
1125:5
1127:13
1129:23
1130:7,25
1131:25
1144:23,24
1145:9,14,19,23
1146:11,23
1147:8,22
1148:1,4,11
1149:1,5,22 1150:9
1152:13
1245:17

anybody
1072:9
1244:18

anyone
1184:23
1217:5,7
1224:17,18
1242:10

anything
1175:22
1182:19
1184:21
1248:17

anyways
1206:4

anywhere
1058:9
1067:21

apartments
1156:16

apologize
1084:22
1105:5
1131:1
1155:14
1173:25

App
1039:2,4,8

appear
1072:13
1111:9
1198:2
1222:5
1241:1

APPEARANCES
990:1

appears
1068:13
1076:16,21
1077:14

appendix
1035:10,13,15,17,19,21,23
1036:3,5,8
1039:5

apples
1064:3

appliance
1116:11

appliances
1159:24

applicable
1094:8

application
993:19
1138:5

apply
1082:17
1090:20
1160:7
1196:12
1238:8

appreciate
1168:11
1173:22
1174:2

appreciated
1247:7

apprised
1251:7
1253:8

approach
1058:18
1059:22,23
1071:24
1078:1,2
1079:9
1125:14
1163:8,11
1164:7
1171:22
1175:13,16,19
1179:11
1208:25

approaches
1060:6

approaching
1058:14
1166:19
1209:15

appropriate
1051:15
1058:11
1060:2
1065:24
1080:16
1090:20
1092:5
1122:15
1125:15
1134:3
1246:7

appropriately 1118:8
1215:6

approval
1137:14,15
1138:5
1167:25

approvals
1138:7,10

approved
1130:24
1167:24
1182:16

approximately 1074:8
1076:1
1077:1,17
1079:1,10
1106:21
1109:16
1122:25
1123:6,23
1124:5
1245:14

April 1141:2

arbi 1234:2

arbitrarily
1234:2,11

arbitrary
1097:14

area 1058:14
1092:3
1110:2
1129:22
1162:22
1181:4
1182:25
1204:15
1206:1
1207:17
1217:19
1252:19

areas
1051:23
1152:14
1158:13
1173:17
1176:19
1183:2

1184:7
1201:18,19
1203:16
1206:10
1207:1
1208:3,5,19 1212:18

aren't
1050:9,22
1104:17
1181:24
1194:25
1196:19
1204:3
1214:22

argue
1082:24

argument
1056:12
1235:7

arises
1088:21

arm
1105:21,22
1192:25
1202:20

arrangements
1188:16

article
1191:24
1192:1

articles
1189:12,17
1190:25
1191:6,8

articulated
1148:10

ascribe
1127:5

aside
1177:21
1184:24

aspect
1149:25
1234:21

aspects
1136:19
1138:8
1142:7

assess
1058:1
1177:18
1183:24
1199:7
1216:8
1243:1

assessing
1067:5
1093:2

assessment
1017:10
1096:21
1154:1
1159:2
1160:10
1201:2

assessments
1162:20
1209:18

asset 1046:8
1228:25
1229:5

assign
1234:3,16

assigned
1143:22
1177:17
1190:10

assistance
1208:11

assisted
1101:24

associated
1196:19
1239:16

Associates
1000:6
1035:8
1038:24
1039:1,3,5,7

assume
1067:3
1115:10
1168:21
1179:1

assumed
1144:15

assuming
1115:20

assumptions
1033:22
1059:5,9
1096:22
1228:24

assure
1224:24

at-generation
1119:3,15

attached
1191:25

attempt
1052:25
1053:3
1147:17
1234:17

attempting
1162:18
1179:14

attending
1130:4

attends
1130:6

attention
1140:21
1144:8
1202:17

attic
1183:17

attitudinal
1175:6

attributed
1105:12

audio
1050:16
1188:12

audits
1162:20

August
993:22,24
1141:11

authorities
1128:17,18

authority
1126:18

automatically 1055:18
1104:21

automobiles
1234:7

availability
1010:7
1096:23
1204:15

available
1094:21
1141:24
1143:9,25
1146:20
1151:11
1154:22
1155:1
1159:9
1160:1,6
1161:18
1167:5,15
1168:9,10
1169:18
1170:22
1171:17
1174:15
1180:8
1182:24
1183:6
1187:5
1190:5
1201:15
1206:11,12
1207:3
1214:16
1246:11,21

Avenue
989:22

average
1231:22
1232:11,13

avoid
1240:19

avoided
1184:12

awaiting
1232:21

aware
1082:9,16
1213:9,15

awareness
1207:12

away 1104:23
1216:14

B

background
1220:6

backup
1197:23

backwards
1148:13

badgered
1181:6

balcony
1224:14

band 1162:19
1173:9
1209:16

band-operated
1209:17

band-owned
1209:17

bands 1162:4

bandwidth
1072:22
1074:4
1086:5

bang 1061:3

Bank 993:6

bar 1036:10
1060:17,23
1061:2
1064:17,18
1075:7

barrels
1137:21,22
1138:3,4,22,23
1141:10,14

bars
1068:9,10

base
1055:5,14
1073:19
1077:11
1183:15
1203:11

based
1058:19
1064:6
1072:3,25
1077:15,20
1084:16
1096:19,21
1098:1
1102:22
1111:12
1116:17,19
1126:21
1154:2
1177:16
1181:22
1182:3
1183:24
1220:4
1230:18
1232:3
1248:7

baseline
1093:24
1099:10
1109:10
1131:12

basement
1183:16

basic
1150:21
1186:12,17

basically
1084:15
1109:8
1138:17
1209:19

basics
1150:15

basis
1071:24
1087:18
1166:16
1177:10
1179:1
1183:24
1196:2
1230:7
1231:10,14
1247:18

BC 1128:11

become
1137:16
1143:4
1229:20

becomes
1135:4
1191:15
1230:11

bedrock
1202:7

before/after
1038:8

beginning
1052:5
1070:11

behalf
1192:18
1248:5,11

behind
1147:13
1212:5
1250:13

Bel 989:16

believe
1050:4
1054:21
1060:9
1061:11
1063:5
1065:18
1071:23
1074:20
1084:11
1085:10
1103:20
1132:9
1133:8
1143:12,21
1148:10
1149:12
1153:16
1155:22,24
1156:15
1157:4
1162:12
1163:18
1164:23
1177:25
1178:7
1181:21
1187:7
1194:9
1205:20
1210:17
1214:15
1216:10,19
1217:23
1226:11
1230:17
1232:19
1244:4,5,21 1245:3
1249:7,22
1250:17,19

believes
1175:15

belt 1205:10

benchmark
1112:17
1118:7
1193:15,20

benefit
1082:20
1168:20
1180:12
1181:14
1182:23
1183:1
1184:17
1191:1
1202:12,13
1203:3,5
1210:23,25

benefiting
1056:19,22
1173:14
1184:20

benefits
1037:6
1041:24
1048:14
1080:16
1178:6
1214:10,17
1217:22
1236:5

Besich
1000:10

best 1060:3
1073:11
1087:9
1088:16
1089:6
1090:4
1142:11
1169:4
1181:12
1216:11
1221:25
1225:19
1230:23
1235:8
1239:18
1242:6
1251:8

better
1062:8
1080:10
1082:22,25
1092:6
1103:25
1115:16
1126:22
1162:13
1166:6
1173:22
1180:10,21,22
1204:7,14
1212:3
1220:24,25
1243:11

beyond
1084:19
1195:21
1229:8
1240:15
1241:10
1246:5,10

bigger
1081:25
1082:2
1112:4

biggest
1212:13

billing
1154:12

billion
1141:15

bills 1056:6

bioenergy
1211:12
1212:13

bio-energy
1203:17
1214:25
1215:11

biomass
1198:2
1199:2
1203:12
1204:16
1212:14,15,19
1214:18
1215:3

biomass-to-energy
1203:18

bipole
1016:18
1149:17
1176:13

bipoles
1149:11

bit 1052:13
1058:16
1074:2
1078:16
1081:5
1092:6
1095:4,18
1100:7
1102:24
1104:8
1115:14,22
1116:2
1123:3
1126:9
1131:2,16
1133:20
1135:9

1137:1
1141:25
1150:22,24
1160:24
1161:6
1163:7
1171:5
1176:22
1196:5
1199:10
1205:10
1210:1
1214:22
1218:5
1224:12
1245:18
1250:3,12

Black 1235:1

blackout
1235:18,25

block
1151:16

blocks
1151:1

blue 1064:17
1071:6,9,12

board
989:3,14,15,16,17,21
990:2
1050:8,14
1051:25
1058:8
1069:11
1121:20
1141:24
1143:20
1150:8
1155:5
1164:12
1185:11
1224:18
1244:1
1246:2,6,19
1248:11,18
1249:22
1251:1,7
1253:8

Board's
1107:14

Bob 990:2

bodies
1090:11,15,21

Bonjour
1051:1,13

book 1003:14
1048:18
1049:5
1052:14,17
1060:1,8
1071:1
1084:12,13
1085:6,11,15
1086:1,21
1093:22
1095:9
1101:5,16
1107:21
1108:10,12
1117:19
1131:4
1145:1,20
1148:1
1224:25
1225:1,2,6,16
1230:15,18
1239:13
1242:18
1244:1,9

border
1137:8,9

bottom
1054:24
1107:22,23
1108:2,5
1109:2
1127:10

bought
1189:17

bound 1098:6
1099:22

boundaries
1092:6

boundary
1096:19
1122:11,13

box
1197:13,14,21

Boyd 990:6
1050:21
1052:12,18
1085:10
1105:18
1108:9,13
1132:12
1136:5
1143:8,19
1144:6,20
1186:25
1187:12,15
1192:9,16
1193:2,15
1225:12
1244:24,25
1245:8

brand
1207:9,12
1220:24

Brandon
1219:13

breach
1248:13

break
1036:10
1095:17
1123:20
1131:15
1152:23
1185:13
1188:14
1199:21
1223:24
1244:17
1253:11

breakdown
1040:18
1222:15

breath
1249:13

brief
1049:15
1071:3
1074:22
1079:15
1080:5
1085:21
1089:19
1092:1,9
1094:3
1095:12
1097:3
1098:10
1100:4,25
1101:11
1103:1
1105:16
1107:25
1110:12
1112:1
1131:22
1132:1
1144:18
1155:6,9
1157:1,8,23 1158:17
1160:14
1164:21
1167:10,20
1168:14
1171:2,9
1174:10
1180:14
1190:1
1192:7
1202:22
1220:12
1222:9,23
1223:2,9
1224:5
1227:22
1233:10

briefly
1121:17

bring
1055:12
1095:9
1105:13
1106:8
1113:22
1129:7,16,17 1144:25
1147:21
1166:13
1207:17

bringing
1129:15
1145:1
1184:1,4

broad
1161:16
1218:8

broad-based
1217:9

broader
1198:15
1216:2
1226:16,17

broadly
1141:4
1201:24
1208:24

brochure
1180:24
1181:11,19

broke
1174:22

broken
1095:17
1222:6,7

brought
1052:2
1113:24
1144:8
1145:24
1178:1

budget
992:5,20
993:23

build
1067:16
1127:20
1129:19
1140:16
1151:8,9
1211:22
1214:22

builder
1127:19

builders
1129:3,10,14,19
1206:14

building
1058:19

1127:17,18
1128:2,4,24 1129:10
1178:23
1205:14
1206:15
1207:24
1238:16

buildings
1157:5,11,12
1209:13,16,17,18,24

builds
1127:20

built
1055:11
1174:17
1230:12

bump 1224:3

Burden
1046:10

business
999:12
1046:16
1088:23
1140:8

buying
1126:19

Byron 990:8
1095:6
1192:21,22
1193:20
1247:8

Byron's
1104:23

C

ca 1237:21

CAC 990:8
1002:17,18,19,20,21,22 1095:9
1105:23
1248:2

CAC/MIPUG
1002:23

calculate
1084:15

calculated
1186:1

calculation
1072:21
1073:17

calculations
1072:11
1078:21
1106:7

camera
1188:9
1244:15

campaign
1206:7,9,22,23
1221:24

Cana 1137:8

Canada
1126:11
1139:23
1141:15
1224:3

Canada-specific
1154:13

Canada-US
1137:9

Canadian
1203:20

candidates
1049:17
1223:4,11

canvass
1049:17
1152:15
1223:3,11

cap 1230:20

capa 1082:19

capability
1240:16

capacity
1029:3,4,5,6,7,8,9
1082:7
1129:17
1137:19
1138:20
1145:6
1146:8
1149:8
1151:10
1212:16
1236:5
1241:7,25
1242:4,6

capital
995:11
996:3
1016:12,14,16
1017:11,13,15,17,20
1019:16,22,23
1028:19
1029:10,15
1030:3
1032:13,15
1036:12,24
1037:4,16,19,22
1038:4
1039:13,21,22
1040:4,5,6,7,8,9,10,11,12,13
1045:23
1133:18
1135:19,21
1176:12

capped
1147:1

Capra 1035:8
1038:24
1039:1,3,5,7

Capra/Manitoba
1006:10
1032:7

capture
1179:15
1229:17

captured
1118:7

captures
1197:6

car 1234:8

carbon
1024:3
1033:13
1215:1

Carbon/GHG
1016:5,7,8,9
1043:14,15,16,17,18,19,20,21,22
1044:4,5,7,8,9,13,14,15

carbon-neutral
1204:13

care 1056:5
1132:13
1202:5

careful
1053:12
1055:24

Caribou
1042:12,14
1044:22

carries
1139:22

carry
1115:21
1141:9
1245:12

case 1038:25
1046:16
1055:5,14
1098:15
1172:11
1178:3
1194:10
1195:8
1203:11
1212:22,23
1238:14,15,19 1250:6

cases
1033:8,9
1038:19
1115:7
1152:11

cash 1036:14

catch
1250:25

catchup
1082:2

categories
1114:22
1115:17
1156:8

categorization 1097:18

categorized
1054:13
1118:22

category
1054:13
1096:2,3,25 1098:7
1119:8
1165:25

cause 1081:6
1151:12
1192:4

caveat
1058:8
1146:19

CEF 1040:18

Central
1140:7

centrally
1212:10

cents
1055:5,11,19,25
1056:1,20
1057:7,8

certain
1054:1
1058:21
1060:1
1064:4
1065:5
1082:22
1083:21
1088:15
1112:24

1114:11
1152:3
1172:20
1180:12
1201:19

certainly
1058:11
1163:16,22
1164:12
1195:23
1219:2
1239:8
1253:3,20

Certificate
991:21

Certified
1254:6

cetera
1088:11
1121:5
1127:2
1142:24
1203:13

CF 1036:15

CFLs 1196:16

chair
1069:11
1130:11,25
1153:3
1186:23
1192:16,21
1194:8
1223:18
1244:25
1247:8
1248:24

Chairman
1050:8
1152:17
1188:1
1223:22
1244:12
1248:4
1253:10

Chairperson
989:13
1050:3
1051:1
1066:6,24
1073:9
1107:15
1130:8
1131:24
1132:3,9
1150:14,20
1152:24
1185:5,8,12
1186:19,24
1187:12,17,23 1190:9
1191:13,19
1192:17
1193:23
1223:19
1245:13
1247:23
1248:19
1249:1
1253:15

challenge
1088:20
1205:20

challenged
1140:7

challenges
1121:23
1125:10
1179:8
1210:3,6
1212:10,13,18

chance
1089:23

change
994:14,15,16,22,23,24,25
996:4,9
997:9,10,11,12
1014:7,8,18,20,22,24
1015:4,6,9,12,15,17,19,21,23
1019:14,15
1027:14,15,17,19
1028:3,5,7
1029:16
1034:15
1038:19
1043:13,23,24
1044:11
1047:4,8,9,17
1057:13
1062:16
1064:5,10
1117:22
1122:3
1128:6
1228:4
1230:3
1231:13
1232:21
1234:1
1236:13,15
1241:13

change;economics
1027:17

changed
1063:23
1115:8

changes
1062:6
1064:7
1115:4
1231:25
1235:11

Chapter
1133:13
1154:15
1159:4

characteristics
1174:13

characterization
1116:5

characterize
1077:5
1098:16
1103:22
1117:21
1172:17
1177:15
1180:10

characterized 1174:23

characterizing 1117:5

charge
1186:6,12,17

charged
1186:10,16

chart
1068:15
1103:10
1117:8
1195:4
1199:12

charts
1036:10
1038:11,13,14

chasing
1250:3

chat 1253:12

cheap
1236:14

check
1072:10
1101:4
1226:14

Cheryl
1254:12

choice
1106:24
1163:21
1183:21
1200:12
1201:4

choose
1061:18
1152:10

chose
1208:15

chosen
1061:15,16
1092:5

Christian
990:21
991:17
1224:2,7,8
1226:4,12,15
1227:2,8
1229:12
1230:14
1231:5
1233:3
1235:13,16
1236:9
1237:10
1238:6
1239:11
1240:5,13,17,21
1241:19
1242:9,16
1243:13,16,18,22
1244:3

Chymko
992:18

circulate
1245:3

circulated
1187:6

circulating
1143:12

circumstances 1058:21
1083:15
1100:19

citizen
1181:5

civil 1238:1

claims
1080:24

clarification 1077:9
1095:4
1098:25
1100:7
1110:7
1118:13
1122:19
1132:21
1146:24

clarified
1250:22

clarify

1069:10
1079:17
1097:17
1099:5
1105:21
1115:23
1147:17
1150:13
1159:12
1196:21
1249:7
1250:8

clarity
1104:13
1131:20

Clark
1000:11

class 1224:3

classified
1220:5

clean
1163:15
1203:21

clear
1076:17
1086:7
1224:9
1249:16,17

cleared
1249:16

clearer
1230:11

clearly
1075:8
1150:6
1166:9
1222:6

clicked
1189:15

client
1097:13
1098:15
1175:12
1247:10,21
1248:1,5

clients
1245:22

client's
1213:15

climate
1014:7,8,18,20,22,24
1015:4,6,9,12,15,17,19,21,23
1027:17
1034:15
1038:18
1043:13

Clipper
1137:14
1138:1
1139:4

close 1058:9
1075:17
1124:8
1183:5
1248:17

closed
1188:9
1243:5
1244:14

closely
1128:16

coal
1033:11,12

Coalition
992:21

code 1121:4
1125:22
1128:2,5,21,24
1129:4,7,8,18 1130:4

codes 1110:4
1114:25
1125:19,23
1126:7,9,12,13,20
1127:5,8,16,24
1128:4,8,16 1129:17
1130:22

cold 1069:21
1081:7
1134:6

colleague
1143:11

colleagues
1153:5
1228:11

collect
1205:8

collected
1221:21

collection
1205:12

College
1204:24

column
1073:19
1108:1
1112:12
1113:11
1114:5

columns
1111:21

com 1190:18

combine
1205:21

combined
1039:20
1211:20

combustion
1039:20

comes 1056:4
1105:8
1108:22
1116:12
1126:6
1130:4
1176:1,2
1179:3
1196:6
1197:16
1199:24
1202:20
1225:12

comfortable
1098:17
1136:20
1203:14
1224:14

coming
1083:13
1112:25
1138:13
1234:4
1236:13

commence
1050:4

commencing
1050:1

comment
1080:17
1091:3
1132:15
1135:9
1224:9
1228:11
1251:25

comments
1091:14
1136:6,13
1248:20
1249:3,9,24
1250:9,14,20,23
1253:16

commercial
1046:14
1126:14
1127:11
1157:3,5,10,12,16
1158:4,23
1159:1,3
1162:21
1170:1
1209:13
1232:6

commercially
1050:14
1188:11
1244:15

Commissioner
1129:6

commit
1238:1

commitments
1141:3

committed
1165:5

common
1182:7,8

commonly
1142:25

communicatio n 1208:5

communities
1156:6,16
1159:10
1160:12,18
1161:11,25
1162:1,4,21
1163:8,13,19,20
1164:1,4,5,8
1165:2,21,24
1166:4,6,19,25
1167:6,16
1168:8,21,24
1169:2,9,12,19,22
1170:5
1171:25
1172:2
1173:20
1178:11,13,16,21
1179:6,9
1180:9
1182:9
1185:16,25
1186:8,11
1195:14,20,25
1196:24
1198:20
1203:25
1204:1
1209:3,7,13,15
1213:9
1217:8

community
999:17
1129:5

1161:21
1162:8,9
1163:10,23
1165:23
1166:11,13
,25
1168:25
1169:17
1170:8,15,
20
1171:20,22
1172:6,7,1
1 1173:9
1178:23,24
1186:15
1194:15
1195:18
1198:4
1208:7,8
1209:9
1212:7
1213:15
1215:19
1216:18
1217:17

community-based
1211:10

companies
1088:1,24
1136:24

company
1130:20
1138:9
1140:15
1142:22

comparable
1103:15

compare
1053:1
1077:24,25
1125:6
1134:20
1166:6

compared
1055:13
1062:13
1078:17
1109:10
1166:4
1236:6

comparing
1070:23

comparison
1094:16
1117:17
1118:6
1158:21
1161:23
1194:14

compensation
1151:2,3

competing
1088:12

competitive
1088:23

compilation
1097:21

compiled
1190:19

complete
1131:5
1158:24

completed
1138:10
1251:12

completing
1088:13

complex
1188:25

complimentary 1224:3

comply
1127:21,24

component
1119:7
1120:9
1122:3
1123:18
1142:14
1178:19
1180:19
1197:16

components
1093:3
1104:7
1122:5
1128:24
1172:23
1199:21
1243:15

composed
1106:14

composite
1182:7

compression
1139:25

compressor
1121:25

comprised
1097:1

computer
1064:4

con 1098:18
1100:15
1107:15
1136:20

Conawapa
994:11
1014:11
1017:14
1021:23
1027:10
1028:24
1029:7
1032:13,15
1038:22
1040:20
1042:11,16
1237:19,25
1238:12,14

Conawapa's
1237:22

concept
1081:20
1082:8

concepts
1093:8

concern
1087:22
1207:18
1226:21
1227:5
1247:18

concerned
1087:11
1143:3
1211:2
1218:24
1247:10

concerns
1191:4
1248:1,6

concerted
1208:22

concludes
1244:13

concluding
1112:19

conclusion
1083:21
1102:24
1105:2

conclusions
1104:21,24

conditions
1046:5
1088:10
1204:5

cone 1066:1
1077:16
1078:17,18

conference
994:4

confidence
1079:3,20
1084:3,7
1135:11

confidentiality
1087:11
1088:18
1143:2,6
1248:10

confirm
1107:4
1112:7
1145:3
1153:25
1194:18

confirms
1193:12

confused
1099:1
1140:19

confusion
1147:15

conscious
1082:10
1124:13,18

consequences
1253:4

conservation
1101:25
1102:2,17
1106:15,21
1207:21

consider
1092:21
1246:7,8

considerable
1128:15
1140:21
1143:6
1181:15
1229:24

consideration 993:4,6
1056:16
1168:6
1236:11

considerations
1045:7,12
1057:17
1080:25
1091:1,22
1235:19

considered
1092:19
1128:10
1159:1,6
1226:22
1227:6
1235:24
1236:1,16
1246:15
1253:16

Considering
1152:20

consist
1141:5

consistently
1068:17
1160:1

Consolidated
1096:7

conspire
1230:5

constraints
1130:3,19
1211:2

construction
1047:19
1140:17
1141:7,8
1159:22

consult
1091:7

Consultants
1188:6

consultation
1091:13
1129:9
1168:7
1169:10

consultations
1091:20,23
1169:14,16

consume
1140:10

consumed
1070:8
1210:5

consumer
1055:2
1088:7
1123:15
1152:8
1233:16
1236:13
1239:24
1240:22

consumers
1087:9,11,19,23
1142:12,15
1143:1
1180:11
1200:24
1207:4
1212:23
1232:7
1239:12,19
1240:1,6,8,19,24
1241:15,20,25 1242:3

consumption
1065:8
1071:13
1093:25
1118:3
1123:4
1210:24
1231:20
1241:12

Con't 993:2
994:1
995:1
996:1
997:1
998:1
999:1
1000:1
1001:1
1002:1
1003:1
1004:1
1005:1
1006:1
1007:1
1008:1
1009:1
1010:1
1011:1
1012:1
1013:1
1014:1
1015:1
1016:1
1017:1
1018:1
1019:1
1020:1
1021:1
1022:1
1023:1
1024:1
1025:1
1026:1
1027:1
1028:1
1029:1
1030:1
1031:1
1032:1
1033:1
1034:1
1035:1
1036:1
1037:1
1038:1
1040:1
1041:1
1042:1
1043:1
1044:1
1045:1
1046:1
1047:1
1048:1

contact
1162:19
1221:6

contemplated
1199:15

contemplating 1057:12

CONTENTS
991:1

context
1082:11
1106:1
1122:13
1216:2
1224:12
1227:10,25
1228:6

continental
1088:14

Contingency
1040:17

continual
1231:10

continue
1050:10,24
1075:17
1107:16
1111:18
1116:20
1146:4
1149:23
1152:22,24
1233:1
1246:23

continued
991:6,13
1051:4,12
1052:23
1069:8
1087:4
1106:4
1107:18
1108:15
1109:24
1118:10
1144:23
1165:16

continuing
1113:5,8
1114:13
1205:11
1214:11

continuously
1063:24

contract
1006:19,20,21,22,23
1007:5,6,7,9,11,13,15,17,20,21,22,23,25
1008:3,4,5,6,7
1009:14,16,18
1010:22
1022:5,9
1027:11
1031:5,6,7,8,9,10,11,12,13,14,15,16,17,18,19,20,21,22,23,24,25
1032:3,4,5,18 1238:1
1239:7

contracts
1006:24,25
1007:3,4,19,24
1032:6,17,18 1033:24
1034:3,5,7,9,11
1035:23
1043:9
1238:22,24
1239:2,9

contracts;Export
1007:21

contractual
1150:7

contrast
1131:8

contribute
1213:1

contribution
1127:9

control
1159:23
1204:7

convened
1218:4

conversely
1065:3
1081:17

conversion
1141:5
1208:10

convert
1140:13
1200:1,8
1205:2
1208:13,16

converting
1120:1

copies
1143:23
1187:5
1189:25
1191:8
1245:3

copy 1146:1
1154:22
1155:3,17

copyright

1191:2
cor 1101:21
Corey 990:19 991:16 1192:18 1194:6,7,23 1195:9,17 1196:4,20 1197:1 1198:1,17 1199:1,9 1200:14,20 1201:12,21 1202:8 1203:1 1209:2,25 1210:13 1211:3,13,16 1212:21 1213:8,14 1214:2,7 1215:14 1216:9,21 1217:18 1219:10,15,25 1220:9,14 1227:24
corner 1107:23 1108:2
corollary 1184:11
Corporation 1120:18 1129:14,24
correct 1052:9 1053:10,16,17 1054:4,11,14,15,18,19,22 1055:3,7,8,14,15,22 1057:4,8 1058:22,23 1059:14 1060:12,13,22,25 1061:8,20 1064:8 1065:17 1069:15,16,22,23 1070:17,19 1071:8 1072:1,14,18,19,23,24 1073:6,7,15,24,25 1074:6,9,15,16 1075:11,15,19,20,23,24 1076:1,2,19 1077:3,12,13 1078:18,19 1079:4,5,12,13 1080:2,3 1083:19 1085:12,17,19 1086:10 1090:9,12 1094:1 1095:15 1096:4,6 1097:1 1099:12,13 1100:2 1105:3 1107:9,10 1108:8,24,25 1109:5,6 1111:4,5,10,11 1113:16 1114:9,25 1117:10,11,15,17 1118:17,18,24,25 1119:4,5,11,12,15 1120:25 1121:6,7 1123:10 1127:24 1143:13 1145:8,11,13,15 1146:9,10,17,18 1149:9 1153:23 1156:4 1170:25 1182:2 1190:13 1193:4,16,17,22 1194:22 1195:15,16 1196:22 1200:22 1201:1,17 1202:2 1210:4,10,12 1213:18 1214:1,19 1226:9 1228:1 1240:2,10,11 1244:7 1254:6
corrected 1114:17,18
corrections 1113:2
correctly 1070:4 1072:12 1089:11 1110:19 1225:23 1227:12 1230:25 1237:12
correspond 1101:9
correspondence 1246:20
corresponding 1210:20
corresponds 1101:3
CORY 1204:17 1205:25 1206:18,24 1207:23 1222:1,20,25 1223:17 1247:25
cost 995:20,21 1016:3 1017:21 1023:8,10,12,14,16,18,20,22,24 1024:24 1025:4,6,8,11 1032:10,13,15 1038:20 1039:14,15 1053:8,13,20,21 1054:3,6,9,10,18,21 1055:12,19 1057:13,18 1127:23 1133:18 1158:22 1162:9 1164:13,15 1172:14 1176:12 1178:12 1179:2 1193:10,13 1194:13 1195:6 1202:3 1204:13 1205:16,22 1215:2,5 1238:12
cost-effective 1125:24 1177:10 1179:16,20,24 1196:1
costly 1201:10 1202:6
costs 995:11 996:3 1016:13,15,17 1017:12,14,16,18 1019:16,22,23 1022:8 1028:19 1029:10,15 1030:3 1036:24 1037:4,16,19 1039:13,21,22,23,24,25 1040:4,5,6,7,8,9,10,11,12,13 1053:15 1056:20 1057:11 1124:13,14 1135:19,21 1177:1 1201:25 1202:5 1212:6
coun 1058:8
Council 1089:14
councillors 1162:5
counsel 990:2 992:10 993:21 1050:9,20 1058:8 1148:7 1188:5 1244:1,22 1246:2,6 1248:2,8 1250:14
counsel's 1091:14
couple 1052:4 1072:6

1088:5
1131:18
1132:13
1146:7
1189:14
1218:12

course
1136:9
1137:3,10
1196:13
1240:20
1248:22
1253:17

court
1086:13

covered
1159:15

covers
1115:17

CPV 1036:10

create
1056:11

created
1058:20
1109:15
1207:11

creates
1212:3

creating
1125:25

criteria
992:25
1080:24
1081:5
1082:17,20
1135:2
1252:10

critical
1136:2
1142:14
1252:10,11

critique
1224:10

cross 1004:3
1224:23

cross-examinatio
n
991:13,15,16,17
1050:11
1051:12
1152:19
1153:1
1194:6
1206:3
1224:7
1243:20

crude
1064:13

CSI 1058:9
1136:21
1139:14
1224:21
1239:1
1245:10,19
1246:4,5,10,14,17
1247:12,16
1249:5,14,21 1251:2

cumulative
996:15
1036:14
1105:12

curmudgeons
1224:13

current
1109:8
1115:15
1138:20
1146:17
1181:22
1182:3,12
1227:17,19
1229:18

currently
1050:22
1104:18
1152:20
1166:8
1171:24
1184:8
1199:23
1203:16
1204:19
1212:12
1213:10
1247:13,20

curtail
1152:12

Curtailab
1147:13

curtailable
1051:21
1131:17
1146:1,22
1147:14,19
1148:9,16
1149:15,25
1150:16,21,25

curtailing
1210:7

cus 1218:15

cust 1056:7

customer
1053:9
1054:2
1056:6
1057:11
1098:2
1114:15
1115:7
1116:9
1119:8
1120:10
1150:4
1153:20
1155:22
1156:1
1178:6
1183:10
1199:24
1216:11
1217:9
1231:23
1232:14

customers
1045:22
1053:21
1054:8
1056:11,12,14
1058:4,5
1142:9
1143:7
1148:17
1150:1,25
1151:15,17,19,21
1152:7
1156:6
1174:5,6,25 1178:20
1183:19,20,23 1186:9
1206:12,25
1207:15,22
1208:12
1215:25
1217:25
1221:25
1239:19
1241:3,5

cut 1050:17

CV
1000:8,10,11,13,14

cvs 1048:16
1143:21
1144:1,4

Cvs 992:18

cycle
1039:20

cycles
1062:4,8,10
1070:14,15
1081:11

cycling
1068:12

D

DALE 991:7
1051:5
1121:22
1122:22
1123:2,8,13
1124:7,10
1125:3
1136:9
1146:10,18
1147:12,25
1148:3,6,12
1149:3,9,24
1150:18,23
1202:24
1203:10
1204:22
1211:22
1240:3,11,14,20
1241:1

Dale's
1211:20

dam 1067:16
1109:15

dams 1184:20
1185:20

DANIEL
1087:14,20
1088:4
1115:1
1126:8
1128:7
1152:16
1213:4,13,22
1214:3,12,21 1229:13
1241:23
1242:14

dark 1064:17
1071:6,9

darker
1060:17

data 1062:21
1068:19
1076:23
1084:7
1154:12,20
1209:3,6
1220:19,20

date
992:4,6,8,10,12,14,16,19,22,24
993:16,18,20,22,24
994:4,6,8
997:16,19,21 999:25
1000:4,7,9,10,11,13,

14,16
1001:5,10,
24 1002:16
1003:4,11,
13,15,17,1
9,21,23,25
1004:4,6
1006:7,9,1
1 1032:8
1035:9,12,
14,16,18,2
0,22,24
1036:4,7,9
,11,13,16,
18,20,22,2
5
1037:5,7,9
,11,14,17,
20,23
1038:5,7,9
,11,13,15,
17,19,22,2
5
1039:2,4,6
,8,12
1040:16,20
,22
1045:7,9,1
0,13,16
1046:13,16
,18
1047:11,20
,22
1048:12,14
1059:5,7,1
4 1071:23
1080:23
1087:17
1109:13,14
1111:1
1116:14
1117:25
1138:11
1139:1
1142:3
1145:22
1160:24
1230:3
1237:22

dates
1229:19

dava 1230:10

day
1003:17,19
,20
1053:24
1082:18,19
1133:8
1137:21,22
1138:3,4,2
2,23
1141:10,14
1190:9
1194:12
1228:21
1237:18

days 1136:10
1200:22

deal 1082:25
1085:3
1089:9
1134:5
1169:8
1184:3
1188:22
1224:22
1228:8
1229:4
1246:25
1247:5
1249:14
1251:4
1252:1,2,9

dealing
1153:12
1179:4
1189:2
1249:15

deals
1056:10
1087:7
1252:21

dealt
1086:15
1121:5
1133:25
1229:9
1236:7,10
1245:25

debate
1092:12

Debt
1045:24,25
1046:4

debt-equity
1020:13,16
1021:6,7,8

Debt-equity
1019:11,12
,13

December
1003:25

decide
1190:20

deciding
1081:2

decision
1046:5,7
1054:2
1081:1
1090:23
1124:13
1126:19,22
1181:12
1199:5

decisions
1077:11
1090:14,20
1122:6
1124:19
1216:13
1245:19

decline
1114:17
1140:5

dedicated
1169:21

deem 1094:13

deems
1058:10

defer
1176:15
1238:15

deferals
1176:17

defining
1150:22

definitely
1099:21

definition
993:12
1098:13,19
,20,22
1099:5,8
1100:9,11

definitions
1097:15

degree
1058:5
1065:1
1080:15
1088:15
1117:2
1164:17
1176:14
1183:20
1229:24
1242:3

deliberation
s 1236:2

delineate
1220:4

deliver
1129:18,21
1169:5

delivered
1161:24
1164:18
1165:19
1166:17
1177:10,12

delivering
1168:12
1172:6

delivery
1168:23
1170:14,24
1171:15
1172:3
1173:18,23
1184:19

demand
1146:17
1210:21
1235:24
1237:11,13
1240:1,9,2
3,25
1241:6,21
1242:23

demand-side
1093:4
1153:12,25
1243:2

demographic
1222:18

demographics
1049:20
1174:6
1219:20
1222:6
1223:6,15

demonstrate
1061:23
1062:8,11
1068:11,18
1070:7
1226:5

demonstratio
n 1094:12
1198:24
1203:23
1204:2,6,2
3

demonstratio
ns 1203:19
1204:9,11

denoted
1094:25

departments
1089:2

depend
1176:21

dependable
1032:9,19
1146:20
1239:6

dependent
1088:10
1163:9
1183:11

depending
1059:8
1079:1,8
1152:10

depends
1050:19

1165:23
1177:6
1201:5

depicted
1232:8

derived
1073:19

describe
1196:4

described
1248:2

describes
1090:4

describing
1150:16

description
992:2
993:3
994:2
995:2
996:2
997:2
998:2
999:2
1000:2
1001:2
1002:2
1003:2
1004:2
1005:2
1006:2
1007:2
1008:2
1009:2
1010:2
1011:2
1012:2
1013:2
1014:2
1015:2
1016:2
1017:2
1018:2
1019:2
1020:2
1021:2
1022:2
1023:2
1024:2
1025:2
1026:2
1027:2
1028:2
1029:2
1030:2
1031:2
1032:2
1033:2
1034:2
1035:2
1036:2
1037:2
1038:2
1040:2
1041:2
1042:2
1043:2
1044:2
1045:2
1046:2
1047:2
1048:2
1049:2,16
1106:1
1144:10
1222:23
1223:2,9

Desiderata
992:18

design
1168:17

designated
1171:12

designed
1126:21
1215:1

designing
1056:17

designs
1057:16

desire
1083:9
1195:17

detail
1068:2
1115:15
1196:5
1236:7
1237:5

detailed
1104:4,9
1174:21
1229:7

details
1162:14

determine
1102:23
1106:6

determined
1151:3

determining
1174:4
1221:23

develop
1092:21
1093:3
1103:14
1128:12
1175:9
1177:16

developed
1091:19
1092:24
1096:7,8
1100:15
1103:12
1104:14
1174:7

developing
1115:15
1173:18
1177:15

development
989:10
1026:15,16,17,18,20
1038:21
1093:17
1103:19
1128:9
1132:25
1140:6
1175:5
1230:11

dictate
1150:2,3

diesel-served
1186:8,11

diff 1059:8

differ
1126:10,25

difference
1063:14
1117:23
1118:5
1120:5
1170:14
1176:5,9
1181:2

differences
1219:14
1226:11

different
1051:25
1088:5
1089:1,2,3
1090:22,25
1093:24
1098:13,14
1103:16
1106:20
1107:5
1119:9
1125:14,18
1127:4
1138:7
1145:3
1146:21
1151:6,7,10 1163:7
1164:7
1171:17,20
1172:24
1173:12
1179:18
1188:24
1201:9
1205:11
1207:16
1221:9,17,19 1252:5

differentiate
1158:8,10,12

differentiation
1156:21

differently
1081:24
1127:1

difficult
1085:24
1126:23
1165:22

diminish
1118:10

diminishing
1114:12

diminishment
1116:16

dipping
1237:20

direct
1174:3
1205:6

directed
1180:2

direction
1194:3

directionally 1080:10

directive
1091:16

directly
1162:15
1170:16
1205:3,9
1242:4,8

dis 1151:23

disagreed
1249:24

disclosed
1246:17

disclosure
1244:19

disconnected
1188:13

discount
1027:9
1037:13
1189:4,11

discuss
1139:13

1217:19
1241:15

discussed
1050:15
1087:8
1091:12
1132:18
1137:11
1144:13
1188:12
1194:14
1195:24
1198:7
1228:21
1229:25
1237:18
1239:1

discussing
1194:13
1198:9
1213:2
1215:20
1228:14

discussion
991:19
1068:6
1080:8
1110:8
1128:20
1135:6,9
1136:19
1184:2
1195:11
1199:13,19
1201:13
1206:16
1244:11

discussions
1136:11
1164:4
1169:25
1199:15
1215:23

displacement
1102:1,17
1106:16,25

displacing
1213:23,24

disposing
1218:25
1219:8

disproportionately
1062:5

disruption
1151:22,24

disruptions
1148:17

disruptive
1229:14

distinct
1139:18

distinction
1097:14
1242:12

distinctions
1226:7

distinguish
1103:4

distributed
1206:19

distributing
1190:5
1212:7

distribution
1046:10
1120:4
1175:6
1240:16
1242:2

distributions
1037:10,12,15,18,21
1038:3,6

district
1211:15,23,25

diverse
1202:18

divested
1182:19

dividend
1184:13,16,23

docs 993:6

document
1052:10
1071:17
1089:16,22
1090:1,3
1101:14
1107:20
1108:4
1111:16
1113:19
1118:21
1121:9
1144:25
1145:24
1146:5
1147:23
1150:7
1155:24
1175:3
1191:14
1192:12
1244:1

documented
1140:3

documents
1003:14
1048:18
1049:5
1052:15,17
1060:1,3,9
1071:1
1084:12,13
1085:7,11,15
1086:1,21
1093:23
1095:9
1101:5,16
1107:21
1108:10,12
1117:19
1131:4
1145:2,20
1148:2
1224:25
1225:1,2,6,10,16
1230:15,18
1239:13
1242:19
1244:9

dollar
1181:14,20

dollars
1183:15,18

domestic
1123:3,23
1237:11,13

done 1069:12
1082:6
1084:14
1109:18
1113:24
1151:20
1153:18
1154:13
1166:3
1175:18
1185:6
1189:9
1207:3
1208:2,6,8
1213:17
1216:16
1217:14,15
1242:17
1250:13
1251:13,16

door 1249:12

doors
1050:17
1181:17

dots 1071:12

downscale
1057:6

downstream
1122:7

downturn
1070:9,11

draft 992:5

drafted
1057:13

drawing
1098:2
1197:17

draws
1122:11

drew 1219:8

drill 1202:7

drive 1221:5

driven
1214:4

drives
1134:7

driving
1212:5

drop
1117:3,5,21 1118:9
1238:3

drought
995:9
1009:14,16,18,24
1010:3
1014:12,14,16
1027:21,22,23,24,25
1032:21,23,24,25
1033:3,4,23 1034:15
1044:3
1046:3

Dsm
994:18,19,20,21
995:4,5,6,7,8,19
996:6
1002:17,18,19,20,21,22
1004:19,20,21,22,23,24,25
1005:3,4,5,6,7,8,9,10,11,12,13,14,15,16,17,18,19
1006:6
1010:20
1021:22
1026:25
1027:4,6
1050:12
1051:18
1054:9

1055:19
1056:1,23
1057:1,6,11,13
1059:13
1092:5,11
1093:8,9,15,24
1094:15
1101:23
1102:7,11,15,24
1103:22
1109:19,21
1110:9
1114:21
1123:21
1131:17
1146:8
1147:10
1158:1
1159:2,5
1193:3,18
1198:4
1202:20
1206:2
1217:23
1218:2
1220:22
1230:10
1232:15
1236:24
1237:21

DSM-related
1195:20

due 1062:10
1140:6
1201:25
1228:4
1248:22
1253:17

duration
1109:23
1148:20
1150:4

during
1065:7
1213:12
1216:10
1253:11

Dynamic
1038:24

E

eager 1143:1

earlier
1152:18
1163:25
1166:24
1171:14
1193:19
1200:11
1206:4
1208:12
1209:6,14
1210:18
1224:9
1225:12
1228:11,14
1229:10
1232:17

early
1058:19
1063:21
1064:12
1111:14
1208:25

earth
1120:15

easier
1081:18
1181:9
1212:9

easily
1088:19
1183:14

East
1141:1,23

eastern
1139:22
1140:6

ecological
1242:25
1243:6

economic
992:16
997:22,23,24,25
998:3,4,5,6,7,8,9,10,11,12,13,14,15,16,17,18,19,20,21,22,23,24,25
999:3,4,5,6,7,8,20
1001:6,7,8,25
1002:3,4,5,6,7,8,9,10,11,12,13,14
1003:5,6,7,8,9
1010:5,8,9,11,13,15,17,19,21,23
1011:3,5,7,9,11,13,15,17,19,21,23
1012:3,5,7,9,11,13,15,17,19,21,23
1013:3,5,7,9,11,13,15,17,20,22,24
1014:3,5
1019:14,15
1026:24
1027:3,5,7
1036:5,17
1037:6
1048:14
1062:6
1070:9,11,14,15
1094:10
1099:25
1113:7
1116:7,17
1124:15
1133:11
1164:15
1177:24
1187:4
1189:2
1208:14
1215:7
1228:18
1229:20

economical
1212:2

economically
1094:21

economics
994:14,15,16,22,23,24,25
996:4,9
997:9,10,11,12
1001:23
1027:14,15,19
1028:3,5,7
1029:16
1034:16,17,18,19,20,21,22,23,24,25
1035:3,4,5
1043:23,24
1044:11
1047:4,8,9,17
1048:11
1183:25
1184:4
1205:23
1212:3
1238:19
1252:18

Economics/ Manitoba
1047:21

economy
1062:3
1081:12
1089:15

Ed 991:12
1051:10
1058:23
1059:4,15,24
1080:11,14
1083:20
1093:6
1109:20
1132:20
1176:4,10
1177:5
1226:25
1227:7
1228:7
1234:18
1235:14
1236:3,17
1237:16
1238:13

Edison
1096:7
1100:15

Edison's
1098:18

educate
1206:25
1207:3,14

education
1206:6,13,22

effect
1053:25
1055:1
1056:22
1057:2
1070:14
1181:13

effective
1057:19
1125:20,24
1126:7
1179:13
1205:16
1238:4

effectively
1180:17
1197:8,12
1199:22
1212:17
1247:21

effectiveness 1112:21
1124:2

effects
996:16
1007:8,10,12,14,16,18
1009:15,17,19,25

1010:4
1040:24
1041:15,17,18,19,20,21,22,23,25
1042:3,4,5,15,17,18
1043:11
1044:6,10,21,25
1045:5

efficiency
1090:6
1091:19
1093:4
1100:22
1102:15
1110:3
1124:19
1125:17,25
1128:14
1162:25
1163:2
1205:3
1209:23
1221:11

efficient
1098:5
1116:14
1179:16
1196:11
1200:8
1221:7

effort
1092:16
1172:3,5
1203:6

efforts
1103:23
1110:2
1130:18
1198:4
1206:2,8
1207:20
1208:22
1209:7
1251:8

eight
1113:11
1138:4
1141:9
1142:2
1152:1
1226:20

eighteen
1157:4
1158:22

eighty
1111:22

eighty-five
1106:23

eighty-four
1146:13

either
1064:11
1073:5
1075:14
1083:14
1130:12
1140:1
1164:25
1197:6
1208:14
1214:24
1219:3
1220:6

elasticity
1237:5

elec 1210:24

elect
1197:11

elected
1090:11,15,21

electri
1202:13

electric
1122:1
1140:1
1141:19
1156:11,13,14 1161:8
1168:19
1174:15
1181:10
1197:4,10,12,15
1200:9
1201:11
1207:1
1208:3
1210:14,24
1211:20
1213:6,23,25 1216:15
1217:2
1233:15
1234:8

electrical
1235:8

electricity
1102:19
1175:1
1176:1
1182:11,12,19
1185:21
1197:5
1200:1,13,16 1202:15
1205:2
1208:14
1210:7
1213:6
1215:4
1217:2
1228:3
1236:14
1240:25

electronically
1143:20,24

electronics
1159:24

element
1218:24

elements
1103:13
1154:20
1234:22

Elenchus
1006:6,8
1068:2
1144:12,15
1155:4,12
1242:21

Elenchus/ Manitoba
1004:5

Elenchus's
1144:11

eleven
1067:19,24
1077:2

elicit
1224:21

eligibility
1178:19

eligible
1160:7
1164:15
1166:1
1178:20,24
1184:13
1200:7

else 1081:19
1184:23
1237:20
1253:6

elsewhere
1080:19

Embedded
1179:18

emerging
1025:19,21,23,25
1026:4,6,8,10,12,14
1043:5,7

emissions
1016:5,7,8,9 1024:4
1043:14,15,16,17,18,19,20,21,22
1044:4,5,7,8,9,13,14,15

emphasis
1199:16
1202:17

employed
1063:19

employees
1063:16

Employment
999:11,21

en 1120:6

enables
1148:22

enacted
1128:25

Enbridge
1136:25
1137:5,25
1138:15
1139:10
1141:22

encapsulated
1237:8

encourage
1198:5
1207:15

encouragement 1246:19

end-of-life
1114:11
1115:10
1116:12

ener 1221:10

energies
1025:19,21,23,25
1026:4,6,8,10,12,14
1043:5,7

energy
1032:9,19
1038:10
1070:7
1082:19
1090:6,7
1091:19
1093:4,25
1098:5
1100:22
1101:8,24
1102:15,17
1106:15
1108:23
1110:2,21
1114:13
1118:17
1119:23
1120:1,6,7,15,16

1122:8,13
1124:19,24
1125:25
1126:16,23
1128:11,14
,23 1130:1
1140:2,10,
15,25
1141:23
1142:14
1145:5
1146:20,21
1151:9
1155:3,17
1162:20,25
1163:2
1170:13
1171:7
1172:12,18
,22
1173:4,6
1174:25
1178:10,17
,18
1179:16,22
,25
1180:18
1183:10
1195:23
1196:1,8,1
8 1199:23
1200:6
1203:7,21
1204:15
1205:2,4,7
,8,14
1207:21
1208:11
1209:18,23
1210:5,19,
20
1211:1,2
1212:1,7
1215:3
1217:10
1221:7,11
1225:20
1231:19,22
1236:4
1239:17,22
1241:12,24
1252:11

energy-efficient
1089:15
1209:21

energy-use
1158:11

EnerNOC
1104:23
1153:14
1158:10
1160:10

EnerNOC's
1107:8

EnerROC
1104:22

engage
1128:5
1142:16
1195:19

engineers
1047:18
1252:4

Engineers/ Manitoba
1046:17
1047:10

enhance
1137:11

enhanced
1102:15
1104:6

enhancement
1138:16,19

enhancements
1063:8,12
1137:12
1176:16

enhancing
1168:6
1180:7

enrolled
1152:7

ensure
1069:24
1180:3
1246:9

entering
1141:2

enters
1137:7

entitled
1184:22

Environment
1022:11,12
,13,14
1029:24,25
1040:25
1041:13
1043:8
1044:23,24
1045:3

environmental 995:13
996:15
997:3,8
999:9,10
1003:10
1035:17
1041:6

EPRI 1082:6

equally
1182:24

equipment
1122:7,9,1
7 1126:17
1127:1
1151:13

equitable
1179:3

equivalency
1102:11

equivalent
1095:19
1183:3

ERA-1 1004:5
1005:3
1006:3

ERA-2 1006:6

ERA-3 1006:8

Errata
1045:10

error 1250:5

errors
1082:23

escalation
1236:12

especially
1210:3

essentially
1139:18
1154:2
1161:23
1170:12
1173:2
1178:6
1186:6

establish
1141:3
1143:6

established
1071:23
1180:1
1200:21
1201:14
1203:2,13

establishing
1204:2

estimate
1067:2
1097:7,24
1112:9
1114:3
1117:24
1147:7
1225:20
1228:20,25
1229:3

estimated
1100:13
1141:8,13

estimates
1077:11
1098:1
1106:18

et 1088:11
1121:4
1127:2
1142:24
1203:13

ethics
1248:9

evaluating
1058:15

evaluation
1046:15
1093:8,9

evaluations
1093:15
1124:16

evening
1082:18
1253:22

event
1148:17
1152:5
1234:16

events
1151:7,11
1233:6,17,
18
1234:20,25
1235:1,6,1
8

eventually
1204:12

everybody
1111:24
1132:11

everybody's
1071:17
1146:1

everyone
1050:12
1186:7,9
1189:9

everything
1251:8

evidence
1095:8
1101:15,17
,20,22
1102:9,22
1144:9
1147:15,18
1153:16
1216:11
1225:8
1229:15

evolution
1231:14

evolved

1170:2
ex 1117:13
exact
1076:23
1082:8
1093:12
1130:15
1142:3
exactly
1080:23
1086:2
1190:12
1213:19
exaggerate
1242:6,10
exaggerating
1242:12
examination
1050:24
1206:3
1224:24
1244:13
examine
1004:4
1204:25
1205:11
examines
1122:13
examining
1115:14
1188:5
1203:18,24
example
1053:7
1054:12
1057:12,13,24
1062:17
1066:11,25
1075:2
1084:7
1087:25
1130:3,17
1134:4
1135:5
1149:6,10,18 1150:24
1180:21
1181:2
1182:5
1183:13,16
1184:11
1197:18
1202:7
1208:2
1212:25
1214:9
1215:15
1225:5
1226:19
1227:3,10
1228:4
1230:16
1247:1
examples
1180:22
1181:8
1233:13
exception
1186:7
exceptionally 1134:6
exchange
1105:20
1151:2
1152:9
exclude
1114:25
excluded
1217:7
exclusive
1142:8
excuse
1104:12
1130:10
1148:13
1198:18
1244:19
1245:11
exercise
1093:14
exhibit
992:2
993:3
994:2
995:2
996:2
997:2
998:2
999:2
1000:2
1001:2
1002:2
1003:2
1004:2
1005:2
1006:2
1007:2
1008:2
1009:2
1010:2
1011:2
1012:2
1013:2
1014:2
1015:2
1016:2
1017:2
1018:2
1019:2
1020:2
1021:2
1022:2
1023:2
1024:2
1025:2
1026:2
1027:2
1028:2
1029:2
1030:2
1031:2
1032:2
1033:2
1034:2
1035:2
1036:2
1037:2
1038:2
1040:2
1041:2
1042:2
1043:2
1044:2
1045:2
1046:2
1047:2
1048:2
1059:7
1132:16
1143:13,16,22
1144:1,4
1155:23
1158:15,25
1167:13
1180:25
1187:7,10
1190:15,17,22
1191:15,21
1192:4
1225:7,11,13
1244:2,6,9
1245:4,6
exhibits
991:3
992:1
993:2
994:1
995:1
996:1
997:1
998:1
999:1
1000:1
1001:1
1002:1
1003:1
1004:1
1005:1
1006:1
1007:1
1008:1
1009:1
1010:1
1011:1
1012:1
1013:1
1014:1
1015:1
1016:1
1017:1
1018:1
1019:1
1020:1
1021:1
1022:1
1023:1
1024:1
1025:1
1026:1
1027:1
1028:1
1029:1
1030:1
1031:1
1032:1
1033:1
1034:1
1035:1
1036:1
1037:1
1038:1
1040:1
1041:1
1042:1
1043:1
1044:1
1045:1
1046:1
1047:1
1048:1
1191:2,3
exist
1211:18
existing
1098:4
1141:6,18
1142:5
1159:15
1160:18
exists
1084:1
1229:22
exits 1137:8
expand
992:11
1110:16
expanded
1107:22
expanding
1170:1
expansion
1139:7
1241:9
expansions
1139:4
1141:16,17
1142:4
expect
1065:15
1134:22

1159:25
1190:24
1230:2

expectation
1065:23

expectations
1236:13

expected
1036:17
1081:9
1109:24
1114:5
1117:9,13
1137:15
1142:2
1152:18
1208:21

expecting
1235:12

expenditures
1036:12

experience
1060:5
1074:18
1077:20
1098:3
1103:14
1205:19

experienced
1140:4

Expert
1188:6

explain
1090:1
1121:15
1131:19
1176:8
1185:14
1225:13

explained
1065:11
1116:2
1210:2

explains
1209:20

explanation
1083:3
1120:23
1121:20
1131:14
1150:21
1206:8

explored
1083:9,10

explores
1169:23

exploring
1083:8
1195:24

export
994:13
995:10
996:5
1006:19,20,21,22,23
1007:5,6,7,9,11,13,15,17,19,25
1008:3,4,5,6,7
1009:14,16,18
1010:22
1016:5
1022:5,9
1027:11
1028:16,17,18,20,21,22,25
1029:3,4,5,8,9
1031:5,6,7,8,9,10,11,12,13,14,15,16,17,18,19,20,21,22,23,24,25
1032:3,4,5,17
1033:10,24
1034:3,5,7,9,11
1035:21,23
1046:6
1047:23
1048:3,5,7,9,11
1058:21
1238:11,18,20

exportable
1032:19

exported
1237:14

exports
1021:12,13
1032:20
1035:6,7
1038:8

exposed
1238:23

exposure
1038:21

extends
1240:15

extensive
1153:19
1206:6

extensively
1134:1
1154:6

extent
1054:1
1090:16
1224:18
1246:9

external
1068:23
1187:4

extra 1054:3
1133:20

extracted
1089:15

extrapolation
1231:10,19

extrapolations 1230:22

extreme
1113:11
1118:20
1135:17

extremely
1088:18

eyes 1108:18

F

face 1212:13
1223:25
1241:2

faced
1121:23

facilitate
1100:22

facilitating
1142:16

facilities
1162:21
1242:2

facing
1194:1,2

fact 1065:5
1135:25
1181:6
1194:24
1219:8
1229:4
1237:13
1250:16

factor
1120:2
1179:3
1241:13

factors
1046:7
1070:16
1135:23
1212:5

factual
1186:3

failing
1151:13

fair
1087:13,15
1090:19
1120:18,21
1124:25
1129:23
1175:25
1201:1
1203:16

fairly
1097:14
1120:9
1123:18
1142:19
1149:12,13
1177:1
1188:24

fairness
1056:4,5,9

fall 1165:25
1172:10

familiar
1063:23
1110:4
1201:9
1211:21

familiarity
1153:4

family
999:17
1156:11

fashion
1212:2

faster
1135:3

favourable
1239:3
1247:4

favourably
1205:24

feasibility
1198:10,16,19
1199:5,6
1204:25
1211:6,8,9

feasible
1246:9

Feb
1000:10,11,13,14

February
992:14,16,19,22,24
1000:5,7,9,16
1001:5,10,24 1002:16
1003:4,11,

13 1004:4
1045:9,10,
13 1138:6

fed 1097:9
1220:20

federal
1125:16
1126:18
1128:13,17
1203:20
1252:12

Federation
1192:19

feed 1188:12

feedback
1077:6
1221:22

feeds
1050:16

feel 1063:4
1091:3
1098:17
1203:14

fer 1109:19

Fernandes
1190:4

fifteen
1061:16,21
1067:17,19
1068:3,8,2
0 1107:13
1132:4
1133:14
1138:11
1181:14,19
1193:7

fifty
1106:24
1137:20
1141:9

fifty-six
1112:21

fifty-six-o-six
1112:14

figure
1038:8,14,
16,20
1067:25
1250:4,12

figures
1038:10,12
,18
1039:6,10
1072:7
1165:18

file 1161:2
1187:2
1249:25
1250:23,24
1251:2,11

filed
1035:20
1083:25
1084:1
1139:9
1141:22
1143:20,24
1150:7
1154:25
1155:4
1245:1

filing
1072:3
1073:12
1078:3,18
1083:11
1084:4
1141:22,24
1161:1
1243:15

filings
1158:25

fill 1148:22

final 1144:6
1189:24

finalized
1194:25

finalizing
1104:18

finally
1054:23
1099:16
1113:10
1246:18

finance
1252:18

financial
1033:23
1036:8
1133:1
1172:8
1219:5
1252:7
1253:4

financials
1132:23
1133:7

fine 1104:8
1243:22,23
1245:13

finished
1144:21
1223:18

finishing
1183:13

Fire 1129:6

firm 1032:20
1148:17,21
1149:7
1151:9
1222:14
1238:24

first
1049:12
1054:17
1069:14
1076:21
1082:18
1088:6
1089:21
1111:13
1132:14
1137:13
1153:13
1156:6
1159:10,20
1160:12,18
,25
1161:18,24
1162:4,25
1163:8,10,
19,20,22
1164:1,5,8
1165:2,11,
23 1166:24
1167:6,16
1168:8,10,
21,24,25
1169:17
1170:5,8,1
0,15
1171:12,24
1172:5
1173:7,8
1176:25
1178:11,13
,16,21,23
1179:6,9,2
3 1180:18
1182:7
1185:15,19
,24 1188:3
1191:22,23
1197:21
1200:5
1205:11
1207:6
1209:7,8,1
3,15
1218:6
1219:22
1220:1
1224:3
1228:12
1231:2
1237:18

firstly
1052:11
1054:17
1085:3
1239:14

Fisher
1194:21
1195:11

fit 1099:4

five
1061:3,5,2
1 1062:1
1064:25
1066:7,8,1
3,18,22
1067:10,13
,21 1068:6
1070:2,6
1076:5,6,1
6,18,24
1077:1,15
1113:12
1121:11
1132:23,24
,25
1133:7,9
1137:4,21
1138:2
1139:24
1142:20
1149:21
1183:14,18
1203:19,23
1219:3
1228:13
1244:16

fix 1228:24

fixed
1238:25

flexibility
1083:12

flip 1093:22
1099:9
1101:3

flipped
1073:3

flow 1069:20

flows
1036:14
1137:19
1138:2

flyer
1206:18

focus
1049:18
1083:4
1169:24
1206:14
1210:17,23
1215:10
1218:3,5,7
,11
1219:12,21
,22,24
1220:16,24
1221:8,16,
22
1222:3,19
1223:4,5,1
2 1241:5

focussed
1101:24

1159:21
1172:13
1210:19

focusses
1054:25
1205:7

focussing
1053:13

fois 1243:23

folks
1189:23

footnoted
1191:25

footprint
1242:25
1243:7

fore 1066:7

forecast
1004:7,8,9,10,11,12,13,14,15,16,17,18
1005:20,21,22,23,24,25
1006:3,4,5,9,12
1010:18
1021:10
1026:22
1027:15
1028:3,5,7
1047:23,24
1048:3,4,5,6,7,8,9,10 1050:11
1059:5
1060:10,22
1061:4
1062:20
1064:18,20,25
1065:3,9,16,19
1066:8,16,18,20,21
1067:5,10
1068:3,16
1069:3,15,19,22
1070:4,7,10,17,24
1072:17
1073:1
1078:6
1079:21,23
1080:1,20,21
1081:6,23
1082:14
1084:11
1087:7,8,18 1092:17
1118:1,2,8,10
1133:23
1134:2,6,20,21
1135:6,11,24 1136:8
1139:3,6,9
1140:23
1153:13
1225:17,19,24
1226:1,2,8
1227:10,15,17,19,25
1228:10,19,22
1229:7,11
1231:2,18,20
1232:5,11,12,18
1233:13,23
1234:12,21
1238:10
1241:23

forecasted
1109:9

forecasting
1061:13,24
1062:10,16
1063:2,5,6,10,22
1064:8,13
1068:14,17,18 1069:1
1073:12
1078:24
1081:17
1226:3
1233:4
1236:18,25

forecasts
995:12
1008:20,21,22,23,24,25
1009:3,4,5,6,7,8,9,10,11,12,13
1027:8
1028:15
1060:1
1062:12
1069:13
1079:18
1084:2
1087:12
1097:9
1118:3
1187:4
1230:6
1232:4
1234:1

foregoes
1182:14

foresee
1241:13

forever
1239:7

Forge
1131:24

forget
1153:7

forgive
1154:24

form 992:3
993:15
1103:25
1212:16

formal
1169:10,15

forms
1203:11

forth 1089:5

forty-six
1113:25
1114:7
1147:2,5

forty-three
1147:6

forum
1139:13,14

forward
1065:24
1067:13
1076:16
1077:10
1093:5
1113:1,5
1115:21
1118:3,11
1129:15
1136:12
1137:3
1146:4
1174:18
1224:15
1229:15,19
1231:14
1232:9
1237:5
1238:9
1241:4
1248:15

fourth
1075:7

frame
1063:20
1066:2
1086:5
1103:23
1142:3
1228:5
1231:7

framed
1247:13,21

frames
1231:8

fre 1253:12

free 1178:8
1216:6

freeing
1213:21

freeze
1228:22

frequency
1150:3

Friday
1249:19

friend
1050:21
1144:7
1182:10
1188:17
1247:9

friends
1182:5,6
1224:20

Friesen
991:7
1051:5
1087:14,20
1088:4
1115:1
1121:22
1122:19,22
1123:2,8,13
1124:7,10
1125:3
1126:8
1128:7
1136:7,9
1146:10,18
1147:12,25
1148:3,6,12
1149:3,9,24
1150:14,18,23
1152:16
1202:24
1203:10
1204:22
1210:17
1211:22
1213:4,13,22
1214:3,12,21 1229:13
1240:3,11,14,20
1241:1,23
1242:14

Friesen's

1107:4
front
1223:24
1239:8
1251:5
fuel 1038:16
1102:1,18
1106:16,24
1174:14
1183:21
1199:12,16,18,22
1200:10
1202:12,14
1203:4,12
1212:14,15,20 1215:2
1216:2,23
fuels 1212:3
fuel-switching
1202:18
1203:8
1206:5
1216:7
fulfill
1148:23
full 1074:13
1123:13
1238:12
fund 1178:17
1179:22,25
1180:1
1183:10
1195:23
1199:23
1200:6
1203:21
1208:11
1242:3
fundamental
1081:12
1082:6
1115:4
1228:2
funders
1128:12
funding
1175:16
1195:1
1203:20
furnace
1197:10,12,13
1200:8,9
1201:10
furnaces
1196:10,11
future
1059:8
1063:25
1098:2
1103:23
1113:3,9
1114:13,18
1115:16,21
1116:20
1128:13
1145:17
1225:20
1229:15,18
1230:9
1235:6
1239:21
1240:1,9,23
1241:8,9,16

G

ga 1200:23
GAC 990:10
gain 1211:25
Gange 990:10
gas
1017:22,23,24,25
1018:3,4,5,6,7,8,9,10,11,12,13,14,15,16,17,18,19,20,21,22,23,24,25
1019:3,4,5,6
1033:11,12,13,14,15,16,17,18,19,20,21
1102:19
1139:21,22
1140:1,5,6,14 1141:6
1174:14,15
1181:17,18
1182:11,14
1183:22
1184:4
1196:10,13
1200:1,4,12,16,22,23
1201:10,15
1202:14
1206:11
1214:18
1215:24,25
1216:1,5
1217:2
gather
1161:18
gathering
1217:15
geared
1168:18
general
1051:23
1082:8
1115:10
1123:17
1126:13
1156:6
1165:20
1166:5,10
1167:3,14
1171:18
1204:1
1217:10
1218:20
1238:1
1241:14
1246:12
1247:6
generalities
1114:20
generally
1068:6
1080:11,14
1081:18
1125:19
1169:17
1195:2,7
1199:3,13
1200:3,11
1202:11
1205:23
1206:13
1207:12
1210:11
1217:9
1241:17
1247:4
generating
1109:9
1196:24
generation
1014:10
1025:9
1035:13
1054:8
1055:11,16,25 1057:3
1080:17
1108:6
1109:3,4
1113:13
1120:2,5,6
1148:15,19
1195:20
1196:6
1198:5
1240:15
generic
1115:2
Geneva
1000:13
geo 1196:21
geographic
1174:16
George
990:15
991:15
1130:10
1153:1,2,24
1154:9,16,21
1155:7,15,19
1156:5,17,20
1157:3,14,18
1158:2,6,14,19
1159:7
1160:3,9,19,21
1161:12,17
1163:4
1164:18,23
1165:16,17
1166:12
1167:1,8,12,18
1168:2,5
1169:7
1170:9,18,21 1171:11
1172:15
1173:21
1175:2,21
1176:6
1177:4,7,20 1178:25
1180:6,20
1182:4
1184:6,9
1185:3,7,9
1248:4
geothermal
1120:13,15,16
1159:22
1163:24
1164:2,3,14 1171:22
1172:11
1194:15
1195:7,18,22
1196:21,22,23
1197:3,11,17,20
1200:2
1201:23
1202:6
Geothermal's
1200:18
germane
1067:25
gets 1088:2

getting
1058:13
1067:3
1087:6,8
1105:18
1125:10
1126:3,5
1128:3
1130:9
1179:8
1181:6
1189:23
1208:20
1231:7
1251:16

GHG 1024:4
1243:15

gigawatt
1056:1
1099:11
1102:11
1106:21
1110:21
1117:10,14
,15
1118:24
1119:4
1122:23

gigawatts
1055:11
1074:2,5,8
1106:8,9
1108:5
1109:4

given
1062:22
1134:1
1161:9
1170:23
1172:5
1175:22
1178:7
1203:1
1205:16
1210:3

gives 1119:9
1173:22

gl 1088:14

glo 1229:22

goal 1065:12
1213:2
1250:24
1251:12

gone 1099:15
1143:5
1189:17
1194:24
1217:4

Gosselin
989:13

governed
1129:6

government
1091:1,12,
17,20
1125:17
1129:16
1199:16,19
1203:21

GRA 1225:25
1226:8
1227:10,11
,14,16
1228:6

gradual
1230:24

Grant 989:17
1217:24

granular
1150:22

graph
1061:14
1071:6
1076:4
1077:20
1094:5
1099:9
1106:11
1125:1,6,9

graphing
1101:18

graphs
1070:22
1230:17
1231:12

GRAs 1150:8
1161:8

greater
1065:8
1070:7
1173:19
1208:19
1226:20
1227:4
1228:2
1242:3

Gretna
1137:9

grew 1134:16

grid 1228:4
1229:25
1230:1,3

ground
1197:6,18

group
1049:18
1051:22
1088:7
1122:21
1125:10
1152:8
1218:4,5,7
,11
1219:12
1221:9
1222:19
1223:4,5,1
3 1252:21

groups
1219:21,22
,24
1220:16,24
1221:16,22
1222:3,16

grow 1065:5
1177:2

growing
1232:11

growth
1081:8
1082:23
1135:3
1136:12,17
1229:1,22
1231:22,24
1232:20
1233:14,21
1235:25
1236:21,23
1237:20
1238:4,17
1241:9

GS 1038:22
1040:20

guarantee
1045:24,25

guess 1067:3
1159:16
1177:5
1220:16

guidance
1103:18

H

ha 1172:19
1234:12

Hacault
990:13
991:14
1050:24
1051:1,12,
13
1052:12,16
,23,24
1053:5,11,
22,25
1054:11,16
,20,23
1055:4,9,1
7,23
1056:18,25
1057:5,21
1058:2,6,2
4
1059:11,17
,25
1060:14,21
1061:1,9
1062:15
1063:7
1064:1,15
1065:2,10,
21 1066:5
1069:8,9,1
7
1070:1,12,
20
1071:5,11,
14,22
1072:5,15,
20
1073:2,8,1
6
1074:1,7,1
0,17,24
1075:6,12,
16,21,25
1076:3,9,1
2,15,20
1077:8,14,
23
1078:9,15,
20
1079:6,17
1080:7,12
1083:2,24
1084:24
1085:13,23
1086:10,13
1087:4,5,1
6,21
1089:8,21,
25
1090:8,13,
18
1091:10,24
1092:3,11
1093:19
1095:2,14,
25 1096:16
1097:16
1098:24
1099:14,24
1100:6,23
1101:1,13
1102:20
1104:10,19
1105:4
1106:4,5
1107:1,7,1
1,18,19
1108:1,11,
15,16,21
1109:1,7,1
7
1110:6,14
1111:2,6,1
5
1112:3,6,1
1,18
1113:10,17
1114:4,19
1115:24

1117:7,12,18
1118:12,19
1119:1,6,13,18,22
1120:8,17,21
1121:3,8,16,19
1122:18,24
1123:5,12,25
1124:9,21
1125:5
1127:13
1129:23
1130:7,8,25 1131:25
1144:23,24
1145:9,14,19,23
1146:11,23
1147:8,22
1148:1,4,11
1149:1,5,22 1150:9
1152:13
1245:15,17
1247:9

half 1074:11
1077:17,19
1114:23
1137:17
1152:19

halfway
1176:7

hand 1176:18
1182:18
1200:16

handle
1083:13
1110:9

handled
1237:2
1243:11

hands 1204:6

hap 1136:1

happen
1059:21
1061:13
1093:12
1136:1
1229:25
1233:25
1234:14,15
1235:3
1245:20

happened
1134:18
1233:1
1253:5

happens
1135:3

happy 1176:7

hard 1189:6

harder
1127:4

Harper
1182:9,10

Harrison
1000:11

hate 1175:21

haven't
1090:23
1163:20
1164:2
1184:21
1198:6

having
1052:13
1074:13
1081:21
1195:11
1228:19
1236:4
1253:22

hea 1216:23

head 1109:20

heading
1054:18
1072:16
1110:17,18
1111:8
1112:7
1113:12
1121:12
1124:3

headings
1111:20
1112:12

hear 1130:11
1169:11
1221:13

heard
1146:12
1185:18
1186:3
1251:19

hearing
1070:16
1109:18
1163:25
1184:10
1244:20
1245:10

heat 1159:22
1168:19
1182:20
1197:5,6,7,17,18
1205:9,14
1207:1
1208:4
1210:5,8,14,24
1211:20
1212:24
1213:7,11,24 1215:4
1216:15
1217:3,6

heated
1181:17
1182:11,12

heater
1181:11,18
1197:15

heating
1168:20
1174:14
1197:3,8
1200:12,17,25
1201:3,5,14 1206:22
1208:13,15
1211:24,25
1212:2
1214:17
1215:12

heavily
1128:8
1129:22
1207:1

Heights
1181:5,7

held 989:20
1219:17,19
1220:16,17

he'll
1182:15

help 1069:10
1102:3,4
1103:23,25
1126:22
1147:10
1152:21
1155:3
1162:6
1172:24
1189:20
1190:8
1193:1
1199:25
1200:5
1208:12
1220:20,24
1221:22
1252:18

helped
1099:5

helpful
1124:19
1133:5
1192:14
1194:4

helps
1173:19

Hendriks
1000:3,14
1003:10

he's
1104:2,5
1170:16

hiccup
1251:14

high 1037:22
1038:4
1069:20
1070:4
1080:15
1082:1
1083:4,7
1092:25
1097:12
1099:4
1106:19
1129:25
1149:13,14
1177:1
1182:21
1205:22
1208:3
1233:6,14,21 1234:20
1236:21,24

high/low
1237:7

high-efficiency
1208:16

high-efficient
1211:19

higher
1036:24
1037:3,16,18 1057:2
1064:22
1065:1
1075:5
1078:16
1080:9
1081:6,16,21 1082:14
1083:13
1102:24
1116:2
1119:14
1133:18,23
1134:14,21
1195:3,6
1229:2
1231:24
1232:2
1237:21

higher-cost

1056:23
highest 1240:24
high-level 1093:8 1103:24 1104:3 1106:18
highlight 1121:10 1146:1
highlighted 1071:16 1078:13 1110:15 1111:23 1150:12
highly 1115:6
Hill 1003:16,18,20,22,24 1004:3
HILL-1 1003:16
HILL-2 1003:18
HILL-3 1003:20
HILL-4 1003:22
HILL-5 1003:24
HILL-6 1004:3
Hillco 1244:6
HILLCO-7 1048:18 1244:9
historical 1038:12 1111:3 1231:19
history 1038:14
1103:14
hit 1147:1 1153:9
hits 1099:10
Hombach 990:3 1050:6,7 1152:17 1187:25 1190:23 1191:6 1192:13 1223:22 1243:25 1244:5,12 1250:8,22 1253:10
Hombach's 1206:3
home 1129:14 1172:18 1173:3 1174:17 1181:10 1182:20 1183:15 1197:8,19 1206:14 1208:1 1209:11
homeowner 1183:7
homeowners 1206:13
homes 1049:12 1127:18 1129:1 1159:21 1163:16 1164:14 1165:6,11,25 1166:3 1173:14 1206:15 1212:24 1221:7
homework 1190:10
honestly 1063:17
hope 1120:17
hopefully 1069:9 1089:10 1110:16 1148:14 1189:22 1204:11
hoping 1204:8
horizon 1062:8 1063:1 1232:9
hot 1201:10,11
hour 1152:2,19 1186:13,17 1188:7 1195:2
hours 1056:1 1099:11 1102:11 1106:22 1110:21 1117:10,14,15 1118:24 1119:4 1122:23 1205:17
house 1127:20 1181:17 1182:10 1197:14 1198:14
household 1174:7
householders 1160:6
houses 1163:1
housing 1159:22
1160:2,4 1162:7 1163:13 1169:23 1170:16 1173:10
Hugh 989:17
hundred 1055:10 1111:22 1112:13,21 1137:20,21 1138:2,4,21,22 1141:9 1146:12 1147:2 1164:2,3 1181:14 1183:14,18
hydraulics 1139:11
hydro 989:7 990:5 991:6 994:5,7 997:20 1003:12 1004:5 1006:10 1032:7 1036:24 1037:4,16 1039:11 1040:15,21 1045:14 1046:11,15,17 1047:10 1049:3,11,15 1050:23 1051:4,24 1053:2 1060:7,10 1061:11 1072:9,21 1073:4,21 1074:18 1075:3,9 1077:18 1078:23 1079:8
1080:10 1082:25 1084:6 1086:18 1087:17 1088:2,7 1091:8,15 1093:25 1095:20,24 1096:1,17 1097:12,18,23 1098:8,13 1099:8 1100:13 1102:25 1103:11 1104:25 1105:8 1114:15 1125:16 1127:23 1128:1,7,11,15 1130:17 1133:25 1136:16 1139:6,19 1140:11 1143:5,13,20 1144:1,11 1147:11,18 1151:4 1153:3,5,18 1154:2,11,22 1155:23 1160:10 1165:9 1170:9 1175:8,20 1177:12 1182:12 1185:14 1187:2 1188:18 1189:16 1191:4,23 1193:4,5,12 1194:20 1195:12 1199:14,19 1202:16

1203:6
1204:19
1206:6
1207:7
1209:2
1213:20
1214:5,7
1215:18
1216:16
1220:20
1221:6
1222:2
1223:2,8
1225:7
1226:3
1228:15
1230:6
1231:12
1233:5
1235:22
1236:12
1239:20,24
1240:7
1249:19,20
,23,25
1250:7,10,
16

hydrological
1015:4,6,8
,11,14,17,
19,21,23
1035:19

hydrology
1014:9,11

HydroRound
1047:21

Hydros
1037:19

Hydro's
989:9
1006:6,8
1050:11
1052:10
1065:12
1073:12
1077:25
1092:16
1098:19,23
1099:4
1108:22
1128:23
1143:9
1144:8
1159:2
1200:14
1206:1,5,8
,25 1218:2
1242:23
1245:2
1249:6

I

IAN 991:10
1051:8

I'd 1052:1
1085:1
1106:10
1107:22
1110:9
1111:18
1131:3
1133:8
1136:15
1154:13
1163:4
1177:20
1217:19
1218:4,21
1229:10

idea 1122:20

ideal
1100:19

identificati
on 1222:17

identified
1103:6,8
1156:7,10
1174:22

identify
1159:5
1162:6

IEC 990:21
1003:22,24

IECs 1250:19

IFF 1059:5,9
1072:4

II 1016:18
1052:17

III 1176:13

I'll
1051:15,24
1058:7
1070:20
1089:9
1106:5,22
1113:20
1114:6
1130:14
1132:3
1136:25
1137:5
1147:20
1148:12,13
1150:23
1153:10
1157:20
1174:3
1182:4,5,7
1184:22
1193:3
1199:20
1204:22
1224:16
1228:3
1235:17
1247:8
1253:11

ill-informed
1226:6

Illinois
1175:4

illustrate
1055:10,18

illustration
1131:5

I'm 1050:8
1051:16
1052:11,13
1058:7,13
1060:2,7,1
6 1063:23
1064:16
1065:25
1067:3,12
1070:21
1083:7
1086:7
1087:6,22
1091:22
1092:12
1096:20
1099:3
1103:13
1104:21
1105:21
1106:6
1107:5
1144:21
1153:6,15
1154:24
1155:12
1158:6
1159:16
1161:22
1167:2
1169:13
1170:3
1175:23
1176:7
1180:23
1181:1
1182:11
1184:9,13,
16,25
1185:2,6,1
7 1192:15
1194:11
1196:20,22
1198:18
1200:23
1201:25
1207:18,19
1212:25
1217:20,21
1219:20
1220:16
1222:1
1225:11
1228:7
1231:7
1236:18,24
1238:8
1242:17
1245:15
1249:1,12

immediately
1194:2

impact
993:7,8,9,
10,11,13,1
4 1002:24
1032:23,24
1038:18
1054:18
1055:16
1063:9
1068:12
1093:16
1116:8
1117:10,14
,15
1125:22
1139:19
1233:6,13
1234:9,20
1241:22

impacted
1056:11
1063:6

impacting
1122:4

impacts
992:16
993:4
995:13
996:7,15
997:3,8,13
999:9,10,1
1,12,14,16
,18,21
1020:15,18
,20
1021:4,5,9
1022:11,12
,13,14
1029:21,24
,25
1032:22,25
1033:3,4
1034:15
1040:25
1041:13
1043:8
1044:23,24
1045:3
1121:4
1126:18
1141:16
1242:1

impaired
1247:11

impairing
1247:19

imperceptibl
e 1061:2

implement

1172:8
1218:15

implementable 1201:24

implementation 1209:23
1212:8

implemented
1091:12
1128:13
1183:12

implementing
1164:11

implications
1122:8
1133:24

implies
1226:20
1227:4

important
1053:19,20
1056:16
1088:18
1127:8
1130:17
1149:25
1154:5
1210:15
1216:12,24

importantly
1182:15

Imports
1021:11,12,13,14,15,16,17,18,20,21,24
1022:17
1030:10,11,12

impose
1150:4

imposed
1090:11

impression
1133:6

improve
1220:21

improved
1163:1

improvement
1137:24
1138:1
1170:8

improvements
1063:3
1125:25
1128:21
1242:4

improving
1125:17
1205:3

inaccurate
1066:9
1233:2

inadvertent
1250:5

in-camera
1050:13

incentive
1216:1
1240:18
1241:20

incentive-based
1110:4
1118:23
1119:7

incentives
1209:22
1214:23
1215:24

include
1038:22
1084:10
1101:15,25
1104:4
1195:19
1233:12
1244:21

included
1072:6
1077:22
1102:6
1139:8
1157:11
1160:5
1163:3
1175:5
1181:25
1187:3
1188:10
1189:3
1230:17

includes
1053:15
1063:15
1102:15,16
1109:13
1110:3
1123:18
1141:25
1155:17
1160:4
1172:13
1179:23
1244:22

including
1109:14
1110:1
1133:15
1176:12
1243:2
1246:22

income
1174:6,18
1178:14,19,22
1179:8,11
1180:4,8
1183:5

increase
1073:23
1119:2
1137:19
1138:2,20
1141:13
1148:19,20
1149:6
1173:1
1232:13
1233:15

increased
1074:3
1113:13
1119:14,18
1184:13,22
1236:4,5

increases
1151:12

increment
1179:19

incremental
1036:10,15

incurred
1053:15

ind 1131:10

Independent
1048:13
1188:6

index 1078:4
1225:1,14

indicate
1087:22
1133:5
1199:17
1225:3

indicated
1059:6
1077:25
1133:8
1141:4,13
1155:21
1195:12
1206:5
1217:24
1238:14,21
1239:5
1247:3

indicates
1108:5

indicating
1248:12

indication
1064:19

indications
1076:17

indicator
1230:1

individual
1084:18
1090:5
1093:2
1121:24
1122:14
1130:4
1163:12
1169:21,22
1170:15
1183:24
1207:14

individually
1058:1
1137:1
1207:13

individuals
1089:6
1160:25
1173:14
1179:12
1186:8,10,14 1202:10
1203:3
1222:18

indulgence
1144:21

industrial
1081:14
1083:14
1110:17
1111:8
1113:12
1115:3,11,18
1121:12,23
1122:16,21
1123:14,16,19,21
1124:4,11,12 1125:7
1126:20,22,24 1127:6
1131:10
1145:25

industrials
1116:1
1117:9
1125:8

industries
1151:24
1152:3

industry
1088:22,25
1110:9
1114:21
1129:11

1142:9
inequity 1182:22
inexperience 1148:14
infer 1066:24
infiltration 1159:23
inflexible 1230:9
influence 1062:5 1094:22 1117:2 1130:22 1183:22
influenced 1232:10
influences 1183:23
influencing 1125:21
inform 1185:24
information 992:23 994:7 997:20 1000:15 1001:4,9,23 1002:15 1003:3 1004:6 1006:11 1032:8 1039:12 1040:16,21 1045:15 1046:12,18 1047:11,22 1050:14 1059:10,12 1062:23 1068:8 1072:25 1073:10 1084:16 1087:8,18, 24 1088:3 1089:5,10 1100:21 1101:21 1103:11,25 1131:8,16 1133:20 1136:8,15 1139:12 1141:25 1142:10,12 1143:2,3,4,7 1153:19 1154:8,10 1160:22,24 1161:2,5,6,13,15 1163:7 1169:1 1188:11 1214:9,13, 16 1216:13 1217:15 1221:21 1222:17 1230:11 1239:21 1241:3,5,11,24 1244:16 1246:5,21 1252:12,24
informed 1217:25
informs 1148:7
infrastructure 999:15 1088:8 1137:13 1213:3,5 1242:8 1252:10,12
INGRID 991:11 1051:9 1089:24 1090:3,12, 17 1091:2 1095:21 1096:5 1097:5 1098:12 1099:13,21 1100:2,12 1103:3 1105:3 1153:22 1154:4,11, 19 1157:10,17 ,20,25 1158:5 1159:4 1174:12,24 1175:10
init 1159:19
initial 1055:4 1141:22 1216:11 1241:10
initially 1111:9
initiated 1220:25
initiative 1106:16,17 1112:10 1113:3 1171:23 1199:22 1206:5 1207:8 1211:11 1214:4
initiatives 1101:25 1104:1,6 1106:14 1111:13,14 1112:24,25 1113:2 1119:9 1120:11 1121:2 1126:13,14 1130:21 1161:10 1162:18 1202:18 1219:7 1232:16
innovative 1246:25
in-office 1198:19
input 1154:5
in-service 1139:1 1142:2 1237:22
insight 1169:4
insist 1088:1
install 1162:8 1173:11 1201:10 1202:5
installation 1203:15
installed 1049:14 1164:1,3 1165:7,14
installs 1116:10
instance 1139:17 1203:12 1204:16 1213:6
instances 1088:24 1203:11
instantly 1105:25
instead 1205:1 1237:14 1250:21
institutions 1158:4
instrument 1219:6
instrumental 1128:3
insulated 1049:13 1165:6,12 1183:16,17
insulation 1159:21 1162:7,8 1163:17 1166:2 1172:13,18 1173:3 1183:13 1196:15 1208:1
integrated 1053:6,14 1057:10 1092:14
intend 1249:3
intended 1112:15 1152:15 1215:12
intending 1051:16
intent 1147:13 1148:8,14
intention 1215:13
intentionally 1243:21
inter 1122:2
interactions 1169:1
interconnected 1235:9
interest 1178:15 1242:6,10
interested 1133:16 1172:2 1195:25 1196:3 1207:20 1217:11

1219:20
1220:17
1221:3

interests
1142:11
1239:18

interim
1104:15
1112:8
1114:2
1117:23
1147:6

interior
1159:21

intermittency
1205:17,21

interna
1088:14

internal
1068:24

international 1088:14

interpreted
1245:24

interrelated
1122:2

interrogatories 1155:5

interrogatory 1155:11
1161:4

interrupt
1147:23
1151:2
1185:6

interruption
1151:25

interruptions 1150:3,5

interval
1079:20

intervals
1135:11

intervener
992:3,20
993:15

Intervenor
1050:20
1244:22

intra 1242:1

introduced
1064:4
1244:2

introduction
1058:16

introductory
1103:21
1225:10

invest
1128:5
1129:22
1141:14
1218:19

invested
1128:3

investigated
1116:24

investing
1219:5

investment
1016:10,12,14,16,19,21,23
1017:3,11,13,15,17,20 1116:18
1128:15
1129:3
1176:21
1177:18
1219:4
1221:12

investments
1088:8
1129:13,25

invests
1128:8

involv
1106:13

involved
1112:19
1137:18
1166:22
1206:14

involvement
997:15
1128:23

involves
1139:24

IR 1003:18
1189:12
1191:17,23

IRR
1019:20,21

IRRs 1046:9

IRs
1003:16,20,25 1045:8
1116:21
1189:11
1251:2,12

Island
1181:4
1182:6

isn't
1081:10
1169:15
1200:15
1201:15,23
1202:16
1203:6
1215:9,11
1245:23

isolated
1157:13

isolating
1217:16

issue
1056:4,5,10 1109:20
1115:22
1135:8
1142:9
1184:2
1202:4
1216:6
1237:4,11
1251:3
1253:13

issued
1249:19

issues
1035:18
1051:21,25
1056:14
1201:25
1215:17
1245:23
1248:21

item 1087:6
1132:17,19
1136:7
1186:23

items
1101:25
1102:6,16
1132:13

it'll
1189:1,20

it's
1052:2,3,4,7
1053:19,20
1054:5,6,24,25
1056:15
1058:17
1065:11
1068:4,5,15,24
1069:3,4
1072:6,7
1078:5,22
1080:18
1081:18,19
1082:6,8
1083:5,25
1084:4,9,10,12
1085:10
1093:14,17
1094:15,16
1103:24
1104:1
1105:5,22
1106:14
1108:17
1110:14,16
1112:3,23,24,25
1114:10
1115:6
1116:16
1117:25
1119:16,19,24
1120:17
1122:15,22
1123:10
1124:7
1126:1,23
1127:4,18,22
1128:20,21,22
1129:13
1131:17
1134:25
1136:3
1139:2
1140:8,18
1142:8
1145:2,14
1151:18
1152:3,11,20
1154:14,25
1155:24,25
1162:21,22
1163:13,18
1164:16
1166:17,18,19,23
1167:24,25
1168:18,22
1170:8,12
1171:6
1173:12,16
1177:6
1180:2
1183:11,12
1184:14
1187:5
1188:24,25
1190:6,17
1191:22,25
1192:5,22
1194:12
1195:3
1196:7
1197:2,4
1201:9
1202:6
1205:10,17,22 1206:1
1213:17
1214:3,16

1216:11
1221:4
1224:14
1225:10
1229:4
1230:2
1231:7,9
1234:22
1238:1,2
1242:5,10
1243:5
1244:5
1248:12,15
1249:16
1250:13
1252:18

I've 1064:6
1070:3
1072:6
1089:10
1184:12
1188:17
1224:10
1246:1

J

Jan
1035:18,20
1037:7,9
1038:7
1048:12

January
992:10,12
997:21
999:25
1006:7,9
1032:8
1035:9,12,14,16,22,24
1036:4,7,9,11,13,16,18,20,22,25
1037:5,11,14,17,20,23
1038:5,9,11,13,15,17,19,22,25
1039:2,4,6,8
1040:16,20
1045:7
1046:13,16
1047:11,20
1048:14
1134:8

Jessica
990:18

July
993:18,20

jump 1105:1

jumped
1135:5

June 992:6

jurisdiction
1080:18

jurisdictions 1221:18

justify
1249:21

K

Kapitany
989:14

Keeyask
1014:11
1017:12
1021:23
1022:3,4,10,15
1028:23
1029:6,22,23
1032:13,15
1038:9
1040:3,19
1041:12
1058:19
1059:14
1072:1
1074:8,11,14
1109:11,16,25
1237:19
1238:12,15,16,18,19
1239:5,6

Keeyask;Conawapa
1043:6

key 1132:25
1133:10,15
1142:7
1158:21
1159:8
1160:11
1189:11

Keystone
1140:18,20,21

kick 1197:23

kicks
1197:25

kilometres
1141:6,7

kilowatt
1186:13,17
1195:2

Knight
1039:11
1040:15,19

knowledge
1090:4

KP-1
1039:11,20
1040:3

KP-2 1040:15

KP-3 1040:19

Kuczek 991:8
1051:6
1053:4,10,17,23
1054:5,15,19,22
1055:3,8,15,22
1056:3,24
1057:4,9,22 1058:3
1063:13
1064:9
1068:22
1091:5,18
1092:20
1093:7
1103:21
1104:12
1106:12
1107:3,10
1130:2,14
1136:14
1161:6
1162:13
1163:6
1165:22
1166:18
1167:23
1169:15
1170:11,19,25
1171:4,19
1172:21
1177:25
1178:9
1179:5
1180:16
1183:8
1184:7
1185:1
1193:1,17,22,24
1194:9,22
1195:5,16,21
1196:7,25
1197:2
1198:8,22
1199:4,20
1200:18
1201:3,18
1202:3
1208:12
1209:5
1211:7,14,17,23
1215:22
1218:10
1219:11
1221:12
1222:12
1227:13
1232:5,17,23

Kuczek's
1123:9,11

KURT 1190:14
1244:7

L

la 1006:10
1032:7
1035:8
1038:24
1039:1,3,5,7 1243:23

labour
1162:10
1173:6,10

lack 1131:19
1212:14

laid 1083:21
1150:6

Lake 1182:6

Lakes 1181:4

land 1093:12

language
1098:16,18

large
1088:21
1121:19
1126:6
1127:10
1188:24
1233:16
1242:4

larger
1081:13
1151:19
1197:22

Larry 989:15

last 1056:25
1070:2,5
1113:22
1120:9
1130:11
1136:10
1137:10
1140:3
1141:21
1182:8
1185:18
1200:22
1220:15
1249:18

late 1064:11

1187:3

later
1059:16
1121:5
1136:21,22
1139:14
1143:25
1184:10
1199:10

latest
1067:1

latter
1137:16

launched
1104:5
1111:13,14
1207:25

Lavigne
1254:12

Law
1248:8,14
1249:8

lawyer
1188:4

LCA 1037:12
1252:4

LCA-1
1006:10
1007:3
1008:3
1009:3
1010:3
1011:3
1012:3
1013:3
1014:3
1015:3
1016:3
1017:3
1018:3
1019:3
1020:3
1021:3
1022:3
1023:3
1024:3
1025:3
1026:3
1027:3
1028:3
1029:3
1030:3
1031:3
1032:3

LCA-10
1035:23

LCA-11
1036:3

LCA-12
1036:5

LCA-13
1036:8

LCA-14
1036:10

LCA-15
1036:12

LCA-16
1036:14

LCA-17
1036:17

LCA-18
1036:19

LCA-19
1036:21

LCA-2 1032:7
1033:3
1034:3
1035:3

LCA-20
1036:23

LCA-21
1037:3

LCA-22
1037:6

LCA-23
1037:8

LCA-24
1037:10

LCA-25
1037:12

LCA-26
1037:15

LCA-27
1037:18

LCA-28
1037:21

LCA-29
1038:3

LCA-3 1035:8

LCA-30
1038:6

LCA-31
1038:8

LCA-32
1038:10

LCA-33
1038:12

LCA-34
1038:14

LCA-35
1038:16

LCA-36
1038:18

LCA-4
1035:10

LCA-5
1035:13

LCA-6
1035:15

LCA-7
1035:17

LCA-8
1035:19

LCA-9
1035:21

LCD-37
1038:20

LCD-38
1038:24

LCD-39
1039:1

LCD-40
1039:3

LCD-41
1039:5

LCD-42
1039:7

LCD-43
1039:10

LCOE 1039:7

lead 1055:20
1086:4
1142:19
1204:12

leaders
1128:10

leads 1108:2
1124:22

learned
1203:22
1224:20

least 1052:7
1071:25
1076:16
1077:15
1078:24
1190:24
1194:4
1204:4
1208:16

leaving
1186:11
1253:22

LED 1168:4

left-hand
1108:4

legal 1148:7

legislated
1127:16,19

legislation
1091:6
1180:1
1186:6
1253:1

legislature
1090:24

lengthier
1131:3

lengths
1143:6

less 1057:1
1068:9,10
1101:2
1116:13
1117:15
1247:9

lessons
1203:22

let's
1095:17
1107:15
1132:4
1152:24
1186:19,20
1187:17
1201:12
1215:16

letter
992:7,9,11
,13,15,20
993:17,19,
21,23
994:3,5
997:15,17
999:23
1003:12,16
,18,20,22,
24 1004:3
1045:8
1249:19

level
1065:24
1084:3,7
1087:22
1092:25
1093:9,13
1097:8
1102:11,14
,15,23
1104:4
1105:8,14
1106:8,13,
20 1116:23
1125:11
1135:18
1138:20
1148:23
1174:18
1175:17
1182:22
1183:12,13
1195:1
1217:16
1232:20

levelized
995:20,21
1023:8,10,
12,14,16,1

8,20,22,24
1024:24
1025:4,6,8
,11
1039:14,15
1054:21
1158:22
1193:10,13
1194:13
1195:5

levelled
1224:17

levels
1093:15
1094:12
1101:9
1102:7
1126:16
1128:18
1179:8
1236:24

liability
1236:5

Licensing
1021:25
1022:6

life 999:17
1115:6
1229:5

lighting
1159:22
1168:4

likely
1188:14
1234:15

Limestone
1109:18

limit
1092:18

limitations
1166:22

limited
1153:11
1191:10

limiting
1062:2,3

limits
1017:6,7,8
,9 1022:7
1100:18

line
1008:9,11,
13,15,17,1
9
1009:21,23
1016:11,20
,22,24
1017:4,19
1046:19,20
,21,22,23
1047:12,13
,18 1058:4
1071:6,9
1095:3
1110:16
1111:7
1131:5
1138:17
1139:4
1140:5,16
1144:9
1216:25
1225:18
1230:24
1231:25
1239:14
1242:21
1243:4

linear
1230:21
1231:10

lined
1105:19

lines 1089:4
1094:7
1103:9
1168:22
1218:14
1226:16

link 1189:15

list 991:3,4
992:1
993:2
994:1
995:1
996:1
997:1
998:1
999:1
1000:1
1001:1
1002:1
1003:1
1004:1
1005:1
1006:1
1007:1
1008:1
1009:1
1010:1
1011:1
1012:1
1013:1
1014:1
1015:1
1016:1
1017:1
1018:1
1019:1
1020:1
1021:1
1022:1
1023:1
1024:1
1025:1
1026:1
1027:1
1028:1
1029:1
1030:1
1031:1
1032:1
1033:1
1034:1
1035:1
1036:1
1037:1
1038:1
1040:1
1041:1
1042:1
1043:1
1044:1
1045:1
1046:1
1047:1
1048:1
1049:1
1054:24
1132:14
1156:10,12
1157:15
1158:24
1159:7
1192:10

listed
1053:2,14
1054:17

listen
1104:24

little
1058:16
1074:2
1078:16
1081:5
1095:4,18
1100:7
1102:24
1104:7
1115:22
1123:3
1126:9
1137:1
1141:25
1150:22,24
1161:15
1163:7
1176:22
1189:22
1196:5,16
1198:14
1199:10
1204:6,7
1205:10
1210:1
1214:22
1218:5
1245:18
1249:13
1250:12

live 1180:4

lives
1112:25

living
1181:3
1185:19
1186:11

LLOYD 991:8
1051:6
1053:4,10,
17,23
1054:5,15,
19,22
1055:3,8,1
5,22
1056:3,24
1057:4,9,2
2 1058:3
1063:13
1064:9
1068:22
1091:5,18
1092:20
1104:12
1106:12
1107:3,10
1130:2,14
1163:6
1165:22
1166:18
1169:15
1170:11,19
,25
1171:4,19
1178:9
1179:5
1180:16
1183:8
1184:7
1185:1
1193:17,22
1194:22
1195:5,16,
21
1196:7,25
1197:2
1198:8,22
1199:4,20
1200:18
1201:3,18
1202:3
1211:7,14,
17 1215:22
1218:10
1219:11
1227:13

LMPs 1038:13

load
1004:7,8,9
,10,11,12,
13,14,15,1
6,17,18
1005:20,21
,22,23,24,
25
1006:3,4,5
,9,12

1010:18
1021:10
1026:22
1027:15
1028:3,5,7
1050:11
1059:4
1060:1
1064:22
1065:4,6
1069:1,12,14,18,22
1070:17
1078:5
1080:9,20
1081:5,8,16,21,22
1082:1,3,14,23
1084:11
1087:7,8,12,18
1092:17
1102:1,17
1106:15,24
1118:1,2,8,10
1122:20
1123:6,14,16,19,21,24
1124:6,23
1125:2
1133:23
1134:2,5,7,9,10
1135:3,6,11,24
1136:8,12,17 1138:12
1139:2,5
1140:23
1142:10
1148:21
1149:7,15,16
1151:1,12
1152:4,5
1176:10,14,16,20,22
1177:2
1210:1,3,6
1213:1,3,21
1225:17,19,24
1226:1,2,8
1227:10,15,17
1228:22
1229:1,7,11,22
1233:14,21,23
1234:21
1236:17,21,23,25
1237:9,19
1238:3,10,17
1241:9,12

loading
1149:14

loads
1081:14
1083:13
1115:3
1176:18

loan 1120:15

lob 1153:9

local
1088:12

locate
1204:3

located
1088:22
1137:6
1185:21
1212:10

locating
1052:13

locations
1142:1

locked
1050:17
1249:12

Lois 991:9
1051:7
1052:20
1060:13,20,25
1061:8,19
1062:19
1064:24
1065:7,18
1066:4,15
1068:1
1069:16,23
1070:5,18
1071:9,12,20
1072:2,13,19,24
1073:7,14,25
1074:6,9,16
1075:4,11,15,20,24
1076:2,7,11,13,19
1077:4,13,21
1078:8,14,19
1079:5,13
1080:3
1084:9
1085:8,18
1086:6,11
1094:5
1101:19
1103:20
1108:8,19,25
1109:6,12
1110:1,25
1111:5,11
1112:5,8,16,22
1113:15
1114:2,10
1115:13
1116:4
1117:11,16,20
1118:18,25
1119:5,12,16,19,23
1120:14,20
1121:1,7,14,18
1125:13
1127:25
1128:19
1145:7,12,16,21
1147:5
1155:2,11,16
1156:4,9,19,23
1158:9
1159:11
1160:8,16,20,23
1161:14
1162:2
1165:4
1167:7,17,22
1168:3,16
1172:16
1174:20
1177:14
1182:2
1186:4,22
1206:17,21
1207:6,24
1209:5
1210:12,16
1214:14
1216:19,22
1219:23
1220:3,23
1222:11,22
1223:1
1226:1,10,13
1231:1,17
1233:12
1237:1
1243:10,14,17,21

long
1006:24,25
1007:3,4,19,21,22,24
1043:9
1050:19
1088:9
1109:18
1142:19
1193:12

longer
1061:24
1062:14
1227:25
1229:6
1238:1
1252:2

longer-term
1226:18
1227:3

longest
1139:20

long-standing
1207:7

long-term
1032:17
1212:9
1225:20,24
1226:21
1227:5
1238:24

Looker
1000:13

loss 1148:18
1233:14,16

losses
1120:4

lost 1149:10
1185:1

lot 1081:10
1105:5
1115:3
1121:24
1174:1
1181:9
1212:14
1218:23

low 1037:22
1038:4
1065:4
1082:3
1083:5,7
1097:13
1172:14
1180:8
1183:5
1215:2
1233:5,21
1234:19
1236:21,23
1237:9,11,13

lower 1065:6
1079:3,20

1081:17,21
,23
1133:23
1172:14
1180:4
1204:13
1229:2
1231:25
1232:3

lower-income
1178:5

low-flow
1159:23

lunch
1050:19
1152:23
1185:13
1186:20
1187:13

lunchtime
1186:25

M

macro
1003:10

macro-environmental
996:20,21,22,23,24,25 997:7
999:19,22
1001:11,12,13,14,15,16,17,18,19,20,21,22

Macroenvironmental
1002:23

Macro-environmental 996:10
1041:3,4,5,7,8,9,10,11,14,16
1042:6,7,8,9,10,13
1044:16,17,18,19
1045:4,6,1
1

Madam
1225:12

madness
1225:4

main 1035:8
1140:5

mainline
1138:16

mainly
1201:24

maintain
1084:6
1197:18
1204:7

maintenance
1212:8

major
1136:24
1139:16

majority
1159:19,25
1162:13
1232:3
1239:6

makers
1081:1

makeup
1222:3

manage
1149:15

managed
1053:1
1212:2
1243:19

management
1047:19
1093:4
1101:14
1113:19
1144:25
1145:24
1153:12,25
1242:24
1243:2

manager
1107:20
1108:4
1118:21
1121:9
1146:5
1147:23
1155:24
1163:13
1169:23
1170:17
1173:10

managers
1089:3

Mani 1137:7
1201:19

Manit 1137:8

Maniti
1153:17

Manitoba
989:3,7,9,23 990:5
991:6
994:5
1003:12
1006:6,8
1037:7,9
1038:7
1046:15
1049:3,11,15
1050:11,23
1051:4
1052:10
1060:6,10
1072:21
1074:18
1075:2,9
1077:18,25
1079:8
1080:18
1081:19
1086:18
1088:2,7,22
1090:20,22
1091:8,9,15 1092:16
1095:23
1097:12,18,23
1098:7,13,19,23
1099:4,8
1100:13
1103:11
1105:8
1114:15
1124:6
1125:2,16
1127:23
1128:1,7,15,22
1130:17
1133:25
1136:16,24
1137:6,7,8
1138:25
1139:6,19,21,25
1140:10,14,18
1141:17,20
1142:1,18
1143:5,9,13,20
1144:1,8,11 1147:17
1151:4
1153:5,18
1154:2,11
1155:23
1159:1
1160:9
1165:9
1166:5,10
1170:9
1175:8,19
1177:12
1178:18
1180:4
1185:14,16,22,25
1186:5,18
1187:1
1188:18
1189:16
1191:4
1192:19
1193:5
1194:20
1195:12
1201:16,19
1203:5
1206:11
1207:7
1212:13,15
1213:10,11
,20
1214:4,7,24 1216:16
1219:14
1221:6,20
1223:2,8
1225:7,21
1226:3
1228:15
1230:6
1236:14
1239:20
1242:23
1245:2
1248:8
1249:6,19,20,23,25
1250:7,10,16

Manitobans
1180:5
1184:18
1203:9

Manitoba's
1065:12
1210:5

manner
1170:24
1214:5
1248:14

March 989:24
1003:15
1153:16
1232:23
1251:13

margin
1073:5

Marilyn
989:14

marked
1144:1

market
1029:3,4,5,6,7,8,9
1032:6
1033:10,24
1034:3,5,7,9,11
1088:10,13,15 1094:9

1095:1,6
1096:23
1097:20
1099:7,17
1100:10,12,16
1101:2,8
1102:4,12,13 1104:25
1123:18
1125:20,23
1168:19
1238:20,22

marketplace
1062:14
1094:14,19,23
1100:19
1129:18
1172:25
1233:25

markets
994:13
995:10
996:5
1016:6
1028:16,17,18,20,21,22,25
1029:3,4,5,8,9
1035:21
1124:20
1139:23
1208:20

Marla 990:6
1052:12,18
1085:10
1105:18
1108:9,13
1132:12
1136:5
1143:8,19
1144:6,20
1186:25
1187:15
1193:15
1244:24,25
1245:8

mass 1123:17

mat 1229:2

match
1105:21
1183:2

material
1060:4
1074:11
1105:5,6
1131:20
1173:25
1174:1
1190:18
1207:2
1229:3

materially
1063:5,9
1247:11

materials
1078:4
1162:10,11
1189:3,21

math 1055:17
1122:25

mathematical
1072:21
1078:21

mathematically 1056:2
1057:6
1073:18

matter
1080:19
1087:6
1089:9
1137:22
1144:6
1146:25
1169:10
1188:25
1206:4
1213:16
1248:9,12
1249:14

matters
1050:9
1188:2,19,22

max 1100:8

maximum
1096:8
1097:7
1100:14,16

may 992:4
993:16
1062:5
1076:22
1080:16
1090:22,25
1104:1
1142:21
1151:12
1153:5,6
1159:20
1169:11
1175:4
1179:13
1194:10
1213:14
1215:3,4
1229:18
1231:25
1232:1,2
1234:14
1241:9
1245:17
1246:13

maybe
1093:20
1141:21
1172:16
1176:8
1180:20
1190:20
1191:14
1192:10
1199:20
1234:24
1235:15
1236:10

mean 1067:15
1148:20
1149:20

meaningful
1247:11,19

means
1064:24
1250:23

meant
1093:14

measure
1054:18
1122:14
1168:23
1183:24
1218:15

measured
1056:7

measures
1049:13
1103:6
1115:4,11
1121:24,25
1124:14
1126:11,15
1127:3,6,7
1158:21,23
1159:1,6,8,9,13,14,20
1160:5,11
1163:2
1164:11
1165:7,13
1172:20
1173:3,11,13 1183:11
1184:1
1196:8,9,10,14

measure-specific
1096:22

mechanism
1125:25
1151:5
1173:19

mechanisms
1129:20
1172:24

medium
1135:18

medium-low
1079:3,22

meet
1075:3,8,14,22
1076:8,25
1080:23
1098:17
1105:13
1178:20
1179:24
1216:14

meeting
1077:18,19

meetings
1130:5

megawatt
1082:24
1133:16
1151:16

megawatts
1134:11,14,21 1146:8

member
989:14,15,16,17
1051:14
1217:23

members
1050:8
1051:14
1150:17
1153:3
1168:25
1169:6
1188:10
1213:15
1244:21
1246:22

mention
1134:3
1194:19
1218:3
1237:3

mentioned
1053:18
1062:22
1092:24
1102:17
1104:2,5
1139:17
1142:6
1161:7
1163:24
1166:24
1170:22
1172:21
1178:14
1179:17
1198:2

1199:11
1204:18
1209:14
1221:12
1222:12
1231:21
1232:5,10,17,23
1237:6

Merchant 1025:9

Merci 1224:8

merely 1094:12,16
1231:18

message 1218:21
1221:13

messages 1221:10,24

messaging 1221:1,4,15,16

met 1076:6,18
1077:3

meter 1120:7

method 1200:24
1225:4

methodologies 1063:19,22

methodology 1049:16
1062:16
1064:13
1222:23
1223:3,10
1226:7
1231:2

Metis 1192:19
1216:18
1217:8
1220:2

metric 1049:7
1053:6,12
1054:1,24
1065:13
1069:4
1070:23
1071:16
1074:3,13
1075:1,10,14,22
1076:6
1077:6,16
1078:23
1079:24
1084:3
1085:2,7,16
1086:3,24
1097:19

metrics 1052:6
1053:1,14
1054:13,14
1055:2
1061:10
1064:4,8
1078:1,24
1079:2,7
1083:6,10,11,17,22
1085:25
1096:8

metric's 1076:6

MF 1156:13

MH 1048:16
1144:4

MH-85 1225:6,9

MH-91 1048:15
1143:16

MH-92 1048:16
1144:4

MH-93 1048:17
1187:10

MH-94 1048:19
1245:6

MHEB 1038:12

M-hm 1207:23
1216:21

Mi 1237:1

mic 1249:10

Michael 990:16,22

microphone 1050:5
1192:18
1193:25
1194:2
1223:20

mid 1097:7

middle 1113:21
1138:14

middle-class 1183:7

mid-level 1097:10,24
1098:22

midst 1115:15

midway 1072:15

Miller 990:11

million 1141:13

mimic 1232:1

mind 1053:19
1057:12
1127:12
1180:21
1239:23
1240:18,22

mindful 1091:13
1246:23

minimal 1151:22,23

minimize 1148:16

minimized 1172:4

minimum 1115:9
1126:16
1151:16

mining 1126:25

Minister 1091:7

Ministry 1128:11

Minnesota-Manitoba 1008:8,10,12,14,16,18
1009:20,22
1016:11,20,22,24
1017:4,18

minor 1117:3

minus 1067:22
1096:13
1197:23,25

minute 1149:21
1155:6
1188:14
1223:24
1244:17

minutes 1107:12,13
1132:4
1152:20
1245:15
1253:14,23

MIPUG 990:13
1002:15
1049:5
1051:22
1085:11
1086:20
1142:9

Mis 1101:19

misguided 1243:7

MISO 1032:23,24
1035:6,7
1038:14,16
1047:23
1048:3,5,7,9

miss 1226:5

missing 1084:22

misstated 1052:7

Mitgation 1043:11

mitigation 1007:7,9,11,13,15,17
1009:15,17,19,24
1010:3
1040:24
1041:15,17,18,19,20,21,22,23,25
1042:3,4,5,15,17,18
1044:6,10,21,25
1045:5

mix 1038:11,16

mixed 1153:6

MKO 990:15
992:3,5,7,9,11,13,15,18,20

MKO/Typlan 992:23

MKO-1 992:3

MKO-10 992:23
993:4

MKO-2 992:5

MKO-3 992:7

MKO-4 992:9

MKO-5 992:11

MKO-6 992:13
MKO-7 992:15
MKO-8 992:18
MKO-9 992:20
MKO's 1202:9
MMF 990:18
993:15,17,19,21,23
994:3,5
997:15
999:23
1000:3
1003:10,12,14 1188:4
MMF/CAC
1002:15
MMF/Elenchus
1001:4
MMF/Manitoba
994:7
997:20
MMF/MNP
1001:9
MMF/Morrison
1003:3
MMF/Potomac
1001:23
MMF/Typlan
1000:15
MMF-1 993:15
MMF-10
997:17
MMF-11
997:20
998:3
999:3
MMF-12
999:23
MMF-13
1000:3
MMF-14
1000:6
MMF-15
1000:8
MMF-16
1000:10
MMF-17
1000:11
MMF-18
1000:13
MMF-19
1000:14
MMF-2 993:17
MMF-20
1000:15
MMF-21
1001:4
MMF-22
1001:9
MMF-23
1001:23
1002:3
MMF-24
1002:15
MMF-25
1003:3
MMF-26
1003:10
MMF-27
1003:12
MMF-28
1003:14
MMF-3 993:19
MMF-4 993:21
MMF-5 993:23
MMF-6 994:3
MMF-7 994:5
MMF-8 994:7
995:3
996:3
997:3
MMF-9 997:15
MNP
1045:6,8,11
MNP/Manitoba
1040:21
MNP-1
1040:21
1041:3
1042:3
1043:3
1044:3
1045:3
MNP-2 1045:6
MNP-3 1045:8
MNP-4
1045:10
MNP-5
1045:11
Mo 1127:17
Mobile
1127:18
mode 1013:19
model
1038:25
1039:1,3,8
1094:1
1102:13
1140:8
modeling
1016:3
models
1015:4,6,9,12,15,17,19,21,23
1064:4
1173:24
moderate
1136:4
moderator
1218:17
moment
1132:13,19
1143:12,23
1220:10
1229:25
Monday
1133:12,19
1177:22
1191:14
1252:16
money
1127:23
1181:15
Monnin
990:21
991:17
1144:7,13
1223:21,23
1224:2,7,8
1226:4,12,15
1227:2,8
1229:12
1230:14
1231:5
1233:3
1235:13,16
1236:9
1237:10
1238:6
1239:11
1240:5,13,17,21
1241:19
1242:9,16
1243:13,16,18,22
1244:1,3
month 1138:5
monthly
1186:12,17
months
1138:11
morning
1050:3,6,7,20
1051:14
1105:20
1133:22
1143:21,24
1144:7
1188:8
Morris
1127:7
Morrison
991:9
1045:14
1046:11,14
1051:7
1052:20
1060:13,20,25
1061:8,19
1062:19
1063:18
1064:24
1065:7,18
1066:4,15
1068:1
1069:16,23
1070:5,18
1071:9,12,20
1072:2,13,19,24
1073:7,14,25
1074:6,9,16
1075:4,11,15,20,24
1076:2,7,11,13,19
1077:4,13,21
1078:8,14,19
1079:5,13
1080:3
1084:9
1085:8,18
1086:6,11
1094:5
1101:19
1103:20
1108:8,19,25
1109:6,12
1110:1,25
1111:5,11
1112:5,8,16,22
1113:15
1114:2,10
1116:4
1117:11,16,20
1118:18,25
1119:5,12,16,19,23
1120:14,20
1121:1,7,14,18
1125:13
1127:25
1128:19
1135:8
1145:2,7,12,16,21

1147:5
1155:2,11,16
1156:4,9,19,23
1158:9
1159:11
1160:8,16,20,23
1161:14
1162:2
1163:12
1165:4
1167:7,17,22
1168:3,16
1172:16
1174:20
1177:14
1182:2
1186:4,22
1201:8
1206:17,21
1207:6,24
1209:5
1210:12,16
1214:14
1216:10,19,22
1219:23
1220:3,23
1222:11,22
1223:1
1226:1,10,13
1231:1,17
1233:12
1237:1
1243:10,14,17,21

mostly 1134:24

motion 994:6
1003:13,17,18,20

motions 1249:5

motivate 1221:14

motor 1122:1

mouth 1169:11

move 1102:4
1111:6
1117:21
1146:3
1190:8
1193:25
1229:19

moved 1063:25

moving
1129:15
1199:2
1205:25
1209:25
1216:14

MP 1038:14
1239:10

MPA-1
1045:14
1046:3

MPA-2 1046:11

MPA-3 1046:14

multi-family 1156:14

multiplication 1119:24

multiplied 1119:17

Muppets 1224:13

myself
1053:18
1181:8,13
1182:18,19

N

narrowed 1084:4

Nation
1159:10,20
1160:12,18
1161:1
1162:4
1163:8,10,19,20,22
1164:1,5,8
1165:23
1168:21,24,25
1169:17
1170:5,8,10,15
1171:24
1172:5
1178:11,13,16,21,23
1179:6,9
1209:7,9,13,15
1219:22

national
1088:13
1141:23

nationally 1128:9

Nations
1049:12
1156:6
1161:19,24
1162:25
1165:2,11
1166:24
1167:6,16
1168:8,10
1171:13
1173:7,8
1176:25
1179:23
1180:18
1185:16,19,25 1220:1

natural
1017:22,23,24,25
1018:3,4,5,6,7,8,9,10,11,12,13,14,15,16,17,18,19,20,21,22,23,24,25
1019:3,4,5,6
1033:11,12,13,14,15,16,17,18,19,20,21
1102:18,19
1139:21,22
1140:5,14
1141:6
1182:14
1183:22
1184:4
1196:10,13
1200:1,4,12,15,23
1201:10,14
1202:14
1206:11
1214:18
1215:24,25
1216:1,5
1217:2

nature
1126:15
1233:7

nearly
1176:4
1177:6

NEB
1137:13,15
1138:5

necessarily
1056:2
1068:16
1077:5
1092:25
1126:1
1191:21
1253:2

necessary
1188:15
1246:9
1249:16

needs-based 1058:18

negative 1073:6

neighbour
1181:16,20

neighbourhood 1179:10

NERC 1252:11

net 1134:9

neutral 1215:2

newspapers 1208:7

NFAT 992:5,8
1003:16
1060:4
1070:22
1072:21
1074:10
1077:11
1078:17
1225:24
1226:2,7,19
1227:4,18
1228:1
1231:16
1242:22

nice 1095:3

nicely
1124:22
1127:14

nine 1224:25

ninety
1106:22
1138:21

ninety-nine
1113:11
1114:1

ninety-three 1121:11

nobody
1057:2
1109:19

non 1220:4
1244:18

none 1107:7

non-gas
1156:11,13,14

noon 1152:21

normal
1069:25
1081:7

north

1080:19
1140:7
1174:16
1176:1,11
1177:13
1202:10,19
1203:3,7
1204:4,5,11,21
1205:16
1207:21
1208:9
1215:16,20
1216:4,17
1219:13
1220:18
1235:10

northern
1156:22
1158:3,8,12
1176:16,18,22
1180:4,9
1185:16,25
1201:16
1203:9,25
1206:25
1207:4
1208:7
1213:10,11
1221:20

north-south
1176:14,15

note 1237:3
1242:17

noted
1167:23
1172:19
1248:20
1253:16

notes 1243:5
1251:24

nothing
1064:10
1192:5
1231:13

notice
1081:15

notifying
1051:24

Nov 997:16
1003:23
1004:6
1006:11
1039:12
1046:18
1047:22

November
994:8
997:19
1040:22
1045:16

np
990:2,11,18

NPV 995:25
996:17
1019:7,8,9,10,17,18,19,24,25
1020:3,4,5,6,7,8,9,10,11,12,14,17,19,21,22,23,24,25 1021:3
1027:12,13
1029:11,12,13,14,17,18,19,20
1032:12,14,16
1038:18
1045:17,18,19,20,21

NRCan
1128:11

NSP 1239:10

nuclear
1024:5

O

ob 1148:25

objection
1247:15,16,17

objections
1248:20
1249:4

objective
1215:9

objectives
1099:18
1180:3

obligations
1148:25
1248:14

obtain
1182:25
1238:20

obvious
1198:12
1241:2

obviously
1068:9
1134:7
1136:2
1210:23
1227:4
1234:22

occasionally
1179:3

occur 1062:9
1063:10
1088:16
1229:18
1230:3
1233:18
1234:10

occurred
1064:10
1149:10
1230:22

occurrence
1135:18

occurrences
1233:24
1234:3

occurring
1062:13

occurs
1152:11

October
992:8
1003:21

odd 1117:14

offer
1183:23
1186:22
1196:15
1208:10
1209:15
1215:25

offered
1159:14
1173:17

offering
1173:5
1214:23
1215:24

office
1129:6
1162:15

offices
1162:19

offset
1180:9

oh 1076:13
1078:5
1084:21
1155:13
1190:3
1191:19
1234:23
1244:25
1245:15

oil
1018:10,11
1137:6
1140:14,17
1141:18
1199:25
1200:9
1208:10,13,15

okay 1052:24
1053:11,22
1060:14,21
1061:1,9
1063:7
1065:2,10
1066:5
1069:17
1070:1,20
1071:11,14
,22
1072:5,15
1073:16
1074:7
1075:6
1076:20
1077:8
1078:9,15
1080:12
1084:24
1085:13
1086:11,16
1087:16
1089:25
1090:8,13
1095:17,25
1096:16
1099:24
1105:4
1106:5
1109:17
1110:6
1111:15
1112:6,11
1113:17
1114:4,19
1119:22
1120:8,21
1123:5,25
1124:9
1125:5
1131:25
1132:9
1145:23
1146:5,11
1153:24
1154:9,16,21 1155:15
1156:20
1157:14
1158:14
1160:3,9,21 1164:23
1166:12
1167:1,8,18 1168:2
1169:7
1170:18
1175:2,21
1177:4,20
1178:25
1180:6,20
1182:4
1186:24

1191:19
1192:15
1197:1
1199:9
1200:20
1206:24
1211:13,16
1216:9
1219:5
1220:9
1222:11
1226:12
1227:8
1230:14
1236:9
1238:6
1242:16
1243:13
1247:23
1253:15

old 1138:18

older 1115:7
1138:18

one-o-three
1114:7

ones 1053:14
1082:14
1099:20
1108:20
1133:2
1161:19
1168:11
1169:3
1177:12
1220:18
1221:11
1235:7
1250:6

one-third
1123:23

ongoing
1169:25
1211:4
1245:18
1247:17

on-site
1204:10

Ontario
1128:11

onwards
1063:16

op 1237:7

open
1141:2,12
1197:14
1241:15

opening
1136:12

operate
1136:24

operates
1122:17

operating
1139:19
1148:24

operation
1016:4
1032:21
1033:5,6
1139:20,24
1140:22

operations
1142:15
1147:11
1148:15

operators
1134:4

opinion
992:15
1102:22
1200:15
1248:7
1249:8

oppor
1209:23

opportunities 999:13
1088:11,17
1168:17
1169:16,18,23
1172:9,14
1179:16
1195:13
1196:18
1209:21,24

opportunity
1033:6
1035:6,7
1058:20
1059:22
1072:10
1168:24
1195:8
1198:9
1200:5
1226:5
1238:22

opposed
1059:22
1085:2
1161:25
1165:20
1166:17
1168:11
1170:24
1211:17
1236:21

optimistic
1064:20
1076:22
1096:21

Optimization
1111:9
1121:12,15
1122:10

Opting
1243:6

option
1022:19,20,21,22,23,24,25
1023:3,4,5,6,7,9,11,13,15,17,19,21,23
1024:3,5,6,7,8,9,10,11,12,13,16,17,18,19,20,21,22,23,25
1025:3,5,7,10,12,13,14,15,16,17,18,20,22,24
1026:3,5,7,9,11,13
1054:7,8
1057:3
1093:2,3
1101:8
1140:1
1152:10
1182:13
1193:18
1200:19
1201:15
1204:12
1211:24
1213:7
1237:21

options
995:17,18
1054:9
1092:12,15,21,23,25
1093:24
1101:7
1103:5
1104:13,14
1150:1,2
1151:6,10
1179:18
1202:19
1204:10
1207:4
1214:19
1243:3

oranges
1064:3

order
993:17,20
1100:20
1221:13
1238:2

ordinary
1181:5

organizations 1098:4

organza
1084:18

Orle 990:15
991:15
1130:10
1152:18,25
1153:1,2,24
1154:9,16,21
1155:7,15,19
1156:5,17,20
1157:3,14,18
1158:2,6,14,19
1159:7
1160:3,9,19,21
1161:12,17
1163:4
1164:18,23
1165:16,17
1166:12
1167:1,8,12,18
1168:2,5
1169:7
1170:9,18,21 1171:11
1172:15
1173:21
1175:2,21
1176:6
1177:4,7,20 1178:25
1180:6,20
1182:4
1184:6,9
1185:3,5,7,9 1248:4

others
1250:18

otherwise
1197:10
1213:25

ought
1226:21

outcome
1073:11
1204:8

outcomes
1220:21

outer
1092:5,17

outline
1090:2

outlined

1084:15
1093:1
1094:17
1233:23

outlook
1187:5

output
1239:6

outside
1136:20
1161:25
1169:18
1179:9

Over/Under
1082:7

overall
1093:3
1117:3
1119:20
1171:6
1177:17
1216:7

overestimate
1241:20

overestimating 1242:13

over-forecasting 1241:22

over-planned
1081:20

overriding
1206:23
1207:7,11

ownership
1046:8

P

p.m
1187:20,21
1254:1

P10 1135:20

P90 1135:20

pa 1052:14

pace 1163:9
1166:24

package
1179:19
1189:8,18
1191:23
1192:12
1196:17

page
991:2,10
992:2
993:3
994:2
995:2
996:2
997:2
998:2
999:2
1000:2
1001:2
1002:2
1003:2
1004:2
1005:2
1006:2
1007:2
1008:2
1009:2
1010:2
1011:2
1012:2
1013:2
1014:2
1015:2
1016:2
1017:2
1018:2
1019:2
1020:2
1021:2
1022:2
1023:2
1024:2
1025:2
1026:2
1027:2
1028:2
1029:2
1030:2
1031:2
1032:2
1033:2
1034:2
1035:2
1036:2
1037:2
1038:2
1040:2
1041:2
1042:2
1043:2
1044:2
1045:2
1046:2
1047:2
1048:2
1049:2,4
1051:8
1052:7,8,14,16
1054:25
1060:9
1070:25
1071:1
1072:6
1074:20
1078:3,16,22 1084:12
1085:1,6,11,15
1086:1,20
1089:17
1092:7
1093:22
1095:10,15
1097:22
1099:9
1101:3,4,15,17,20,22
1102:8,21
1106:22
1107:20,21
1108:10,11
1110:10
1113:19
1117:19
1118:14
1127:10
1131:3,6
1132:18
1144:8
1145:1,18,19
1147:17,23
1155:23
1156:3
1157:25
1158:15,20,23 1159:8
1167:2,5,12 1174:21
1225:5,6,8,10,11,15,18 1230:15
1233:23
1239:13
1242:18,21
1245:12

pages 989:25
1052:4
1072:6
1143:11
1147:9

paid 1184:21
1185:15
1186:1,16
1191:7

panel 991:6
1048:16
1050:12,24
1051:4,14,24 1083:19
1131:16,19
1134:2
1143:21
1144:4
1147:10
1150:12,17
1152:15,21
1153:3,4
1185:10,15,24
1188:23,24,25
1194:17
1201:22
1202:10
1217:20,23
1224:18
1225:22
1243:12
1244:14
1245:9,12
1247:16
1248:22
1249:18
1253:20,25

panel's
1202:9
1217:20

paper 1127:1
1143:23

parabolic
1204:25

paragraph
1147:21

parameters
1051:19
1094:18
1096:12
1097:9

Pardon
1158:19

parity
1228:4
1229:25
1230:1,4

Park 1003:3
1045:14
1046:11,14

partial
1133:17

participants
1171:24
1218:23

participate
1049:18
1151:19
1163:23
1164:10
1166:25
1178:21
1207:15
1223:4,12

participated
1056:14
1163:21

participates
1183:11

participating 1130:21
1151:18
1166:9
1172:2
1178:12
1183:9
1222:4
1247:22

participatio

n 992:7
1124:1
1125:7
1160:25
1161:3
1166:23
1170:4
1172:4

particular
1055:1
1078:10,25
1093:1
1095:15,16
1114:24
1122:1,12
1124:3,24
1131:13
1142:23
1146:15,16
1150:11
1151:21
1159:18,19
1161:15
1175:8
1194:15,25
1195:10
1199:3
1201:6
1203:2
1206:1,14
1217:17
1224:17
1244:14

particularly
1128:1,20
1168:18
1220:17
1229:3
1247:12
1251:14

particulars
1231:8

parties
1068:24
1190:20,24
1223:25
1244:17

Partnership
997:4

pass 1194:10

passed
1152:5

past 1062:5
1069:2
1149:10
1161:8
1199:14
1207:25
1230:22
1231:19
1232:1,2
1233:2
1246:24

path 1189:22

pathway
1215:6

pathways
1203:18
1215:3
1230:12

Patti 990:5
1105:19
1188:21
1190:3,12,15,16
1191:5,16,20
1192:9,15
1248:24
1249:2

PAUSE 1071:3
1074:22
1079:15
1080:5
1085:21
1089:19
1092:1,9
1094:3
1095:12
1097:3
1098:10
1100:4,25
1101:11
1103:1
1105:16
1107:25
1110:12
1112:1
1131:22
1132:1
1144:18
1155:9
1157:1,8,23 1158:17
1160:14
1164:21
1167:10,20
1168:14
1171:2,9
1174:10
1180:14
1190:1
1192:7
1202:22
1220:12
1222:9
1224:5
1227:22
1233:10

pay 1053:21
1054:8
1162:10
1173:10,11
1182:21
1186:13
1189:16
1242:7

payback
1124:16
1218:15
1219:2

paybacks
1124:17

paying
1057:2
1173:6
1182:15
1185:20
1186:12
1202:17
1203:6
1215:8

payment
1152:9,11
1184:19

pays 1182:12

PB 1205:1

PDP 1046:15

PE-1 1046:17
1047:3

PE-2 1047:10

PE-3 1047:18

peak
1134:5,9,11,12,14,15,17,18,19,20,21
1135:5
1146:17
1149:14,15
1210:21
1211:2

peaking
1151:8

Peguis
1194:21
1195:11

penetrating
1124:20

penetration
1160:11,17
1166:14
1173:1
1208:3,19,21 1209:3

people
1056:22
1101:14
1127:23
1133:6
1178:1
1181:7
1185:19
1189:7,17,20 1192:2
1214:8,23
1217:11
1221:1,18,19 1222:4
1229:11
1235:1
1236:18,25
1249:11
1250:2,11
1251:3,4,5,21
1252:15,18

per 1116:18
1137:21,22
1138:3,4,22,23
1141:10,14
1169:16
1186:13,16
1191:9
1193:6
1195:1
1211:8
1214:4,23
1215:8
1218:13
1231:23
1232:14
1253:3

percent
1036:23
1037:15
1049:6,7,8,9,10
1056:19
1060:18
1064:19
1065:13,20
1066:1,13,19
1067:2,7,13 1072:22
1073:5,22
1074:3,13
1075:2,8
1076:1,11,25 1077:22
1078:2,11,25
1079:1,2,4,8,9,10,11,19,25
1081:4
1083:9
1084:3,5,6,16,20,21
1085:2,7,16
1086:1,2,3,4,9,22,23,25
1087:1,2
1096:14
1119:15,17,20
1120:3,22,24
1123:15,17
1124:1
1125:2,7,1

2 1126:3
1131:12,13
1135:10,20
,25 1136:1
1210:4
1218:19,20
1219:3,4
1232:12,14
,19 1234:6

percent/80
1084:19

percentage
1066:9
1096:13

perception
1236:14

perfect
1080:20,23
,25
1100:21
1206:18
1219:15

perfectly
1081:25
1082:3

performance
1063:6
1068:21
1111:8
1121:15
1122:8,10,
14 1126:16

performed
1062:13

performing
1065:19
1069:1
1077:7

perhaps
1051:15
1082:11
1083:12
1095:8
1101:4
1136:6
1145:2
1147:9
1155:2
1183:1
1187:15
1188:19
1199:14
1218:2
1253:11

period
1061:11,24
1062:6,14,
18,20
1063:2
1065:8
1070:8
1073:17
1074:12,15
,19 1077:3
1110:22
1111:8
1145:15
1149:11,12
1152:2
1210:8,14
1228:24
1229:6
1230:20
1231:4

periods
1068:13
1073:13
1088:9

permission
1191:7
1245:9

permissions
1191:11

persistence
1113:1
1115:11,14

person
1052:8
1111:16
1113:19
1130:6,13
1144:25
1145:24
1175:14

Personal
999:16

persp 1216:8

perspective
1037:9
1038:7
1054:7
1057:10
1059:1,3,1
9 1068:19
1116:7
1136:11
1146:8
1201:7
1216:4,8
1231:9
1240:24

pertinent
1135:6

Peter 990:11

Peters 990:2

Phase
1137:14,24
,25 1139:3

philosophica
l 1180:23

physical
1252:20

physically
1127:5
1152:12
1204:3
1205:14

picked
1189:10

picture
1115:20
1213:23

Piesold
1040:19

Piesold/
Manitoba
1039:11
1040:15

pilot
1198:24
1199:2

Pimicikamak
992:21

pipe 1196:17

pipeline
1136:11,24
1137:19
1138:1,2
1139:16,17
,21
1140:8,14
1141:4,5,6
,8 1142:8

pipelines
1138:18

places
1251:10

plan 989:10
1006:7
1022:18
1030:4,5,6
,7,13,14,1
5,16,17,18
,19,20,21,
22,23,24,2
5 1031:3,4
1036:21
1037:6,8
1038:21
1052:21
1072:3
1093:4
1103:5,12,
15
1104:14,16
,17
1108:22,24
1109:8
1110:20
1117:24
1118:16
1133:16
1145:10
1232:22
1234:13,20
1235:2
1236:6
1237:17,19
1242:24

planned
1136:21

planner
1083:22
1134:3

planners
1081:1
1082:9

planning
1035:11
1039:10
1080:17
1081:18
1082:7,10
1116:25
1134:24
1135:13
1141:14
1148:23
1190:16
1227:15
1233:22
1234:23

plans
1026:15,16
,17,18,20
1035:16
1036:19,23
1037:3
1041:6
1045:23
1082:22,23
,24 1083:1
1091:19
1093:17
1103:19
1104:17,18
1122:17
1132:23,24
,25
1133:10,14
,15
1177:23
1230:11
1236:6
1241:9

plant 1151:8

play 1056:4
1082:2
1179:3

players
1088:22

please
1118:20
1131:6
1132:15
1144:16
1146:4
1147:10
1148:2
1149:23

1150:17
1152:25
1153:25
1155:25
1159:12
1192:20
1193:24
1224:19,21
1225:3
1230:15
1240:4
1242:19
1244:3
1247:17

pleased
1242:17

pleasure
1187:1

plenty
1205:19

plug-in
1234:8

plus 1067:22
1096:13
1102:16
1120:24
1175:18
1232:12

POE 1039:1

point
1050:16,18
1055:13,20
1056:10
1057:7,23
1069:25
1076:6,18
1077:9,15,17 1079:25
1091:6
1094:18
1103:24
1111:23
1113:11
1119:10
1120:10
1121:11
1126:17
1127:7
1129:4
1136:2
1147:2,6
1151:17
1188:12
1191:6
1200:13,17
1201:23
1210:16
1214:20
1225:17
1234:6
1244:18,22
1250:24
1252:7

pointed
1056:9
1094:7
1115:13
1163:12

points
1076:23
1094:16
1212:22
1252:25

policies
1033:25
1034:4,6,8,10,12
1091:21

policy
1035:18
1090:14,20,22,25
1091:11
1127:15
1168:7
1169:8

pool 1149:4

pops 1121:10

population
1056:19,21
1165:20
1166:5,10
1187:4
1231:21,24
1232:4,11

Portage
989:22

portion
1056:21
1099:7
1123:17
1127:11
1140:13
1239:1
1242:4
1245:10

position
1132:11
1144:10
1187:2
1224:19
1249:6

positioning
1088:15

positive
1073:5

positively
1213:1

possibilities 1093:10

possibility
1133:22
1204:2
1233:5

possible
1085:5
1146:25
1152:3
1203:24
1233:17
1246:20

possibly
1146:25

POT-1
1047:21
1048:3

POT-2
1048:11

potential
1094:8,9,10,11,13,15,25
1095:1,6,22,23
1096:9,10
1097:7,8,10,11,12,25
1098:14,16
1099:15,17
1100:10,13,14,17
1101:2,8,23
1102:5,13
1103:4,8,22 1104:25
1123:22
1131:10
1158:1
1159:2,5
1229:17
1237:8
1240:25

potentially
1106:19
1138:12
1164:6
1167:24
1204:9,14
1212:24

potentials
1099:25

Potomac
1047:21
1048:11

power
1010:5,8,9,11,13,15,17,19,21,23
1011:3,5,7,9,11,13,15,17,19,21,23
1012:3,5,7,9,11,13,15,17,19,21,23
1013:3,5,7,9,11,13,15,17,20,22,24
1014:3,5
1022:18
1026:24
1027:3,5,7
1030:4,5,6,7,13,14,15,16,17,18,19,20,21,22,23,24,25 1031:3,4
1032:6
1046:17
1047:10,18
1052:5,21
1053:2
1056:15
1091:19
1108:22
1109:8
1110:20
1114:6,21
1116:1,3,25 1118:16
1120:15
1124:2
1129:1
1130:18
1145:10
1149:3
1170:10
1179:15
1193:7
1195:20
1196:5,24
1206:23
1207:8,9,12 1209:11
1219:7
1220:24
1221:10
1232:22
1237:13
1239:25
1240:7
1252:3,12

practical
1150:24
1180:22
1198:23

practically
1061:2
1146:13,16

precise
1228:19

precluded
1248:9

precludes
1151:17

predominantly 1123:16

prefer

1216:22
1223:23

preference
1213:16
1216:23

preferences
1174:7
1217:6,12

preferred
989:10
1200:23
1236:6

Pre-hearing
994:3

preim 1249:9

preliminary
1093:9
1249:9

premise
1242:15

prepare
1233:21

prepared
1070:10
1139:13
1224:25
1225:25
1233:20
1248:10,17

prescriptive
1126:15,24
1127:22

present
1068:4,5,6
1084:17
1115:10,25
1152:6
1159:20
1203:3
1225:19

presentation
1051:20
1055:6
1093:23
1123:9,11
1131:9
1194:12,14
1199:12

1210:2
1232:5

presentations 1136:13

presented
1060:4
1062:23
1073:10
1084:8,11
1094:6,11
1101:20,22
1102:7,12
1112:23
1113:6
1116:17
1117:24
1147:16
1174:1
1186:15

presenter
1152:22

presenters
1185:18

presently
1142:19
1159:9

President
1224:9
1243:24

press
1241:11

pressure
1059:18

pretty
1064:13
1075:17
1246:25

prevent
1176:15

prevents
1247:21
1248:15

previous
1060:6
1078:24
1084:2
1134:12,14
1201:22

1210:1
1246:19

previously
991:7,8,9,10,11,12
1051:5,6,7,8,9,10
1119:2
1129:1
1150:8
1209:11

price 995:12
1008:20,21,22,23,24,25
1009:3,4,5,6,7,8,9,10,11,12,13
1027:8
1028:15
1033:11,12,13,14,15,16,17,18,19,20,21
1047:23,24
1048:3,4,5,6,7,8,9,10 1195:1
1237:4
1238:11,23,24

prices
1033:10
1048:12
1239:2
1247:3

primarily
1120:16
1140:6
1151:18
1169:24
1172:13
1210:19

primary
1096:8
1154:17
1180:3
1215:10
1237:12

prior 1061:5
1062:24
1064:12
1066:13,22,23 1078:1
1170:4
1232:15

priority
1162:16
1253:18,20

private
1087:24

pro 1062:4
1161:10
1210:18

probabilities
1037:10,12
1073:21

probability
1037:15,18,21
1038:3,6
1049:7
1079:4,25
1084:20
1085:16
1086:23
1135:20,21
1233:6
1234:3,16,20

probably
1062:2
1067:25
1075:14
1076:5,24
1107:12
1109:19
1117:20
1125:14
1126:1
1133:4,5
1134:24
1138:13
1177:11
1181:12
1190:24
1211:20
1212:12
1238:2
1242:1

problem
1135:4
1253:7

problems
1215:20

proceed
1188:1

proceeding
1059:12
1070:22
1073:13
1139:9
1147:16
1191:9
1230:8
1245:24

proceedings
1050:5
1132:10
1187:24
1228:15
1235:17

process
1091:8,13
1094:17
1112:19
1115:8
1122:2,4,12
1126:21,25
1142:13,17,20
1169:14
1174:4
1198:18
1227:18
1230:6,13
1235:23
1245:24
1247:12,15,18

processes
1115:5
1129:21
1151:21

prochaine
1243:23

produce
1191:11
1212:16
1214:15

1227:15

produced
1227:17

production
1016:3

profile
1124:6
1125:2

program
1051:21
1053:2
1055:1
1056:20
1057:15,19
,25 1104:4
1111:9,10
1112:20
1116:18
1120:18
1121:12,15
1122:11
1124:2
1129:2,3
1131:17
1146:2,7,1
5,22,24
1147:11,14
,19
1148:9,16
1149:25
1150:16,22
,25
1151:15,18
,19 1152:7
1159:17
1162:3,15,
16,25
1166:15
1168:4,17
1170:10,12
,13,24
1171:7,13
1172:6,11,
12,18,19,2
2,24
1173:3,4,7
,15,16,18
1177:10
1178:2,5,1
0,11,17,18
,20
1179:22,23
,24
1180:18,19
1183:1,10
1193:6,8,1
1,14
1194:16,19
1195:10,18
,22,23
1196:2,6,9
,23
1199:23,25
1200:6,7
1207:13
1208:1,10
1209:9,10,
11 1213:19
1214:25
1215:11,13
1216:3

programming
1102:16
1104:3,7
1114:18
1177:19
1220:22

programs
1056:13,15
,17
1093:12
1098:5
1100:21
1104:5
1105:10,13
1106:8,10
1109:22
1110:3,4
1114:6
1125:11
1129:15
1159:13,15
1160:4,5,7
,12,18
1161:1,3,7
,18,24
1165:1,19
1166:9,14
1167:4,13,
15,23
1168:6,9
1169:5
1170:22
1171:12,16
,17,18,21
1177:8,16
1178:3
1179:4,15
1180:5,7
1182:23,24
1183:5
1194:20
1195:4,7,1
9 1198:2,4
1199:17
1208:18
1209:4
1210:13,18
1217:23
1218:1,2
1230:10

progress
1107:6
1163:9
1171:5

project
1021:25
1022:6
1041:24
1137:14
1138:8
1140:13,19
,20,21,24
1141:1,15,
23 1142:23
1198:25
1199:2
1205:9

projected
1108:23
1136:11
1138:25
1193:6
1236:12

projecting
1067:17,18
1125:22
1126:3
1131:12

projection
1103:24
1111:3
1120:1
1131:12
1231:21
1233:21
1241:10

projections
1084:20
1145:17

projects
1080:10
1092:18
1111:12
1142:7
1154:12
1203:23
1209:12

promise
1205:15

promote
1203:7
1206:2
1207:8,12,
20 1208:22

promoting
1207:9

promotion
1206:13
1207:3,14

promptly
1253:19

pronounced
1089:11

pronouncemen
t 1142:22

propane
1199:25
1200:9
1208:10,13
,15,16

properly
1072:10
1083:15

proportion
1126:6

proposal
999:23
1181:23

proposed
1075:1
1167:14
1250:6,20

proposing
1058:19
1075:3,9

prote
1252:10

protecting
1252:22

protection
1041:6
1237:12
1252:11

provide
1049:3,11,
15,19
1068:2,7,2
3
1084:23,25
1085:1,5,9
,14,24
1086:7,18
1105:25
1106:1,13
1130:16
1133:17
1135:1
1152:8
1161:13
1162:9,19
1163:3
1164:24
1165:5,9
1169:4
1172:7
1176:17
1192:10
1193:6,10
1203:8
1209:20
1216:12
1222:15,16
,17,23
1223:2,6,8
,13
1239:20
1240:24
1241:3,25
1242:2

provided
1057:24
1072:25
1084:16

1089:11
1123:9
1133:11
1139:12
1149:19
1161:8
1238:7
1250:9,14

provides
1103:18
1204:12

providing
1142:13
1214:8

province
1037:7,8
1038:6
1149:16
1160:2
1177:18
1180:11
1181:3
1182:25
1207:10
1217:5,11

provincial
1125:16
1126:18
1128:14,17
1138:7
1216:4
1217:16

prudent
1240:23

PUB
992:7,9,11,13,15,20
993:17,19,21,23
994:3,5
997:15
999:23
1003:12,16,18,20,22,24 1004:3
1045:8
1131:17
1224:12
1250:8,13
1252:5

PUB/Elenchus-1
1155:13

PUB/Elenchus-2
1155:14

PUB/Manitoba
1191:23

PUB-Elenchus
1155:13

public
989:3,21
993:5
1050:10
1129:9
1136:16,18
1137:23
1140:21
1141:1
1142:22
1143:4
1147:21
1150:7
1155:5
1188:10
1244:13,21
1246:22
1247:6

publically
1140:3

publicly
1141:24
1214:16

publishing
1232:21

pull 1225:3

pulp 1127:1

pumping
1137:6,12,18
1138:20,24
1140:2,17
1141:18,19
1142:1

pumps
1159:22

purchase
1191:12

purchased
1116:14

purchaser
1126:19

purchases
1116:10

purely
1215:9
1238:20
1241:5

purpose
1068:15
1104:15
1147:13
1148:8,9
1215:14
1218:7
1220:23
1221:8,16
1225:19

purposes
1068:5
1093:18
1094:12
1113:7
1116:18
1224:23
1226:3
1227:16

pursue
1104:1
1168:18
1195:13
1204:10
1210:15

push
1059:13,15
1129:12

pushing
1237:22

puts 1059:18

putting
1052:11
1081:2
1094:18
1177:23
1188:24
1189:24
1202:17
1246:8

Q

qualificaitons 997:18

quantity
1105:11

quantum
1239:1

question
1057:14
1058:11
1069:11
1073:9
1105:24
1133:24
1153:13
1159:12
1166:20
1167:3,14
1174:4
1175:22
1177:21
1202:16,25
1207:19
1215:15
1216:25
1217:24
1218:6,8,13,16
1219:16
1220:15
1222:2
1226:17
1227:1
1229:9,13
1235:15
1238:8
1240:4
1242:19

questioning
1095:3
1131:5
1133:22

questions
992:14
1051:17,18
1058:7,10
1069:10
1083:4
1099:2
1127:15
1131:18
1150:13
1152:14
1153:8,11
1180:23
1185:10
1194:3,8
1199:10
1202:9
1223:18
1224:16,21
1225:17,22
1239:12
1242:20
1243:8
1246:3,4,10,11,13

quick
1242:19

quicker
1078:17

quickly
1065:6
1151:22,23

quilt
1039:1,3,8

quite
1063:14
1115:11,12,14 1117:6
1123:10
1124:22
1126:15
1128:8
1131:2,3
1135:6
1140:3
1143:1,3
1146:5
1148:10
1151:23
1160:23
1161:6
1162:22
1170:7
1176:17
1222:6
1224:14
1239:2
1241:15

R

R&V 993:19

R12 1127:20

radio
1208:5,8

raised
1142:9
1248:6,21

Ramage 990:5
1188:18,20,21
1190:3,12,16,23
1191:5,16,20
1192:9,15
1193:2
1248:24
1249:2
1253:12

ramping
1059:13

ran 1249:11
1250:1

range 1065:3
1066:1
1067:4
1081:8
1086:4
1096:11
1102:12
1107:6
1122:22
1136:4
1183:18
1195:2

ranges
1085:25
1247:2

RAP
1095:19,21
1097:13
1098:22
1099:2,4
1100:8

rapid
1149:19,20

rapidly
1152:4

rate 993:12
996:7
997:13
1020:15,18,20
1021:4,5,9
1027:9
1029:21
1039:3
1054:18
1055:6,15,20 1057:2
1065:5
1119:15
1146:1
1150:16,22,25
1186:5,10,13,16
1232:12
1233:1

ratepayers
1055:12

rates
1038:24
1102:2,18
1106:15
1124:17
1181:22,23
1182:3,13,15,16,21
1184:13,19,22
1185:15,24
1186:7
1189:4,11
1227:11
1236:12

rate's
1106:21

Rates
1037:13
1146:22
1147:14,19
1148:9,16
1149:25

rather
1111:19
1142:16
1180:22
1224:19
1247:15

ratio
1019:11,12,13
1020:13,16
1021:6,7,8
1046:4
1117:5
1165:18

raw 1212:15

re 989:7
992:7,9,11,13,15,20
993:21
994:3,5
997:15
999:23
1000:3
1003:12,16,18,20,22,24 1004:3
1045:6,8,11 1110:25
1148:24
1163:16

reach
1109:14
1173:1,19

reaches
1115:5

readily
1084:1

reading
1096:20
1098:20
1187:1
1189:8
1190:6,19

readjust
1069:14

reads
1239:14

ready 1050:4
1132:10

real 1200:15
1201:23
1238:9
1251:3

realistic
1095:22
1096:9,11
1097:8,10,25 1201:24

reality
1225:8

realized
1179:7
1181:11

really
1097:20
1099:4
1121:20
1131:1
1135:17
1142:11
1148:15
1163:9
1177:3
1189:5,6,20 1216:8
1221:24
1230:21,23
1231:13
1242:5
1251:15

reason
1052:3
1131:7
1179:12
1185:17
1199:6
1249:10

reasonable
1058:5
1098:1
1125:3

reasonably
1065:15,19
1102:25
1124:7

reasons
1058:21
1082:16
1116:1
1135:13,23
1142:23,24
1143:5
1236:20

rebundling
1173:4

rebuttal
1065:11
1101:15,17,22
1102:9,22
1144:9
1147:18
1148:5,10
1225:7,9

recall
1053:3
1063:18,22
1096:14
1101:1
1153:21
1178:4
1206:16
1218:13

recalling
1098:21

recap 1052:1

received
1129:11
1137:13,15
1138:5
1248:8

receiving
1140:20
1168:11
1206:12

recent
1067:1

recently
1128:22,25
1153:18

recess
1190:9
1245:14
1249:2
1253:23

recessed
1248:23

recessing
1132:6
1187:20

recognize

1081:3
1082:15
1088:6,19
1101:23
1113:1,8
1114:12
1120:4
1146:19
1219:13
1221:18
1233:24
1234:14
1241:7

recognized
1140:22

recognizing
1114:10
1116:8,19

recommend
1217:2

recommended
1190:6

recommending
1189:8

recommends
1242:24

record
1115:21
1118:2
1134:11,12,17
1136:16,18
1137:23
1144:16
1147:21
1160:24
1190:7,18
1191:1,9,15
1192:5,11
1245:21
1248:1,3
1249:5

recorded
1118:23

recover
1238:11

recovered
1088:9

recovery
1152:2

rectified
1149:16

red 1123:17
1204:24

redact
1251:19,22

redacted
1246:8
1250:15
1251:2,12
1253:2

redactio
1250:9

redactions
1249:23
1250:1,4,5,9,15,20
1251:4,16
1252:1,4,8

redu 1205:3

reduce
1198:4
1213:5
1232:18

reduced
1213:1

reducing
1210:14,24
1211:1
1213:2

reduction
1210:20

reductions
1140:9
1176:14

Ref 1038:25

refer 1131:4
1158:14
1167:2
1175:3
1180:23
1190:25
1191:1
1192:2
1228:3
1235:18

reference
1077:17
1192:3
1253:3

referenced
1095:5
1189:12

referred
1140:18
1191:24
1193:19
1208:12
1210:17
1225:12
1229:14

referring
1052:14
1109:13
1133:10
1155:12
1176:24
1194:19
1224:10
1225:11
1231:1,3

refers
1225:7

refine
1212:19

refined
1093:11
1212:14

refinements
1063:24

refining
1212:16

reflect
1097:15
1112:15
1144:16

reflected
1118:8
1233:17

reflects
1070:9
1112:16

refrigerator
s 1159:24

regard
1206:9
1226:16
1233:4
1238:9

regarding
1136:6
1160:24
1239:21

regards
1128:2
1168:8
1177:22
1218:17

regimes
1139:19

region
1174:16
1208:21

regions
1208:23

Regis 989:13

registering
1247:14

regroup
1253:14

regular
1183:7

regulated
1126:17

regulation
1126:24

regulations
1128:14

regulatory
1100:20
1142:24

rehabilitati on 1138:17

reinvest
1115:9

reinvested
1114:14

related
1126:12,14
1130:20
1134:25
1136:8
1161:7
1177:21
1200:11
1206:1
1237:13
1238:10
1241:12
1243:14

relates
1060:4,6
1079:22,25
1089:9
1120:24
1121:11
1124:5
1142:13

relations
1040:23

Relative
1046:7

relatively
1081:14

release
1146:22

releases
1252:25

releasing
1232:22

relevant
1054:6,10

reliability
1028:9,10,11,12,13,14
1046:24,25
1047:3,5,6,7,14,15,16 1082:20
1148:25

reliance
1216:15

reliant
1202:12,14
1228:19

relied

1089:3,4
rely 1207:1
relying
1253:6
remainder
1243:19
remaining
1056:21
remember
1175:4
remembers
1109:19
remind
1050:12
remote
1176:19
1203:25
renewable
1090:7
repackaging
1173:4,12,
17
repeat
1058:7
1086:8
1106:6
1130:14
1150:19
1153:15
1202:25
1227:1
1240:4
1245:21
1246:18
1248:5
repeated
1086:14
1130:12
repeating
1053:18
1247:15
rephrase
1205:5
replace
1116:13
replacement
1197:3
report
1000:4,6
1003:10
1017:10
1035:8
1045:6,11
1047:19
1048:11
1144:11
1154:14
1157:21
1158:1
1159:5
1174:21
1209:20
1218:22
1222:12
1242:22
1250:21
1252:14
reporter
1086:14
reporting
1089:2
1113:4
reports
1095:7
1162:15
1250:15,19
1252:1,3
report's
1218:22
represent
1071:13
1092:16
1097:24
1111:1
1125:15
representation 1123:14
1126:2
1128:25
1219:22,24
1220:2
representations
1247:11,20
representative 1061:12
1088:2
1089:1
1153:14
represented
1139:5
1156:13
1193:7
representing
1116:6
represents
1071:10
1119:20
1120:3,16
1121:1
1122:25
1147:6
1231:20
repurchase
1116:11
request
992:3,11
993:15
1088:25
1089:7
1161:16
1246:15
requested
1096:2
1161:4
requesting
1249:20
requests
992:23
994:8
997:21
1000:15
1001:4,9,24 1002:15
1003:4
1004:6
1006:11
1032:8
1039:12
1040:16,22
1045:15
1046:12,18
1047:11,22
1130:20,23
1155:1
require
1104:8
1138:23,24
1166:2
1179:21
1197:10
1239:25
1240:7
required
1091:15
1148:24
1242:5
1243:1
1245:10
1253:1
requirement
1127:19
1213:6
1242:1
requirements
1128:2
1225:20
requires
1091:7
1151:15
1162:7
1176:11
1186:6
requiring
1071:25
1129:18
research
1175:17
1222:14
reserve
1081:4
1156:11,13,14 1157:6
1158:3
1161:25
1165:20
1174:17
reserves
1134:23
1135:2
1148:23,24
1156:18,21,22
1157:12
1158:8
1160:4,6
reserving
1245:22
Reservoir
1032:21
1033:5,6
residential
1113:18,20,25
1114:23
1115:18
1116:3,9
1117:4,13
1118:15
1120:15,25
1121:2
1123:6
1124:23
1125:1,9,10,20,21,23
1126:4,14
1127:6,11
1153:17
1154:1
1155:3,17
1156:5
1157:15
1158:7,11,21,22,25
1159:2,8
1160:11
1163:16
1164:13
1169:25
1174:5,14
1175:6
1178:22
1186:9
1207:21
1217:10
1232:6
residual
1228:20,25
resinate
1221:24
resinated
1221:11
resolved
1253:13
resonate
1221:1

resource
995:17,18
1021:19
1022:18,19
,20,21,22,
23,24,25
1023:3,4,5
,6,7,9,11,
13,15,17,1
9,21,23
1024:3,5,6
,7,8,9,10,
11,12,13,1
6,17,18,19
,20,21,22,
23,25
1025:3,5,7
,10,12,13,
14,15,16,1
7,18,20,22
,24
1026:3,5,7
,9,11,13,2
3
1030:4,5,6
,7,13,14,1
5,16,17,18
,19,20,21,
22,23,24,2
5 1031:3,4
1035:10,16
1037:6
1039:10
1054:7
1072:3
1080:17
1082:9
1083:22
1134:3
1135:13
1149:8
1194:13
1195:6
1204:14,15
1215:5

resources
1081:2
1172:7
1183:2

respect
1049:6
1051:17,19
1054:3
1058:14,25
1070:16
1073:12
1078:23
1084:7
1085:15
1086:22
1087:23
1089:4
1090:5
1092:4
1095:5
1099:7
1114:21
1118:21
1122:6
1123:6
1124:3
1129:25
1131:10
1132:15
1136:16
1139:2
1144:10
1220:15
1225:22
1229:22,23
1239:12
1242:20
1243:9
1244:15
1245:19,22
1249:4

respected
1089:7

respond
1151:11
1235:6,11
1238:5
1249:3

responded
1132:16

responding
1151:7
1166:20

response
993:17
1048:15,17
,19 1106:2
1143:9,16
1144:10
1149:20,21
1150:2
1151:4
1155:4,12
1187:2,10
1191:17
1202:9
1245:2,6
1250:1

responses
1189:12
1246:4

responsible
1091:7
1175:14

rest
1067:7,14
1189:5

restart
1187:24

restarted
1151:23

restrictions
1191:3

result
1058:20
1115:4
1127:4
1128:22
1138:19
1142:4
1151:12,13
1152:1
1235:25

resulted
1140:9,16

resulting
1232:14

results
1056:2
1057:20
1099:18
1141:12
1164:25

resume
1132:10
1187:14

resuming
1132:7
1187:21

retrofitted
1163:18
1165:25

return
1124:18
1129:25
1186:21
1199:10
1218:19,20
1221:12

Revenue
1039:7

revenues
1048:12
1056:8

reverse
1080:13

revert
1115:7

review 989:9
993:7,8,9,
10,11,13,1
4 1006:6,8
1040:19
1048:13
1089:23
1167:25
1189:4
1242:22,23

reviewed
1074:4

revised
1049:4
1085:14
1086:19

Richard
989:16

Rick
1000:3,14

ridership
1216:6

right-hand
1118:15
1156:3

rights
1245:22

risk
994:14,15,
16,22,23,2
4,25 995:9
996:4,9
997:9,10,1
1,12,22,23
,24,25
998:3,4,5,
6,7,8,9,10
,11,12,13,
14,15,16,1
7,18,19,20
,21,22,23,
24,25
999:3,4,5,
6,7,8,20
1001:6,7,8
,25
1002:3,4,5
,6,7,8,9,1
0,11,12,13
,14
1003:5,6,7
,8,9
1009:14,16
,18,24
1010:3
1014:12,14
,16
1019:14,15
1027:14,16
,18,20,21,
22,23,24,2
5
1028:4,6,8
1029:16
1032:18
1033:23
1035:20
1043:23,24
1044:3,12
1046:10
1047:4,8,9
,17
1081:16,21
,22
1082:1,2
1228:2
1233:22
1235:21,24
1236:11
1237:12
1238:10

1239:24
1240:6
1241:2

risks
1022:16
1226:21
1227:5
1239:16

River
1181:5,7
1194:21
1195:12
1204:24

road 1177:2

roadblock
1250:2

Rohmund
991:11
1051:9
1089:10,24
1090:3,12,17 1091:2
1094:7,17
1095:7,16,21 1096:5
1097:5
1098:12
1099:13,21
1100:2,12
1101:24
1102:21
1103:3
1104:16
1105:3
1127:15
1153:22
1154:4,11,19 1155:20
1157:10,17,20,25
1158:5
1159:4
1174:3,12,24 1175:10
1245:11

room 1081:10
1188:13
1189:5,9,18 1190:6
1191:11
1244:20
1249:15,17

rooms
1050:17

roughly
1109:24
1114:20,22
1123:2
1197:25

Round 994:7
997:20
1003:16,18,25 1004:5
1006:10
1032:7
1039:11
1040:15,21
1045:15
1046:12,17
1047:10
1191:24

route 1205:1

run 1239:24
1240:6
1253:7

running
1182:19

runoff
1014:21,23

rural
1221:19

Russel
999:24

Russell
997:16,18
1000:6,8

S

sake 1201:13

sales 1033:7
1239:9

Salvage
1032:12

sample
1158:20

sampling
1061:12

Saskatchewan
1137:7

sat 1218:12

satisfaction
1203:14

saturation
1153:18
1154:2,4,17,22

Saunders
990:18

save
1183:14,18

saved 1176:1

Saver
1172:19
1173:4

saving
1181:20,21
1182:14
1210:19,20

savings
1067:8
1105:8,12
1108:23
1109:10,13,24
1110:21
1111:1
1112:9,17
1113:1,3,4,8
1114:3,13
1115:16,20
1116:19
1117:25
1118:9,17
1119:23
1124:24
1126:4
1127:5
1130:1
1145:22
1147:7
1180:12
1181:25
1183:6,8,19 1193:6
1196:1,8,12,18

saw 1084:1
1093:23
1123:21
1181:11

scenario
1079:3,22
1193:8,9,11 1237:7,9
1241:19

scenarios
1006:12,13,14,15,16,17,18
1037:19
1135:14
1193:18
1201:9

Schedule
997:17

schedules
999:24
1003:23

scope 992:12
1107:8
1226:17

screen
1052:3,11
1054:25
1071:17
1096:20
1113:25
1145:1
1207:5

Screening
1022:19,20,21,22,23,24,25
1023:3,4,5,6,7,9,11,13,15,17,19,21,23
1024:3,5,6,7,8,9,10,11,12,13,16,17,18,19,20,21,22,23,25
1025:3,5,7,10,12,13,14,15,16,17,18,20,22,24
1026:3,5,7,9,11,13

screens
1145:25

scroll
1111:16
1113:19

S-curves
1036:19,21,23
1037:3,8

se 1116:18
1169:16
1191:9
1214:4,23
1215:8
1218:13
1253:3

sealing
1159:23

season
1141:3,12

second
1054:13
1069:18
1139:16
1181:18
1197:21
1246:1

secondary
1154:12

Secondly
1133:21

section
1052:5,21
1147:18
1224:11
1242:20
1243:11
1252:4

sector
1076:21
1088:25
1116:9
1117:4,13
1121:24
1122:16
1124:12,24

1126:4,10,
20,25
1127:1
1153:17
1154:1
1157:4
1169:25
1173:7,8
1174:14
1232:6

sectors
1103:7
1125:18
1159:3
1172:25
1207:16

secure
1087:17

security
1082:19
1236:4
1252:20

seeing
1232:13
1238:3

seek 1131:18
1241:4

seem 1219:6
1231:9

seems
1075:13
1182:22

seen 1090:23
1120:22
1224:1
1232:1,2
1246:20

segment
1122:1
1174:13,25
1175:6

segmentation
1123:10

segments
1153:20
1155:22
1156:1,3
1157:4,5,1
3,15,16
1174:5,22

segregate
1158:3

segue 1095:3

select
1049:17
1223:3,10

selected
1036:19,23
1037:3,8
1222:4,19,
21,24

self-identified
1220:6

self-identify
1220:7

sending
1178:1

sense 1064:2
1068:25
1093:11
1115:3
1124:23
1171:20
1177:24
1178:2
1196:2
1198:11
1199:7
1200:2
1201:4
1211:11
1214:1
1215:7
1216:5
1218:18
1237:15
1247:6

sensitive
1050:14
1188:11
1244:15

sensitivities 1082:15
1135:15

sensitivity
1014:12,14
,16
1036:20
1037:13
1092:22
1104:15

sent 1153:8

separate
1083:18
1092:13
1129:5
1157:13

separately
1123:21
1155:21
1171:5

September
994:4,6
1003:17,19

series
1150:1
1203:19

serve 1242:5

served
1168:19

service
1119:8
1120:10
1123:17
1137:16
1138:11,13
1142:14,16
,18
1151:14

services
999:15
1028:20,21
,22,23,24,
25 1152:9
1171:15
1173:5
1209:16

serving
1093:17

session
1050:13,18
1188:10,15
1218:11
1244:15

sessions
1136:21
1188:4
1218:23
1219:12

setting
1094:16
1135:14,15

seven
1055:5,13,
20 1057:7
1119:10
1137:6
1138:22
1197:24

seventeen
1197:25

seventy
1137:21
1138:3
1226:19

seventy-eight
1228:5,10,
17 1231:15

several
1090:10
1136:10
1137:11
1182:8

shadow
1185:19

shaking
1109:20

shale 1140:6

share
1057:18
1089:5
1142:12
1143:1
1241:16

shareholder
1142:24

sharing
1057:14
1142:10
1143:3

sheet
1110:18

Shefman
990:19
991:16
1192:18,19
,23
1194:6,7,2
3
1195:9,17
1196:4,20
1197:1
1198:1,17
1199:1,9
1200:14,20
1201:12,21
1202:8
1203:1
1204:17
1205:25
1206:18,24
1207:23
1209:2,25
1210:13
1211:3,13,
16 1212:21
1213:8,14
1214:2,7
1215:14
1216:9,21
1217:18
1219:10,15
,25
1220:9,14
1222:1,20,
25
1223:17,20
1227:24
1247:24,25

She's 1145:1

shift 1228:3

shifting
1210:1,3,7

shipping
1162:10

shock 993:12

shop 1113:7

short
1007:22
1051:21
1081:14

1087:6
1148:20
1149:11
1202:9
1224:24
1227:6

short-circuit 1243:19

shorter 1062:6
1109:23

shortfall 1239:17

short-term 1149:6,20
1226:22

showerhead 1159:24

showing 1061:22
1074:11
1108:23
1116:16

shown 1049:4
1055:5
1066:9
1077:16,20
1079:24
1085:14,25
1086:19
1103:5
1114:23
1125:1
1156:3
1167:4

shows 1096:18
1131:11

shut 1151:22

sic 1084:22
1088:13
1104:22
1127:7

sign 1248:13

signed 1166:7
1239:9
1244:18

significant 1064:7,10
1081:15
1140:4,25
1176:20
1181:21
1182:14,25
1196:11,15
,19

significantly 1062:16
1064:5
1082:13
1140:8

signing 1248:9,16,
17

silence 1245:23

similar 1089:22
1101:21
1175:19
1176:13
1195:13
1215:24

Simonsen 1143:14
1190:14
1244:6,7

simplest 1198:12

simply 1058:18
1129:8
1190:17
1220:5
1229:4
1231:12
1232:25
1251:13

simulate 1204:5

single 1156:11

sink 1197:7

sir 1148:5

sit 1223:23

sitting 1194:1

situation 1149:17
1201:6
1215:7

situations 1087:25
1088:21

six 1076:24
1133:15
1137:4
1140:17
1152:1
1196:16
1238:2

six-o-five 1073:20

sixth 1204:2

sixty 1138:22

sixty-five 1073:23

sixty-one 1105:9

sixty-seven 1229:5

size 1109:15
1134:15,17
1146:13,16

sizing 1122:6

sledding 1189:20

slide 1055:5
1060:15
1078:10
1089:13
1123:9,11,
15
1131:11,13
1194:12,13

slides 1060:5
1089:12

slight 1114:16
1146:19

slightly 1075:5
1098:14
1107:5
1119:14

slope 1231:25

small 1108:17
1110:19
1117:6
1203:13
1204:19
1205:20,21
,22

smaller 1108:20
1110:15
1151:17
1176:19
1197:24

Smart 1052:5,21
1053:2
1056:15
1091:19
1108:22
1109:8
1110:20
1116:25
1118:16
1124:2
1129:1
1130:18
1145:10
1170:10
1171:13
1179:15
1193:8
1206:23
1207:8,9,1
2 1209:11
1219:7
1220:24
1221:10
1232:22

Society 1248:8,14
1249:8

socio 992:15
1048:13

socio-economic 994:9,10,1
1,12

Socio-economic 993:7,8,9,
10,11,13,1
4
995:15,16,
23,24
996:8,11,1
2,13,14,18
,19
997:5,6
999:11,12,
14,16,18,2
1
1000:4,17,
18,19,20,2
1,22,23,24
,25 1001:3
1043:5,7
1044:23,24

soft 1252:25

solar 994:17
997:14
1039:16,17
,18,19
1203:12
1204:18,22
,25
1205:18

sold 1239:7

Soldier 989:15

solely 1102:10
1113:6

solution 1203:25
1204:13
1215:16

solutions 1215:19,20

somebody 1185:21

somebody's 1077:10
someone 1147:9 1181:2,3 1216:20 1253:6
sometime 1137:16 1138:13
somewhat 1060:17 1101:21 1106:20 1164:7 1228:14 1229:1,2
somewhere 1081:19 1099:16
somewheres 1064:11
sophisticated 1063:21
sorry 1052:7,12 1062:25 1066:8 1069:21 1078:5 1085:3 1101:5 1107:21 1134:13 1139:8 1141:21 1145:16 1147:22,25 1148:12 1150:18 1153:6 1155:13 1182:11 1185:2,6 1192:22 1196:20 1202:24 1217:21 1220:9 1226:25 1234:23 1239:19 1240:3,14 1242:21 1244:25 1245:15 1249:1
sort 1211:22 1213:19 1214:21 1218:18 1243:19 1252:23,25
sorts 1056:13 1198:5 1215:17,19
source 1140:2 1197:5 1212:1 1213:25 1216:23
sourced 1089:14
sources 1154:7,10, 12,13 1215:2
south 1174:16 1176:2,10, 11,15 1177:11 1181:2 1213:21
southern 1156:21 1158:3,8,1 3 1180:11 1185:21 1201:19 1203:5 1204:5 1206:10 1214:24 1221:19
SOW 993:23
space 1081:5 1168:20 1200:12,17 ,25 1201:3,14
speak 1088:4 1102:2 1128:9 1136:25 1204:22 1250:17
speaking 1136:18,20 1153:17 1195:7 1200:3 1202:11 1210:11
speaks 1117:8
special 1173:15
specialized 1252:19
specific 1093:12,13 1106:23 1139:7 1148:23 1159:17 1161:2,3,1 5 1169:8 1172:25 1173:16 1177:3 1195:18 1208:4,6 1209:6 1217:5 1218:13 1246:10,14 1247:1
specifically 1088:25 1102:2 1107:8 1156:18 1159:13 1161:2 1162:3,5 1171:12 1172:19,23 1173:8,13, 18 1175:3 1204:23 1206:10 1207:18 1208:2,9 1209:10 1216:17 1217:4,7,1 6,21 1220:4 1225:18
specifics 1154:14 1162:14
specify 1229:21
spectrum 1093:10
spend 1056:6
spending 1055:25 1057:1 1203:6
spirit 1235:17
SPLASH 1010:5,7,9 ,11,13,15, 17,19,21,2 3 1011:3,5,7 ,9,11,13,1 5,17,19,21 ,23 1012:3,5,7 ,9,11,13,1 5,17,19,21 ,23 1013:3,5,7 ,9,11,13,1 5,17,19,20 ,22,24 1014:3,5,1 9,21,25 1016:3 1032:9,10, 11 1033:10 1034:13,14
spoke 1144:7 1156:2 1195:10 1201:22 1232:19
spoken 1200:11 1230:8 1246:1
spurt 1081:8
staff 1130:21 1250:8 1251:6
stage 1199:8 1205:12,13
stand 1252:15
standard 1065:22 1126:13 1129:19 1196:11 1200:8
standards 1090:6,7 1110:5 1125:19,24 1126:7,10, 13,21 1127:5,9,2 1 1128:8,12, 16 1129:1 1130:22 1252:11
standby 1152:9
standing 1139:20
stands 1095:21 1253:25
start 1051:15 1058:15 1063:11,21 1094:18 1111:7 1137:5 1146:2 1175:22

1194:11
1198:16
1230:1
1238:3
1251:9,11

started
1050:10
1237:24
1238:16

starting
1089:16
1099:1
1103:24
1183:12
1242:21

state
1167:22
1193:3
1228:1
1232:25

stated
1130:19

statement
1103:21
1226:18,23
,24 1233:2
1237:15

statements
1186:3
1247:2

states
1090:5,10,
21 1126:12
1139:23

stating
1245:20

stations
1137:6
1138:24
1139:25
1140:17
1141:18,19
1142:2,5
1208:8

statistic
1210:4

Statler
1224:11

status
1003:22,24
1090:4
1162:24
1220:4,5

statuses
1161:9

staying
1114:6,20
1116:1,3

step 1096:17
1104:15
1148:13
1230:3

Steven
1182:9,10

stop 1146:6
1149:1

stopped
1238:17

storage
1151:9

stove
1198:13
1214:17

stoves
1199:3
1211:5,8,1
8,19
1212:23,24
,25
1213:11,16
1214:8,24
1215:10

strategies
1207:14

strategy
1206:20,25
1207:11
1208:18

streamflow
1014:19,21
,25

streamflows
1015:3,5,7
,10,13,16,
18,20,22

stress
1014:13
1051:19
1058:14
1059:20
1065:24
1070:23
1072:22,23
1073:4
1074:11
1075:1,3,8
1076:17,25
1077:3,5
1078:1
1092:4,18,
21 1093:21
1143:2
1236:23

strong
1115:12
1240:18

strongly
1175:15
1235:9

structural
1228:4

structure
1221:23
1230:13

studies
1082:5
1175:15,18
1229:17

stuff
1179:19

Sturgeon
1042:19,20
,21,22,23,
24,25
1043:3,4
1044:11

subject
1051:23
1087:5
1089:9
1109:21
1138:6
1146:25
1147:14
1167:25
1188:25
1217:22
1218:4
1226:13
1238:18,19

submission
1236:19

subscribe
1150:2
1151:1,16

subsequent
1069:10
1136:13
1243:11

subset
1097:1
1171:6

subsets
1096:3

subsidize
1058:4
1215:12

subsidizing
1056:22

substance
1231:8

substantial
1088:7
1123:18
1125:21
1126:5
1172:5
1233:25

substituted
1144:14

success
1120:19
1164:25
1194:15

successful
1164:9,16

sudden
1151:12
1238:16

suddenly
1151:14

sufficient
1212:16

sufficiently
1062:17

suggest
1050:23
1057:24
1058:25
1059:18
1064:9
1065:22
1076:5
1087:10
1090:14
1129:24
1131:15
1143:25
1186:20
1191:13
1192:24
1193:23
1244:16
1253:11

suggested
1073:4
1192:10
1206:9

suggesting
1059:12
1072:22
1107:4

suitable
1203:15
1239:17

suited
1204:14

summary
1036:17
1045:10
1049:19
1052:6
1131:10
1136:23
1223:6,14

summer
1149:10

Sunk 1022:8

sun's
1205:1,4,6
,17

supplemented

1154:7
supplements 1197:7
supplied 1140:10
supply 1014:9,10,18,20,22,24 1015:24 1018:10,11 1027:19,21,22,23 1239:18,25 1240:7
support 1115:4 1129:9,10 1148:15 1172:8 1175:16 1209:22 1241:17
supported 1179:25
suppose 1220:18
sure 1059:19 1060:16 1064:16 1066:7 1091:22 1097:18 1099:19 1103:13 1105:21 1108:18 1158:6 1170:3 1184:9 1189:24 1201:25 1202:8 1217:21 1219:10 1236:18,24 1250:18
surplus 1032:20
surpluses 1082:4
surprising 1238:3
survey 1153:19 1154:3,5,17,22 1155:4,18 1158:12 1217:10
surveying 1217:14
surveys 1217:10
suspect 1105:24 1236:10
Sustainability 992:25
Sven 990:3 1050:7 1152:17 1187:25 1190:23 1192:13 1223:22 1243:25 1244:5,12 1253:10
Swan 1235:1
switch 1181:13 1182:13 1223:25
switched 1145:6
switching 1102:1,18 1106:17 1199:13,16,18,22 1200:10 1202:12,14 1203:4,11 1216:2
Sworn 991:8,9,10,11,12 1051:6,7,8,9,10
synergy 1016:25 1017:5
system 1010:5,8,9,11,13,15,17,19,21,23 1011:3,5,7,9,11,13,15,17,19,21,23 1012:3,5,7,9,11,13,15,17,19,21,23 1013:3,5,7,9,11,13,15,17,20,22,24 1014:3,5,15,17 1016:4 1026:24 1116:8 1122:2,4,5,14 1138:19 1149:14,15 1151:11 1197:3,11,17,20,24 1202:6 1210:25 1211:12,15 1233:19 1234:10 1252:20,22
systems 1027:3,5,7 1164:2,4 1211:24,25 1212:9 1235:8

T

TA1 1039:10
Tab 1052:3,5 1059:25 1060:8 1071:1 1074:20 1089:16,17 1092:7 1147:9 1225:5,15 1230:15
table 991:1 1049:4 1060:11 1072:8,16,17 1079:18 1084:25 1085:2,6,10,14,24 1086:7,8,19 1101:7,20 1114:24 1118:15,20 1121:6 1145:3,6 1174:21 1199:18
tables 1145:5
tabs 1224:25
tabulated 1127:10
tails 1250:3
takeaway 1231:11
takin 1173:16
taking 1066:10 1072:7 1133:14 1161:19 1173:2 1198:20,21 1203:22 1207:19 1218:1 1248:16
talk 1057:15 1064:21 1082:16 1092:23 1094:22 1097:23 1169:9 1201:12 1218:5 1236:4
talked 1082:17 1083:12 1119:2 1133:3 1179:8,18 1180:24
talking 1055:24 1063:9 1064:3 1066:12 1070:15 1109:2 1111:4 1114:20 1117:22 1142:19 1169:9 1173:15 1177:25 1178:5 1181:24 1184:16,17 1196:21 1198:3 1216:14 1220:21 1234:19 1235:7
tank 1201:11
target 1172:24 1208:2,18
targeted 1162:3 1206:10 1207:15 1209:8
targeting 1172:23 1173:8
targets 1090:11

team 1187:13

Tech 1039:5

technical
1035:10,13,15,17,19,21,23
1036:3,5,8
1094:11
1099:25
1172:8
1188:15
1229:17
1245:18
1247:9

technically
1094:20

technologies
1114:11
1203:24
1229:14,20,23

technology
1115:5,8,9
1203:15
1204:25
1205:12,15,18

temperatures
1149:13

ten
1055:11,19,25
1056:20
1057:7
1060:23
1061:15,20
1062:24
1064:18
1065:13,15
1066:1,22
1067:13,22
1068:6
1071:15
1073:17
1074:3,12,14,19,25
1075:9
1078:23
1086:3,5
1152:1,20
1188:14
1245:14
1253:14,23

tend
1176:16,18

tendency
1124:12

tenth
1072:18

tenuous
1099:17
1100:11

term
1006:24,25
1007:3,4,19,21,22,24
1043:9
1166:8
1227:6,25
1235:1

terms
1057:19
1069:1
1100:20
1117:6,23
1118:6
1130:18
1132:21
1134:16
1141:16
1159:18
1162:25
1164:12,15
1168:7,16
1177:7
1178:1
1182:23
1183:20,23
1189:23
1191:10
1193:2
1200:24
1209:3,10
1217:6
1218:15
1219:7
1222:15
1232:20
1235:5
1241:24
1251:15
1253:3

terrorism
1252:23

test 1014:13
1058:14
1065:24
1072:22,23
1073:4
1074:12
1075:1,3,9
1076:17,25
1077:3,6
1078:1
1083:15
1092:18,21
1093:15,21
1221:9,16,17,21
1223:5
1236:23

testify
1251:21

testimony
1000:3
1155:20
1156:2
1200:21
1201:22
1210:18

testing
1049:19
1070:23
1108:18
1221:9
1223:5,13

tests
1051:20
1059:21
1092:5
1179:24

tha 1081:8

thank
1050:25
1058:6
1064:1,15
1070:12
1071:20
1077:8,23
1078:8,14
1083:2
1089:8
1091:24
1093:19
1095:2
1097:16
1098:24
1099:5
1100:23
1102:20
1104:10,19
1107:1,11,19 1108:13
1110:6
1112:5
1115:24
1117:7
1118:12
1120:23
1122:18,19
1123:25
1127:13
1130:7
1143:7,8
1144:20,24
1146:23
1149:22
1150:9
1152:13,16
1153:2
1155:7,19,25 1158:2
1163:4
1172:15
1173:21
1174:2
1175:2
1176:7
1185:3,8,10 1186:19
1187:8,16,18,25
1188:21
1192:14
1194:7
1195:9
1204:17
1209:25
1213:8
1214:2
1217:18
1219:17
1220:10
1222:25
1223:19
1229:12
1235:16
1243:23,25
1245:13
1247:7,22,25
1248:19,22
1253:21

thanks
1124:21

that'll
1091:21

that's
1052:5
1053:10,20
1055:22
1056:4
1057:4,16,24 1058:20
1060:7
1063:16
1065:22
1066:9
1068:14,15
1070:8,13
1071:1,15
1074:1
1077:16
1079:22,24
1082:2,11,16 1084:16
1085:6
1086:15
1091:8
1094:6,15
1095:14,15
1096:5
1097:8,17
1099:17,21
1101:21
1107:10
1109:18
1111:23
1112:8
1114:2
1119:2,6,7
1123:13
1124:19
1125:3
1127:9
1133:20
1134:15,24
1135:19
1136:2

1137:22
1140:7,20
1146:5
1149:9
1150:7
1153:22
1155:16
1161:16
1163:21,23
1165:22
1168:19
1169:21
1170:23,25
1173:25
1175:23
1176:6
1177:22
1178:2,9,10 1179:15
1180:25
1181:12,14,16,21
1184:24
1189:1
1190:19
1191:5,17,18,24
1192:3
1193:13
1194:16,22
1195:16
1196:14
1197:17
1200:11
1204:14
1205:14
1206:21,22
1207:15
1208:24
1212:4,17
1215:10,13
1221:17
1225:8,13
1227:20
1230:22,23
1232:10,14
1235:5,14
1236:3,19,22 1237:16
1239:10
1240:11
1243:22,23
1245:13
1246:16
1250:20,21
1251:21
1252:3,17,21,22
1253:1

theme 1218:8

themselves
1092:24
1244:20

theoretical
1094:12
1100:1,17,18

theoreticor
1100:17

thereabouts
1170:4

there'd
1179:7

therefore
1124:18
1226:21
1227:5

there'll
1068:9
1141:17

there's
1052:6
1059:11
1061:2
1068:10,12
1069:11
1072:16
1079:19
1080:21
1081:15
1082:19
1084:15
1088:15
1091:11
1097:19
1102:14
1104:6
1105:5
1109:3
1111:21,22
1112:12
1118:22
1119:8
1120:9
1125:13
1131:1,3,14,19
1150:11
1158:20
1164:4,13,15 1165:24
1166:22
1174:1
1175:13
1178:12,22
1179:2
1181:19
1184:3
1189:24
1192:5
1196:9,11
1205:19
1210:23
1211:7,18
1215:7
1219:14
1225:1
1229:23
1234:5,21
1236:20
1237:25
1240:18
1242:11
1245:18
1246:3
1247:5
1249:8
1251:24

thermal
1037:22
1038:5
1205:4,8
1215:4

they'll
1115:9
1242:7

they're
1075:25
1082:13
1088:9,12,13,23
1099:19
1104:13
1114:14
1116:12
1124:15,16
1126:21
1138:16
1150:6
1161:19
1164:9,11
1171:20,21
1173:2
1178:24
1190:3,4,25 1196:10
1200:6
1211:11
1219:8
1235:1,3
1241:17
1251:10
1252:19

they've
1116:14
1138:10
1213:17
1229:14
1248:20
1249:12

third 1123:2
1125:8
1135:8
1140:24
1197:9

thirty
1061:16
1063:17
1119:10
1175:18
1228:12,16
1230:20
1231:3

thirty-five
1228:9,17,23 1229:8

thirty-seven
1163:19

Thomas
1000:10

Thomson
1217:1
1237:18
1238:21
1239:5

Thomson's
1136:12

thou 1141:11

thoughts
1169:2
1217:12

thousand
1073:20,23
1109:3
1137:20,21
1138:3,4,21,22
1141:9
1163:18
1181:19

throughout
1062:18
1178:18
1190:5
1194:17
1212:7
1219:14

throw
1235:20

thrown
1251:15

thunder
1104:23

Thursday
1185:18

tie-line
1082:24

ties 1127:14

time-consuming
1142:17

time-frame
1112:20

time-frames
1078:12

timeline
1111:12
1199:2

time's
1251:20

title 1078:4
1079:19

1170:23
titled 1242:22
to-date 1112:10 1114:3 1118:3
today 1051:16 1077:10 1115:25 1136:22 1139:15 1194:8 1211:18 1224:16 1250:13,22
today's 1050:4
tomorrow 1190:10 1250:1,24
tool 1068:24 1154:17
tools 1102:3
top 1079:19 1087:8,10, 19,23 1088:6 1099:10 1108:2 1123:15 1125:9 1142:11,15 ,25 1152:7 1232:7 1239:12,24 1240:1,6,8 ,18,22,23 1241:14,20 ,25 1242:3
topic 1199:13
torm 1227:25
total 1036:12 1054:10 1056:6 1108:5 1109:4,24 1113:20,25 1114:23 1118:23 1119:21 1120:22 1123:23 1125:12 1142:2 1145:25
totally 1165:24
touched 1051:20
touches 1189:24
tough 1189:19
towards 1102:4 1125:17 1127:10 1184:21 1229:19 1241:24
track 1160:17 1171:5 1209:2,12
tracked 1209:9
tracking 1113:3
Trading 1032:6
traditionall y 1214:15
Trans 1046:19,20 ,21,22,23 1047:12,13
TransCanada 1136:25 1139:17,18 ,20 1140:4,12, 15,25 1141:1
transcribed 1072:11
transcript 991:21 1132:18 1143:11 1246:8,16
transcriptor 1130:13
transcripts 1251:20
transfer 1017:6,7,8 ,9 1022:7
transition 1230:2
transmission 995:14,22 1008:8,10, 12,14,16,1 8 1009:20,22 1010:7 1016:10,11 ,12,14,16, 19,20,21,2 2,23,24 1017:3,4,6 ,7,8,9,10, 11,13,15,1 7,18,20 1022:7 1032:10 1034:16,17 ,18,19,20, 21,22,23,2 4,25 1035:3,4,5 1036:3 1038:20 1043:10,25 1044:20 1046:8,24, 25 1047:3,5,6 ,7,14,15,1 6,18 1120:3 1142:18 1148:18 1176:11,20 1177:1 1240:16 1242:1 1252:2,3,1 4,15
transportati on 1234:7
travel 1130:3,19, 20,23
tried 1082:2 1093:25
trouble 1052:13
true 1080:13 1099:22 1179:6 1234:22
truly 1246:4,17
try 1081:25 1092:16 1130:21 1174:1 1193:3 1208:18 1253:17
trying 1055:10 1062:11 1067:12 1083:6 1097:17 1105:20 1106:6 1130:16 1135:22 1163:15 1213:20 1218:17 1249:13
tuning 1104:8
turbine 1033:21 1039:20
turn 1050:5 1070:25 1152:4 1188:19 1192:16,17 1223:20 1225:15 1242:18
turned 1164:16 1250:2,4
turns 1175:23 1249:17
twelve 1152:2
twenty 1061:11,14 ,18,23 1062:7,18, 21 1063:1 1067:11 1068:3,9,2 0 1073:3 1077:2 1079:7 1107:12,13 1158:21 1159:8 1182:17,21 1184:12,14 1197:23 1228:9,12 1229:8 1231:2,4,6 1232:9
twenty-eight 1073:20
twenty-five 1191:8
twenty-nine 1105:9 1155:21 1156:1,7
twenty-seven 1073:22,23
twenty-two 1120:10
TyP-1 1048:13
type 1081:14 1151:2,25

1176:23,24
1199:18
1252:13

types
1129:13
1151:7
1163:2
1169:5
1183:6
1234:3

typical
1149:18

typically
1103:17

Typlan
1048:13

U

unable
1239:25
1240:7

uncertain
1235:6
1240:22

uncertainties 1082:21

uncertainty
1070:14
1080:22
1081:3
1083:1
1135:1,7
1136:7
1189:3
1226:20
1227:4
1229:21,24
1238:23

underestimate 1240:1,8

underestimating
1240:19

under-forecasting 1068:14

underlying
1103:16
1135:3

under-planned
1081:20

understand
1058:17
1060:3,15
1064:16
1065:12,17
1066:7
1067:12
1069:12
1071:5
1080:8
1083:6
1089:16
1092:4,6,15 1100:1
1121:17
1124:17
1147:10
1166:21
1186:2
1189:6
1207:18
1211:4
1214:5
1225:23
1226:19
1227:12
1230:19
1237:11
1239:23
1240:6
1253:18

understanding 1053:6
1060:12,22
1064:12
1090:1,9,10 1094:20
1096:4
1115:16
1120:12
1124:16
1126:9
1137:2
1173:23
1186:1
1196:23
1213:18
1220:25
1252:8

understands
1121:21

understood
1057:21
1059:2
1064:6
1069:3
1070:3
1091:11
1093:21
1095:8

undertake
1092:22
1185:14,23
1227:14

undertaken
1110:2
1116:25
1158:10
1204:23
1209:12

undertaking
1048:17,19
1063:21
1085:1,14
1086:14,15,18
1094:15
1105:23
1106:2
1124:15
1132:16,22
1133:3
1138:16
1140:25
1161:13
1164:24
1165:9
1187:3,10
1193:2,5
1203:19
1211:10
1222:2
1223:1,8
1244:19
1245:1,2,6
1247:13,20

undertakings
991:4
1048:15
1049:1
1050:22
1143:10,16
1162:22
1245:19

undertook
1140:13
1218:11

unexpected
1148:18,19
1149:6,19
1233:13,15,16
1235:2,24

unforeseen
1083:14

unfortunately 1222:5

uniform
1186:5,13

unit 1175:25
1197:22

United
1090:5
1126:12
1139:23

unless
1161:3

unlikely
1115:6

unt 1175:11

unusually
1069:20,21

upcoming
1133:19
1143:21

update
1003:22
1049:11
1132:24
1133:7,9,17
1162:14,24
1165:5,10

updated
1045:12
1133:1
1232:22

updates
1161:9

upgrade
1137:18
1139:7
1177:1

upgrades
1137:12
1139:4
1162:7,9
1163:3

upon
1050:1,24
1051:20
1052:2
1072:3,25
1111:12
1132:6,7
1150:4
1181:22
1182:3
1187:20,21
1232:3
1235:22
1248:7
1254:1

upper
1096:19
1098:6
1099:22
1100:18

upstairs
1189:23
1249:12

upstream
1122:7

uptake
1161:9
1209:10

usable
1212:19

useful
1070:13
1115:6
1131:2
1219:1,9

user 1126:22

users
1124:12

Usual 1202:4

usually
1163:13
1170:16
1196:16
1199:5
1202:4,5

utilities
989:3,21
1090:15
1098:3
1150:8
1175:17

utility
1053:8,13,16
1054:14,21
1055:12
1057:9
1095:17
1096:2
1100:21
1155:5
1193:10,13

Utility's
1056:8

utilize
1213:11

V

valiant
1052:25
1053:3

value
1032:12
1036:17
1063:4
1117:6
1151:3,4
1176:3
1177:8,11,17
1228:20,25

values
1135:16

variability
1074:14

variables
1174:19

variation
1037:21
1038:4
1079:1,12

variations
1134:22
1146:4

varied
1079:10

varies
1166:11

variety
1138:7
1142:23

various
1111:17
1138:7
1150:8
1228:24
1230:8
1249:3

vary 1059:7
1062:10
1183:10

varying
1078:25

vast 1162:13

vehicles
1233:15
1234:7,8

ver 1162:3
1211:1

version
1243:5

versus
1120:6
1122:14
1214:18
1220:4

viable
1201:15
1204:20

video
1188:12

view 1062:3
1226:18
1227:3,9
1252:7

viewed
1129:24

virtual
1109:15

visualize
1197:13

vol 1003:14

volume
1052:16,19

volumes
1140:5

voluntarily
1142:10

voluntary
1087:17

W

wa 1249:25

Waldorf
1224:11

walkthrough
1162:19,20

warm 1149:12

wasn't
1057:24
1081:9
1097:17
1170:5
1190:16
1219:4
1224:10
1249:9

waste
1218:24

water
1014:9,10,15,17,18,20,22,24
1015:24
1027:19,21,22,23
1168:20
1172:18
1173:3
1181:10,18
1182:11,20
1197:7
1200:17,25
1201:5,11

WATFLOOD
1015:3,5,7,10,13,16,18,20,22

ways 1088:5
1164:9
1205:11
1235:8
1237:17
1246:25
1247:5

weather
1069:18,21,22,24,25
1134:19,25

weather-adjusted
1071:10

website
1191:10
1214:17,20

we'd 1059:1
1222:6
1249:15
1252:14

Wednesday
1250:25
1251:25

week 1134:1
1138:16
1141:21
1188:23
1189:20
1190:8
1236:8
1250:2
1251:5

weight
1046:7

weighted
1241:24

Weinstein
990:22

welcome
1194:9

we'll
1070:15
1078:5
1079:20
1083:16
1085:3
1107:4
1111:19
1133:19
1143:24
1148:13
1184:9
1187:24
1188:23
1208:21
1224:22
1245:12
1247:14
1253:13

we're 1050:4
1053:12,13
1055:24
1058:3,14,19 1059:20
1061:10,22
1062:11,21,25 1064:2
1065:25
1066:12,16,17
1067:16,17
1069:24
1071:15
1074:11
1076:22
1082:11,14,15
1084:22
1091:8
1093:7
1101:6
1104:17
1105:18
1109:7
1114:20
1115:14,19,20,22
1116:8
1119:25
1126:2,4
1129:15,16

1132:10
1133:14,17
1135:15
1138:12
1142:19
1163:10,15
,21,25
1164:14
1166:5
1169:3
1170:6
1177:15
1180:17
1184:17,20
1189:1,22
1196:3
1198:3,9,1
4,15
1199:9
1203:15,17
,18,22,23
1204:1,8
1205:2,11,
18 1208:20
1211:1,9
1212:18
1215:1,5,8
,20
1216:14
1220:21
1227:3
1229:6
1230:8
1234:11
1235:11
1238:22
1245:20
1248:23
1251:8,19
1252:2,16
1253:6

we've
1053:12
1059:20
1060:1
1061:9
1063:3
1071:6,23
1072:10
1074:4
1075:21
1077:7
1083:9,10
1084:10,14
1087:7
1089:15
1092:7
1099:15
1104:5
1109:2
1113:24
1114:22
1116:23
1120:22
1125:7
1134:1
1145:6
1154:13
1161:8
1162:22
1163:2,7,1
7
1165:6,24
1166:3
1170:6
1175:12,18
1181:24
1189:9,10
1190:18
1191:25
1193:13
1194:24
1195:24
1200:20
1201:14
1203:2
1204:23
1207:8,9,1
1,25
1208:2,6,8
,25 1213:2
1215:22
1217:8,14,
15 1224:25
1230:7,17
1232:1,2
1233:23
1237:24
1246:20
1251:6

whatever
1212:1
1227:19

whatsoever
1153:13

whereas
1237:18

whether
1064:2
1065:25
1072:10
1079:2,8
1080:18
1081:19
1086:4
1090:6
1092:13
1097:20
1114:14
1160:17
1169:13
1171:14
1174:15
1176:1,2
1177:24
1179:10
1184:2
1199:7
1211:10,11
1217:1
1218:18
1219:21
1220:1
1229:1
1246:3,7,1
5 1249:24
1253:12

Whichever
1153:9

Whitfield
997:16,18
999:24
1000:6,8

Whoa 1113:21

whoever
1058:10
1060:2

whole 1054:9
1142:13
1236:20

who's 1052:8

widens
1078:17

wider
1083:11
1084:2

wife 1226:4

wildly
1242:6,10,
12

William
990:10

Williams
990:8
1095:6
1099:1
1105:20
1133:16
1192:21,22
1193:20
1247:8

willing
1058:3
1142:22
1143:1
1151:1
1163:22,23
1164:10
1218:18,19
1241:17

willingness
1166:25

wind 1000:4
1016:25
1017:5
1022:20
1024:10,11
,12,13,14,
15,16,17,1
8,19,20
1025:6,8,1
4
1026:19,21
1030:8,9
1037:23
1038:5
1043:12
1203:13
1204:19
1205:20,21
,22
1251:18

Winnipeg
989:23
1179:10
1183:7
1203:4
1204:24
1219:12
1221:19

winter
1081:7
1134:7
1213:12

wishes
1107:14

withdrawal
992:9

withstand
1082:23

witness
1150:10

witnesses
1131:7

Wojczynski
991:12
1051:10
1052:9
1058:23
1059:4,15,
24 1072:2
1080:9,11,
14
1083:3,20
1092:23
1093:6
1132:15,20
1136:14
1146:12
1176:4,10
1177:5
1193:1,24
1226:25
1227:7
1228:7
1230:19
1234:18
1235:14
1236:3,17
1237:2,16
1238:13
1247:3

Wojczynski's
1136:6

wonder

1185:12,13
,23
1223:23

wondering
1169:13
1222:1

wood 1198:13
1199:3
1211:5,8
1212:23,24
,25
1213:11,16
1214:8,17,
23
1215:9,12

wordy 1148:8

work 1068:1
1093:11
1097:6
1107:6,8
1128:16,17
1138:25
1161:10
1162:6,8
1163:11,12
,14,22
1164:10
1173:9
1203:16
1204:19
1205:23
1219:6
1236:24

worked
1133:14
1162:12
1175:12

working
1069:25
1115:23
1125:16,17
1129:3,14
1139:10
1160:25
1162:4,18
1163:10,25
1166:7
1169:3,21
1170:7,15,
16 1194:20
1195:25
1222:13
1250:7
1251:9

works
1060:15
1105:23
1109:9
1123:22
1169:22
1172:1
1180:22
1225:14

Worksheet
1036:14

world 993:6
1205:18

worry
1179:11

worse
1081:22

worst
1073:11

worth
1181:14

WPS 1239:10

wrap 1196:17

wrench
1251:15

wrestling
1105:21,22
1192:25

writing
1110:19

wrong
1052:18
1069:4
1093:20
1166:8
1175:23
1196:22
1200:23
1210:5

Wuskwatim
1134:15,17
1146:14,20

X

XL 1140:20

Y

yesterday
1052:1,25
1059:7
1095:6,10
1132:16,22
1188:9
1206:4,19
1232:19

yet 1035:20
1090:23
1163:21
1167:24
1219:1
1222:12

York 1096:7

you'll
1072:7
1080:1
1113:4
1197:15
1198:17
1225:5
1242:16

you've
1054:13
1057:18
1060:5
1064:3
1069:20
1098:7
1099:5
1102:23
1116:2
1157:4
1165:1
1171:18
1222:5
1238:7
1243:18

Z

zero 1111:23
1146:2

zeros
1111:10

zero-zero
1147:2

zoom 1118:14

Tab 51

TSCRIPT.COM™ Digital Transcription Services
"When You Talk - We Listen!"

MANITOBA PUBLIC UTILITIES BOARD

Re: MANITOBA HYDRO
NEEDS FOR AND ALTERNATIVES TO
REVIEW OF MANITOBA HYDRO'S
PREFERRED DEVELOPMENT PLAN

Regis Gosselin	- Chairperson
Marilyn Kapitany	- Board Member
Larry Soldier	- Board Member
Richard Bel	- Board Member
Hugh Grant	- Board Member

HELD AT:

Public Utilities Board
400, 330 Portage Avenue
Winnipeg, Manitoba
March 4, 2014
Pages 321 to 636

APPEARANCES

Bob Peters	)Board Counsel
Sven Hombach	
Patti Ramage	)Manitoba Hydro
Marla Boyd	
Byron Williams	)CAC
William Gange	)GAC
Peter Miller	)
Antoine Hacault	)MIPUG
George Orle	)MKO
Michael Anderson	)
Jessica Saunders	)MMF
Christian Monnin	)IEC
Michael Weinstein	)

TABLE OF CONTENTS

	Page No.
List Exhibits	324
List of Undertakings	373
MANITOBA HYDRO PANEL 3:	
DALE FRIESEN, Affirmed	
LLOYD KUCZEK, Sworn	
LOIS MORRISON, Sworn	
IAN PAGE, Sworn	
INGRID ROHMUND, Sworn	
ED WOJCZYNSKI, Previously Sworn	
Examination-in-chief by Ms. Marla Boyd	379
Cross-examination by Mr. Sven Hombach	486
Certificate of Transcript	636

LIST OF EXHIBITS

No.	Description	Page No.
1	Order in Council 128/2013 Date: April 17, 2013	
2	Terms of Reference - Needs for And Alternatives to (NFAT) Date: April 17, 2013	
3	Public Notice of May 16, 2013 prehearing conference Date: May 16, 2013	
4	Transcript of prehearing conference on May 16, 2013 Date: May 16, 2013	
5	Olthuis Kleer Townsend Letter to PUB re prehearing conference Date: May 29, 2013	
6	PUB Board Order 67/13 Date: June 11, 2013	
7	Pimicikamak Review & Vary Application Date: June 25, 2013	
8	PUB letter to Manitoba Hydro re IEC access to Manitoba Hydro staff/ information Date: August 9, 2013	
9	PUB Board Order 91/13 Date: August 9, 2013	

LIST OF EXHIBITS (Con't)

EXHIBIT NO.	DESCRIPTION	PAGE NO.
10	PUB Board Order 92/13 Date: August 9, 2013	
11	Olthuis Kleer Townsend letter to FR re Order 91/13 Date: August 29, 2013	
12	Transcript of NFAT prehearing conference on September 4, 2013 Date: September 4, 2013	
13	Pimicikamak Notice of motion for leave to appeal Date: September 9, 2013	
14	Olthuis Kleer Townsend letter re Service of Notice of motion Date: September 9, 2013	
15	Affidavit of D. Paupanakis sworn September 25, 2013 Date: September 25, 2013	
16	PUB letter to Manitoba Hydro re NFAT motion day Date: September 26, 2013	
17	Transcript of Manitoba Hydro motion re round 1 IRs on September 30, 2013 Date: September 30, 2013	

LIST OF EXHIBITS (Con't)

EXHIBIT NO.	DESCRIPTION	PAGE NO.
18	PUB Board Order 119/13 Date: October 4, 2013	
19	PUB Board Order 126/13 Date: October 21, 2013	
20	PUB Board Order 127/13 Date: October 21, 2013	
21	PUB letter to Manitoba Hydro re internal load forecast Date: October 23, 2013	
22	PUB letter to Manitoba Hydro re scope of work for IECs Date: October 23, 2013	
23	PUB subpoena to Manitoba Hydro Date: October 29, 2013	
24	PUB/Manitoba Hydro round 1 Information Requests Date: November 2013 - 1 load forecast - 2 population and customer growth - 3 weather adjustment calculations - 4 weather adjustment calculations - 5 typical space and water heating costs	

LIST OF EXHIBITS (Con't)

EXHIBIT NO.	DESCRIPTION	PAGE NO.
PUB 24	- 6 top consumer/industry sector load growth	
	- 7 Mass Market consumers	
	- 8 MISO Exports	
	- 9 MISO Exports and Imports	
	-10 MISO Unit export revenues	
	-11 MISO Energy Resources	
	-12 MH Export revenues v. Exchange rate	
	-13 Natural Gas Supply Forecasts	
	-14 MISO Market Energy Demand Growth	
	-15 CCCT natural gas Generation vs. MISO Market Prices	
	-16 Transmission Constraints	
	-17 MISO market	
	-18 MISO & Other market activities	
	-19 MISO market	
	-20 MISO Market	
	-21 MISO market	
	-22 Export Energy/Energy Supply	
	-23 Dependable Hydraulic Energy Definition	
	-24 Alternative Power Resource Scenarios previously considered	

LIST OF EXHIBITS (Con't)

EXHIBIT NO.	DESCRIPTION	PAGE NO.
PUB 24	-25 thermal generation considerations	
	-26 Wind energy	
	-27 DSM energy	
	-28 Export contracts	
	-29 Export contracts	
	-30 Export contracts	
	-31 Export contracts	
	-32 Monthly hydraulic generation and river flows	
	-33 Annual System Flows/hydraulic generation net revenue	
	-34 Total Energy in Reservoir Storage	
	-35 Drought impacts and mitigation	
	-36 Progression of major G&T Project costs	
	-37 New generation incremental energy costs	
	-38 Wuskwatim cost escalation	
	-39 Wuskwatim component costs	
	-40 Keeyask and Conawapa cost escalation	
	-41 Transmission - HVDC peak demand levels	

LIST OF EXHIBITS (Con't)

EXHIBIT NO.	DESCRIPTION	PAGE NO.
PUB 24	-42 Transmission - HVDC functional Usage	
	-43 Greenhouse gas displacements in the MISO market	
	-44 On-peak and off-peak sales into MISO	
	-45 Greenhouse gas impacts	
	-46 Greenhouse gas impacts	
	-47 Minnesota-Manitoba Transmission line	
	-48 Minnesota-Manitoba Transmission line	
	-49 Minnesota-Manitoba Transmission line	
	-50 Minnesota-Manitoba Transmission line	
	-51 Minnesota-Manitoba Transmission line	
	-52 Financial forecasts	
	-53 Financial forecasts	
	-54 Financial forecasts	
	-55 Financial forecasts	
	-56 Financial forecasts Assumptions	

LIST OF EXHIBITS (Con't)

EXHIBIT NO.	DESCRIPTION	PAGE NO.
PUB 24	-57 Financial forecasts Assumptions	
	-58 Financial forecasts Assumptions	
	-59 Export price forecasts	
	-60 KPMG report	
	-61 Financial forecasts	
	-62 In-service revenue requirement	
	-63 JKDA	
	-64 JKDA	
	-65 Interest rate forecasting methodology	
	-66 Interest rate risk	
	-67 Risk Analysis comparison	
	-68 RWACC	
	-69 ICF report	
	-70 ICF report	
	-71 ICF report	
	-72 ICF report	
	-73 Payments to governments	
	-74 Wuskwatim	
	-75 In-service revenue requirement	
	-76 In-service revenue requirment	
	-77 Wuskwatim	
	-78 JKDA	

LIST OF EXHIBITS (Con't)

EXHIBIT NO.	DESCRIPTION	PAGE NO.
PUB 24	-79 IRR	
	-80 In-service delay cost consequenes	
	-81 Finance expense	
	-82 Internally generated funds	
	-83 Financial forecasts	
	-84 Credit rating	
	-85 Credit rating	
	-86 Financial targets	
	-87 Financial targets	
	-88 Financial targets	
	-89 Debt management	
	-90 Financial targets	
	-91 Debt management	
	-92 Socio-economic	
	-93 Socio-economic	
	-94 Socio-economic	
	-95 DSM	
	-96 DSM	
	-97 DSM	
	-98 Avoided cost estimates	
	-99 Avoided cost estimates	
	-100 DSM	
	-101 DSM	

LIST OF EXHIBITS (Con't)

EXHIBIT NO.	DESCRIPTION	PAGE NO.
-102	Load forecast	
-103	New transmission inter-connections	
-104	New generation - resource option	
-105	HVDC transmission issues	
-106	Capital expenditures K19/Sales/ C25/750 assets values	
-107	In-service revenue requirement Calculation	
-108	In-service revenue requirements	
-109		
-110	All gas scenarios	
-111	All gas scenario CCGT only	
-112	Wuskwatim cost escalation	
-113	Cost forecasts for Conawapa G.S.	
-114	NFAT base case - all gas scenarios	
-115	NFAT base case - all SCGT costs	
-116	Keeyask/Conawapa scenarios	
-117	Keeyask/Conawapa scenarios	
-118	Natural gas/Conawapa scenarios	
-119	Natural gas	
-120	K19/gas/250 MW Scenario	
-121	All gas scenario	
-122	All CCGT gas scenario	

LIST OF EXHIBITS (Con't)

EXHIBIT NO.	DESCRIPTION	PAGE NO.
PUB 24	-123 Import availability	
	-124 Export contract	
	-125 Project management	
	-126 Project management	
	-127 Project management	
	-128 Project management	
	-129 Project management	
	-130 Project management	
	-131 Transmission	
	-132 Transmission	
	-133 Transmission	
	-134 MISO	
	-135 Transmission	
	-136 Load Growth	
	-137 Environmental impacts	
	-138 Environmental impacts	
	-139 Export markets	
	-140 Export markets	
	-141 Transmission	
	-142 Transmission	
	-143 Transmission	
	-144 Transmission	
	-145 Transmission	

LIST OF EXHIBITS (Con't)

EXHIBIT NO.	DESCRIPTION	PAGE NO.
PUB 24	-146 Capital costs	
	-147 Capital cost comparisons	
	-148 Net revenue comparison	
	-149 Ratepayer impacts	
	-150 Ratepayer impacts	
	-151 IRR analysis	
	-152	
	-153 Economic evaluation	
	-154 Study period	
	-155 Study life	
	-156 RWACC	
	-157 Export price forecasts	
	-158 Export price forecasts	
	-159 Export prices	
	-160 Export prices	
	-161 Export prices	
	-162 Export prices	
	-163 Economic variables	
	-164 Economic variables	
	-165 Economic variables	
	-166 Economic variables	
	-167 Economic variables	
	-168 Economic variables	

LIST OF EXHIBITS (Con't)

EXHIBIT NO.	DESCRIPTION	PAGE NO.
PUB 24	-169 Economic variables	
	-170 Economic evaluation	
	-171 Economic evaluation	
	-172 NPV	
	-173 Discount	
	-174 NPV	
	-175 NPV	
	-176 Economic Uncertainty	
	-177 Economic uncertainty	
	-178 Economic uncertainty	
	-179 Transmission	
	-180 Probabilistic analysis	
	-181 Carbon/GHG emissions	
	-182 Capital cost	
	-183 Export revenues; rate revenues	
	-184 Export revenues; rate revenues	
	-185 Export revenues; rate revenues	
	-186 Economic uncertainty	
	-187 Export markets	
	-188 Export contract	
	-189 Minnesota-Manitoba transmission line	

LIST OF EXHIBITS (Con't)

EXHIBIT NO.	DESCRIPTION	PAGE NO.
PUB 24	-190 Minnesota-Manitoba transmission line	
	-191 Minnesota-Manitoba transmission line	
	-192 Transmission reliability	
	-193 Access (Transmission)	
	-194 Drought (risk)	
	-195 Climate change	
	-196 Sturgeon	
	-197 Sunk costs	
	-198 Rate impacts	
	-199 Combined Cycle construction turbine	
	-200 Debt-equity ratio	
	-201 Debt-equity ratio	
	-202 Debt-equity ratio	
	-203 Debt-equity ratio	
	-204 Debt-equity ratio	
	-205 Drought (risk)	
	-206 Drought (risk)	
	-207 Rate impacts	
	-208 RWACC	
	-209 Economic evaluation	

LIST OF EXHIBITS (Con't)

EXHIBIT NO.	DESCRIPTION	PAGE NO.
PUB 24	-210 DSM	
	-211 DSM	
	-212 DSM; GHG	
	-213 DSM	
	-214 DSM	
	-215 DSM	
	-216 DSM	
	-217 Export markets	
	-218 Export contract	
	-219 Minnesota-Manitoba transmission line	
	-220 Minnesota-Manitoba transmission line	
	-221 Minnesota-Manitoba transmission line	
	-222 Transmission reliability	
	-223 Access (transmission)	
	-224 Economic impacts	
	-225 Economic impacts	
	-226 Economic impacts	
	-227 Economic impacts	
	-228 Economic impacts	
	-229 Economic impacts	

LIST OF EXHIBITS (Con't)

EXHIBIT NO.	DESCRIPTION	PAGE NO.
PUB 24	-230 Conclusions	
	-231 Conclusions	
	-232 Ratepayer impacts	
	-233 Ratepayer impacts	
	-234 Ratepayer impacts	
	-235 Export Price Forecasts	
	-236 Export Price Forecasts	
	-237 Export Price Forecasts	
	-238 Conawapa	
	-239 NPV	
	-240 NPV	
	-241 NPV	
	-242 NPV	
	-243 Ratepayer impacts	
	-244 Project benefits	
	-245 Project benefits	
	-246 Project benefits	
	-247 DSM	
	-248 DSM	
	-249 DSM	
	-250 Load Forecast -251 Load Forecast	
	-252 Load Forecast -253 Load Forecast	
	-254 Load Forecast -255 Load Forecast	

LIST OF EXHIBITS (Con't)

EXHIBIT NO.	DESCRIPTION	PAGE NO.
PUB 24	-256 Load Forecast -257 Load Forecast	
	-258 Load Forecast -259 Load Forecast	
	-260 Economic outlook	
	-261 DSM	
	-262 DSM	
	-263 DSM	
	-264 DSM	
	-265 DSM	
	-266 DSM	
	-267	
	-278	
	-269	
	-270	
	-271	
	-272	
	-273	
	-274	
	-275	
	-276	
	-277 Emerging technologies	
	-278 Load forecast	
	-279 Conclusions	
	-280 Export contracts	

LIST OF EXHIBITS (Con't)

EXHIBIT NO.	DESCRIPTION	PAGE NO.
PUB 24	-281 Export contracts	
	-282 Export contracts	
	-283 Export contracts	
	-284 Export contracts	
	-285 Export contracts	
	-286 MISO	
	-287 Export Volumes	
	-288 Export Contracts	
	-289 Export Contracts	
	-290 Export Constraints	
	-291 Export Volumes & Revenues	
	-292 Partnership agreements	
	-293	
	-294	
	-295 Export Prices	
	-296 Export Prices	
	-297	
	-298	
	-299	
	-300 Capacity pricing	
	-301	
	-302 Carbon pricing	
	-303	

LIST OF EXHIBITS (Con't)

EXHIBIT NO.	DESCRIPTION	PAGE NO.
PUB 24	-304	
	-305 Average export prices	
	-306 Carbon pricing	
	-307 MISO	
	-308 Export price forecasts	
	-309	
	-310 Capacity price	
	-311	
	-312 Export price forecasts	
	-313 Export price forecasts	
	-314	
	-315	
	-316 Export Contracts	
	-317 Export Contracts	
	-318 Export contracts	
	-319 Export Contracts	
	-320	
	-321 Export contracts	
	-322	
	-323 Export contracts	
	-324 Export contracts	
	-325 Export contracts	
	-326 Export contracts	

LIST OF EXHIBITS (Con't)

EXHIBIT NO.	DESCRIPTION	PAGE NO.
PUB 24	-327 Transmission	
	-328 Transmission	
	-329	
	-330 Transmission	
	-331 Transmission	
	-332 Transmission	
	-333 Round 1 Information Requests	
	-334 Export contracts	
	-335	
	-336 Export contracts	
	-337 Access (Transmission)	
	-338 Access (Transmission)	
	-339 Access (Transmission)	
	-340 Export contracts	
	-341	
	-342	
	-343	
	-344	
	-345 Aggregated Export Revenues	
	-346	
	-347 Export pricing	
	-348 Energy values	
	-349 Round 1 Information Requests	

LIST OF EXHIBITS (Con't)

EXHIBIT NO.	DESCRIPTION	PAGE NO.
PUB 24	-350 Internal Load Forecast	
	-351 Internal Load Forecast	
	-352 Internal Load Forecast	
	-353 Internal Load Forecast	
	-354 Internal Load Forecast	
	-355 Internal Load Forecast	
	-356 Internal Load Forecast	
	-357 Internal Load Forecast	
	-358 Internal Load Forecast	
	-359 Export revenue	
	-360 Load Forecast	
	-361 Export revenue	
	-362 Load forecast	
	-363 Load forecast	
	-364 Load forecast	
	-365 Load forecast	
	-366 Load forecast	
	-367 Load forecast	
	-368 The need for new resources	
	-369 The need for new resources	
	-370 Wind Energy	
	-371 Wind energy	
	-372 Export revenue	

LIST OF EXHIBITS (Con't)

EXHIBIT NO.	DESCRIPTION	PAGE NO.
PUB 24	-373 Capital expenditures	
	-374 Capital expenditures	
	-375 Carbon	
	-376 Carbon	
	-377 Financial forecast	
	-378 Financial forecast	
	-379 Electricity prices	
	-380 Electricity prices	
	-381 WACC	
	-382 Capital	
	-383 Capital	
	-384 Corporate Finance	
	-385 Corporate finance	
	-386 Financial targets	
	-387 Long term debt	
	-388 Corporate finance	
	-389 Sunk costs	
	-390 Sunk costs	
	-391 NPV	
	-392 DSM	
	-393 DSM	
	-394 NPV	
	-395 Purchased wind energy	

LIST OF EXHIBITS (Con't)

EXHIBIT NO.	DESCRIPTION	PAGE NO.
PUB 24	-396 Wind storage service	
	-397 Declining drought impacts 2009 v. 2011	
	-398 New revenue requirements	
	-399 Drought risk mitigation - PDP	
	-400 CEF 13 Capital forecasts	
	-401 Export revenue	
	-402 System transmission losses	
	-403 US off-peak sales	
	-404 Dependable energy unit costs	
	-405 Power resource alternative	
	-406 Ratepayer impacts	
	-407 Export revenue calculations	
	-408 Power resource alternative	
	-409 Keeyask partnership revenue	
	-410 Keeyask G.S. startup	
	-411 Financial situation	
	-412 Marginal or avoided cost	
	-413 Marginal value of Power Smart Plan	
	-414 Marginal value of Power Smart Plan	
	-415 Enhanced export capabilities	
	-416 HVDC system operation	

LIST OF EXHIBITS (Con't)

EXHIBIT NO.	DESCRIPTION	PAGE NO.
PUB 24	-417 Incremental in-service revenue requirements	
	-418 Future value of sunk costs	
	-419 Cost of deferrals	
	-420 Economic variables	
	-421 Capital constructions costs	
	-422 Residual value	
	-423 Macro-economic	
	-424 Ratepayer impacts	
	-425 Ratepayer impacts	
	-426 Internal rate of return	
	-427 Ratepayer impacts	
	-428 Internal rate of return	
	-429 Internal rate of return	
	-430 Risk	
	-431 Export price forecasts	
	-432 Ratepayer impacts	
	-433 Transmission	
	-434 Sunk costs	
	-435 Sunk costs	
	-436 Socio-economic	
	-437 Payments to government	
	-438 Payments to government	

LIST OF EXHIBITS (Con't)

EXHIBIT NO.	DESCRIPTION	PAGE NO.
PUB 24	-439 Payments to government	
	-440 Socio-economic	
	-441 Economic outlook	
	-442 Joint Keeyask development agreement	
	-443 DSM screening marginal cost	
	-444 Net present value	
	-445 First Nations	
	-446 Capital costs	
	-447 Capital costs	
	-448 Capital costs	
	-449 Capital costs	
	-450 Transmission	
	-451 First Nations	
	-452 First Nations	
	-453 First Nations	
	-454 Export Revenues	
	-455 Bond yields	
	-456 Economic evaluation	
	-457 Load forecasts/Top consumers	
	-458 Lake Winnipeg license constraints	
	-459 Watershed flows - useful for hydraulic generation	

LIST OF EXHIBITS (Con't)

EXHIBIT NO.	DESCRIPTION	PAGE NO.
PUB 24	-460 Power resource alternative evaluation	
	-461 Export revenue assumptions in revenue requirements	
	-462 Additional revenue rates	
	-463 Export price forecasts	
	-464 Load forecasts	
	-465 Load forecasts	
	-466 MISO export price forecasts/CO2 adders	
	-467 Peak period energy prices in MISO	
	-468 MH's export price forecasts	
	-469 MISO renewables	
	-470 MISO Contract implications	
	-471 MISO market	
	-472 MISO & other market activitities	
	-473 MISO market	
	-474 MISO exports	
	-475 MISO power prices	
	-476 MISO typical space & water heater costs	
	-477 Fuel switching	

LIST OF EXHIBITS (Con't)

EXHIBIT NO.	DESCRIPTION	PAGE NO.
PUB 24	-478 Industry sector load growth history/forecasts (Gwh/yr)	
	-479 Top consumers	
	-480 Industrial load growth since 2004/08	
	-481 Power resource alternative	
	-482 Ratepayer impacts	
	-483 Power resource alternative	
	-484 CCGT/C 26 Scenario Project cost	
	-485 K19/C25/250 MW and K19/C25/750 MW export revenues vs. Water rentals/ F&PP	
	-486 Capital expenditures	
	-487 Drought	
	-488 $100M Power sale to SaskPower	
	-489 Access (Transmission)	
	-490 Access (Transmission)	
	-491 Minnesota-Manitoba Transmission line	
	-492 Transmission reliability	
	-493 Lake Winnipeg operations	
	-494 Upper Nelson flows	
	-495 Wind Energy availability	

LIST OF EXHIBITS (Con't)

EXHIBIT NO.	DESCRIPTION	PAGE NO.
PUB 24	-496 Manitoba Hydro/Minnesta Power Wind Energy Exchange	
	-497 Electric heating load	
	-498 CCGT/SCGT	
	-499 First Nations	
	-500 Transmission	
	-501 Economic evaluation	
	-502 Discount rate	
	-503 Discount rate	
	-504 Base Capital expenditures	
	-505 Capital expenditures	
	-506 Transmission	
	-507 Ratepayer impacts	
	-508 Ratepayer impacts	
	-509 Internal load forecast	
	-510 Internal load forecast	
	-511 Internal load forecast	
	-512 Internal load forecast	
	-513 Internal load forecast	
	-514	
	-515 Internal load forecast	
	-516 Internal load forecast	
	-517	

LIST OF EXHIBITS (Con't)

EXHIBIT NO.	DESCRIPTION	PAGE NO.
PUB 24	-518 Internal Load forecast	
	-519 Internal load forecast	
	-520 Internal load forecast	
PUB 25	PUB letter to Manitoba Hydro re internal load forecast Date: November 29, 2013	
PUB 26	PUB letter to Hill re extension of IEC reports Date: December 23, 2013	
PUB 27	PUB letter to Manitoba Hydro re Manitoba Hydro letter to PUB December 13, 2013 Date: December 24, 2013	
PUB 28	PUB letter to Manitoba Hydro re IEC budget increases Date: Dec. 27, 2013	
PUB 29	PUB/Manitoba Hydro Round 2 Information Requests Date: January 2014	
PUB 30	PUB letter to Manitoba Hydro re IR Responses Date: January 9, 2014	
PUB 31	PUB letter to Manitoba Hydro re approved scope of work for Knight Piesold Date: January 13, 2014	
PUB 32	1 - PUB letter to Manitoba Hydro to revised pre-hearing timetable 2 - Revised Timetable Date: Jan 15,2013	

LIST OF EXHIBITS (Con't)

EXHIBIT NO.	DESCRIPTION	PAGE NO.
PUB 33	PUB letter to MIPUG re budget increase for Public sector finance expert Date: January 23, 2014	
PUB 34	PUB letter to MKO to request to expand scope of intervention Date: January 27, 2014	
PUB 35	PUB letter to R. Roddick and D'Arcy & Deacon LLP re socio-economic considerations Date: January 28, 2014	
PUB 36	PUB letter to MMF re budget increase Date: February 5, 2014	
PUB 37	PUB letter to MKO re request to expand scope of intervention Date: February 5, 2014	
PUB 38	PUB letter to CAC/MMF re joint proposal Date: February 7, 2014	
PUB 39	PUB letter to CAC to socio-economic evidence Date: February 7, 2014	
PUB 40	PUB/La Capra Information Requests Date: February 20, 2014	
	-1 Internal Expert Analysis Report	
	-2 Internal Expert Analysis Report	
	-3 Internal Expert Analysis Report	

LIST OF EXHIBITS (Con't)

EXHIBIT NO.	DESCRIPTION	PAGE NO.
PUB 40	-4 Internal Expert Analysis Report	
	-5 Internal Expert Analysis Report	
	-6 Internal Expert Analysis Report	
	-7 Internal Expert Analysis Report	
	-8 Internal Expert Analysis Report	
	-9 Internal Expert Analysis Report	
	-10 Internal Expert Analysis Report	
	-11 Internal Expert Analysis Report	
	-12 Internal Expert Analysis Report	
	-13 Internal Expert Analysis Report	
	-14 Resource Planning	
	-15 Resource Planning	
	-16 Resource Planning	
	-17 Resource Planning	
	-18 Resource Planning	
	-19 Resource Planning	
	-20 Resource Planning	
	-21 Resource Planning	
	-22 Resource Planning	
	-23 Resource Planning	
	-24 Resource Planning	
	-25 Resource Planning	
	-26 Resource Planning	

LIST OF EXHIBITS (Con't)

EXHIBIT NO.	DESCRIPTION	PAGE NO.
PUB 40	-27 Resource Planning	
	-28 Resource Planning	
	-29 Resource Planning	
	-30 Resource Planning	
	-31 Generation Alternatives	
	-32 Generation Alternatives	
	-33 Generation Alternatives	
	-34 Generation Alternatives	
	-35 Generation Alternatives	
	-36 Generation Alternatives	
	-37 Generation Alternatives	
	-38 Generation Alternatives	
	-39 Generation Alternatives	
	-40 Generation Alternatives	
	-41 Generation Alternatives	
	-42 Generation Alternatives	
	-43 Generation Alternatives	
	-44 Generation Alternatives	
	-45 Generation Alternatives	
	-46 Generation Alternatives	
	-47 Resource Plans	
	-48 Resource Plans	
	-49 Resource Plans	

LIST OF EXHIBITS (Con't)

EXHIBIT NO.	DESCRIPTION	PAGE NO.
PUB 40	-50 Resource Plans	
	-51 Resource Plans	
	-52 Resource Plans	
	-53 Resource Plans	
	-54 Resource Plans	
	-55 Resource Plans	
	-56 Resource Plans	
	-57 Resource Plans	
	-58 Resource Plans	
	-59 Resource Plans	
	-60 Environment	
	-61 Environment	
	-62 Environment	
	-63 Environment	
	-64 Environment	
	-65 Environment	
	-66 Environment	
	-67 Environment	
	-68 Export Contracts	
	-69 Export Contracts	
	-70 Export Contracts	
	-71 Transmission	
	-72 Transmission	

LIST OF EXHIBITS (Con't)

EXHIBIT NO.	DESCRIPTION	PAGE NO.
PUB 40	-73 Transmission	
	-74 Transmission	
	-75 Transmission	
	-76 Transmission	
	-77 Transmission	
	-78 Transmission	
	-79 Economic Analysis	
	-80 Economic Analysis	
	-81 Economic Analysis	
	-82 Economic Analysis	
	-83 Economic Analysis	
	-84 Economic Analysis	
	-85 Economic Analysis	
	-86 Economic Analysis	
	-87 Economic Analysis	
	-88 Economic Analysis	
	-89 Economic Analysis	
	-90 Economic Analysis	
	-91 Economic Analysis	
	-92 Economic Analysis	
	-93 Economic Analysis	
	-94 Economic Analysis	
	-95 Export market	

LIST OF EXHIBITS (Con't)

EXHIBIT NO.	DESCRIPTION	PAGE NO.
PUB 40	-96 Economic analysis	
	-97 Projections	
PUB 41	PUB/Elenchus Information Requests	
	Date: February 20, 2014	
	-1 Load Forecast	
	-2 Load Forecast	
	-3 Load Forecast	
	-4 Load Forecast	
	-5 Load Forecast	
	-6 Load Forecast	
	-7 Load Forecast	
	-8 Load Forecast	
	-9 Load Forecast	
	-10 Load Forecast	
	-11 Load Forecast	
	-12 Load Forecast	
	-13 Load Forecast	
	-14 Load Forecast	
	-15 Load Forecast	
	-16 Load Forecast	
	-17 Load Forecast	
	-18 Load Forecast	
	-19 Load Forecast	

LIST OF EXHIBITS (Con't)

EXHIBIT NO.	DESCRIPTION	PAGE NO.
PUR 41	-20 Load Forecast	
	-21 Load Forecast	
	-22 Load Forecast	
	-23 Load Forecast	
	-24 Load Forecast	
	-25 Load Forecast	
	-26 Load Forecast	
	-27 DSM	
	-28 DSM	
	-29 DSM	
	-30 DSM	
	-31 DSM	
	-32 DSM	
	-33 DSM	
	-34 DSM	
	-35 DSM	
	-36 DSM	
	-37 DSM	
	-38 DSM	
PUB 42	PUB/Knight Piesold Information Requests	
	Date: February 20, 2014	
	-1 Capital Cost	
	-2 Capital Cost	

LIST OF EXHIBITS (Con't)

EXHIBIT NO.	DESCRIPTION	PAGE NO.
PUB 42	-3 Capital Cost	
	-4 Capital Cost	
	-5 Capital Cost	
	-6 Capital Cost	
	-7 Capital Cost	
	-8 Capital Cost	
	-9 Capital Cost	
	-10 Capital Cost	
	-11 Capital Cost	
	-12 Capital Cost	
	-13 Capital Cost	
	-14 Capital Cost	
	-15 Capital Cost	
	-16 Capital Cost	
	-17 Capital Cost	
	-18 Capital Cost	
	-19 Capital Cost	
	-20 Capital Cost	
	-21 Capital Cost	
	-22 Capital Cost	
	-23 Capital Cost	
	-24	
	-25	

LIST OF EXHIBITS (Con't)

EXHIBIT NO.	DESCRIPTION	PAGE NO.
PUB 42	-26	
	-27	
	-28	
	-29	
	-30	
	-31 Capital Cost	
	-32 Capital Cost	
	-33 Capital Cost	
	-34 Capital Cost	
	-35 Capital Cost	
	-36 Capital Cost	
	-37 Capital Cost	
PUB 43	PUB/MNP Information Requests	
	Date: February 20, 2014	
	-1 Macro-environmental	
	-2 Macro-environmental	
	-3 Macro-environmental	
	-4 Macro-environmental	
	-5 Macro-environmental	
	-6 Macro-environmental	
	-7 Macro-environmental	
	-8 Macro-environmental	
	-9 Macro-environmental	

LIST OF EXHIBITS (Con't)

EXHIBIT NO.	DESCRIPTION	PAGE NO.
PUB 43	-10 Macro-environmental	
	-11 Macro-environmental	
	-12 Macro-environmental	
	-13 Macro-environmental	
	-14 Macro-environmental	
	-15 Macro-environmental	
	-16 Macro-environmental	
	-17 Macro-environmental	
	-18 Macro-environmental	
	-19 Macro-environmental	
	-20 Macro-environmental	
	-21 Macro-environmental	
	-22 Macro-environmental	
	-23 Macro-environmental	
	-24 Macro-environmental	
	-25 Macro-environmental	
	-26 Macro-environmental	
	-27 Macro-environmental	
	-28 Macro-environmental	
	-29 Macro-environmental	
	-30 Macro-environmental	
	-31 Macro-environmental	
	-32 Macro-environmental	

LIST OF EXHIBITS (Con't)

EXHIBIT NO.	DESCRIPTION	PAGE NO.
PUB 43	-33 Macro-environmental	
	-34 Macro-environmental	
	-35 Macro-environmental	
	-36 Macro-environmental	
	-37 Macro-environmental	
	-38 Macro-environmental	
	-39 Macro-environmental	
	-40 Macro-environmental	
	-41 Macro-environmental	
	-42 Macro-environmental	
	-43 Macro-environmental	
PUB 44	PUB/Morrison Park Advisors Information	
	Requests Date: February 20, 2014	
	-1 Plan Evaluation	
	-2 Plan Evaluation	
	-3 Exports & Imports	
	-4 Exports & Imports	
	-5 Manitoba Demand	
	-6 Resource Options	
	-7 Government impacts	
	-8 Resource Options	
	-9 Resource Options	
	-10 Ratepayer impacts	

LIST OF EXHIBITS (Con't)

EXHIBIT NO.	DESCRIPTION	PAGE NO.
PUB 44	-11 Demand	
	-12 Exports & imports	
	-13 Construction costs	
	-14 Ratepayer impacts	
	-15 Ratepayer impacts	
	-16 Ratepayer impacts	
	-17 Ratepayer impacts	
	-18 Cost of Capital	
	-19 Ratepayer impacts	
	-20 Ratepayer impacts	
	-21 Ratepayer impacts	
	-22 Exports	
	-23 Exports	
	-24 Exports	
	-25 Exports	
	-26 Exports & imports	
	-27 Magnitude of Distress	
	-28 Magnitude of Distress	
	-29 Cost of Capital	
	-30 Cost of Capital	
	-31 Cost of Capital	
	-32 Cost of Capital	
	-33 Manitoba Hydro Distress	

LIST OF EXHIBITS (Con't)

EXHIBIT NO.	DESCRIPTION	PAGE NO.
PUB 44	-34 Government impacts	
	-35 Plan evaluation	
PUB 45	PUB/Power Engineers Information Requests Date: February 20, 2014	
	-1 Transmission	
	-2 Transmission	
	-3 Transmission	
	-4 Transmission	
	-5 Transmission	
	-6 Transmission	
	-7 Transmission	
	-8 Transmission	
	-9 Transmission	
PUB 46	PUB/Potomac Economics Information Requests Date: February 20, 2014	
	-1 MISO	
	-2 MISO	
	-3 MISO	
	-4 MISO	
	-5 MISO	
	-6	
	-7	

LIST OF EXHIBITS (Con't)

EXHIBIT NO.	DESCRIPTION	PAGE NO.
PUB 46	-8	
	-9	
	-10	
	-11	
	-12	
	-13	
	-14 MISO	
	-15 MISO	
	-16 MISO	
PUB 47	PUB/Typlan Information Requests	
	Date: February 20, 2014	
	-1 Socio-Economic	
	-2 Socio-Economic	
	-3 Socio-Economic	
	-4 Socio-Economic	
	-5 Socio-Economic	
	-6 Socio-Economic	
	-7 Socio-Economic	
	-8 Socio-Economic	
	-9 Socio-Economic	
	-10 Socio-Economic	
	-11 Socio-Economic	
	-12 Socio-Economic	

LIST OF EXHIBITS (Con't)

EXHIBIT NO.	DESCRIPTION	PAGE NO.
PUB 47	-13 Socio-Economic	
	-14 Socio-Economic	
	-15 Socio-Economic	
	-16 Socio-Economic	
	-17 Socio-Economic	
	-18 Socio-Economic	
	-19 Socio-Economic	
	-20 Socio-Economic	
	-21 Socio-Economic	
	-22 Socio-Economic	
PUB 48	PUB/CAC Information Requests - Gunn/ Olanguju Date: February 20, 2014	
	-1 Macro-Environmental	
	-2 Macro-Environmental	
	-3 Macro-Environmental	
	-4 Macro-Environmental	
	-5 Macro-Environmental	
	-6 Macro-Environmental	
	-7 Macro-Environmental	
	-8 Macro-Environmental	
	-9 Macro-Environmental	
	-10 Macro-Environmental	
	-11 Macro-Environmental	

LIST OF EXHIBITS (Con't)

EXHIBIT NO.	DESCRIPTION	PAGE NO.
	-12 Macro-Environmental	
	-13 Macro-Environmental	
	-14 Macro-Environmental	
	-15 Macro-Environmental	
PUB 49	PUB/CAC Information Requests - Simpson/ Gotham Date: February 20, 2014	
	-1 Load Forecast	
	-2 Load Forecast	
	-3 Load Forecast	
	-4 Load Forecast	
	-5 Load Forecast	
	-6 Load Forecast	
	-7 Load Forecast	
	-8 Load Forecast	
	-9 Load Forecast	
	-10 Load Forecast	
	-11 Load Forecast	
PUB 50	PUB/CAC Information Requests - Gibson/ Gaudreau Date: February 20, 2014	
	-1 Sustainability	
	-2 Sustainability	
	-3 Sustainability	
	-4 Sustainability	

LIST OF EXHIBITS (Con't)

EXHIBIT NO.	DESCRIPTION	PAGE NO.
	-5 Sustainability	
	-6 Sustainability	
PUB 51	PUB/CAC Information Requests - Dunsky	
	Date: February 20, 2014	
	-1 DSM	
	-2 DSM	
	-3 DSM	
	-4 DSM	
	-5 DSM	
	-6 DSM	
	-7 DSM	
	-8 DSM	
	-9 DSM	
	-10 DSM	
	-11 DSM	
	-12 DSM	
	-13 DSM	
	-14 DSM	
	-15 DSM	
	-16 DSM	
PUB 52	PUB/GAC Information Requests	
	Date: February 20, 2014	
	-1 Fuel Switching	

LIST OF EXHIBITS (Con't)

EXHIBIT NO.	DESCRIPTION	PAGE NO.
PUB 52	-2 Fuel Switching	
	-3 Fuel Switching	
	-4 Fuel Switching	
	-5 Fuel Switching	
	-6 DSM	
	-7 DSM	
	-8 DSM	
	-9 Wind Integration	
	-10 Wind Integration	
	-11 Wind Integration	
	-12 Wind Integration	
	-13 Wind Integration	
	-14 Wind Integration	
	-15 Wind Integration	
	-16 Wind Integration	
	-17 Wind Integration	
	-18 Wind Integration	
	-19 Wind Integration	
	-20 Wind Integration	
	-21 Wind Integration	
PUB 53	PUB/MIPUG Information Requests	
	Date: February 20, 2014	
	-1 Time Frame	

LIST OF EXHIBITS (Con't)

EXHIBIT NO.	DESCRIPTION	PAGE NO.
PUB 53	-2 Rate Increases	
	-3 Load Forecast	
	-4 Sunk Costs	
	-5 NPV	
	-6 Discount Rate	
	-7 Export Prices; Capital Costs	
	-8 Discount Rate	
	-9 Export prices; capital costs	
	-10 Economic Conditions	
	-11 Conawapa	
	-12 DSM	
	-13 DSM	
PUB 54	PUB/MKO Information Requests	
	Date: February 20, 2014	
	-1 Socio-Economic	
	-2 Socio-Economic	
	-3 Socio-Economic	
	-4 Socio-Economic	
	-5 Socio-Economic	
	-6 Socio-Economic	
	-7 Socio-Economic	
	-8 Socio-Economic	
	-9 Socio-Economic	

LIST OF EXHIBITS (Con't)

EXHIBIT NO.	DESCRIPTION	PAGE NO.
PUB 54	-10 Socio-Economic	
	-11 Socio-Economic	
PUB 55	PUB Letter to MKO re Budgets and Request for counsel Date: February 20, 2014	
PUB 56	PUB letter to parties re socio-economic matters Date: February 20, 2014	
PUB 57	PUB letter to Manitoba Hydro and IEC counsel re Cross-Examination by IEC counsel	
PUB 58	PUB Board Counsel Book of Documents -1 Vol 1 to be referenced in questions of Manitoba Hydro's president and CEO Mr. Thomson -2 Manitoba Hydro's load forecast & DSM Panel	
PUB-58-2	Board counsel book of documents	375
PUB-59	Chart prepared by PUB advisors	376
PUB-60	Information Requests from the PUB to CAC's witness, Mr. Gotham	376
PUB-61	PUB's Information Requests to CAC's witness Mr. Harper	376

LIST OF EXHIBITS (Con't)

EXHIBIT NO.	DESCRIPTION	PAGE NO.
MH-87	PUB presentation on load forecast and DSM	377
CAC-44	PowerPoint Presentation of Opening Statement of CAC (Manitoba)	466
MMF-28	MMF Book of documents Volume I	467

UNDERTAKINGS

No.	Description	Page No.
7	Manitoba Hydro to provide a calculation on page 33 of the Board's book of documents Volume II based on a success rate of the fuel switching initiative	551
8	Manitoba Hydro to provide an order magnitude for average degree-day cooling adjustment per year in the load forecast	568
9	Manitoba Hydro to explain: a) attribution of 600 additional gigawatt hours per year to domestic losses; and b) whether this is because of longer transmission lines or whether incremental export losses are attributed to domestic demand	600
10	Manitoba Hydro to indicate an estimated time for financials to be filed	625

UNDERTAKINGS (Con't)

No.	Description	Page No.
11	Manitoba Hydro to indicate when the plans on page 15 of Mr. Wojczynski's presentation, and financials for the five (5) plans will be filed	627
12	Manitoba Hydro to confirm assumptions going into DSM analysis	635

-- Upon commencing at 9:10 a.m.

THE CHAIRPERSON: Good morning. I believe we're ready to start. So we apologize for the technical glitches, but -- so, good morning. This isI -- we -- second day of the -- the hearing process. And I turn the microphone over to Mr. Hombach.

MR. SVEN HOMBACH: Yes. Good morning, Mr. Chairman, good morning members of the Board, and good morning to the Manitoba Hydro panel and all the Intervenors in the room. Today is reserved for Manitoba Hydro's presentation on load forecast and DSM, and cross-examination by Board counsel.

But before we go ahead with Manitoba Hydro's presentation, there are a few housekeeping matters. The Public Utilities Board has a few exhibits it would like introduced.

Firstly, I filed a book of documents of Board counsel that should be Exhibit 58-2. Manitoba Hydro should have electronic copies of it. The panel should have paper copies in front of it. If anybody else would like a paper copy, I have a few spares but not enough for everybody in the room.

--- EXHIBIT NO. PUB-58-2: Board counsel book of

documents

MR. SVEN HOMBACH: The second exhibit is Exhibit 59. That is a chart prepared by PUB advisors that was circulated yesterday evening.

--- EXHIBIT NO. PUB-59: Chart prepared by PUB advisors

MR. SVEN HOMBACH: Exhibit 60 should be the Information Requests from the PUB to CAC's witness Mr. Gotham.

--- EXHIBIT NO. PUB-60: Information Requests from the PUB to CAC's witness, Mr. Gotham

MR. SVEN HOMBACH: Exhibit 61 should be the PUB's Information Requests to CAC's witness Mr. Harper.

--- EXHIBIT NO. PUB-61: PUB's Information Requests to CAC's witness Mr. Harper

MR. SVEN HOMBACH: Now, do any of the other parties have exhibits this morning that they'd like to see introduced?

MS. MARLA BOYD: I will be introducing exhibits in connection with this panel. I can also confirm the exhibit number from the presentation that was filed yesterday, if this is the appropriate time to do that.

MR. SVEN HOMBACH: Yes, please.

MS. MARLA BOYD: Exhibit number 86 was the tentative number given to the presentation yesterday by Mr. Wojczynski, so I've confirmed that number now with Mr. Singh this morning. And I can also ask that the presentation that's been circulating for the load forecast and DSM panel be marked as Exhibit number 87.

--- EXHIBIT NO. MH-87: PUB presentation on load forecast and DSM

MR. BYRON WILLIAMS: Mr. Chair, Byron Williams here. We will be getting the appropriate number for our PowerPoint and ask at the break. We'll provide our advice after that and the exhibit number that should be assigned.

MR. SVEN HOMBACH: Mr. Chairman, I now suggest that the panel call upon Manitoba Hydro to deliver its presentation.

THE CHAIRPERSON: Good morning, Ms. Boyd. I turn it over -- back to you.

MS. MARLA BOYD: Thank you. Good morning. Good morning, Mr. Chair, Board members Kapitany, Bel, Grant, and Soldier. My name is Marla Boyd, and I'm pleased to present to you this morning the load forecast and DSM panel.

By way of introduction, we have a little bit of juggling because Mr. Wojczynski is part of this panel and is seated in the second row, so you may hear the odd voice from the wilderness. Mr. Wojczynski was introduced to you yesterday and is still sworn after yesterday.

To my immediate left is Mr. Dale Friesen, who's the division manager of Industrial and Commercial Solutions. Next to him is Mr. Lloyd Kuczek, vice president, of Customer Care and Energy Conservation. Next to Mr. Kuczek is Ms. Ingrid Rohmu -- Rohmund. She's the director of Energy Analysis and Planning for EnerNOC Inc. Next to her is Ms. Lois Morrison. She is the division manager of Consumer Marketing and Sales. And finally, Mr. Ian Page is

division manager of Corporate Planning and Strategic Review.

I might also introduce the row behind me. Immediately behind me is Mr. Rob Armstrong. He's the manager of Customer -- Custom Eng -- Customer Engineering Services. Next to him is Ms. Colleen Kuruluk who's the Marketing Programs manager. Cheryl Pilek is the Power Smart Planning Evaluation and Research manager.

Next to her is Mr. Louis Kessler, who is the Market Forecast manager. Then we have Mr. Wojczynski. And to his left is Tyler Markowsky, who's the senior economist with Manitoba Hydro.

The panel is ready to be sworn. And then we can proceed, please.

MANITOBA HYDRO PANEL 3:

DALE FRIESEN, Affirmed

LLOYD KUCZEK, Sworn

LOIS MORRISON, Sworn

IAN PAGE, Sworn

INGRID ROHMUND, Sworn

ED WOJCZYNSKI, Previously Sworn

EXAMINATION-IN-CHIEF BY MS. MARLA BOYD:

MS. MARLA BOYD: Mr. Friesen, could you please outline your qualifications and areas of responsibility with respect to this portion of Manitoba Hydro's filing?

MR. DALE FRIESEN: Thank you, Marla. Sorry for that. Good morning, Mr. Chairman, members of the Board, Intervenors, and others present. My name is Dale Friesen, and I hold the position of division manager for the Industrial and Commercial Solutions Division within the Customer Care and Energy Conservation Business Unit.

I'm a graduate of the University of Manitoba, Faculty of Engineering, holding a bachelor of science degree in mechanical engineering. I have been a profes -- registered professional engineer in the Province of Manitoba since 1993. I have served with Manitoba Hydro for over twenty-two (22) years, and for much of that time worked in various roles supporting our Power Smart initiatives, with an emphasis on industrial and large commercial sector programming.

Throughout my time at Manitoba Hydro I have been an active participant in the development of national and international codes and standards governing the energy performance of electric

equipment, working with Natural Resources Canada and others to implement energy efficiency codes, standards, and regulation across a broad range of equipment and end-use sectors, impacting the Manitoba market.

In this capacity, I serve as Manitoba Hydro's representative on the Canadian Standards Association, Steering Committee on the Performance of Energy Efficiency and Renewables, otherwise known as SCOPEER, where I also serve is the chair of the Technical Committee for the Industrial Committee -- or for Industrial Equipment, sorry.

Prior to my role, current role, I co-led the team responsible for the development of the -- time-of-use rate structure for Manitoba Hydro's largest general service consumers, including the majority of Manitoba Hydro's top consumers and other larger industrial and commercial users, accounting for approximately 25 percent of Manitoba's domestic energy consumption.

I am responsible for management of Manitoba Hydro's commercial and technical relationship, with four hundred (400) plus key and major account customers that represent Manitoba's largest domestic energy users.

The division also provides core technical and end-use expertise and support for Manitoba Hydro's Power Smart and customer service initiatives, including power in quality and customer-sided renewables, such as biomass and solar.

In my testimony today and in the next couple of days, I will be providing evidence with respect to Manitoba's top consumers and consideration of demand-side management opportunities, including codes, standards, industrial programming, load displacement, industrial conservation rates, demands and response programming, and energy efficiency measures contained within the DSM Potential Study and Manitoba Hydro's Power Smart programming. Thank you.

MS. MARLA BOYD: Mr. Kuczek, could you please outline your areas of responsibility with respect to this proceeding?

MR. LLOYD KUCZEK: Good morning, Mr. Chairman, members of the Board, and others present here this eve -- this morning. As vice president of Customer Care and Energy Conservation, I will be addressing policy issues and related manners which fall in -- fall under my responsibility, including energy conservation and load forecasting.

MS. MARLA BOYD: And can you please

outline your qualifications for the Board?

MR. LLOYD KUCZEK: I have over thirty (30) years of broad experience working at Manitoba Hydro, including having responsibility for Manitoba Hydro's load forecasting and demand-side management, functional responsibilities for an extensive period. My academic qualifications include an MBA and a bachelor of science degree in electrical engineering.

I'm also a member of the Canadian Electrical Association Customer Council Committee and the Canadian Gas Association Market Development Committee, both of which we dialogue and share information of participating utilities' demand-side management activities.

MS. MARLA BOYD: Thank you, Mr. Kuczek.

Ms. Morrison, could you please outline your qualifications and areas of responsibility with respect to this portion of Manitoba Hydro's filing?

MS. LOIS MORRISON: Good morning. Having my own technical difficulties here. Good morning Mr. Chairman and Members of the Board, Intervenors, and others present. My name is Lois Morrison, and I hold the position of division manager of Consumer Marketing and Sales of the Customer Care

and Energy Conservation Business Unit. I'm a graduate of the University of Manitoba Faculty of Commerce, and I have been with Manitoba Hydro for over twenty-four (24) years, and for the majority of that time working in various roles, supporting our Power Smart initiatives.

In 2007 I moved into the role of division manager of Business Support Services, with responsibilities including billing, metering, and collections, returning to the Consumer Marketing and Sales Division in 2010. I have been involved in several proceeding related to Manitoba Hydro's electrical and natural gas applications.

In my testimony, I'll be providing evidence with respect to Manitoba Hydro's electric load forecast and the Corporation's heating fuel choice initiatives. I will also be providing evidence with respect to Manitoba Hydro's demand-side management initiatives, focussing on the residential and commercial markets. Thank you.

MS. MARLA BOYD: Thank you, Ms. Morrison.

Mr. Page could you please outline your qualifications and areas of responsibilities with respect to the filing?

MR. IAN PAGE: Good morning, Mr. Chairman and members of the Board, Intervenors, and others present. My name is Ian Page, and I hold the position of division manager of Corporate Planning and Strategic Review within the Corporation -- Corporate Relations Business Unit. I am a certified management accountant and have an MBA in finance from the University of Manitoba.

I have been with Manitoba Hydro for over twenty-six (26) years, a majority of which was actually in the financial planning area. I moved into the role of division manager of Corporate Strategic Re -- Review in 2009, which then evolved into my current role in 2011. I am responsible for the corporate planning, corporate review, and economical analysis functions.

I have previously testified before the Public Utility Board as part of an electric rate hearing. I will provided (sic) evidence at this hearing on a number of areas throughout the hearing, such as discount rates, the appropriateness of using net present value, and on economic impact analysis. For the purpose of this panel, I will be giving evidence regarding the population growth forecast.

MS. MARLA BOYD: Thank you, Mr. Page.

Ms. Rohmund, you are the director of Energy Analysis and Planning at EnerNOC Inc.?

MS. INGRID ROHMUND: Yes.

MS. MARLA BOYD: And you are responsible for the preparation of the DSM Potential Study for Manitoba Hydro?

MS. INGRID ROHMUND: Yes.

MS. MARLA BOYD: Could you please describe for the Board your qualifications in respect of that work?

MS. INGRID ROHMUND: In my role as leader of the Energy Analysis and Planning practice at EnerNOC Utility Solutions, I direct projects in the areas of energy efficiency and demand response that include market assessments, end-use forecast, resource potential assessment, program design, strategic planning, and business strategy.

I have over twenty-five (25) years of experience conducting and managing large-scale research and consulting engagements for the energy industry. I am a recognized expert in the -- in energy efficiency and demand response, planning, load forecasting, energy and technology modelling, and market assessment.

In the past five (5) years with

EnerNOC, and previously with Global Energy Partners, I have led more than thirty (30) energy efficiency potential studies for utilities across North America, including Seattle City Light, Los Angeles Department of Water and Power, Tennessee Valley Authority, the Ameren companies, the State of New Jersey, and the State of Hawaii, and, of course, Manitoba Hydro.

In addition to the experience with potential studies and planning, I've also directed the development of several software tools that include end-use forecasting models, energy analysis software, building simulation software, and technology assessment software. Thank you.

MS. MARLA BOYD: Thank you. Mr. Chair, with that we would ask that Ms. Rohmund be accepted as an expert for the purposes of providing evidence in this proceeding on the analysis of DSM potential in North American utilities.

MR. SVEN HOMBACH: No objections from Board counsel. Does anybody else wish to make submissions?

MR. BYRON WILLIAMS: We -- on behalf of CAC, we certainly accept the qualifications of this witness.

MR. ANTOINE HACAULT: No objections

from MIPUG.

MR. WILLIAM GANGE: No objections from Green Action Centre either, Mr. Chair.

MR. MICHAEL ANDERSON: No objection from MKO.

MR. CORY SHEFMAN: No objection from MMF.

THE CHAIRPERSON: Welcome.

(BRIEF PAUSE)

MR. CORY SHEFMAN: I apologize, my name is Cory Shefman, S-H-E-F-M-A-N.

THE CHAIRPERSON: I'm sorry, Messr. Monnin...?

MR. CHRISTIAN MONNIN: Merci, Messr. President, no objections either from the IECs.

THE CHAIRPERSON: Back to you, Ms. Ramage.

MS. MARLA BOYD: I have a little trouble with the red light. Mr. Kuczyk, if you'd like to begin with your presentation, please, for the Board? This has been marked as Exhibit number 87.

MR. LLOYD KUCZYK: Okay. I -- I prepared a presentation on primarily demand-side

management and -- and just a short presentation on load forecast, which we'll start with. And through both of those I will be providing you with an update where we are in terms of our thinking in terms of the load forecast, as well as our demand-side management plans at this time.

Just a few slides to quickly put things in perspective in terms of where we are. This is what our load currently looks like in Manitoba. We have 24,400 gigawatt hours roughly of consumption currently, and we break that down into our different market sectors: residential, general service mass, and the top consumers are the primary categories. And we'll talk about how we forecast -- or how the forecast is for over -- the overall market, as well as each sector.

So before I get into that, the forecast is updated annually to reflect the most current available information. We do this each and every year. Forecast for each load sector is forecasted separately, and we use different methodologies for forecasting each sector. We believe there's sound justification for doing that. Each sector is -- has its own unique characteristics, and one particular model isn't necessarily the best to do -- to undertake

forecasting for each of the sectors. We fore -- the forecast models and methods are adjusted whenever appropriate to make improvements. This is done on an annual basis whenever deemed appropriate.

And we also, as a feedback loop, we monitor how our forecasts have been in -- in the past with regards to accuracy. So we look at the -- the past five (5) years' forecast and the past ten (10) years and monitor that.

In terms of our forecast, we're forecasting our load growth to grow by 1.5 percent overall in the Manitoba market over the next twenty (20) years; broken down by sector, pretty much the same in all sectors, 1.4 percent in the residential sector, primary drivers, population, and the market share of electric heat.

General service mass market, 1.5 percent over the next twenty (20) years and the primary drivers are population and the general GDP and economy growth in Manitoba. And the general service -- the top -- general service top consumers we're forecasting to grow by 1.6 percent per year over the next twenty (20) years.

Just a quick slide on how our forecast compares to other regions. And this is the data from

a number of utilities under -- undertaken by the North American Electric Reliability Council, a survey that they undertook to -- compares load forecasts or -- forecasts throughout North America. And you can see that Manitoba Hydro's forecast is in the general range of other forecasts throughout the US, slightly higher than the Canadian average, and slightly lower than the US average.

The other thing I want to just quickly cover is the general framework for our load forecast and what's included in it. We -- I guess going back to the North American Electric Reliability Corporation, the survey there, they exclude station service as well include -- they include DSM. So the forecast there is different than what our load forecast is.

Our load forecast, if you adjust for those factors, is 1.14 percent. Our -- our internal forecast that we do is slightly different. We include the codes and standards of our DSM efforts in our forecast and we exclude our DSM marketing initiatives from the forecast. So you can see the three (3) lines there. The blue line, if you took out the codes, our load forecast would be growing by 1.6 percent, and our official forecast states 1.5. And if you were to

subtract the DSM efforts, it's 1.4 percent.

In terms of accuracy, we're comfortable with the accuracy that our load forecast has achieved over the past number of years. We think it's reasonable that with -- if you look forward five (5) years, that it be within a band of approximately 5 percent.

And we think it's reasonable because when you look at the -- or you take into account the -- the inherent nature of forecasting, there's -- you -- it's always going to be wrong, as was stated yesterday. And the other factor that has a significant impact on each year, of course, is the -- how the economy changes. And there's different growth periods within our ec -- our economy over the years. And there's recessions, as well, as we recently experienced in 2008 and '09.

And the ten (10) year forecast, our objective is to try to be within a band of a plus/minus 10 percent. And you can see we're generally within that range.

Probably the more important slide is this one, and it provides you with an update of our current thinking. I will caution you though, this is -- this high level. It requires further analysis.

And when we undertake our 2014 forecast this summer was -- we will be assessing each one of these factors, and possibly other ones, in more detail.

Each year, when we do a load forecast there's always pluses and minuses. And this year, the pipeline sector is a significant plus. And there's been some discussion about that already, and so what we offer is a -- just as a proxy is possibly seventeen hundred (1,700). We don't know exactly what the load growth's going to be and -- but that's what we're using currently as a proxy.

Codes and standards, we're aware of some changes due to codes and standards that need to be incorporated into our load forecast. That'll take 300 gigawatt hours off our forecast. And again, we need to do more work to confirm that that'll be the number, but it's in that range at this point is our thinking.

Price elasticity, we -- we actually agree that, given our rate increases on a go-forward basis being higher than inflation and higher than the past, that we need to consider that. And at this point, we're currently thinking that could be in the 5 to 600 gigawatt hour range. And we're planning to do more work in that area certainly to refine that

estimate.

Fuel choice, we're planning to increase our education efforts in -- on that front. And we think we're likely going to reduce the -- the load forecast by about a hundred gigawatt hours due to that effort.

And --

THE CHAIRPERSON: Mr. --

MR. LLOYD KUCZEK: And the other thing that we'll have to concurrently do is we'll have to review our potential large industrial load value that will be used in the 2014 load forecast.

THE CHAIRPERSON: Could you explain the date? I'm trying to understand why --

MR. LLOYD KUCZEK: Oh.

THE CHAIRPERSON: -- for example --

MR. LLOYD KUCZEK: The dates are just when we expect those impacts to actually occur. So I don't have all the same dates for you, but the pipeline sector, we're just thinking that if the pipelines are actually going to take -- or if there is going to be new pipeline growth, it'll be by that date.

And codes and standards is just -- and the other three (3) are just a benchmark '27/'28. So

those numbers could change as you move forward into the future, correct?

THE CHAIRPERSON: Just to clarify again, on the price elasticity, I would think that that number -- you know, the increases in rates would have impact annually over a length of time.

And this suggests to me -- I'm just wondering why you picked that date in particular.

MR. LLOYD KUCZEK: I -- I actually would have preferred to have all the same dates. But we picked '27/'28, I believe, because that's when our Power Smart Plan is roughly. Yeah. There -- there was no particular reason other than we needed a date. We needed a date into the future and far enough that made some sense.

But it will be a gradual increase and we'll have to do more analysis in terms of how that's going to take place. And this is a cumulative number. It's not... So in the first year it'll certainly be a smaller number, and as we move forward...

Just some background. We undertook a market potential study and hired EnerNOC. We signed a contract in 2011. And the -- the rationale for undertaking this study was to get more insight into our marketplace and seek some expertise from a -- from

an external party.

The concept between -- behind undertaking a market potential study is to -- is to use our internal expertise, along with the consultant, to develop the load for -- or the market potential study. The -- it's -- it's not just relying on what the consultant brings to the table. It's important to recognize that our internal resources understand our marketplace, and they -- they bring value in that regard. So it's a team effort. And the result of the study is -- is more valuable to us by taking that approach.

The other comment I'd like to make about the market potential study is you need to -- you need to use the information with -- in the context that it's undertaken. It's a very high-level study. Generally, when you undertake these studies, the next step is to actually do a more detailed analysis within the particular DSM opportunities that are identified and refine both the targets and -- and develop strategies, in terms of how you're going to achieve those -- those DSM targets.

And one (1) more comment. We actually had Ingrid provide a presentation to our board, and it's on the market potential study. It's the same

presentation. And we also asked her to provide comments on her views in terms of target setting. And so given Ingrid's here, we thought we might as well have her present that to you, as well.

(BRIEF PAUSE)

MS. INGRID ROHMUND: Thank you, Lloyd. So what I would like to do now is walk through several areas -- several topics, starting with our experience conducting these types of studies; high-level review of the study objectives; an overview of how we conduct the analysis, how we conducted the analysis for Manitoba Hydro and how we conduct it for other entities as well; and then delve into some of the specifics of the studies. And we'll conclude with talking about setting targets, focussed primarily how it's done in the -- in the United States.

Okay, so leading off with our experience in these types of DSM market potential studies, I show a map here of North America. The shaded areas, the blue shaded areas, light and dark, represent EnerNOC Utilities Solutions's experience with program planning, market assessment, and evaluation. The dark-blue areas are the states and

provinces in which we have conducted potential studies like the one for Manitoba Hydro.

So you can see, we -- we have worked all over North America. We even have some studies that are outside of the US, and we have done several studies that are regional or national with respect to the US. We did a national study for the Electric Power Research Institute. We've done studies for the Institute of Electric Efficiency, and for firm on-demand response. So we have a lot of experience in diverse settings, and we have several clients indicated with asterisks who have worked with us more than once to develop their potential studies.

And our hallmark is we have a very well established process that I'll describe. We have a tool that we've developed and -- and refined over time for these studies that we deliver to our clients for their -- some clients for their use. And we -- we bring independent and an unbiased look at potential in each of the regions we work in.

So our goal for this study when we set out in 2011 was to develop updated estimates of technical, economic, and market-attainable savings by performing a quantitative assessment of the opportunities, the technology opportunities and the

market opportunities. And we worked closely with Manitoba Hydro staff to bring the local experience and knowledge to the -- to the project. This is invaluable in every one of our studies. And we bring a well-vetted process and perspective of how things are done elsewhere to the -- to the study.

So we used 2011 as the reference year, and we developed estimates out to 2031 -- fiscal year 2130 -- 2031/'32.

So I'll walk through a few definitions that we use throughout the study. The first is the LoadMAP baseline projection. LoadMAP is our tool. It stands for Load Management Analysis and Planning, and that's the tool we use. And as a first step, we characterize how customers use energy currently or in the base year, in 2011. And then we project that forward to describe what energy use would be in the absence of future energy efficiency programs.

And this baseline projection includes the effects of building codes and appliance standards, and naturally occurring conservation. It is separate and distinct from the load forecast. It is developed specifically for the purposes of estimating the energy efficiency potential.

Once we have developed that projection

-- and in later slides we show an example -- we then assess the energy efficiency potential. And in accordance with industry practice, we develop -- we develop four (4) levels of energy efficiency potential as outlined here; technical being the broadest definition, and achievable being the -- the most narrowly defined. And we'll walk though those one (1) at a time.

And this is standard industry practice in North America to develop these four (4) levels. Sometimes it's only one (1) level of marketed achievable, but we prefer to estimate a range of potential that is characterized as achievable in market in this study.

So the -- the broadest definition of energy efficiency potential is called technical potential, and this is the theoretical upper limit of potential. It assumes that all customers will replace their failed equipment with the most efficient option available in the market at that time regardless of cost.

So we don't assume that -- that everything is replaced in a flash cut, but rather when refrigerators fail, or fridges fail, and when air conditioners fail and furnaces fail, that they are

replaced with the most efficient option. And -- and every customer does this.

And then there are other measures like insulation and programmable thermostats and non-equipment measures, as we call them. Those also get re -- get installed over time.

A subset of technical potential but also a theoretical upper limit is economic potential. And to estimate economic potential we take every measure in every segment in every year of the forecast, and we run those measures through a cost-effectiveness screening using a TR -- total resource cost test.

And measures with a benefit cost ratio of one (1) or greater pass the economic screen and are included in economic potential, and those with a benefit-cost ratio of less then one (1) are excluded from that estimate. As far as customer adoption, it is like technical po -- potential and it assumes that everyone will adopt those cost-effective measures. Okay.

So the mar -- the third level and subset of economic potential now is market potential. And this is the amount of savings that can obtained through market intervention -- and these are carefully

chosen words -- under ideal market implementation, regulatory and customer preference conditions.

So everything is favourable towards the adoption of energy efficiency, and the only real barrier is customer preference for a technology or measure. And an excellent example is compact fluorescent lamps. There is widespread use in parts of North America; however, in some applications they are not preferred.

And at the risk of -- of showing gender bias, women, in particular, do not like compact fluorescent lamps in bathrooms because we don't look good under compact fluorescent lamps. So there is a resistence to those lamps, and unless forced to do so, they will find an alternative. So we look -- we -- we think of market potential as a theoretical upper bound on what can actually be achieved.

And then finally, we look at the achievable potential. This is a subset of -- of the market potential, as well, and it recognizes that the -- the market conditions are not ideal. There is not perfect information. There is not perfect program implementation. The regulatory circumstances may not be ideal, as well.

So this is -- this is a level of

potential that can be achieved. And the way we think of it, as -- as the -- as the consultant, is that it is -- it -- it is the goal that can -- that can be met and there is -- but it is -- we view this as a range. A range of potential is achievable to market, and somewhere in there are utilities generally choose a path, doing much more analysis about specific programs and how measures might be presented to customer segments or how they might be grouped together to develop the actual program plan.

So we provide guidance through these estimates and solid information from -- with which our clients can move forward to develop their specific program plans. So we did not engage in that part of the analysis.

THE CHAIRPERSON: Can I ask a question to --

MS. INGRID ROHMUND: Of course.

THE CHAIRPERSON: -- clarify in my own mind. In respect of classifying these data, the test that you're using for the work you did for Manitoba Hydro is not using values or formulas different than elsewhere in North America?

MS. INGRID ROHMUND: Correct, correct.

THE CHAIRPERSON: So, for example,

total resource cost is what you're using for any of the other studies you're going to cost?

MS. INGRID ROHMUND: In most of the studies, because some of -- some states require that -- in the US require that a different test be used. There is -- there -- in some states there's a move now towards the utility cost test. So -- but the majority, the vast majority, of the studies rely on the total resource cost test.

THE CHAIRPERSON: Another question. In -- in relation to looking at the market potential, that excludes any activity the government might undertake to subsidize DSM adoption? In other words, if the government was to say, We're going to subsidize -- let you buy a cheaper fridge, we'll give you a subsidy for a fridge, that would mean what in -- in the calculations you're doing here? They're as exogenous to...

MS. INGRID ROHMUND: Yes, in the -- in the definition of market potential, we -- the only barrier is the customer preference towards the -- towards the technology as I described with the compact florescent lamps. So if -- if a subsidy or other mechanism were employed outside of Manitoba Hydro, that would be part of market potential.

MS. MARILYN KAPITANY: But just further to that question, any of the subsidies employed by Manitoba Hydro would be part of this analysis?

(BRIEF PAUSE)

MS. INGRID ROHMUND: Could I ask you to -- to repeat the question?

MS. MARILYN KAPITANY: Yes. So if there are subsidies by Manitoba Hydro that -- that would encourage people to put in more insulation, for example, would -- that type of subsidy would be included in your analysis?

MS. INGRID ROHMUND: The fact that the subsidy is taking place would be included in the analysis. The actual dollar amount would not.

MS. MARILYN KAPITANY: And could you just clarify your last point, the last bullet point on this slide, where it says:

"Not synonymous with setting specific DSM targets or with program design."

MS. INGRID ROHMUND: So the -- the analysis is designed -- was designed to provide

guidance to Manitoba Hydro to develop its programs, develop and refine its programs. And so as a next step they would look at the specific results by measure, and by customer segment, and for new and existing buildings, and they would look at those results and say, Okay, over -- over time, and use that information to develop the program more specifically.

So perhaps they might combine some programs to -- measures together into a specific program for a specific market, say hospitals, for example. Or they may chose to accelerate or decelerate the timing of some of our modelling results.

So as I said, this provide guidance into that process, and therefore it is not synonymous with setting the targets or with program design.

(BRIEF PAUSE)

MS. INGRID ROHMUND: Okay. So now I'd like to give you an overview of how we conduct the study. So we use what is called a bottom-up analysis approach. So working on this slide form the bottom to the top.

We always start with our clients'

objectives in mind. And, so as -- as I said, our pro -- our process here was to provide guidance to Manitoba Hydro for its program planning process. And -- and each client has its own specific objections, and that was our objective for the study.

The first step we do is to characterize the market, as we call it. And so the -- the actions that we take are on the left side moving up by the arrow, and the horizontal bars in grey and blue identify the interim deliverables that we develop along the way.

And so to characterize the market we use a variety of data sources. Those are the ones in the -- in the white space: Manitoba Hydro billing data, Manitoba Hydro surveys, program data, and our own energy market profiles data base to characterize how customers use energy in -- in the base year, which was 2011.

And it's at a very granular level. We segment the market: residential, commercial, and industrial. There are segments within those -- those sectors. There are end uses and fuels, and then there are technologies. So it is a very specific characterization of the market, and we feel it's very important to start in the right place as -- as best as

we can define it, so that when we move forward we're -- we're moving forward appropriately.

After we develop that characterization, we project the baseline, and this is the expected energy use for all those granular segments in absence of future programs. And so we take into account codes and standards. We take into account some of the data that Manitoba Hydro uses to develop its forecast. And then we supplement, as needed, for our model with other secondary sources. And that gives us the jumping-off point for assessing the potential.

And, as I said, it's distinct from the load forecast. It's a different process, and often results in a different projection than what the load forecast shows.

Once we have the baseline forecast, we look at -- at other efficiency options for equipment and other measures that could be adopted by customers and would generate savings. So we have a -- a process where we develop that list of measures. We characterize those measures in terms of their cost and savings. We utilize Manitoba Hydro data as much as we can, because it is local and has been used in practice. And then we supplement with data from other sources.

We use that information to calculate technical and economic potential. It's very straightforward, as described earlier. And that gives us those estimates.

And then the final step is to establish customer acceptance of those measures, and we develop a set of acceptance rates that reflect market potential and also reflect achievable potential. And that allows us then to calculate the market and achievable potential.

MS. MARILYN KAPITANY: When you establish customer acceptance, how do you stratify customers, or is it just customers writ large? Or do you look at, you know, income? Do you look at people inside Winnipeg, outside Winnipeg? How is that stratified?

MS. INGRID ROHMUND: So in -- in the next slide, we'll show you how the -- for example, the residential segment is -- sector is segmented. So it's a -- it's consistent with how we are characterizing everything else in the study, in terms of the -- the sector, the segment, and the end use; we have acceptance factors. So it can be very granular.

So now we'll describe the market segmentation. This is the -- the market

characterization. We took the billing data for 2011 and segmented into residential, commercial, and industrial. And our definition for commercial and industrial is usually different than what our clients may be tracking as commercial and industrial. We look at commercial buildings, so office buildings, hospitals, schools, colleges, et cetera. And the industrial sector is defined as -- as manufacturing -- primarily manufacturing facilities.

And so you see that -- that the service territory is -- is fairly well balanced, meaning roughly equal shares of energy use for each sector. Although, the industrial sector is the largest; and that's a bit unusual for our studies, that the industrial sector is the largest.

The measure assessment step that we take is to develop a list of measures. We have a list that EnerNOC maintains that's developed and maintained from studies that we do all over the place. And then we provide that to Manitoba -- provided it to Manitoba Hydro and got feedback on that measure list. So review and feedback, measures were added, measures were excluded, and we ended up with the list of measures we used for this study.

And so we went through that process

together to identify those measures that are the most relevant for the service territory. We try to be -- we are comprehensive in our measure list, but not necessarily exhaustive, including every possible measure, since we do have to perform the calculations and get through the study. So we do introduce a bit of practicality into the process here.

Once we have developed the measure list, we characterise the savings, the cost, the lifetime and the applicability. We have values that we have developed from other studies and a database that we now maintain over time. But we always rely on our clients to provide us with local information, particularly for the industrial sector. It's -- it's critical that we work together to develop these assumptions.

So what I'd like to do now is to walk you through the residential sector in a bit more detail, to give you a feel for how we go through the process, and to show you some of the results.

So, for the residential sector, Manitoba Hydro had -- has done recently a saturation survey and had extensive information about it's customer segments. And we -- we analyzed separately twenty-nine (29) customer segments, and the largest of

those is the blue-shaded area in the upper right. It's the single family homes with gas, space heating, that were cons -- that were constructed before 2000; and those homes account for 26 percent of the electricity used in 2000 -- 2011. And then the second largest is the single family electrically heated homes where gas is available that were constructed before 2000, with 16 percent of the use. So you can see, we'd -- we went at -- at the segmentation in a very granular fashion.

For the commercial sector we did building types, I believe the number was eighteen (18). I have to look these things up to be specific. And then the industrial sector was approximately eight (8) industries that we isolated. For each of these segments then, we characterized electricity use by end-use.

So the bar chart in the lower right shows the intensity, that's the use per household in 2011, differentiated by end-use. And red is space heating, and in some segments is more than half of the electricity use, particularly in those areas where gases may not be available. And, I'm sorry, where elec -- yes where gas may not be available.

And then cooling is blue; you can see

that's very small across all the segments. Appliances, includes refrigerators, clothes washers, dishwashers, all white goods, appliances, is the green bar; and then the miscellaneous use is the remainder, and electronics.

So there's a wide variety of -- ride -- variety of intensities across the service territory. The pie chart in the upper left shows, across all homes in 2011, our estimate of usage by end-use.

I -- I think I'll mention also the miscellaneous category is -- stands at 14 percent in 2011. That includes all the uses that we did not classify elsewhere. So we -- we're very granular about heating and cooling and technologies within those, but then there are many other uses that -- that we don't break out separately: the plug loads, the air compressors, power tools, exercise equipment, hair dryers, all those things get lumped into miscellaneous.

Okay. As far as the potential results, this slide shows you the savings, the cumulative achievable savings, that we estimated for 2031/'32. And these are the measures, the top twenty (20) measures, that account for 92 percent of the cumulative savings, in that year. And, as was not a

surprise to us, savings associated with heating, space heating, whether it be equipment measures or insulation or other thermal shell measures, account for more than half of the savings. And the other end-use: lighting is always a -- a significant cont -- contributor to savings in the studies we conduct and -- because the technology is changing. And -- and then we have savings from all the other uses as well.

On -- on the next slide, we show the summary across all of the measures for the residential sector. And we show -- here we show all four (4) levels of potential in the bar chart, and also in the table. And so the achievable savings -- and these are -- are at 570 gigawatt -- cumulative gigawatt hours in 2031/'32. And as a percentage of our baseline projection, it's about 6 1/2 percent of the savings in that year. And the market potential estimate in that year is about twice that, so that, in our minds, is -- is the range of -- of achievable -- of potential savings that could be achieved through programs.

We don't go through all the detail for the other sectors. It is exactly the same process in terms of the market characterization and the baseline projection and the measure characterization and the identification of the top measures.

The commercial sector has the highest potential of the three (3) sectors in Manitoba's service area, with just over 1,100 gigawatt hours of achievable potential in 2031/'32. And that's about 17 percent of our baseline projection in that year.

The industrial sector has the lowest level of achievable savings. This is typical of potential studies and of our potential studies as well. The industrial sector included all of the industrial sector, including very large customers who are already very active in developing their own energy efficiency, meeting their own goals. And so it is not unusual for the -- for the savings from the industrial sector to be the smallest.

Okay. So as a summary across all three (3) sectors, we estimated just under 2,000 gigawatt hours of savings, achievable potential savings, in 2031/'32. That's just under 8 percent of the baseline projection that we developed. And this particular slide shows you all -- again, all four (4) levels of potential.

The -- the pattern you see here for technical potential being around 30 percent, economic potential at about 25 percent -- and I'm looking at 2031/'32 and across all sectors -- is -- is consistent

with findings from other studies. And then the range of -- of market and achievable potential in the range of 8 to 16 percent. And -- and that representative fraction of economic is also representative.

THE CHAIRPERSON: You indicated other studies. Do you mean other studies outside Manitoba?

MS. INGRID ROHMUND: Yes. Yes, other studies we've conducted.

So in -- this is a different view of the study results. So this is -- this is now looking at it from the perspective of the projections. And so the blue line on the top is our baseline projection that we developed for the study, and the other lines show the potential projections for each level.

And so if you were to focus on the achievable potential line and the gap between it and the baseline projection, the achievable potential offsets about a third of the -- of the expected growth in energy use, which is -- and the market potential offsets almost all the growth. So these are -- these are pretty significant savings.

And here's the summary by sector. So as I already alluded to, the -- the commercial sector offers the largest amount of savings throughout the -- the forecast horizon. The residential sector comes in

second. It is -- we have found in our studies that the amount of potential from the residential sector is declining because of naturally occurring conservation and appliance standards.

So there is -- and already the significant adoption of efficient technologies, like compact fluorescents and the successive programs. So the future potential for the residential sector is smaller now than it was, say, three (3) or four (4) years ago when we did this -- these studies.

And as mentioned, the industrial sector is -- is the smallest wedge here because that sector is also -- is already active. And -- and that is consistent also with what we see in other studies.

Okay. So I'll add -- add a little bit of information about target setting. And my experience with target setting is limited to the -- to the US. And we work with some clients to develop their targets, and in other cases we provide the information so that they develop the targets on their own, or that the regulators -- or the legislatures develop the targets.

So there are basically two (2) approaches for developing the targets that are used in the US. The bottom-up method is typically based on

analyzes like we did for Manitoba Hydro. And using that as information, the targets are set. We -- judgment is used to determine the amount and timing of the annual savings targets.

So it may be that -- that more -- the targets are higher in the early years, or they may be less and ramping up. All of that gets decided based on the information that's provided. And this usually involves a negotiation between the utility and the regulators and/or the stakeholders to develop targets that can be met and that can -- that -- the budgets also get taken into account in this process. Something that we did not consider in the Manitoba Hydro study.

The other approach is a top-down approach, where -- where targets are specified as a -- as a -- an absolute number in each year in terms of -- of gigawatt hours, or in -- as a percentage of the forecast. And these are usually set by legislators or regulators in the US. And they may -- may be based more on what are the neighbouring states doing, or other states that we want to be like. What are they doing, rather than on a bottom-up assessment.

There are advantages to -- pros and cons, as we say, to each of these methods. The

bottom-up method is generally preferred by utilities because they are grounded in an analysis that the utilities generally participate in. And the downside that has been called out by stakeholders is that they may not be aggressive enough and may not push the utilities enough to achieve higher targets.

The top-down method may end up in targets that cannot actually be achieved, or will be very expensive to achieve. And when those targets are imposed in a top-down approach, it -- there may be an adversarial relationship between the utilities and the regulators, especially when the regulatory mechanism doesn't support the -- the achievement of those targets.

So in the US, here's this -- a picture -- a state map showing in green the utilities that have an energy efficiency resource standard, and a couple of states that have a combined energy efficiency and renewable energy standard: so Nevada, North Carolina, and Hawaii.

And so twenty-five (25) states have energy efficiency resource standards, and that represent 61 percent of US electricity use. So these are -- are fairly popular in the States. And the form of those requirements vary from state to state. And

there is a ACEEE document that describes that, summarizes that. And there is some flexibility in terms of how states meet those requirements. So I just give two (2) examples.

Washington State has a requirement to achieve all cost-effective conservation. That is the mandate. But utilities set their own goals every two (2) years; they're two (2) year goals, biennium goals. And they -- the utilities have a choice on how they develop those goals. They can do a conservation potential assessment and use that assessment to help them set the goals. And we've worked with several utilities in Washington State to help them set their -- their goals.

The State of Illinois is ano -- is -- is at a different -- takes a different approach. It has set a requirement of 2 percent savings per year, that's off the load forecast, and it has also imposed a spending limit. And those two (2) metrics are not in alignment in some -- in -- from some utilities.

The -- the one that we did the analysis for, the -- the savings -- the 2 percent savings was very difficult to achieve and it required much more spending than that cap allowed. So there was a negotiation that was underway after we finished the

project.

Many states have a stakeholder process whereby stakeholders are involved along the way as the goals are set. And the -- the stakeholders tend to push for high goals. On the other side is the states being under -- being under pressure to keep rates low and sometimes adopt pushing for additional energy efficiency will push the cost -- the price up. So the regulatory mechanism may not be in alignment with promoting additional energy efficiency. And each one (1) of these twenty-five (25) states has its own specific story.

So as far as target setting goes, we do recommend that -- that targets are grounded in detailed bottom-up assessments of energy efficiency savings. And it may be wi -- prudent to average the savings over a few years. So rather than taking the -- the modelling results literally for the first year and second year and third year, it may be better to average across those three (3) years to get an average target.

And in developing the targets or developing programs, it may be appropriate to increase or decrease individual measure savings goals, taking into account how those measures might be implemented

or on specific knowledge of the market. And we believe it's important to have good systems in place to track the results on an ongoing basis so that those can be used in future planning and program design efforts.

And we recommend that these -- these planning studies be conducted periodically. You know, we'd like to say annually or every two (2) years, in practice. It is often longer than that. But at least a routine that says we're going to come back and look at how we've done and use that information to develop the goals for the next planning period.

Questions?

MS. MARILYN KAPITANY: I have a question, but it's actually for you, Mr. Kuczek. You had mentioned in your presentation that you're looking at load growth of 1.5 percent over twenty (20) years, 1.4 percent with DSM.

Could you just let me know how that 1 per -- 1.4 percent relates to the numbers that we just heard in terms of potential savings?

(BRIEF PAUSE)

MR. LLOYD KUCZEK: I'm just wondering

if it might be better to -- to go through my presentation and maybe try to address that at that point.

MS. MARILYN KAPITANY: Sure. That would be fine. Thanks.

DR. HUGH GRANT: Could I ask, while we're on the topic of load forecast, could you go back to slide, I think, 10. It was with respect to forecast accuracy.

(BRIEF PAUSE)

DR. HUGH GRANT: Could -- could you explain this a bit further? Because I don't really understand this slide.

Is this forecasting how accurately you've forecast the annual rate of growth, or is it how accurately you've forecast the absolute level of consumption?

MR. LLOYD KUCZEK: I'll give you an example. It probably would explain it the simplest. So if we were testing our -- our five (5) year forecast, what we would do is -- the accuracy of it, we would go back five (5) years, look at the forecast of what we were forecasting for the current year, and

-- and compare it to the weather adjustment actuals. And that difference would be the measure of accuracy.

And so you can go back five (5) years and look at this year. You can go back six (6) years, but then you would look at the prior year.

DR. HUGH GRANT: Okay. But that would be of total consumption as opposed to the rate of growth in consumption?

MR. LLOYD KUCZEK: Correct.

DR. HUGH GRANT: Okay. And just -- one (1) other small point. Do you do your own population forecasts, or do you just rely upon Canadian -- StatsCan, Conference Board?

MR. IAN PAGE: I can -- I can address that. Our population forecast is produced by a -- from a consensus of another -- a number of independent forecasts that we purchase. So for the 2013 forecast, there would have been five (5) separate forecasts that we would have used.

THE CHAIRPERSON: I have a question for Ms. -- Ms. Rohmund. And specifically, what I'm -- what I'm trying to understand is when you assessed the potential of the measures, you were given a set of measures by Manitoba Hydro to assess.

In other words, were you looking at the

full range of measures applicable in North America, or were you just looking at those measures that Manitoba Hydro said, These are the measures we'd like you to address?

MS. INGRID ROHMUND: In our process, we start with the measure list. We -- we deliver a preliminary measure list to our client; so to Manitoba Hydro. And they reviewed the measure list and gave us feedback. And in that process, some measures were added to our list that -- that are relevant here, and other measures were taken off of the list.

THE CHAIRPERSON: One (1) of the experts has indicated to us that the tests that are used by Manitoba Hydro to identify those measures which might be useful in Manitoba are not the same as those used elsewhere. And -- and ergo, that means that some measures are being screened out that had market potential in Manitoba.

And I guess the question I'm trying to get at is -- what I'm trying to get at is trying to understand to what extent that those measures that you used were uninfluenced by the screening-out that might have been done by Manitoba Hydro?

MS. INGRID ROHMUND: So the measures -- each measure goes -- goes through the screening

process using the total resource cost test. And that results in a benefit-cost ratio.

And we included the measures with benefit-cost ratios of one point zero (1.0) and higher and excluded the ones that were less than one (1), which is what we've done in all of our studies. So -- and that is -- that is standard practice for our studies.

If a client were to tell us to lower the threshold, then that would give a different potential. But one point zero (1.0) is what we've used in our studies, and it's -- it's common.

DR. HUGH GRANT: Can I just follow up on that? Because you mentioned, when you looked at the achievables, you listed things that passed the sort of cost-benefit test. That's cost-benefit to whom?

Is that a social cost-benefit, or is it specific to Hydro?

MS. INGRID ROHMUND: It is a -- it is a total resource cost test, but it is specific to Manitoba Hydro in the sense that the savings and the -- from the measures and the costs of the measures reflect local conditions, and the benefits through the avoided cost are specifically Manitoba Hydro's.

So the formula is the same across the studies, but the -- the data in the formula are specific to Manitoba Hydro.

DR. HUGH GRANT: If -- if I could pose it differently then, suppose there was a DSM measure that was determined not to be of net benefit to Manitoba Hydro but might potentially be of net benefit to the province.

Would that get screened out?

(BRIEF PAUSE)

MS. INGRID ROHMUND: So the total resource cost test looks at the -- the benefit and the cost of the resource independent of who pays for it. And so it's -- the -- the information is the avoided cost and the savings and measure costs are all Manitoba specific, but the meth -- it -- it wouldn't matter if it were.

(BRIEF PAUSE)

MR. RICHARD BEL: Could you give us an example of a measure and how you would screen it? For example, we heard a presentation on Thursday that

discussed switching residences who don't have the option of gas from electric heat to geothermal by Hydro financing the upfront capital cost. And it was claimed at that -- in that presentation that that would generate additional available energy at three (3) cents a kilowatt hour. Is that correct?

So how would -- how would you approach that measure? A concrete example. So is -- is geothermal considered a measure to switch people to geothermal?

How would you evaluate that?

MS. INGRID ROHMUND: So geothermal heat pumps were a measure, and we looked at customers with electric resistence heating switching to geothermal heat pumps. We did not...

(BRIEF PAUSE)

MS. LOIS MORRISON: Hello. In the study we did include geothermal heat pumps as one of the measures, and that's one that we actually specifically requested to be included in the study. And so it did get screened in and was looked at based on the energy efficient -- the energy savings that are realizable within the Manitoba market.

And as Ms. Rohmund referred to, we looked at specifically in the case of electric resistence heating or where there's an electric furnace in existence, because you -- there -- you need the ducting to -- to make the system operational.

And so, yes, those measures were included in this analysis. And then to build on -- I believe it was Mr. Lorenz's presentation, Manitoba Hydro does offer financing for geothermal heat pump systems through our earth -- our Residential Earth Power Program. We also offer funding -- or financing through our residential Power Smart PAYS Program. We also have incentives to support geothermal heat pump systems in non-gas-available areas for commercial buildings.

THE CHAIRPERSON: Okay.

MS. MARLA BOYD: Mr. Chair, just being mindful of the hour. I expect Mr. Kuczyk's -- the balance of his presentation will be about fifty (50) minutes. I don't know if you'd prefer a morning a morning break now, or if you'd like to hear the balance of the presentation.

THE CHAIRPERSON: I think we should do it now. Before -- I have one (1) more question I wanted to -- to understand, and this is to do with the

total resource test -- the total resource cost test.

One of the experts that we -- expert reports has indicated that -- that we should be addressing these measures at a portfolio level as opposed to a individual measure level, which would suggest to me that as long as the portfolio is lower than one (1) and -- globally, you should be considering other measures that otherwise would fail the introductory test.

Now, in your case you looked -- you were looking at the total resource cost for individual measures, right? You -- you didn't consider measures that would otherwise have failed an individual test.

MS. INGRID ROHMUND: That is correct.

THE CHAIRPERSON: Okay.

MR. LLOYD KUCZYK: I'm not sure I'm going to make fifty (50) minutes, but I'll -- I'll do my best here. There's a lot of issues with DSM that seem to get confused at times, and what I'm going to try to do here is clarify some of the issues so that when we have a dialogue in the next -- about DSM in the next three (3) days, that we're all on the same ground.

And there's some areas of concern that were also brought up that I'd also like to address and

hopefully provide some clarity on.

The first area that I want to touch on is our Integrated Resource Plan. And the concern expressed there was that Manitoba Hydro doesn't include options, DSM options, and so for -- the end result is our resource plan is not optimal.

And what I'd like to do is go through what our combined DSM integrated resource proc -- planning process is at Manitoba Hydro, which should provide some clarity and hopefully some comfort that the end result is that we are including in the -- at least in the ideal case, all economic opportunities within our resource plan.

So it starts with -- and it's not quite as simple as I've got it on this diagram. But on the left side, this would be a integrated resource planning staff. They update the marginal value. And this is the value of energy at the margin to Manitoba Hydro.

They provide that value to our DSM staff. Our DSM staff update the plan based on that value. They do the screening, and I'll get into that. And then we provide our plan back to the resource planning people, and they undertake their integrated resource planning process.

So if we go to the DSM process, once -- once the marginal value has been provided to us we undertake an assessment of opportunities and basically filter out those that are economic and those that aren't. And we use what's called a resource cost. And -- and I'll just point out, when we say, "resource cost," this is the total cost of the -- implementing DSM; it's not just the utilities cost.

And this is what Ingrid mentioned earlier that people take into account. It -- it really shouldn't matter who's paying for the DSM measure. The relevant cost is the total cost because if a utility pursues a supply-side option, ratepayer -- customers pay for that cost, the total cost for rates.

If you pursue a DSM option, customers also pay for the total cost. Part of that's paid through the utilities rates which incorporate the DSM investment, and the other part is through the participating customers' contributions through the DSM. So at the end of the day, it's the integrated cost that really matters, and measuring that against the marginal value.

THE CHAIRPERSON: And you -- I'm sorry, could you define 'marginal value' for me?

MR. LLOYD KUCZEK: The marginal value is the value to the Corporation of energy at the margin.

THE CHAIRPERSON: Could you tell me what the number is roughly?

MR. LLOYD KUCZEK: Oh, that's the number you'll hear when we provide you with a proxy of seven point four (7.4) cents. I think -- what is it, seven point four (7.4) right now roughly? It varies each and every year, but...

THE CHAIRPERSON: In the neighbourhood of seven (7) point something, right?

MR. LLOYD KUCZEK: Seven point five (7.5). It's been at eight (8) cents and...

And so in the -- the ideal world, and -- and there's never an ideal world, but the result of our -- our DSM annual review is that the economic opportunities are supposed to get filtered out. They're combined as a package, as what we refer to as the Power Smart Plan. And then we provide that back to the resource planning people.

So what you see is they get a package. And, essentially, it's just one (1) bubble. And they -- they used to compare it to other resource options. But what they found is that it was always economic.

And then it just ended up in -- I'm not sure what year they started doing this, but, you know, it was just on the base cases, clearly part of our resource plan and didn't need to be assessed against the more cost of -- more costly options.

So if -- if you look at the combined process, we do the filtering in the DSM shop, provide that package of, hopefully, all economic opportunities. And as we get into the discussion further and where we're going you'll -- you'll actually -- there's -- there's actually some red in there, as well. And that's where you get into combining, and so -- and at the margin it might not be cost effective, so a lot -- a lot of judgment is used in that regard.

But at the end of the day, the DSM package is there and you have your metrics to tell you what the value and the costs are associated with that DSM plan.

In theory, you could integrate the two (2) filters and we could provide the resource planning people with all those options. In reality, there's an infinite number of options, so it's -- in practice, it's -- it's really not practical.

So if you wanted to drill down and --

and identify all the individual technology opportunities, that would be one (1) way of doing things. But what you really have to do is you have to develop a program. And so there's -- there's many ways of pursuing DS -- DSM opportunities, including various incentive levels, incenting the customer, incenting the -- the suppliers. So -- so there's many ways of doing it.

So in practice what you end up doing is you -- you come up with what you think is the most appropriate plan for a particular initiative, and you filter it through that filter. And if it's economic, it gets passed on as a package to resource planning. And -- and later on I'll explain that we actually will -- we approve programs without -- we don't just approve programs, individual programs, once a year, we -- it's a continuous process at Manitoba Hydro.

And so the marginal value that we -- and this may help in understanding, but it also provides some comfort in terms of -- the value that we use is developed using the same model that is used to provide the incremental system costs and benefits for economic comparison of resource options and from the perspective of indivi -- incremental system value.

So in theory, in the ideal world, it --

it should at least be -- the economic opportunities should filter through. The bigger issue would be whether or not those economic opportunities are developed in concept.

So the conclusion that I've come to monitoring this process, is that, given how the marginal value is determined, Manitoba Hydro's combined DSM integrated resource process should result in all those economic DSM opportunities being filtered into the Corporation's plan; in the ideal -- ideal world.

I want to talk just at a high level about what our strategy is. And if somebody were to ask me what Manitoba Hydro's DSM strategy is, it -- it's basically this in -- in a simple sense: It's to pursue all cost-effective DSM opportunities, and as measured by what I'll explain later is a modified total resource cost ratio. It's the same -- same test that Ingrid was mentioning, except slightly modified. And then, combined with that, we have to balance being fiscally responsible and being considerate to ratepayers and all customers. And I'll touch on that later to explain what that means.

Our strategy is also a comprehensive approach. It's not about just offering incentives,

offering programs. Codes and standards is probably the most effective way of achieving energy savings, and it's a very important component of our strategy. Education is another important component of our strategy, programming where appropriate, and economic -- a lot of judgment on the economic, and we'll talk more about that, and also monitoring and supporting emerging technologies.

I mentioned codes and standards is a very important component of our strategy. The green shaded area shows what we're expecting to achieve through codes and standards, and the red is what -- what we're expecting to achieve through our DSM programs.

And while I'm here, for -- for the -- the most part, it -- it's important to recognize, you know, when you're -- when we're looking at what's been achieved within a region, not just looking at what's achieved through the marketing programs, but it's the combined effort. At the end of the day, from an integrated resource planning process, whether it's included in the load forecasts or codes and standards or through the DSM programs, it really doesn't matter. It's -- that would be the net impact on your load in -- in Manitoba, in this case.

So I'll talk about the DSM screening and the metrics, and touch base on how Manitoba Hydro uses it. And given that RIM has been such a topic of discussion over the past number of years, I also want to touch on that and provide clarity.

So in terms of the industry, there's a number of DSM metrics. You can put them in three (3) buckets. One (1) is from the resource perspective. And -- and it's important, when people talk about metrics, economics, there's -- there's three (3) different perspectives, generally speaking. So if somebody were to say to me, Something's economic, I would right away ask, From what perspective are you talking about? So there's confusion sometimes.

So the resource perspective is irrespective of who pays for it, and -- and that's how we filter DSM opportunities out. And our -- our view is, and our strategy is, to pursue all OF those opportunities. As the Utility here to serve Manitobans, we think it's in the integrated perspective that makes the most sense.

Then within that category, you get into what's called a societal resource cost, which is -- is a modified version of the total resource cost, and you're -- you're including non-energy benefits. And -

- and I mentioned that we use a modified version and I'll talk about what that is.

And then there's the levelized resource cost, which is just the denominator of that ratio. So the total resource cost is a simple benefit cost ratio; the levelized resource cost is the -- is the denominator, which is just the cost component.

From the Utility perspective, the general metrics that are used is the levelized utility cost. And again this is just the cost. It's not looking at what the revenue impacts are. The rate impact measure, which is -- I'll talk about that. And then NPV which I think most people understand what that is. And also the customer perspective.

There's a benefit cost ratio that's used that's called a participant customer cost test which is just benefit over cost from the customer's perspective. And then we use also a simple payback period, because a lot of customers just think in those terms.

So how are DSM metrics used? And -- and this is in general, and it -- it -- there's no -- it's not consistent across all regions, but in general the TRC, or a modified verison of that, is used as a go/no go decision. It -- it -- generally speaking,

the benefit should be greater than the cost from the combined utility customer perspective if you're going to pursue it. So it just makes sense.

In terms of program design decisions, that's where you start to use all the other metrics. And what you're trying to decide there is: What is the best program to pursue the DSM opportunities available? And you have to take into account trying to maximize the energy savings, take into account how those should possibly be shared, the costs should be shared between the utility which is basically all ratepayers, and those that are benefiting by participating in the programs. And you should also think about how you should change the design possibly over time, because having a static program might not be necessarily the optimum approach to take.

Just to share with you some information from an ACEEE report that was undertaken -- and I won't run through all the numbers, but you can see that utilities use -- regions and utilities use a variety of the metrics. And it -- this won't add up to fifty (50) states; this was a survey undertaken and about forty-three (43) or forty-four (44) states responded, as far as I know.

This is the simple equation for the

total resource cost test -- benefits over costs, as I mentioned -- and at a true total resource cost ratio test without being modified. That's just taking that marginal value to a utility and dividing that by the resource cost: not the utility's cost, the resource cost. The resource cost is the combination, as I mentioned before, of the utility cost plus the customer cost.

And -- and I've seen it in evidence provided at this hearing where people will actually talk about the utility cost and measure that against the marginal value. You -- you can do that, but when you're really looking at the -- making a decision on whether or not to pursue an opportunity, the relevant measure is against the resource cost. It's okay to look at the utility cost, but just keep in mind what decisions you're going to make when you're -- when you're doing that, and what relevance it has.

So how do we use the TRC? I've explained this before. In the bottom part of the slide it -- it shows what we use as an equation. And what we've decided to do is we include any measurable non-energy benefits as part of that equation. And an -- an example of that would be if there was savings in -- in water use, we -- we would take that into account

as clearly something that could be measured.

We considered using the societal resource cost test s number of years ago; looked at what other utilities were doing, and, generally speaking, what it amounts to for the most part, and things may have changed, but when I looked at it it was just adding an adder. You know, like you -- it's very difficult to measure what those benefits are, and so we thought about -- I -- what we do with ours, we -- we do calculate it, but it's just adding 10 percent onto the -- the marginal value.

So the conclusion that -- that I come to in terms of our use of DSM metrics, it's generally consistent with the industry, and the metrics are -- should be used as guidelines rather than rules, and I'll talk a bit about that. But the general gist of that is, is by using guidelines as opposed to rules, in my -- my opinion, I think you can achieve more; and I'll talk a bit about why that makes sense.

So first, each DSM opportunity is uni -- has unique characteristics. The target market's different and you need to take that into account. And I'll give you an example: If you're pursuing a low-income target market and you're looking at how you're going to split the costs, we've decided we'll just pay

the -- the total cost when it comes to the insulation component of that program. And there's another program called the Water and Energy Savers Program. We decided with that program it was best for Manitoba Hydro just to pay the entire cost. So each opportunity we assess differently depending on the barriers and the situation. No hard rules.

So at the end of the day, when staff come up with a design, it's supposed to be what we would consider and the staff consider the most appropriate design, taking into account all the metrics and the Corporation's objective of achieving all cost-effective measures, and still being fiscally responsible.

The other thing that you need to take into account is where on the market transformation curve you are. And when I say, "market transformation curve," if you -- if you take -- talk natural gas furnaces, for example, if you're trying to convert that market from standard to high efficiency, you're -- you're at the -- you're -- you're at the far end of the transformation curve already, because there's not a lot of furnaces left in the marketplace. There's more than what we'd like, but you're further up the curve.

So you need to take into account where you are within that market transformation curve. You need to take into account wha -- what options the customer has should that oppor -- or in -- in this case, a furnace -- when they're going to potentially die, what -- and it's the same with the inefficient refrigerators that are in place in the marketplace. And there's different barriers that need to be considered.

And another important point that I would like to make is DSM proging -- programming isn't an exact science. And when we make judgment calls in terms of what program design is acceptable we're not concerned about the rounding error in our shop. We're more concerned about a long-term plan, being in the marketplace and not -- not entering the marketplace, and then when things change, pulling out and going back in later when -- when our marginal cost numbers, for example, change.

So we'll -- we will take into account market conditions. For example, in 2008 and '09, when there was a recession, we didn't think -- and the market prices and the export market were slow, well, we didn't think it was necessarily the best time to be launching some new -- new programs.

Levelized utility cost. During -- we're -- we're -- we don't believe rules should be established for that, as well. And we're willing to -- - we're willing to have programs with different levelized utility cost for two (2) reasons. One (1) is it may make more sense to achieve the -- the DSM opportunities within a particular opportunity because the barriers, and we just have to pay more, like the Water and Energy Savers Program. The other reason is, and this is very important, is our mar -- when we compare it to the marginal value, that marginal value number that you hear is just a proxy number. The energy is worth more to us depending on the season and depending on the year. So if the energy's being captured during the wintertime, we're willing to pay more for that because it's worth more to us.

And my last point is the optimum program designs may mean offering different incentive levels over time.

And my other point is it's not all about -- and I mentioned this already -- about paying higher incentives, and I have a few examples to demonstrate that.

So this is our home insulation program and on the top, the different coloured coding is when

-- indicates when the incentives offered to customers changed. This is the combined incentives that -- offered to customers by Manitoba Hydro, and the Federal Government in this case. So we started the program by offering -- and this is just a typical number -- it's each -- each customer -- it depends on which measures you put in place, but just typically about five hundred dollars ($500) for the first period of time, you'll see in blue there. And the -- just to orient you, that's the number of customers that participated within a quarter. And what happened approximately a year later, a little longer, is the Federal Government came with -- came out with Eco-Energy Program, offering a thousand dollars. So incentives were tripled at that point, and you can see that participation didn't triple.

So it's not all about offering incentives. And -- and so if you were to measure how cost effective that ext -- additional thousand dollars were that the gov -- Federal Government offered, you really should assess it from an incremental perspective and say what would have happened without it, and -- and evaluate the -- the cost relative to just the incremental energy savings that would have been achieved with that additional thousand. And you

have to keep in mind when you are accessing that cost, all customers that participated in that program, whether influenced by that thousand, or just Manitoba Hydro's five hundred (500), would have to be taken into account on that assessment. So at the margin, just looking at that, I -- I would suggest that, that was not cost-effective on their part.

They subsequently came out with inc -- an initiative to increase that to twelve hundred and fifty (1,250) instead of a thousand and they also had a tax credit associated with that. And I believe it was time limited. Time limited actually will assist in influencing customers as well.

And you could see that there was a spike, and I would suggest that the time limited component of that actually drove the spike. But if you look under the shaded area of the green there, and if you were to evaluate that program, or -- or that particular incremental component of the federal contribution, you -- you might not conclude that, that's economic either because what probably happened was that you advanced some people from -- to -- advanced some customers that would have installed the measures anyways had you not added that incremental incentive there. So it -- it becomes quite

complicated and there is a lot of judgement that would be used.

So when you hav -- offer something like that for a time limited period, in our judgement is, you advance some and -- customers that would participate otherwise and -- and they just part -- participate earlier. And of course some are actually are impacted by that opportunity.

The subsequent period is in purple there. This is when we went back to just Manitoba Hydro's incentive, and you can see the participation actually declined. But I'll also point out that you'll notice that there's an overall decline throughout this entire period, and that's generally what you expect to happen when you're pursuing a particular opportunity; the market size is diminishing as you get more and more custom -- customers to participate, similar to furnaces. At one (1) time we had about sixty thousand (60,000) standard efficient furnaces. As you move along in time, it's fifty (50), then forty (40), and so there's less customers that are available in your target market.

Subsequent to that period -- and I'll go to the -- the orange there -- the Federal Government came out with the an -- an aggressive eco-

energy program which was comparable to what they had before they re-announced it. And we increased our incentives at the same time, and you can see that, that -- that captured a number of customers -- or influenced a number of customers to participate, so.

But at that point, now you're at four point six (4.6) times the incentive level, but -- and not increasing participation by four point six (4.6). And now we're back to where our current program is, at -- at eight hundred dollars ($800).

So -- so there are some lessons to be learnt in and -- and just looking at what happened under that program. And well I've -- I've mentioned them already, but it's not all about incentives; it may make sense to change your incentives over a period of time; it may make sense to offer time-limited incentives to influence people. But in the end, it takes time to get customers to participate.

There's -- there's different customers. Customers are at different space in -- at -- at different times in the future, and so as you move along in time, more customers are -- might be willing to insulate their home for different reasons: They're -- they maybe have more money. They're at a different stage in their life. People change homes that they

live in, so new people moving into a home after they've been there for a while might be willing to do it as opposed to the previous people.

Geothermal: You mentioned geothermal as -- I could talk about geothermal for quite a while. So -- so geothermal -- there's a couple things about geothermal. The one (1) thing that I -- I -- I'll start with, the level of incentives offered here did not result in a lot of participation. So if you start on the left in pink, red, the incentive levels were thirty-five hundred dollars ($3,500), they weren't insignificant, and the participation was extremely low.

In the green area, you can see participation again was not high. And at that point, the -- these are Federal Government incentives -- the Federal Government raised it from thirty-five hundred (3,500) to forty-three hundred dollars ($4,300).

And -- and then when we move to the orange, they increased the incentives to over five thousand dollars ($5,000). And you could see that certainly more customers participated, but is not a significant number.

Geothermal -- and I'll just offer a few comments on geothermal. I've been working on

geothermal going back to the Waverley West days, if you recall, with the Manitoba Government interested in installing geothermal in Waverley West. I've been involved in the Canadian GeoExchange Coalition. I was a chairman. I chaired the board on that -- that coalition for -- for a year and I was a board member for a number of years. But the Federal Government and Coalition, as well as our local government, as well as Manitoba Hydro, have been scratching their heads and trying to figure out a way of making geothermal work and getting more customers to participate in geothermal.

The challenge with geothermal is, is it's not a mature market. So when you don't have a mature market, the cost of installing geothermal can be rather high, and so the payback period isn't very good on geothermal, and it's a significant cost. If you got a quote for a geothermal system, you'll be looking at over twenty thousand dollars ($20,000). It's like buying a car.

So when customers are thinking about installing a heating system that could cost thirty-five dollars ($3,500), four thousand dollars ($4,000), and they -- they have that option, it -- it's very difficult to go down the geothermal path.

And if you're in an existing home, the other thing that you'll be -- become aware of, if you look into it, is your yard is going to become a mud bath when it's installed. It -- you have to totally la -- re-landscape, so it's not just the cost of installing geothermal; it's also the cost of re-landscaping. So fairly significant.

We have been successful with working with a couple of First Nation communities, however. And this part summer, Peguis First Nation and Fisher River have become very inter -- well, they're interested in installing geothermal. And we have a program with them that's called the Community Geothermal Initiative. And by taking a utility model, you can drive down the cost and it can become more cost effective. And so tha -- we were able to do that with them, and working with the industry to install geothermal systems at a much lower cost, so that they would be cost effective. But even then they're not cost effective for every home.

So we're currently doing that. There was a hundred and seven (107), I think, installed this last summer where they're -- the communities are planning to install more next year. I think both communities are planning to install at least fifty

(50) per community. We're working -- talk -- discussing the same initiative with four (4) other communities.

But geothermal doesn't always work in every area. So one (1) of the communities that we've talked to, the home is very small. So if the homes aren't big enough there's just not enough savings there, so those homes don't make sense, so.

The other thing to take into account, if you have to drill through rock to put the loops in, very expensive, so that doesn't make sense. So even when you do the utility model or community model those aren't cost effective either, so.

So the -- the applications of geothermal are limited and the barriers to -- in getting a significant number of geothermals installed in the marketplace is very challenging.

(BRIEF PAUSE)

MR. LLOYD KUCZEK: A couple of comments on the use of RIM. I think it's been mentioned by others that it's a crude metric and it doesn't have much value. I'll agree that it's a crude metric, but we do pro -- we do think it provides

marginal -- some value to Manitoba Hydro in the context of all the metrics that we use.

And so given that it provides some value, we still calculate the RIM and provide that information, along with all the other metrics, when we look at program designs. So it provides some insight in terms of directional impact. If the directional impact is negative, that doesn't mean Manitoba Hydro won't -- will not pursue a program. The key measure for us is if the benefits are greater than the costs, we should be pursuing that program. It's really the program design that makes the most sense to us.

And it also provides some insight when we're looking at that total resource costs or the levelized resource cost because of the seasonal different values.

So when staff are presenting me with some information and I see a levelized utility cost for two (2) different opportunities that are the same, it might be more -- one might be more valuable to me. And all I have to do is look at the RIM and it tells me that. And it's just a comparative measure. That's all it really is.

(BRIEF PAUSE)

MR. LLOYD KUCZEK: So some people also ask the question: Why doesn't Manitoba Hydro invest more in DSM? Our levelized utility cost is only two point four (2.4) cents and our marginal cost is much higher.

The simple answer is we pursue all cost-effective measures. So when we talk about what the program cost is, that is the average of all our initiatives. So it's inherent that if you're pursuing all opportunities that are below your marginal value, there's going to be some that are less than that or -- they're all going to be less than that, and some that are going to be considerably less than that. So when you do the average for the program -- the plan, clearly the number's going to be lower.

The other -- the other reason is -- is because we share the costs with our participating customers. We don't always pay it. In this diagram here, it'll show you what -- how they're shared between our customers with the different programs, the green being what Man -- the customer contributes, and the red being -- or the blue being what the Utility contributes.

And you can see the first one I mentioned, that on your left is the Water and Energy

Savers Program, where we pay the entire cost, and the third one is lower income, where we pay the entire cost. And the -- the sharing is different for each program, as I mentioned to you before.

We -- we come up with a -- a sharing based on what we think was -- would be the most effective program to achieve the results. And as you move along in time, that ratio could change.

The other -- the other point I guess I should make as well is: How do we compare to other utilities? Is -- is our levelized utility cost extremely low compared to what other utilities invest in?

And I don't have a slide that shows this, but Mr. Dunsky's testimony provides on page 34 a graph that compares what Manitoba Hydro's first-year costs, I believe, are compared to other utilities. And it's generally -- with the exclusive of four (4) utilities, generally in the same range. There's variations among regions, but generally in the same range. BC Hydro's two point nine (2.9); we're two point four (2.4).

This subject is a little more complex, but I gave a -- in -- in -- I'll provide you with the reference. This is PUB/Manitoba -- or our response to

PUB/Manitoba Hydro-1 to 16(b). I provided there an example to hopefully shed some light into why utilities don't spend more possibly on -- in terms of DSM costs than what you see being spent in the industry.

And -- and so it tries to address: Why do utilities not invest as much on DSM as they do on generation? So one (1) of the considerations is -- is, first of all, you need to look at the total resource and the cost, not just Manitoba Hydro's cost. So when we're talking to the utility cost, that's just that component to start with.

So the example I -- I provided there -- and this is very simple. This is not the real world; that I provided a very simple example just to help people understand why this might be the case.

So one of -- one of the key principles to understand is -- is DSM is different than supply-side options in the sense that when you pursue DSM in an ideal world, and if you're not interconnected with other utilities, there is no revenue associated with DSM, whereas with supply-outside options, there is revenue associated with generation because your -- your load is increasing, you build more generation and, so there's more revenue coming to the -- into the

company.

So what -- what the example is intended to show is if you just look at a simple utility not interconnected, what would be the impact of the decision to either pur -- pursue new generation, which is at a higher cost, or pursue DSM options?

So I -- I provided a very simple example where the generation is equal to the load to start with, 1,000 gigawatt hours of load, 1,000 gigawatt hours of generation. The utility's rate is seven (7) cents; just call it levelized for argument's sake. And the total revenues brought in through the company are 70 million. So I'll just walk you through if -- what would happen if you chose different paths.

So this is the existing situation. The rates are seven (7) cents. And I'll suggest they're levelized just for argument's sake. The bills being paid by the customers -- and people argue that bills are more important than rates and we agree with that. It's -- it's the total bills that the customers pay that's relevant. And each customer in this case have paid seven hundred dollars ($700) for a yearly energy bill.

If you pursue the generation option, which has higher cost of ten (10) cents, and you do

the math the utility has a larger customer base and -- but its costs have gone up because the -- the incremental generation costs ten (10) cents as opposed to its embedded cost of seven (7) cents prior to that.

So now it has to raise rates, and the math -- it'll come out to seven point two seven (7.27) cents. Customer -- customers' total bills are 80 million. And the customer average bills, even the -- if you consider each customer being the same and -- their bills go up. So there's new customers, everybody uses the same, but now the bills are up 'cause new generation cost more. It's just all the math, if you roll through it.

Now, if you take the alternative option of pursuing DSM and your position is, is that you're going to spend just as much on DSM as you spent on new generation, what happens there is, is that the rates have to go up even more. And the reason the rates have to go up even more is because now you have -- you don't have as much energy that you're selling, and you spent the same amount on -- that you would have on generation. So if you do the math, now the rates actually have to go higher.

And so the total bills for the customers in aggregate is the same. So -- so the

argument is the total bills is what's relevant, and you -- you should be indifferent, Manitoba Hydro -- or utility, and you should spend that. The concern is the fairness issue, and -- and this is the point.

So what happens is participating customers' total bills are actually lower than they were before, and the total bills of non-participating customers are higher, so...

So what I did was I -- I did the calculation to say, Well, what -- what would you have to do if you were a utility and you were -- you wanted to be fair to your customers? And so then you should invest in DSM at least to the same degree as what their impact -- bill impacts would be the non-cust -- participating customers as they would be if you pursued new generation options.

And -- and so the outcome of that would be is that the bills for the non-participating customers, they go up from the base case just like they do with new generation, but they go up no higher than they would should you chose new generation. So those customers aren't impacted in a negative way. The participating customers' bills are even lower. But the offset, of course, to that is they have to invest in the DSM opportunity and -- and pay a portion

of that.

So I offer that as an example, as a simple example to -- to give you a feel for what may make sense from a utility's perspective if you were taking fairness into account. This is very crude, this example. We -- we don't think in terms of this. The real world is much different. But it provides some insight if you take into accou -- just recognize that with DSM there -- there is no revenue associated to that when you pursue DSM; with generation options, there are.

And the other point I'll add, because it's come up at our GRA, is the marginal value relative to the export market. So people -- you -- you've asked the question about, you know, like, how -- how do you think in ter -- or how do you compare that, what I just explained, and co -- compare spending on DSM relative to new generation as opposed to the export market.

So if the value is determined by the export market, what I would suggest is, from a utility's perspective, the relevant metric would be you should -- or -- or a guideline should be that you should spend just as much -- you should be willing to spend an amount that's equal to the difference between

the value in the export market relative to what your loss revenue is domestically, because that's the economic benefit to you as a utility, so...

And so generally speaking, if you looked at the export market and if your rates were five (5) cents domestically and the export market was seven (7) cents, you should be willing to spend two (2) cents on your DSM opportunities, because there's an economic benefit to you as the utility.

So in the real world it's much more complicated. And -- and you could -- the -- the panel that deals with our integrated resource planning process can discuss all those issues. But the point I was just trying to make here is -- and trying to assist you with is trying to understand that it's generally in the same range. And also, the important -- the other important part is the fairness issue.

Having said that, I would say that Manitoba Hydro doesn't -- doesn't look at it that specifically in terms of what we're willing to spend on DSM on a particular measure. Our primary criteria in our decision making is what's the most effective, in terms of a program design to achieve the -- our objectives.

And I think -- I think I've already

talked about this slide. So benchmarking. Based on my experience being in this industry, or at least working in the DSM area, I offer three (3) comments. Benchmarking should consider a utility's DSM efforts from a broader perspective beyond just programming achievements. And I touched on that earlier in terms of codes and standards is very important, but it goes beyond that; as well as looking at what's been achieved through codes and standards, the -- the marketing efforts, the -- the education, and supporting emerging technologies.

My second comment is -- and observation has been that there's no single metric that should be used to benchmark DSM efforts among utilities. Regional differences can result in misleading information.

And the third point, probably the most important, is caution needs to be exercised in any comparative analysis, as reported. Energy savings can be misleading. There's gross energy savings relative to net energy savings. There's inner active effects that some utilities take into account, others don't.

Accuracy of baselines. I've got a slide that'll explain this in a little more detail. And there's the free ridership issue. I mentioned

there's a lot of judgment used in -- in this industry. And -- and because of that, a lot -- one has to be careful with comparative measures.

When one talks about gross savings, that -- that's just looking at what's been achieved regardless of whether -- what's been achieved in the marketplace through both natural conservation and what would have happened with and without programming. And -- and so that's what gross means.

The net savings is, is looking at what is really being achieved only because of your programming efforts. And it even becomes more complicated within programs, as I mentioned earlier, because when you're thinking about program designs and you want to start assessing things from an incremental perspective, your brain could explode sometimes thinking about the different options that are available.

So -- so you -- you can't get lost in the detail in terms of looking at too many infinite opportunities. You have to just decide on a program that makes general sense.

Baselines: there's a lot of judgment. When I say "baseline", that's what's going to happen in the marketplace for a particular opportunity if you

don't intervene in the marketplace. So that's just a projection of what you think's going to happen.

So if you take LED lighting right now, our staff would be looking at the marketplace and trying to project what the participation is going to be with L -- LED lighting into the future. There's a lot of judgment in -- into that. The -- the projection of what that would be today is different than what it would have been a year ago, because the marketplace has moved faster than what -- what we thought.

Okay. I'm going to move into the sensitivity analysis and how...

MS. MARLA BOYD: Apparently we need a bit of a time out, Mr. Chair.

THE CHAIRPERSON: Think it would be an opportune moment to take a break. Why don't we take -- ten (10) minutes enough, or do we need fifteen (15)?

MS. MARLA BOYD: Either's fine, sir.

THE CHAIRPERSON: Okay. So let's resume again at twenty (20) after, please. Okay. Twenty-five (25) after.

--- Upon recessing at 11:14 a.m.

--- Upon resuming at 11:28 a.m.

THE CHAIRPERSON: I believe that we're ready to resume the proceedings. Before we ask further questions, Mr. Williams, you had some --

MR. BYRON WILLIAMS: Yes. Lest Mr. Simonsen get too -- too angry with me, I'd ask that the PowerPoint presentation of the opening statement of CAC (Manitoba) be marked as CAC Exhibit Number 44.

--- EXHIBIT NO. CAC-44: PowerPoint Presentation of Opening Statement of CAC (Manitoba)

THE CHAIRPERSON: The panel has no further questions, at least at this time, for -- for you, Mr. Kuczek. So I wonder -- we're now proceeding to -- to you, Mr. -- I might go back to you -- back to you, Ms. Boyd.

MR. SVEN HOMBACH: I -- I don't think Manitoba Hydro is completely finished with its presentation.

THE CHAIRPERSON: Okay.

MS. JESSICA SAUNDERS: And my apologies, Mr. Chair. Mr. Chair, Jessica Saunders. I -- I intended to jump in right after Mr. Williams, but in terms of outstanding matters from yesterday we also

need to name our book of documents Volume I from the cross-examination of Mr. Thomson from yesterday as Exhibit number 28. So I would ask that that be added as MMF Exhibit 28, please. Thank you.

--- EXHIBIT NO. MMF-28: MMF Book of documents Volume I

THE CHAIRPERSON: Thank you. Mr. Kuczyk, back to you then.

CONTINUED BY MS. MARLA BOYD:

MR. LLOYD KUCZYK: Thank you. The remaining slides I have shouldn't take too long. There's -- there's not a lot of detail discussed within each. But the first area that I want to talk about is the sensitivity analysis that our staff are undertaking with regards to DSM options, and I want to just share with you how we develop those options.

And so what we did is we -- we looked at our existing opportunities, programs that we're pursing today, and we asked staff to drill down and see if they could come up with program designs that were more aggressive. And they did that. And then we sat down and we -- we reviewed those designs. Some of

them actually were well under way anyways, and we were planning to pursue those. Some were not, so not quite as much analysis went into them. So I'll just suggest you need to use some caution with some of the program designs that we included.

But so we -- we looked at the number of programs that were offered, and we put into the bucket -- one bucket the ones that we -- were economic as -- as filtered out by that marginal value, and we ended up calling that Level 1. And the other bucket, we threw in some program designs that were non economic as measured by the margin of value, and we ended up calling that Level 3.

And so I'll -- I'll talk a bit more about what those programs are, but essentially they're the same programs just different designs. And there's a few new programs that were on the horizon related to LED lighting that -- where the costs have recently dropped and we decided we would pursue those, or at least include them in this package. But we have decided that we're pursuing them anyways.

The other category of options that we looked at was -- and -- and they're somewhat different than energy efficiency, so we included them as -- in a different bucket. And these are initiatives that we've

been looking at for a while.

Fuel choice, a campaign that we've had in place. We mentioned that our current strategy was to use an education approach and try to convince customers, or educate customers and let them make a choice. And our -- our -- we felt that they would chose natural gas over electricity should they have the choice for the most part.

What we did with that particular initiative is we said, What if we were more aggressive and offered a potential incentive program? Could we get more customers to actually change out their existing systems, and go to natural gas? So that's -- that's one of the opportunities we included in this package.

The other one is load displacement. We've been doing some work on load displacement for a while. We actually had a pilot in place. It goes back to roughly 2006, where one of our customers was doing -- undertaking self-generation. And we discontinued that one when the export market went down in 2008/'09. I -- I forget the year that we cancelled it, but that program was the -- was based on the economics associated with the export market.

It was a short-term arrangement with

the customer. I can't recall if it was based on a six (6) month time period, but the value to us was based on the short-term market, so it wasn't there anymore. And -- and there's some other initiatives that we currently have in place that we've been pursuing under that load displacement category.

What we did do is we looked at -- into the future and looked at -- for potential other opportunities for the load displacement. And so what we included in that bucket was those opportunities as well. So that's another category.

And the third category that we included in here was having energy conservation rates, and we started down that path in 2010, and -- which ended in 2011. Wasn't a very aggressive approach. And so what we included in the package was conservation rates but more along the lines of what BC Hydro is offering their customers, and it's a more aggressive approach.

So it's a two (2) tiered system where the rates would be significant enough to impact customers, and -- and you'd have some influence in terms of reduced electrical consumption in Manitoba.

So that's the three (3) packages. We did some high-level estimates in terms of what it would cost, the energy savings. And when we looked at

that second category that I talked about, put it through the filter, it -- it was economic. So we called that Level 2 because Level 1 was economic based on our assessment, Level 2 was economic, and Level 3 wasn't. And we provided that to our integrated resource planning staff for assessment, and they're undertaking that assessment.

So this graph here shows you the high-level estimate of what the energy savings we thought we could potentially achieve. Again, this was a very high-level estimate, and so I caution you to use it in that regard -- or in -- taking that into account.

And my last point would be that our 2014 Power Smart Plan that we're currently working on updating will be different than any of those levels, which brings us to what can I tell you about our 2014 DSM Plan.

You can expect most programs identified in DSM Option 1 will be pursued. Not all, but there'll be modifications.

Level 2 DSM initiatives required broader consideration. Load displacement looks promising, I would say. Energy conservation rates need to be thought through carefully. They also require the Public Utility Board approval. And I'm

sure the Intervenors will have an interest in what we do in that regard. And fuel switching requires further discussion with our -- our government.

Level 3 DSM initiatives is not likely to be pursued.

So I want -- I want to just share a bit of information with you in terms of those programs. So one might be left with the impression that there was a lot of new opportunities that came out of the market -- the market potential study, and that's not necessarily the case. The programs that we're looking at for the most part, other than three (3) new programs, are the existing initiatives that were economic before, still are economic. We've just changed -- we did two (2) things.

One is we -- we've extended the time period where we're going to be offering these programs, and we estimated what we would get for participation there. So naturally you're going to get more energy savings because of this extension of some programs; not all programs.

And the other thing we did is -- with some programs is we took a more aggressive approach; so in some cases, higher incentives. And -- and so that ended up with more energy savings.

The three (3) new programs, they were on our -- our radar screen for a while now. We've been assessing roadway lighting; we've done some pilots. It would be only appropriate to maybe discuss our 2013 plan. We've stated that, I believe, in our rebuttal, that it was a conservative plan.

What we decided to do with our -- when we designed our 2013 plan is to only include those opportunities which were approved for the most part. And so it did not include the LED lighting at that time.

The other two (2) ini -- one was roadway lighting that we included; the other one is residential LED lighting, so both related to LED lighting.

The price has dropped substantially. I still recall when Philips announced the -- the typical bulb was going to be around ten dollars ($10) as opposed to, I think, thirty-five (35) before that. So that was a significant change in price. And it prompted us to look at the -- the opportunity more seriously.

And the community geothermal program, we launched that this summer. And there's a lot of challenges with geothermal. But given how successful

we were with Peguis and Fisher River, we're hoping to pursue more opportunities with communities like that and capture some opportunities there.

(BRIEF PAUSE)

MS. MARILYN KAPITANY: Mr. Kuczek, just before you move, could you give a couple of examples of what these Level 3 DSM initiatives that are not likely to be pursued?

MR. LLOYD KUCZEK: They're actually the same opportunities. So -- so what we did, and I meant to share this with you as well, is -- so we tried doing this actually in 2007/'08 -- I'm not sure what year it was -- was I asked my staff to take a look at all their programs and try to come up with an option that's more aggressive. And so what I tried to do is assess whether or not it made economic sense to take a more aggressive approach and assess it from an incremental perspective.

Because there's so much judgment involved in designing programs and -- and the participation levels and the baseline and all that, what -- what the outcome of that was is that the incremental cost back then was so high, nothing looked

like it was going to make sense. So we just stayed with our existing programs for a number of years.

What we did this time is we -- we've moved along in time, and staff are more informed and more aware of what the issues are and what the opportunities are. Plus the time frame for when the programs were scheduled to end was much closer. So when they looked for options to get more savings, they were able to have a better sense of what they can capture in the future because the time frame wasn't so far out.

You asked for examples within -- so if I took lighting, you would just -- you might give them away free and -- as opposed to -- buy one (1), get one (1) free sort of -- sort of thing.

So the -- the outcome of our -- the assessment was such that, even on the -- with our Level 1 option that we developed at the margin, it still came in at over eight (8) cents.

So when I mentioned earlier that -- the bubbles that are filtering down through the filter there, there's still some red in there because -- and that's what becomes complicated about these program designs because you can always have an infinite number of designs. So it's best to just look at fairly

significant changes and try to assess what the economics are associated with that.

So you get into this realm of, okay, so what's acceptable in terms of having some red in there? And it's this averaging as opposed to just, you know, what's -- if you -- if you pursue it -- and when I talked about the insulation program, for example, so when you first launch that program, you offer five hundred dollars ($500). You could have offered -- a thousand dollars ($1,000) or two thousand dollars ($2,000) probably didn't make sense.

So -- so when you look at those two (2) different options, you try to assess what you're -- what -- what you're going to achieve with the incremental incentives, and -- and do the economics based on that.

And so when we did our economics of Level 1 against our current program, it came in at around eight (8) cents. So not economic, but we're really not -- you know, you don't want to get concerned about that -- that sort of detail because it's just too much judgment involved.

Level 3 was just taking it another step beyond that. And that came in I believe around nine (9) cents, but there's a lot of uncertainty associated

with that, but the same opportunities.

THE CHAIRPERSON: The Level 2 DSM initiatives that you're considering will show up when in the rate application?

Would you expect not the current one that's slated to be tabled --

MR. LLOYD KUCZEK: The --

THE CHAIRPERSON: -- shortly, or --

MR. LLOYD KUCZEK: -- the energy conservation rates? No, that -- that would prob -- that's going to take us, I would suggest, a year. And at that point, we would, subject to receiving internal approvals, like -- likely bringing something forward. But again, that has to be discussed internally. That'll have to be discussed with government as well. It's -- it -- it would be a significant change in terms of what we offer our customers.

DR. HUGH GRANT: Could I -- could I come back to this marginal value argument again? Could you explain how you reached this marginal -- marginal value with respect to, say, domestic price or export price, or what other considerations you have in mind?

MR. LLOYD KUCZEK: Well, the marginal -- I'm not an expert in this, so I'm not going to --

it's subject to correction by the panel that will deal with this. But the marginal value is determined by a computer model taking into account -- oh, go ahead.

MR. ED WOJCZYNSKI: Good morning. Ed Wojczynski speaking. The marginal value of what we -- there's three (3) components to the marginal value. There's a generation component, a transmission component, and distribution component. The largest component is the generation component.

What we do -- and I'll -- I'll take a -- a example of a base load, the simplest explanation I can give, where it's a flat load through the whole year. Something like a very large industrial customer might be like.

So what we do is take the -- every year we do a calculation, we take the Power Resource Plan -- Plan, the same one you see in the IFF, and we apply a five hundred (500) gigawatt hour load reduction across the plan and all year, summer and winter evenly. And we do an evaluation without the reduction. We do an evaluation with the reduction.

And the change in the generation production costs, meaning exports thermal operation, everything across all the flows, just like we do in a IFF and we do in the normal generation evaluations, we

determine the cost saving or the cost benefit by reducing the load.

And -- and that would be the component of marginal value for that five hundred (500) gigawatt hours from the generation side. Then we divide by the energy and you get a dollars-per-megawatt-hour or cents-per-kilowatt-hours saving.

The second component would be transmission, and the third is distribution. And there we do something much different. We go periodically, we take the next ten (10) years of capital expenditures on gen -- on transmission, and we determine which of those, if we had that same load reduct -- kind, a one (1) year's load reduction in load growth. And we -- we determine how much of that capital forecast would be pushed back by that year. And we divide that by the amount of load reduction and we get a dollars per kilowatt or -- savings or benefit. And it's only capacity, not energy.

And similarly on the distribution side, we look at what the distribution budget is, how much it would be reduced or deferred, if we had a load reduction and -- and then we applied that for the capacity. And then we put those all together and get a number, depending on which year, it's varied from

year to year, but in the order of seven (7) cents a kilowatt hour.

DR. HUGH GRANT: So -- so the marginal value is generally higher or lower than the average cost that, say, a residential consumer would pay?

MR. ED WOJCZYNSKI: That would depend on the year and the exact rate. I -- I -- the -- the number in 2012 was six point six-nine (6.69) cents for this flat load that I'm talking about, which isn't what a residential consumer has. A residential consumer is more peaky than that. So the cost by the residential consumer would be higher than that. But off -- offhand I don't know how much more it would be.

So you'd have to go to the specific customer load shape and then compare against the specific rates for that customer. So that would be fairly customer segment specific.

DR. HUGH GRANT: I guess the reason I ask is in -- in terms of demand-side management, if you have many instances where the marginal benefit to the, say, residential consumer is greater than your marginal evaluation, then why are you engaged in this activity at all? Right, in other words, the residential consumer can look at there own cost and benefits and if they're a fully informed consumer,

which is a bold assumption, then they would just undertake these initiatives on their own -- their own right.

MR. LLOYD KUCZEK: The problem is they don't though. So there's -- there's a broag -- broad range re -- broad range of reasons why customers don't participate. But I'll -- I'll go to the very simple example of our lower-income program, where we pay for everything on the insulation side. And I've thrown -- thrown out a comment before, you would think when you offer a program like that, people would be lined up at our front door at 360 Portage to sign up for that program. That's not the case, we struggle to get people to sign up for that program.

You know, if you -- you would think if a customer had a natural gas standard efficient furnace, that was twenty-five (25), thirty (30) years old, and you offered seven hundred dollars ($700), why -- why wouldn't they take that seven hundred dollars ($700) and replace it today, as opposed to waiting for it to possibly break or fail in the wintertime next year? But -- but they just don't.

Even customers that are well informed, including the person to my left, did not replace their furnace, knowing all that. You know so, another one

(1), two (2) to my right, by the way.

So -- so, you know, they all have their reasons. Work too hard, I think is one (1) of the reasons I was given on the left.

And not a priority. You know, we had a focus group session with some customers where we asked questions about, you know, would they be willing to implement DSM measures if they -- if there was a 10 percent -- I think it was a 10 percent rate of return. We tried to get a sense for -- and the -- the comment we got back was -- or the sense was not top of mind, not a big enough rate of return.

And then the other concern, which is really interesting, was if the particular technology or -- or clients, whatever the measure was, if it wasn't at -- at its end-of-life, they were concerned about disposing something that was still useful yet.

MS. LOIS MORRISON: I would like to go on the record that I have replaced my furnace. Thank you.

MR. LLOYD KUCZEK: After it failed. Okay. So I just wanted to touch base with -- or -- or touch on the -- the actual process we do within Manitoba Hydro. It's not all linked to the integrated

revor -- resource process.

So when we have a DSM opportunity whatever time of the year that there is, that we've done our assessment, and it makes sense based on the marginal value that we have at the time, we take that initiative to our executive committee and we approve it -- or we seek approval. If approved, we implement it at that time. It does not have to go through the integrated resource process.

And just to exemplify that, we're -- we're already ramping up with our programs in terms of pursuing a more aggressive approach. These are the programs that we've approved at the executive level and are currently either implementing or actually in the process of implementing. And I also have two (2) more in my office that I need to review when I'm done on this panel, so. And Ms. Morrison might have some more in her office.

But the plan is, is to actually -- I mentioned, you can expect that most of the programs at Level 1 will be implemented, and this -- this demonstrates that, or it gives you some indication that it's likely that would be the case.

So in terms of time-lines, we're -- we -- we have a different process in the last year plus

with the legislation that's in place, the Energy Savings Act. We have to now complete our energy plan by March 31st of every year in consultation with the Minister responsible for Manitoba Hydro.

So what we did last year is we prepared a three (3) year plan under those consultations. And then, subsequent to that, we created what was called a fifteen (15) year supplemental plan. And the reason we created the supplemental plan is we require that for internal proc -- our internal planning processes.

So on a go-forward basis, is that going to change? It's looking like -- we're -- we're into March now -- it's looking like we are going to develop an updated three (3) year plan. And then we'll have to create a fifteen (15) year supplement plan, as well.

Time-line's March 31st. Clearly we got to do that, according to legislation, and complete that. And our supplemental plan we're hoping to have completed by April 30th. Thank you.

MS. MARLA BOYD: That concludes our direct examination, Mr. Chair. We're available for cross.

MR. SVEN HOMBACH: Thank you. Mr. Chair, I note it's about eight (8) minutes to noon.

I'll be happy to use those eight (8) minutes wisely, or if the panel prefers to break for lunch now, I'd be happy to start after the lunchbreak.

THE CHAIRPERSON: I think that the panel concludes that we should have lunch now. And so resume again at say quarter to 1:00. Is that possible? Quarter to 1:00. Thank you.

--- Upon recessing at 11:54 a.m.

--- Upon resuming at 12:54 p.m.

MS. MARLA BOYD: Just before Mr. Hombach begins his cross-examination, Board member Bel asked Mr. Wojczynski a question yesterday regarding the gas and Keeyask scenario. Mr. Wojczynski was looking for and has been able to locate the material in the record. So if we could have just a minute to speak to it, that would be useful.

MR. ED WOJCZYNSKI: Yes, Board member Bel asked me yesterday in all the plans and pathways that there wasn't a pathway that had Keeyask gas. We had -- pardon me, we had Keeyask gas, but we didn't have gas-Keeyask. And I'd indicated in a somewhat fumbled answer, I might say, that we did have that kind of information and that -- that it wasn't

economic.

But we located that piece of information and it was in an Interrogatory, LC and Manitoba Hydro, Round 1, 336. And in it we provided, at the reference scenario, three (3) plans: the all gas plan, and the Keeyask gas plan just like is in the submission, but we provided an additional plan that had two (2) gas turbines prior to Keeyask, and then Keeyask in 2028; and that's with no sales, just domestic load growth.

And what we found in there is that the gas-Keeyask plan was $709 million more economic than the all-gas plan, but that the Keeyask gas plan, where Keeyask goes first was $887 more beneficial.

So in other words, having Keeyask before gas was more economic by $178 million compared to gas and then Keeyask. Okay.

CROSS-EXAMINATION BY MR. SVEN HOMBACH:

MR. SVEN HOMBACH: Thank you and good afternoon. My name is Sven Hombach. I'm counsel to the Public Utilities Board. I will be having a few questions for you. I'll likely take the better part of the day. But before we get started, I'd like you to know that my questions will be questions to the

panel. They will not be questions to individual witnesses. So by all means, choose who the most appropriate pers -- person is to answer those questions. And if you need to consult with your colleagues, or if you need to consult with your backbench, go ahead.

Also, you should be aware that I'm not trying to elicit any commercially sensitive information, or CSI. If I'm asking a question to which you believe the answer entails CSI, I don't expect you to answer it on the record. There will be a brief CSI session on Thursday afternoon. I also fully expect that Ms. Boyd will have her finger on the buzzer in case I'm about to elicit anything.

Now, having heard the presentation from Manitoba Hydro's CEO Scott Thomson yesterday and the presentation from this morning, does Manitoba Hydro see it as its primary responsibility to meet the needs of Manitobans for electricity?

MR. LLOYD KUCZEK: I -- I thought that question was asked of Mr. Thomson yesterday?

MR. SVEN HOMBACH: And I -- I wasn't quite clear whether it was to be one (1) of the top three (3) or whether it was to be the primary one, but -- I -- I didn't anticipate this to be a controversial

question.

MR. LLOYD KUCZEK: Well, I got to be careful that I don't say something different than what Mr. Scott Thomson said.

MR. SVEN HOMBACH: Right. But -- but this Board is being asked to assess the Need and Alternatives to Manitoba Hydro's Preferred Development Plan. And -- and dealing for a moment with just the need, does need to you mean the ability to serve the electricity demand in Manitoba at any given point in time, including during peak load?

MR. ED WOJCZYNSKI: Ed Wojczynski, here. I'll answer that one. Yes.

MR. SVEN HOMBACH: All right. And Manitoba Hydro determines its ability to meet the need based on prospective load forecast that it prepares on an annual basis.

Does it not?

MR. ED WOJCZYNSKI: Yes.

MR. SVEN HOMBACH: Those load forecasts are prepared once a year?

MR. ED WOJCZYNSKI: Yes.

MR. SVEN HOMBACH: When are they usually issued?

MR. JARED WHELAN: Mr. Kuczek can

answer that better.

MS. LOIS MORRISON: They're issued in June of each year.

MR. SVEN HOMBACH: The NFAT filing is based on Manitoba Hydro's 2012 load forecast projections, is it not?

MR. ED WOJCZYNSKI: It's actually -- it -- it is based on the 2012 load forecast, but also within it was the 2013 load forecast where we had, in Chapter 12, an update to the earlier information. Because of the timing of getting the forecast, because of the timing of the IFF cycle, and the -- and the long duration of time to do all of the studies and write the report, we -- we -- it's inevitable that you cover more than one (1) cycle. So we did the majority of work using the 2012 load forecast, but then we provided an update in -- in Chapter 12, as I said.

MR. SVEN HOMBACH: The 2014 load forecast is not available yet, I assume?

MS. LOIS MORRISON: No, it is not.

MR. SVEN HOMBACH: I'd like you -- to refer you to an excerpt from the 2013 load forecast which was filed as Appendix D to Manitoba Hydro's NFAT filing, which I believe is Exhibit -- Manitoba Hydro Exhibit 14. The document on the screen in front of

you is Table 2 from the 2013 load forecast, which is page Roman Numeral IV of the document.

And on a weather adjusted basis, this shows that the total demand for energy in Manitoba during the 2012/'13 year was 24,404 gigawatt hours. That's correct data?

MS. LOIS MORRISON: That is correct.

MR. SVEN HOMBACH: And the actual amount was slightly more than that: 24,759 gigawatt hours. And weather adjustment just means that you are adjusting it to a weather-normalized basis, so that if there's an exceptionally cold winter, or an exceptionally hot summer that doesn't skew the demands?

MS. LOIS MORRISON: That is correct.

MR. SVEN HOMBACH: So those twenty-four thousand four hundred and four (24,404), that compares to an average projected output for Keeyask of about 4,400 gigawatt hours per year?

MR. ED WOJCZYNSKI: Dependable energy, yes.

MR. SVEN HOMBACH: Mr. Wojczynski, I believe the dependable output for Keeyask is about 3,000 gigawatt hours?

(BRIEF PAUSE)

MR. SVEN HOMBACH: If I refer you to Table 2.1 of the NFAT filing, chapter 2, page 4 of 59, which should be on the screen in front of you. It's about three thousand (3,000)?

MR. ED WOJCZYNSKI: Oh. Yes, that's the problem with turning sixty-two (62), your memory starts going.

So, yes, the dependable ener -- that was the average energy that -- that I -- not the dependable energy that I was thinking of.

MR. SVEN HOMBACH: And for Conawapa, dependable energy would be about 4,650 gigawatt hours?

MR. ED WOJCZYNSKI: In -- in -- around there, four thousand six hundred (4,600), yes.

MR. SVEN HOMBACH: And -- and to be clear on that distinction between average and dependable, dependable energy means the energy that you can produce during the worst drought on record --

MR. ED WOJCZYNSKI: Yes.

MR. SVEN HOMBACH: -- in Manitoba Hydro's hundred year history, to make sure that demand can always be met?

MR. ED WOJCZYNSKI: The answer is yes,

but I -- just a slight twist to that. It's not that it can always be met. You can have a situation worse than the worst drought on record, but to meet -- supply the load under that condition.

MR. SVEN HOMBACH: So when Manitoba Hydro is internally trying to assess the need for the Province of Manitoba, it must meet the need projected in the load forecast from dependable generation?

MR. ED WOJCZYNSKI: Yes.

THE CHAIRPERSON: Just to clarify that -- what you just described as the worst of the -- worse than the worst drought you've had on record. Does that constitute dependable energy? No, I --

MR. ED WOJCZYNSKI: Our -- our -- the definition of dependable energy we use is that energy that is available under the -- the worst drought on record. And we've actually had a -- two (2) -- more than one (1) that had more or less the same low level, so it's -- it's not just once in the hundred years, it's a -- a few times.

But it is -- it has happened, historically, from anecdotal information, that the -- the flows on the rivers in Manitoba in -- in the last few hundred years have been lower than that. And there is a significant likelihood, with climate

change, that we'll get some greater volatility and we could have -- we might have higher average energy from our system, but there could be more volatility which might mean some droughts worse than the ones we've seen.

THE CHAIRPERSON: But in assessing drought risk in relation to the application -- or, pardon me, the plan that's before us, you didn't -- the numbers you used for dependable energy are in relation to the worst drought on record as opposed to what could potentially be the worst?

MR. ED WOJCZYNSKI: Yes. And as I'd indicated yesterday, you look at energy security from two (2) points of view. One (1) is what is our criteria for dependable energy, which is the worst drought on record; and the other, the second part, is that you -- you can have droughts that are worse than that, and so you get -- some of the plans provide energy security above that minimum amount. And that's -- that is a benefit to Manitobans, and we do evaluate that separately. And that will be covered in the -- the panel next week.

MR. SVEN HOMBACH: Now, when Manitoba Hydro is projecting the need of Manitobans into the future, it's projecting both the total energy as well

as the peak capacity. And could you please explain for the panel on what the distinction is between the energy usage versus the peak capacity to deliver?

(BRIEF PAUSE)

MR. ED WOJCZYNSKI: Sorry. I thought somebody else was answering. With -- both peak and energy drive us.

MR. SVEN HOMBACH: And, Mr. Wojczynski, if it's easier for me to direct my questions to a specific witness, I'll be happy to do so. I try to accommodate Manitoba Hydro.

MR. ED WOJCZYNSKI: No. We'll just look at each other a bit more.

MR. SVEN HOMBACH: So peak, though, essentially means the ability to flow a certain quantity of electricity through at a given amount in time, total energy; that is the total usage number of kilowatt hours or gigawatt hours actually consumed in Manitoba, correct?

MS. LOIS MORRISON: That is correct.

MR. SVEN HOMBACH: Now, in chapter 12 of its NFAT filing, Manitoba Hydro indicated that there were some changes between the 2012 forecast and

the 2013 forecast that only became available in the summer. And I'm referring you to one (1) of the pages; it's chapter 12 of the NFAT filing, page 2.

That highlights some of the changes. And it's my understanding that what happened is, the 2013 projection for energy is quite a bit lower. It's a reduction of 1,159 gigawatt hours over a, essentially, twenty (20) year period, until 2031/'32.

And I believe peak demand is also projected to be lower, is it not?

MS. LOIS MORRISON: Yes, that is correct.

MR. SVEN HOMBACH: And to put that into perspective, in the NFAT, Manitoba Hydro indicated that one (1) year of growth is approximately equivalent to 420 gigawatt hours.

Is that still the number that's being used today?

MS. LOIS MORRISON: It's close. Under the 2013 forecast, one (1) year growth is equivalent to approximately 413 gigawatt hours.

MR. SVEN HOMBACH: But either which way, what that means is the twenty (20) year projection and the 2013 forecast shaves off about three (3) years worth of growth, give or take?

MS. LOIS MORRISON: You're referring to the change between the two (2) forecasts?

MR. SVEN HOMBACH: Correct.

MS. LOIS MORRISON: Yes, that is correct.

MR. SVEN HOMBACH: I'd earlier taken you to Table 2 of the 2013 forecast, which shows a projection over a -- a period of twenty (20) years.

Is it usual for Manitoba Hydro to only project use over a twenty (20) year period in its forecasts?

MS. LOIS MORRISON: Yes. We have traditionally prepared our load forecast on a twenty (20) year horizon, at which it is passed over to our resource planning group who project it to a longer period of time for planning purposes.

(BRIEF PAUSE)

MR. SVEN HOMBACH: So beyond the twenty (20) year time-frame, could you please explain to me what methodology you use to project load growth beyond the twenty (20) year time period?

MR. ED WOJCZYNSKI: I can give you a preliminary answer here and -- and the panel next week

could give a more detailed one, if you want. But we simply take the -- the end of the forecast that was done in detail and then just -- essentially just extrapolate it. And that's for -- that's to the end of the thirty-five (35) year study period.

MR. SVEN HOMBACH: And is it a -- a linear extrapolation?

MR. ED WOJCZYNSKI: Yes.

MR. SVEN HOMBACH: Based on what? Based on a regression analysis of the data points over twenty (20) years or just using --

MR. ED WOJCZYNSKI: No, just the -- the latter years, not through the whole time period.

MR. SVEN HOMBACH: Now, it appears from looking at Manitoba Hydro's financial analysis that was filed in the NFAT, that beyond the year 2047 you're not projecting any additional growth.

Do I have that right?

MR. ED WOJCZYNSKI: Yes. And that -- that is not part of the thirty-five (35) year study period. That's where we us -- we calculate a residual value at the end of the thirty-five (35) year study period. So it's not the -- it's not the normal detailed resource planning evaluation. It's a -- an evaluation of residual value. So it's done

differently in a somewhat conservative manner.

MR. SVEN HOMBACH: Right.

MR. ED WOJCZYNSKI: Trying to keep assumptions flat.

MR. SVEN HOMBACH: Now, for purposes of conducting the NFAT though, you're looking at a seventy-eight (78) year net present value period. So you're looking beyond the twenty (20) years and you're looking beyond the thirty-five (35) year horizon.

Does that mean that beyond 2047, for purposes of conducting your analysis, you're not assuming any increase in demand in Manitoba?

MR. ED WOJCZYNSKI: We -- we -- what the analysis beyond 2047 is doing is not attempting to assume whether there will be continued load growth or not. What it's doing is saying at that point in time we're going to stop our detailed studies and we have to get -- give some value, pres -- probably a conservative value of: You've got an asset that still has life, what would the value of that asset be at that time?

So we took a somewhat conservative assumption to say the -- for instance, that load growth did not continue and -- and use that. But that is in no way an attempt to forecast that there would

not -- whether there was load growth or not. We -- we were not making that conclusion.

MR. SVEN HOMBACH: So, Mr. Wojczynski, if I'm looking at Appendix 11.3 of the NFAT, and I'm currently showing page 2 of that document, beyond 2047 the domestic revenue projections are essentially staying the same. That then is based on the underlying assumption for analytical purposes, that there's no additional Manitoba demand, I take it?

MR. ED WOJCZYNSKI: Correct.

(BRIEF PAUSE)

MR. SVEN HOMBACH: And you mentioned that the assumption for load forecast is -- was done as a conservative method.

Total exports though are contingent on how much need you actually have in Manitoba and how much is used locally, is it not?

MR. ED WOJCZYNSKI: Yes.

MR. SVEN HOMBACH: Can you explain to me on -- on why it's conservative then to assume that there is no further load growth beyond 2047?

MR. ED WOJCZYNSKI: It -- it -- this is related to the fact that in any given year in the

future, you do -- there is a -- a wide range of amount of energy that would be available. And if you are fixing the amount of hydro we have in your system and -- and continuing to add, let's just say it's gas generation, the higher the load you have in your system, the more often -- the -- the more often the high flow years with lots of water produce a -- a higher value.

So even though you -- you are not adding more hydro generation, if you're adding more gas generation as the load grows, the hydro projects tend to get increasingly valuable because more and more of the high flow energy is very highly valued in terms of stopping imports, or -- or -- yeah, stop -- displacing imports or displacing a gas generation from operation.

MR. SVEN HOMBACH: But anything beyond dependable energy though, does not get taken into account for meeting the need, right? It just would be surplus power to export?

MR. ED WOJCZYNSKI: There's -- but in -- when you evaluate the -- the costs and benefits, you look at when you need new generation, but also, in each and every year what is the cost of running that generation. And even though you don't add more --

with -- within -- post-2047, if we had increasing load growth -- no, pardon me, if we had continued load growth we would find the hydro projects become -- provide more value in -- in the production costing in the year-to-year operation. But by keeping the load flat, we -- we don't provide the hydro that benefit.

MR. SVEN HOMBACH: Have you actually conducted that analysis where you've taken a scenario where you're assuming ongoing load growth and determined how that affects export revenue as opposed to analyzing it how you just described it?

MR. ED WOJCZYNSKI: No, but what -- what I've just described is -- and I -- we don't know how significant that additional benefit would be, but we generally know that's the tendency.

MR. SVEN HOMBACH: So you haven't actually analyzed that effect on export revenue of this assumption?

MR. ED WOJCZYNSKI: No, we haven't. No.

MR. SVEN HOMBACH: Now --

MR. ED WOJCZYNSKI: But maybe I can just add, we're confident it wouldn't go the other way.

MR. SVEN HOMBACH: Okay. If -- if you

haven't analyzed it, you -- you've obviously given the matter some thought. Is -- have you conducted an -- an analysis on that issue?

MR. ED WOJCZYNSKI: It is from -- un -- understand the underlying principles of how a integrated hydraulic, thermal, and import system work. And it's from the -- all the analysis we've done over many years in many different circumstances that I could draw that conc -- judgment and conclusion.

MR. SVEN HOMBACH: Generally though, do you disagree -- do you agree with me in that if there was increased domestic demand, that would result in lower export revenues? Or is there something that I'm not understanding correctly?

MR. ED WOJCZYNSKI: Yeah. Okay. Oh, yeah. No, I -- I think I see where you're going. In the hydro plan -- let's say we're -- we're comparing the hydro plan versus an all-gas plan. I think that's what we're probably talking about. In the Hydro plan, if you had increased domestic load post-2047, instead of keeping it flat, you would have less export revenue and -- and higher import cost in that hydro plan. In the gas plan, you'd have an even higher increase in costs.

So both, all-gas plan and the hydro

plan, would have, with the continued load growth, would both have increased costs, production costs, but the increase would be more with the all-gas sequence.

MR. SVEN HOMBACH: So are you saying then, that if you're comparing it across several plans, it doesn't matter that you're keeping the load flat after a certain point in time because that doesn't change the analysis between those plans?

MR. ED WOJCZYNSKI: What -- what I was trying to say earlier is that I -- I think my judgment is that we took a conservative approach by doing that. And I think the trend would be if you extended the load growth longer the -- the plans that have hyd -- more hydro versus more gas, the ones with more hydro would -- would get some additional benefit. How large that benefit is, I don't know. But we decided to not -- is to take the conservative approach and just it flat. And -- and the -- we felt the analysis was already a complex analysis, and -- and we were trying to keep it as simple as possible.

And also, as I said, we are calculating not doing a detailed -- as detailed analysis out there. We were simply trying to calculate and get an estimate of the residual value of the asset at that time, which is a bit different than -- than the front-

end, which is a full scale, detailed evaluation.

MR. SVEN HOMBACH: Okay. So that's dealing with the actual twenty (20) year period that you're forecasting as part of the electric load forecast. I'm showing you the index of the 2013 forecast just to show the different classes. Manitoba Hydro's projecting load growth by customer class, is it not? And there's, broadly speaking, the residential group, the general service mass market group, the top consumer group, and a few other minor ones?

MS. LOIS MORRISON: That is correct.

MR. SVEN HOMBACH: And just to put that into perspective, if I can refer you to Board counsel's book of documents, page 18. It's PUB Exhibit 58-2. That just provides a broad overview with how much, on a percentage basis, each of the different classes are consuming.

And it's about 29 percent, or 30 percent, for residential customers, 34 percent for general service mass market, about 23 percent of top consumers. And then there's another category that has about 13 percent that's losses and station service. I wonder if you could please explain what that pertains to.

MS. LOIS MORRISON: Losses and station service would be the -- the losses that occur through the transmission lines, taking the energy from the generation stations to the substations. There is a loss of electricity in that process.

Then there's also the distribution losses, which is the point where you take it from the substation to the customer's home. And in addition to that is -- there's energy consumed by our stations themselves. So those are primarily what's composed of that sector.

MR. SVEN HOMBACH: How does Manitoba Hydro distinguish between transmission and distribution? Is it a 50-kilovolt cutoff like some other jurisdictions use, or just based on the location of the substation? How -- what does Manitoba Hydro consider to be transmission versus what it considers to be distribution?

MR. LLOYD KUCZEK: Subject to check, I think it's the 66 kV.

MR. SVEN HOMBACH: So I'd like to deal first with the residential class, and I'll take you through some of the load forecast projections for the different classes.

Now, the primary focus for determining

future residential consumption is the population level in Manitoba, is it not?

MS. LOIS MORRISON: Yes, the population forecast is a primary input.

MR. SVEN HOMBACH: And I believe I heard -- I wasn't sure if it was you, or if was Mr. Kuczek this morning, saying that Manitoba Hydro obtains external population forecasts?

MR. IAN PAGE: Sorry, that was me who provided that.

MR. SVEN HOMBACH: Okay. Are you at liberty, sir, to disclose those forecasts, or is that commercially sensitive information?

MR. IAN PAGE: No, they're not commercially sensitive. They were provided in the response to ERA-MH Round One, Question 3F.

MR. SVEN HOMBACH: Okay. Can you just briefly explain who those service providers are?

MR. IAN PAGE: They're -- they're I guess professional forecasting agencies. There's Conference Board, which I'm sure a lot of people are familiar with, Spatial Economics, Global Insights, Infometrica, and the Manitoba Bureau of Statistics.

MR. SVEN HOMBACH: And does Manitoba Hydro simply average those five (5) forecasts, or how

does it --

MR. IAN PAGE: Yes, we do. We -- yeah, we just simply average them.

MR. SVEN HOMBACH: Okay. So the economic outlook that Manitoba Hydro prepares, that's the average on an annual basis?

MR. IAN PAGE: Yes, it is.

MR. SVEN HOMBACH: Now, there's been some variation in the economic outlook over the past three (3) years where it increased between 2011 and 2012. And then, for the 2013 forecast, it decreased again.

Can you explain the reason for that increase from one year followed by a decrease for the next?

MR. IAN PAGE: Are we referring to strictly a population?

MR. SVEN HOMBACH: Yes.

MR. IAN PAGE: What the -- the forecasters will do is, we'll -- they'll look at the results of current -- current trends, and -- and particularly things like the success of the Provincial Nominee Program. And there was a -- in 2011, there was a -- I guess, since about 2005, there had been a very steady increase in -- in the amount of

immigration into Manitoba. That -- in 2011, that number was -- was quite high. So that information was available for the 2012 forecast.

There was a cap that was put on federally in 2010, but that didn't sort of -- because of the lag results, didn't real -- didn't really affect the immigration levels until 2012. So the 2012 number was slightly lower than the 2011 number. So the 2013 forecast reflected that -- that newer information, so -- so it would -- made a projection based on that lower number.

MR. SVEN HOMBACH: Do you know where those numbers are heading for 2014, or is that not information you've received yet?

MR. IAN PAGE: We -- we're just at the preliminary stage of putting together the information, but it appears that it's very similar to what we saw in -- in 2013.

(BRIEF PAUSE)

MR. SVEN HOMBACH: Is it the 2012 numbers that Manitoba Hydro used to prepare the NFAT?

MR. IAN PAGE: Those -- those were what was pro -- was -- formed the basis for the

majority of the NFAT document, but as Mr. Wojczynski has -- has referred to, they were -- the 2013 numbers were included in that Chapter 12 update.

MR. SVEN HOMBACH: Just for illustration purposes I'm taking you to page 8 of the Board counsel book of documents, which is Appendix A.1 from the spring 2012 economic outlook.

And in each year, Manitoba Hydro takes the population level and then calculates the number of residential customers. Can you explain to me how that number of residential customers gets determined?

MR. IAN PAGE: Sure. The residential customer number -- forecast is based on the population forecast. And we look at the ratio, the historical ratio, of residents -- residential customers to population. And that number had been declining over the last few years. In the early '70s it was around four (4) people per -- per residential customer. I may inadvertently say per residence, but I mean residential customer.

And that number has declined to -- in the early '90s to about two point eight (2.8), and it's remained relatively flat ever since. So that two point seven nine (2.79) is actually the average of the last two (2) years, and that's what we use at our

forecast.

MR. SVEN HOMBACH: And, sir, I've seen the number of two point seven nine (2.79) in several documents, but when you calculate it, it also seems to go to two point seven seven (2.77).

Is it two point seven seven (2.77), or two point seven nine (2.79)?

MR. IAN PAGE: Well -- well, the two point seven nine (2.79) was -- was used in the forecast. It depends on how many years you include in the average.

MR. SVEN HOMBACH: Now, looking back at the past few years, what the charts do show is that on a year over year basis, the increased number of people in Manitoba and the increased number of customers show that the incremental additions are actually at a higher rate than the two-point-seven-seven (2.77) or two point seven nine (2.79).

Do you agree with that?

MR. IAN PAGE: I -- I would agree with -- mathematically with that result, but I think that what we're getting into is -- is -- I think it's a bit of a false premise to make that calculation that way, because it -- you're -- what that number would be trying to do is attribute all of the changes in -- in

residential housing -- or resident -- customers per -- people per residential customer to -- to the changes in population.

But even if that population were to remain fixed, we'd see a lot of variation in the -- in the, you know, people -- people as they age and -- people get married, people get divorced, people have kids, people get older and move to retirement homes. So there's a lot of changes in the underlying number of people per -- per customer than even outside of what's happening on the -- on the population growth side.

MR. SVEN HOMBACH: When Manitoba Hydro made that argument in its rebuttal that one shouldn't just be looking at a few years, one should be --

MR. IAN PAGE: No, I wasn't just referring to the number of periods. If -- I was actually referring to the calculation that was done on the -- on the document you've got up on the -- up on the screen right now, where -- where the change in customers is -- is compared to the change in population.

Whereas when we're doing the forecasts, we look at the change in residential -- in the -- change in residential customers compared to the change

in population, which is a much, much more stable number and it does incorporate that underlying change in the -- in the number of people per -- per residence that would happen irrespective of population growth.

MR. SVEN HOMBACH: Okay. And I'd like to explore that issue with you just a bit further to determine the impact, if any, on the load forecast.

For the record, the chart you're referring to, that's page 13 of the Board counsel book of documents?

MR. IAN PAGE: Yes, that's correct.

MR. SVEN HOMBACH: It's a chart prepared by PUB advisors?

MR. IAN PAGE: Yes.

MR. SVEN HOMBACH: It's not a Manitoba Hydro document, so I'm not asking you to accept the numbers unless it's subject to check.

But what that document shows is that, if you look back to 2006/'07 and calculate it to today, the incremental addition is about two point nine three (2.93) people per household --

MR. IAN PAGE: And that's the number I would disagree with.

MR. SVEN HOMBACH: Yeah. Well, you mentioned before, sir, that --

MR. IAN PAGE: I -- I'm not disagreeing with the mathematics that, yes, eighty-five (85) divided by twenty-nine (29) gives you two point nine three (2.93). What I'm disagreeing with is that attributing column -- the change in column 4 to the change in column 2, and I'm saying that there's things -- items -- things that are happening within -- in column 1, the total population, that this type of calculation is ignoring. And -- and I -- and I think that's erroneous to do that.

MR. SVEN HOMBACH: So let's take that issue in two (2) parts. The -- most of the population growth appears to be due to immigration, does it not?

MR. IAN PAGE: A good portion of it. But you'll see that -- if you look at -- at the increase in population, you'll see that it's also happening -- the number is increasing over time.

And -- and the calculation that you've done would also put greater weight on those later years, which is saying that -- that the population changes -- how the population and customer numbers are changing in 2011 or '12 or '13 is more important than what happened in -- in 2007 and '08. And, again, I don't think that's a correct assumption to make.

MR. SVEN HOMBACH: Well, there's an

article that we included at page 14 of the Board counsel document. It's an article from the Winnipeg Free Press --

MR. IAN PAGE: Yes.

MR. SVEN HOMBACH: -- a few weeks ago, that suggested that about 80 percent of the population growth in this province is attributable to the provincial nominee program -- immigration from other countries.

MR. IAN PAGE: And I -- and I -- and that number's not correct. The -- about 80 percent of the change in Manitoba's population is due to immigration, but a large portion of that is not due to the provincial nominee program.

People who ex -- who already are in Manitoba can -- can bring relatives in. There's refugee programs, there's a number of things that -- that are -- have to be included in -- in that total immigration.

MR. SVEN HOMBACH: Now, I appreciate your point, sir, that if you take these numbers, the incremental addition is not the only thing that you need to take into consideration, because there might be demographic shifts happening in the population that's already here that could change it. But does

Manitoba Hydro have any handle on that? Has it ever analyzed to what extent --

MR. IAN PAGE: We -- we haven't -- we haven't gone into that in detail, because we didn't see the value in trying to do that. Even if -- if you just look at it from a pure mathematical basis, that you -- the number you've just scrolled off the screen, the -- that right-hand column, you see incredible variation in that number. And if you just did a quick standard deviation of that column, you'll see your two point nine three (2.93) has got a standard deviation of point eight (.8). If we do our calculation, I get two point seven seven (2.77) using those particular years, a standard deviation of point zero one (.01).

And I would suggest that if that's something that's got a variation of eighty (80) times greater than doing it another way, it would not give you a meaningful forecast.

MR. SVEN HOMBACH: So there's not a lot of precision to those numbers --

MR. IAN PAGE: No. And -- and actually, if you really want to get down into high school maths, you can get it -- you say, Well, there's only one (1) significant digit in there, so really you're saying it's three (3) and -- and you've got a

variation from two (2) to four (4). And that's absolutely worthless for forecasting.

MR. SVEN HOMBACH: You should never threaten a lawyer with high school math.

MR. IAN PAGE: Oh, we're getting -- we're getting to -- oh.

MR. SVEN HOMBACH: But -- but all I'm trying to show, sir, is that there is -- there is a potential impact, just what -- if -- if you take the two point nine three (2.93) and if you carry it through, that means, pursuant to that number, there might be fifty-three hundred (5,300) fewer customers down the road --

MR. IAN PAGE: What I would -- what I would say, there's a large number of dynamics involved in population forecasting, and that's why we do it on an aggregate basis. If we try to pick apart individual pieces, we're going to see numbers that -- that are -- are meaningless on their own.

And I think to -- to do an extrapolation then based on a number that's arrived from using a meaningless calculation in itself would be meaningless. So I -- I cannot attest -- I can say that mathematically, yes, if you use two point nine three (2.93) instead of two point seven nine (2.79)

you will get a different number.

I -- what I am saying is that I don't believe there's any basis for using two point nine three (2.93).

MR. SVEN HOMBACH: The consensus forecast, did you actually file those in response to the undertaking you refer to on the record?

MR. IAN PAGE: That ERA question that I referred to, 3F, has the year-by-year numbers for each -- each of those forecasts, and it has some of the documentation that was -- that we received with those forecasts. I think that's all that we had available to us.

MR. SVEN HOMBACH: Does Manitoba Hydro ever track the precision of the population forecast similar to the way it tracks the overall load forecast precision?

MR. IAN PAGE: We -- we don't. And it's because, you know, as we've said, there's -- there's -- there have been changes with things like the Provincial Nominee Program. So a forecast that was done years ago that didn't assume the Provincial Nominee Program was obviously going to be too low. So we're trying to -- trying to recognize the current events to the best we can.

MR. SVEN HOMBACH: And have you adjusted for all the recent changes to the program at all?

MR. IAN PAGE: Yes, the -- the 2013 forecast was lower than the 2012 due to that -- the lower number of immigrants that have came in under the Provincial Nominee Program.

(BRIEF PAUSE)

MR. SVEN HOMBACH: The chart I'm showing you now is tab -- page 19 of the Board counsel book of documents, and that show's Manitoba Hydro's projections for just residential customers and the differences between the 2012 forecast and the 2013.

So do you agree with that number, sir, that --

MR. IAN PAGE: I -- I can't speak to that number, because now we're into the electric heat customers. So I think Ms. Morrison would be better to speak --

MR. SVEN HOMBACH: Sure.

MR. IAN PAGE: -- to that.

MR. SVEN HOMBACH: And there's two (2) -- just for the record, there are two (2) charts.

There is a similar chart for residential standard customers and for residential electric heat customers.

Ms. Morrison, can you --

MS. LOIS MORRISON: Yes, I've found those pages.

MR. SVEN HOMBACH: -- confirm the numbers?

MS. LOIS MORRISON: M-hm.

(BRIEF PAUSE)

MS. LOIS MORRISON: Yes, I've found the reference. Could you repeat the question, please?

MR. SVEN HOMBACH: Do you agree with the number on this page that the distinction be -- the difference between the 2012 forecast on which the NFAT was based and the 2013 forecast is about fourteen thousand seven hundred and fourteen (14,714) electric customers?

MS. LOIS MORRISON: Yes, there is that difference in electrically heated customers.

MR. SVEN HOMBACH: And it's about two thousand two hundred and eighty-seven (2,287) fewer standard customers?

MS. LOIS MORRISON: That is correct.

MR. SVEN HOMBACH: And a standard customer compared to an all electric is somebody that uses a gas furnace to heat, correct?

MS. LOIS MORRISON: They heat with another source other than electric, so it would include any other type of fuel source.

MR. SVEN HOMBACH: So wood burning stoves, pellet stove, oil tank?

MS. LOIS MORRISON: That is correct.

MR. SVEN HOMBACH: What's Manitoba Hydro's reason for keeping track of these two (2) customer groups on a separate basis, all electric versus standard?

MS. LOIS MORRISON: We have information in our billing system that allows us to code people either as electric-heat billed, or non-electric heat billed. We also coordinate that -- or -- or verify that through our residential energy use surveys to make sure that the information in the billing system is accurate.

MR. SVEN HOMBACH: And the electric heat customers usually use quite a bit more electricity than standard heat customers?

MS. LOIS MORRISON: Yes.

(BRIEF PAUSE)

MR. SVEN HOMBACH: Now, trying to translate this number on the chart in front of you at page 19 into actual annual usage, the number I'm coming up with is a reduction of about 306 gigawatt hours.

Does Manitoba Hydro agree with that, or can you take it subject to check?

MS. LOIS MORRISON: We'll take it subject to check.

MR. SVEN HOMBACH: And if that's correct, that number's not quite one (1) year worth of deferral or one (1) year worth of growth, but it's pretty close to the four hundred and sixteen (416), was it?

MS. LOIS MORRISON: Yes. It's just shy of the four hundred and thirteen (413) one (1) year reduction.

MR. SVEN HOMBACH: Can you explain the reasons for this very significant reduction, specifically with respect to the all-electric group?

MS. LOIS MORRISON: What you're seeing here is the reflection of the changes in our forecast due to the change in the population forecast going

from the 1.2 percent on average annual growth being reduced to 1.1 percent annual growth.

And it's also reflecting the -- our anticipated success with our heating education campaign. We adjusted our targets to our -- our -- we adjusted our future penetration of electric space and water heating to reflect our -- our anticipated success with that program.

So what we saw -- what you're seeing here is we reduced -- even if we had held the population forecast constant, you would have seen a reduction in the number of electric heat customers because we were reducing the saturation to reflect that -- that heating education campaign.

MR. SVEN HOMBACH: Does that include that fuel switching initiative when you were discussing the education campaign, or is that the same program?

MS. LOIS MORRISON: Our -- the -- what I'm referring to is our education. The fuel switching initiative, we've called it that. We've called it the heating education campaign. That's what we're referring to.

MR. SVEN HOMBACH: So that campaign was not included in the 2012 forecast?

MS. LOIS MORRISON: No, that was not reflected in the 2012 forecast.

MR. SVEN HOMBACH: Which means it's not reflected in the NFAT economic analysis either.

MS. LOIS MORRISON: As Mr. Wojczynski noted, it was reflected in the Chapter 12 analysis that was undertaken in the update.

MR. SVEN HOMBACH: Has Manitoba Hydro analyzed the geographic distribution of these changes? Does it -- is -- is there any significant expected reduction in all-electric customers in one (1) area of the province but not the other?

MS. LOIS MORRISON: Well, we've -- I believe we've filed a number of interrogatories relates to where we're seeing the increased number of electrically heated customers in gas-available areas. And that is the south gas-available area of Manitoba.

And so where we adjusted our targets or our anticipated saturation rate is in that area specifically because we are targeting our education campaigns to those individuals building in that area and heating in that area to encourage them to choose natural gas where it's economically attractive.

MR. SVEN HOMBACH: Is it fair to assume that in the areas where gas currently is not

available, that you're not expecting a switch away from electric heat to any significant extent?

MS. LOIS MORRISON: It's a reasonable assumption to make. We are -- as Mr. Thomson referenced, we are continuing to -- where it's economic and we're able to extend gas, we are bringing gas into areas. And so in those areas we are seeing some conversions.

And -- but as he mentioned, a lot of our focus lately has been on assisting those in -- those organi -- operations that are facing the upcoming coal ban.

(BRIEF PAUSE)

MR. SVEN HOMBACH: Dealing then with standard customers, I've taken you to the chart that showed that the expected reduction compared to the 2012 load forecast is about two thousand two hundred and eighty-seven (2,287) customers. Again, by my math, that would equate to a reduction of about 117 gigawatt hours.

Can you accept that, subject to check?

MS. LOIS MORRISON: Subject to check, yes.

MR. SVEN HOMBACH: Yeah. So adding that to the previous number, you'd actually get a load reduction slightly in excess of about one (1) year's worth of growth?

MS. LOIS MORRISON: Yes, that is correct.

(BRIEF PAUSE)

MS. LOIS MORRISON: I believe at page 12 of our 2013 load forecast that you referenced, we do denote the difference that was as a result of the change in the population forecast and the change that was as a result of our anticipated heating education campaign, specifically broken out between the 2012 forecast and 2013 forecast.

MR. SVEN HOMBACH: And in your rebuttal evidence at, I believe, page 10, Manitoba Hydro indicated that it's expecting growth of about 1.4 percent exclusive of DSM.

So that heating education campaign, or the fuel switching initiative, or whatever it's called, is that included in the 1.4 percent, or is that also factored out?

MS. LOIS MORRISON: Yes, it is

reflected in the 1.4 percent.

(BRIEF PAUSE)

THE CHAIRPERSON: To clarify in my own mind, the fuel switching campaign that you referenced is not the same thing as what was mentioned this morning as fuel changes? This -- we're talking about an incremental initiative and -- which would impact the results we're seeing here, obviously?

MS. LOIS MORRISON: Yes, the fuel switching -- or the fuel switching program that Mr. Kuczek referenced would be in addition to the heating education campaign anticipated results.

CONTINUED BY MR. SVEN HOMBACH:

MR. SVEN HOMBACH: Now, also in the rebuttal at page 10, you should actually have it in the screen in front of you now, you indicate that the average use per customer is still being forecast to grow at the rate of 0.3 percent for the next twenty (20) years.

Why is that?

MS. LOIS MORRISON: I believe if we go further into the rebuttal, we do provide some

additional detail into that. Specifically, even just with our standard heated customers we're seeing an increase in the energy consumption related to furnace fan motors as customers convert from standard-efficiency or even mid-efficiency fans. We have single-stage fans moving into the high efficiency fans. Most are choosing the two (2) stage fans, which operate at the lower level, but operate on a con -- operate on a continuous basis to provide more comfort and ventilation. And that's adding to our electricity use of a standard heated customer.

In addition to that, when we go -- there's -- there's further points down on -- at the end of -- on that page that speak to our building codes in Manitoba. We require all new homes to be constructed with an HRV now -- which is a heat re -- heat recovery ventilation unit.

Now, what that does is in an electric-heated home it will reduce your electricity consumption. But on a natural-gas-heated home it will increase your electricity consumption. It will save you on your natural gas cost, but it will increase your electricity consumption.

So these components are -- along with still anticipating a higher saturation of electric,

space, and water heating, these are all contributing to our overall increase in energy in average use.

MR. SVEN HOMBACH: So does this .3 percent in -- include other energy efficiency matters? This morning we heard LED bulbs are becoming cheaper. Other appliances might be getting more efficient.

Is this a net number?

MS. LOIS MORRISON: The .3 percent reflects the codes and standards that we've reflected within the load forecast. So it reflects the minimum energy performance standards that have been outlined for lighting. It would reflect improved code requirements for new homes. It would reflect new -- improving appliance standards that we are aware of today. It would not reflect any of the programming or the opportunities that we're going to be pursuing in the future, ones that Mr. Kuczek alluded to this morning in his presentation.

MR. SVEN HOMBACH: I'd like to speak to you for a minute about price elasticity. And I'm not sure if that's your bailiwick, Ms. Morrison, or one (1) of your colleagues. So by all means feel free to punt the question. Manitoba Hydro has filed several IFFR documents that show the rate increases it's projecting over the next twenty (20) years. And

I'm wondering whether you've given some thought to price elasticity. And you've addressed it in your rebuttal. And you've said the numbers are inconclusive.

But have you compared the cumulative increases that you are currently projecting to prices in other jurisdictions, let's say even other Canadian cities that have higher rates, to see what -- how it affects customers?

(BRIEF PAUSE)

MS. LOIS MORRISON: We haven't done a province-by-province or jurisdiction-by-jurisdiction review of price -- projected price increases and -- compared to our jurisdiction. We've taken a very cursory review. As you mentioned, we have not to date been able to determine or derive a -- a reasonable or a -- a -- an elasticity that would be -- that we could rely upon. However, we've -- we recognize that given the price increases that we're looking at going into the future, that we do want to take a closer look at this. And we'll be incorporating this into our future forecasting.

MR. SVEN HOMBACH: Are you at liberty

to tell whether that's something that'll be reflected in the 2014 load forecast, or is that something to be left for future years?

MS. LOIS MORRISON: We are looking at incorporating an adjustment for the 2014 forecast. However, we recognize that it would be a very rudimentary adjustment at this point, because we do need to undertake a -- an in-depth study to look at the Manitoba marketplace in and of itself, recognizing that it is unique. And so we will be doing a study to -- to identify the elastic -- elasticity that would be appropriate for Manitoba.

But as part of our crude review that we've done to date, we'll be incorporating some of that information. And we will, as Mr. Kuczek pointed out in his presentation, look to include some representation of price elasticity in the 2014 forecast.

MR. SVEN HOMBACH: All right. Yesterday, your CEO commented on the fact that Manitoba Hydro intends to file a new general rate application soon.

Is that going to be based on the 2014 forecast, or is that forecast not going to be ready for a few months?

MS. LOIS MORRISON: Could you refresh my memory as to when he's planning to file it? Because that will tell you whether or not it'll incr - - I -- the -- the 2014 load forecast will not be available prior to June.

MR. SVEN HOMBACH: Okay.

MS. LOIS MORRISON: And that application, I believe, is coming to the Board prior to that date. So it will not be including or reflecting that.

MR. SVEN HOMBACH: Which answers my second question as to whether or not it's going to be filed in this NFAT. But you're telling me that won't be the case.

MS. LOIS MORRISON: We physically can't begin the load forecasting process until the fiscal year is complete. So we can't begin the forecasting process until March 31st -- or April 1st.

THE CHAIRPERSON: I want to explore that issue of price elasticity a little bit more. There are a number of published studies that address price elasticity of electricity in North America.

And I -- I admit that there may be adjustments required for Manitoba, but could you explain to me what you -- what you perceive as being

adjustments that are unique to Manitoba, relative to what they would be elsewhere?

MS. LOIS MORRISON: Well, Manitoba is a marketplace where we have not seen significant rate increases over or about the rate of inflation for a very long period of time. We're also a marketplace that has currently a relatively low cost for energy. We're a very heavily heat-dominated market. We have a lar -- we have a large number electrically heated homes.

So there -- there are certain characteristics that would affect an elasticity that would be appropriate for Manitoba as opposed to, say, an environment where you're primarily cooling dominated and you have customers that might be more willing to accept a slightly warmer temperature in the house as opposed to a slightly colder temperature in the house. We ha -- or a starting rate that is, say, in the range of thirty (30) cents a kilowatt hour.

We recognize that all of those components, where you start from, will influence what elasticity might be applied to the marketplace. We also recognize that we're not the expert in this and that we would be well served to bring someone in that would be able to aid us in this.

(BRIEF PAUSE)

CONTINUED BY MR. SVEN HOMBACH:

MR. SVEN HOMBACH: Now, before I continue, it's my intention to keep asking questions with respect to the load forecast, but I appreciate that you have an external consultant on the panel.

Is Ms. Rohmund planning to be here tomorrow to answer question on DSM, or should I be asking DSM-related questions today?

MS. LOIS MORRISON: I believe Ms. Rohmund had committed to stay with us for the duration.

MR. SVEN HOMBACH: Fair enough.

(BRIEF PAUSE)

MS. MARLA BOYD: That's assuming it ends on Thursday.

THE CHAIRPERSON: I don't -- I don't want to belabour this point, but just in your re -- you know, following up on what you just said about price elasticity of demand in Manitoba relative to other jurisdictions, I'm getting the sense that you -- you are of the view that perhaps the price response in

Manitoba is less than would be the case in other jurisdictions, given that we're paying lower rates?

MS. LOIS MORRISON: I -- I don't necessary want to draw a conclusion at this point yet, because I'm not an expert in price elasticity. However, what -- based upon our crude review to date, we have found that there -- that some of those components might drive a different price elasticity than, say, a jurisdiction that would have a high starting point for a rate or have different characteristics, as I mentioned.

So we want to make sure that what we're doing is what's appropriate within the Manitoba marketplace.

MR. DALE FRIESEN: In support of what Ms. Morrison is saying -- sorry, it's Dale Friesen speaking. I think we have to recognize that there's some technical considerations to the Manitoba market that are rea -- very, very important to consider, given the fact that we are heat dominated.

So you have to look at the measures that cus -- consumers might undertake as price elasticity responses. So let's take an obvious measure: turn out the lights. So all of us might become a little bit more conscious about how many

lights we leave on in the room. Well, if we make that initiative to turn out more lights, we are effectively reducing the amount of heat that is in that space. That heat has to be replaced. That's a particularly important consideration in a heat-dominated climate such as Manitoba.

So in the case of a -- of a gas heat home, the replacement will be gas heat, and the customer may realize a benefit in their electricity bill. In the case of an electric heat home, the furnace will need to operate for a longer period of time to make up for that energy that would norm -- or that heat that would have normally been gained from the lighting system.

As a result, the net impact that the customer may realize on their energy bill will be minimal. And that may be a discouraging aspect to conserving energy, because the customer doesn't realize the net benefit from their effort.

So when you look at how this interplays in the context of our particular climate, you have to recognize that that may, over the long-term, have an important impact on price elasticity. And then you look at what measures could a customer implement to achieve real change.

And real change, I mean, how could they reduce their heating requirement. And a measure such as building envelope improvements, et cetera, are relatively expensive measures. And that may discourage the customer from implementing them at a rate that other jurisdictions may not recognize in their price elasticity consideration.

So there are unique characteristics to the Manitoba market relative to many of the price elasticity studies that have been done in other regions. And I think what Ms. Morrison is telling you is that we haven't had a chance to really sit down and work with price elasticity experts to fully recognize what those differences will result in or what the outcome -- how the outcome will change if we recognize those differences.

DR. HUGH GRANT: It just -- it just comes as a bit of a surprise that if you're doing -- essentially forecasting demand, you don't have a price variable at all. Is this -- let me put it this way.

Is it -- is it true, then, in your load forecast you're assuming a price elasticity of zero?

MR. DANIEL FRIESEN: I'll let Ms. Morrison answer that.

MS. LOIS MORRISON: We are not

assuming, necessarily, the price elasticity is zero. But you are correct that we do not have a component reflecting price elasticity. We -- prior to 2013, we used to look at the ratio of the change in the electricity cost to the ratio of the change in the gas price in order to assign fuel share. Like, who was going to choose electric heat versus who was going to choose a natural gas alternative for heating their home.

And what we found was that when we were obs -- what we observed with our model was that the model was no longer predicting that -- that behaviour. There -- the -- the model was no longer showing that relationship. And so in 2013, we removed that model from -- from that component of the forecast. So it's not that we've ignored price in its entirety, but there are two (2) components.

So -- so we did look at it from that perspective prior to the 2013 forecast. And in addition to that we have looked at it, but when we do our models we've not had price come out as a significant variable. It tends to get overshadowed by the other components because our price changes haven't been enough to -- to derive a -- a relationship that we could use in our models.

DR. HUGH GRANT: Normally one questions their model, then. But in any event, can I ask you a more question about this forecasting? It's more out of curiosity than anything.

Do general patterns, residential -- shifting residential patterns enter into a load forecast at all? I'm thinking of population aging, or a trend away. Say, a trend towards home ownership as opposed to a -- a rental accommodation. Do -- do factors like that enter into it? Let me put it this way.

A hundred people living in single-family dwellings suddenly all move into one (1) large apartment building.

MS. LOIS MORRISON: We -- our -- our residential forecast is -- recognizes and is based on a forecast for single detached -- electric-heated single detached, natural gas -- or, sorry -- other than electric heated, multi-attached row housing, side-by-sides, and also does apartments. So we do forecast based on those building types.

DR. HUGH GRANT: Do you forecast changes -- changing patterns within those building types?

(BRIEF PAUSE)

MS. LOIS MORRISON: We use our residential energy survey and calibrate it to information in our billing system to look at more recent penetrations or market penetrations of those different sectors, and apply that going forward. So we would look at the penetration of single detached homes in 2009, not the overall system as a whole, and then move forward.

So it -- it's -- it's, to a certain extent, recognizing that shift as to whether or not there's more people living in apartments versus living in single detached homes.

CONTINUED BY MR. SVEN HOMBACH:

MR. SVEN HOMBACH: So to follow up on Board member Grant's question, when -- you're not projecting changes then over the twenty (20) year forecast period. You're looking at where the situation currently is, you're taking changes into account.

But are you projecting changes going out twenty (20) years?

(BRIEF PAUSE)

MS. LOIS MORRISON: We adjust based on the penetration going forward, and there are some areas where we do make some projections, anticipating greater growth in. So as I mentioned, in the south gas-available area, we make a projection for increased -- we make a projection for new homes and single detached homes and in the Winnipeg area and in the non-gassable areas.

And those projections are done so that they're reflecting trends that we're seeing in growth in those areas. But the -- the building demographic is applied based on that 2009 survey.

MR. SVEN HOMBACH: And we've discussed the -- the fuel switching initiative a bit. And Manitoba Hydro provided us with an answer to Information Requests. It's PUB-MH-1-253A, which is found at page 29 of Board counsel's book of documents.

Can you provide a brief overview, Ms. Morrison, please, what that initiative actually entails in them more or less?

MR. IAN PAGE: I believe we gave a very detailed description of what was involved in the heating education or the fuel choice initiative at our

response to PUB-253B.

Primarily at this point in time, we are aggressively advertising our education campaign. We are specifically targeting the south gas-available area. We are also targeting Winnipeg, but we're -- as I mentioned, the majority of our focus is in the south gas-available area.

We are working with home builders and developers, and we are also having a -- an advertising campaign targeted to those communities. The -- let's see if I can find my...

(BRIEF PAUSE)

MS. LOIS MORRISON: And so what we've done, as I mentioned, we -- we've -- we've got an -- an aggressive advertising campaign that's targeted to the south gas area available (sic) primarily. We're looking at -- the advertising is broken into two (2) different targets. We're focussed on new homes and people purchasing new homes in that area, and giving them -- giving them the appropriate messaging as to what they should consider when they're purchasing heating systems.

They should be looking at, from our

perspective, the life cycle costs and not just the up-front costs. And with that, we're supporting it with information on our website. We have a heating fuel choice calculation tool where you can put information into the website about what your choices are for heating systems, the costs and such, and it'll tell you what the -- what -- what the different costs are if you were to choose a natural gas system over an electric heated system, or if you were to choose a geothermal system.

And in addition to that, we've -- doing bill inserts and other general information mailers. We are working with home builders. We attend -- we have regular developer sessions with the developers to talk about changes with services and such, and we've been working -- attending those developer sessions to explain to them what is in the best interests of the customers, and to ensure that they are fully aware of what the different costs are of the different fuel choices are, and of the different implications from an environmental perspective.

MR. SVEN HOMBACH: And Manitoba Hydro's perspective is it's better for the customer to have a gas furnace than an electric furnace? Cheaper, in any case.

MS. LOIS MORRISON: Maybe to answer the question that you posed to Mr. Thomson yesterday, that if you were to ask me what I would tell a customer, is I would ask the customer what's important to them, what's driving their decision making, and provide them with the information they need to make sure that the decision best meets their needs.

MR. SVEN HOMBACH: Okay. Appreciating that Manitoba Hydro focusses on information, and appreciating that this was a very diplomatic answer, has Manitoba Hydro considered actually setting any incentives or disincentives for builders to put in gas compared to electric? Because you've focussed only on information so far.

MS. LOIS MORRISON: M-hm. That is one (1) of the things that we are considering, and is actually one (1) of the -- the -- I almost want to call it a white paper, but it's not a white paper. It's -- it's a topic that's sitting on my desk. One (1) of those topics that Mr. Kuczek alluded to is sitting on our desks waiting for us to -- to spend some time on.

But, yes, we have considered what opportunities there might be from a service extension policy perspective, working with -- with builders and

developers.

MR. SVEN HOMBACH: When a builder's currently putting in a new subdivision or putting in a home, is Manitoba Hydro charging them a connection fee to hook up hydro?

MS. LOIS MORRISON: When -- it's a -- yeah. When a bel -- when a -- when a developer comes to us to have service extended to a development, they pay for the -- the development to be serviced. And we have to differentiate between the developer and the home builder. The devel -- the home builder and the developer are not always the same people.

And so when a developer comes to Manitoba Hydro and they say they would like service, they will come -- we -- we will provide them with information on how to -- they will provide them with a quote on extending electrici -- electric service and natural gas service to their development. In many cases, particularly in areas where gas is available, if there's enough -- most times, the developer won't have to pay to have gas installed, because we expect a certain level of connection or attachment rates with the appliances, or the home builders building homes in that area.

There is a cost that the developer does

pay up front for the electricity. And if -- depending on how many attachments we get for the electricity -- sorry, for the houses; I shouldn't call them electricity -- how many attachments we get for the houses, they'll get an allowance back, based on the fact that they have attached so many. So they basically prepay, and then if the house attaches service then the developer will receive a certain contribution back on their -- their service.

The difference is, on the gas side, that contribution is applied at the beginning of the service. This is where there's differences between the gas side of our operations and the electric side of our operations. And -- and I -- I know the Board is fully aware of why that is.

So -- so there are costs that the -- that the developer pays up front.

The builder does not pay for a service connection if they're in a development that's already served. The developer takes that responsibility.

MR. SVEN HOMBACH: And Manitoba Hydro wouldn't have any control over whether the developer passes the cost on to the builder or not, or how that is done?

MS. LOIS MORRISON: Yes. We're

getting quite far into the allowances here. We have less control over the home builder in that scenario. There is a cost for connecting the house, but generally the allowances pay -- cover that cost from the electric side. The same -- and -- and so when the -- so the developer pays for it up front, and the allowance is then applied to the developer, and the developer has -- has already passed on that savings to the home builder.

So -- and this is getting into some of the complexity of how our -- our ser -- service extension policies are set up, and some of the -- the nuances of how it -- the allowances work, that we're trying to work through and determine a best way to -- to encourage builders to move in the right direction. And is there an opportunity using these allowances and these -- these connection -- we don't have a connection charge per se in place right now for home builders, but are there opportunities right now? But it would be something outside of what we normally do.

MR. SVEN HOMBACH: Now, at page 29 of the Board counsel's book of documents, you've listed the expected savings that you're attributing to the fuel savings initiative. And if my high school math still serves me okay, it's -- you're looking to shave

down total demand by about 366 gigawatt hours.

First of all, do -- do you agree with the math?

MS. LOIS MORRISON: Yes, your math is good.

MR. SVEN HOMBACH: That's -- that's heartening. My second question on that issue is does -- does that include any of the measures that are set out in the white paper you discussed, Ms. Morrison? Or is that just purely based on the current educational initiatives?

MS. LOIS MORRISON: When we set these initiatives out, or these -- these targets out, we were considering the possibility of if we were not -- if the heating education campaign did not achieve what we were setting out to achieve, then we look at other intervention strategies, which could possibly include the -- looking at service extensions and -- and allowances.

So, to answer your question, it's something that could be used to get to these targets if we were in -- if we were realizing we were not getting there.

MR. SVEN HOMBACH: And at page 34 of the Board counsel book of documents is a chart that --

that calculates what we think the reduction would be if the program were to be a hundred percent effective. It's -- it's on screen in front of you, Ms. Morrison. The -- the three-sixty-six (366) is Manitoba Hydro's projection. 942 gigawatt was our calculation of what it would be if you were a hundred percent successful, appreciating that one rarely is.

Are we in the ballpark?

(BRIEF PAUSE)

MR. SVEN HOMBACH: I mean, I'd be happy to walk you through how we get to those numbers if that helps.

MS. LOIS MORRISON: I -- I would appreciate that. I -- I have notes here --

MR. SVEN HOMBACH: All right.

MS. LOIS MORRISON: -- assuming that there's zero new electric space heated homes in Manitoba, in the gas available area, and zero new electric water heated and no con -- conversions, is that what you were -- yes, I would appreciate if you could tell me your assumptions underlying this.

MR. SVEN HOMBACH: Yeah. I mean, I'll -- I'll walk you through the -- the first one, for

example, a new home space heating. We assumed that there would be thirty-four hundred (3,400) new homes in the gas area, of which 34 percent would choose electric heat. So over the course of a 20-year forecast.

So you multiply thirty-four hundred (3,400) new homes by twenty (20) -- so it's on an annual bas -- basis -- times 34 percent. That gives you approximately twenty-three thousand (23,000) homes that would choose electric heat. Average customer use is about 18,500 kilowatt hours per year.

So multiplying those two (2), that would get -- get you to the four hundred and twenty-five (425). And I appreciate it's not an exact science, but I just want to get a handle on what percentage of success Hydro is projecting compared to total potential.

MS. LOIS MORRISON: The eighteen thousand five hundred (18,500) is the average use per home. It's not the average use of an electrically heated -- it's not the electric heat component of a -- or is -- is -- I guess I'm wondering -- 'cause you said it's the average use of a home. Are you assum -- are you adding the water heating to the space heating to come up with that number, or how are you deriving

that?

MR. SVEN HOMBACH: It should just be for the -- it's my understanding that that number is just for the furnace.

MS. MARLA BOYD: Do you have a source for the number?

(BRIEF PAUSE)

CONTINUED BY MR. SVEN HOMBACH:

MR. SVEN HOMBACH: That calculated from the numbers on page 33 of the Board counsel book of documents.

But, either way, Ms. Morrison, it's -- it's -- I'm not asking for an exact science. We're -- just try to get a handle on what percentage of success Manitoba Hydro was actually projecting, and how the 366 gigawatt hour reduction would compare to, let's say, 100 percent success rate.

(BRIEF PAUSE)

MR. SVEN HOMBACH: I believe in the 2012 fuel switching report you actually gave a number of 875 gigawatt hours per year.

MS. MARLA BOYD: Mr. Hombach, perhaps we can undertake to have a look at this and -- and try and confirm it. It's -- it's a bit difficult without having all of the material in front of us to be able to make a -- a reasoned answer.

MR. SVEN HOMBACH: That's fine, Ms. Boyd. If I can get an undertaking from Manitoba Hydro just to advise what it's calculation would be based on 100 percent success rate, that's fine.

MS. MARLA BOYD: Yes, we'll do that.

--- UNDERTAKING NO. 7: Manitoba Hydro to provide a calculation on page 33 of the Board's book of documents Volume II based on a success rate of the fuel switching initiative

CONTINUED BY MR. SVEN HOMBACH:

MR. SVEN HOMBACH: Now, Ms. Morrison, I took you through the reductions from the 2012 to the 2013 forecast, both for all-electric and for all-gas. And just to recap those numbers, were 306 gigawatt hours per year -- sorry, for all-electric, and 117 gigawatt hours for standard.

Those 366 gigawatt hours that Hydro is projecting are attributing to the fuel switching initiative. Would those be subsumed in those initial numbers, or is that additive?

MS. LOIS MORRISON: As I mentioned, the 366 gigawatt hours is reflected within those numbers, but there were other changes that were presented in that -- or adjustments to the forecast between the 2012 and the 2013 for the residential sector. I mentioned they were at page 12 of our forecast. And in it we referenced point 3 of the -- point 3 on the page states:

> "An adjustment to reflect the initiatives being undertaken by Manitoba Hydro was included to reduce the number of customers choosing electric space and water heating, and it represents 366 gigawatt hours."

The -- the other two (2) adjustments to -- between the 2012 and the 2013 forecast were related to the population forecast dec -- decreasing by approximate -- well, by -- not approximate -- by sixteen thousand nine hundred and one (16,901) customers, which represented a reduction of 282

gigawatt hours in the -- between the 2012 forecast and the 2013 forecast.

And then there was also an adjustment to our appliance and unit energy consumptions based on our conditional demand analysis model that adjusted the -- the energy use up by about 212 gigawatt hours. So those are the three (3) components that led as a net.

So yes, the changes that you are speaking to in your charts do reflect that 366 gigawatt hours of reduction.

MR. SVEN HOMBACH: Okay. Thank you for that clarification.

(BRIEF PAUSE)

MR. SVEN HOMBACH: I would like to take you to page 35 of the Board counsel book of documents, and discuss the consumption without water heating for a minute.

But first of all, in terms of the major consumption, somebody can have a gas or electric furnace, and a gas or electric water heater, correct? Those are basically the choices, leaving aside pellet stoves, or other niche products.

MS. LOIS MORRISON: Yes, those are your -- those are the -- those are the most commonly chosen options for -- for heating.

MR. SVEN HOMBACH: And this chart in front of you, that's a PUB adviser chart, once again not a Manitoba Hydro document. And one (1) of the assumptions that this makes is that somebody who has a gas furnace may choose to have an electric water heater. But somebody who gets a -- has a gas water heater probably is not going to make the choice to have an electric furnace, given the cost impact.

Is that a reasonable assumption, from Hydro's perspective?

MS. LOIS MORRISON: Yes, that's a reasonable assumption.

MR. SVEN HOMBACH: So what we try to do is factor in -- factor out the impact of water heating to determine the actual average consumption that you are projecting. And the numbers for this document and the math is found at page 36 behind -- and -- and what the chart shows is that even though the overall numbers for the 2013 load forecast are lower, you're actually projecting a sharper increase in the per capita consumption for standard customers.

And is that just attributable to what

you spoke about earlier, the heat recovery ventilation systems and other matters?

MS. LOIS MORRISON: Yes, there's -- there's one (1) nuance to the math that isn't being incorporated into your table, related to the fact that not all customers with electric space heat have water -- electric water heatings -- systems. That would be our apartment dwellers. Some of the people in apartment buildings don't have electric water tanks.

But, fundamentally, the majority of this would be likely derived from the increase in the HRVs, as I mentioned, in the homes, and the multi-speed fans being used in standard heated homes..

MR. SVEN HOMBACH: And on the electric side you wouldn't see a similar increase because people have an overall reduction --

MS. LOIS MORRISON: In -- in an electrically heated home, the customer installing an HRV would have a reduction in their energy consumption overall, yes.

(BRIEF PAUSE)

MR. SVEN HOMBACH: Mr. Chairman, I'm about to start the next topic. Would the panel like a

break, or are we good to continue?

THE CHAIRPERSON: I think it would be a good idea to have a break. Let's take ten (10) minutes.

--- Upon recessing at 2:27 p.m.

--- Upon resuming at 2:45 p.m.

THE CHAIRPERSON: Okay. I believe we're ready to resume the proceedings. Back to you, Mr. Hombach.

MR. SVEN HOMBACH: Mr. Chairman, we seem to be having some technical difficulties again with the little wireless device.

(BRIEF PAUSE)

MR. SVEN HOMBACH: The computer is telling me that the issue has been resolved. I'll have to trust it.

CONTINUED BY MR. SVEN HOMBACH:

MR. SVEN HOMBACH: We briefly touched on the issue of weather adjustment earlier, and that Manitoba Hydro adjusts weather on a weather normalized

basis, so that if there's an exceptionally hot summer or an exceptionally cold winter, that doesn't skew the load forecast or isn't assumed to be usual.

And those are based on the concept of degree-day heating and degree-day cooling, are they not?

MS. LOIS MORRISON: That is correct.

MR. SVEN HOMBACH: And a degree-day cooling is one where the average number between the daily high and the daily low for that particular day is higher than 18 degrees Celsius?

MS. LOIS MORRISON: That is correct.

MR. SVEN HOMBACH: And for heating, it's basically the same thing in reverse, where the average between the coldest point of the day and the hottest point of the day is less than 14 degrees Celsius?

MS. LOIS MORRISON: That is correct.

MR. SVEN HOMBACH: Can you explain why eighteen (18) is used for cooling but fourteen (14) for heating?

(BRIEF PAUSE)

MS. LOIS MORRISON: A number of years

ago, we used 18 degree days, 18 degrees for both heating and cooling. And with the purchase of the natural gas company, the natural gas company determined a number of years ago that 14 degrees was better for forecasting on the gas side.

We later aligned the electricity side to the gas side after we did an analysis and determined that the differential for the degree-day heating was that there was no -- that there -- there was no material difference between using a fourteen (14) as the -- as -- as the degrees or eighteen (18) as the degrees for the heating side, in terms of calculating the degree-day heating.

MR. SVEN HOMBACH: And Manitoba Hydro determines sensitivity coefficients on an annual basis, right? Does it compare the actuals against the projected DDH or DDC numbers? Or how are those sensitivity coefficients determined?

Specifically, Ms. Morrison, I'm referring you to a -- a list of coefficients that was produced by Elenchus, one (1) of the independent experts appointed by the Board, which is reflected at page 38 of Board counsel's book of documents.

(BRIEF PAUSE)

MS. LOIS MORRISON: Mr. Hombach, I would -- I would refute -- refer to our page 22 of our rebuttal, which outlines how those degree-day se -- coefficients are -- are created. And it's through a regression-based model.

And I believe our updated model is on page -- sorry, I correct that -- is on page 24. And it is a model that is based upon the difference between -- it's based on a regression analysis.

(BRIEF PAUSE)

MS. LOIS MORRISON: Sorry. I apologize. It is, as I noted, at the beginning of page 24 on our rebuttal, we outline it is statistically derived using the previous twenty-four (24) months of data to determine the coefficients.

MR. SVEN HOMBACH: And help me understand this concept. When you're determining the coefficients, do you only look at these that qualify as DDH or DDC days, meaning that where the average, let's say, for degree-days cooling exceeds 18 degrees, or is it every day of the month and then you just tally them up over the course of the month?

MS. LOIS MORRISON: It's every day of

the month and tallied over.

MR. SVEN HOMBACH: What's Manitoba Hydro's reason for only looking at the past, is it two (2) years, to determine the coefficients?

(BRIEF PAUSE)

MS. LOIS MORRISON: We look at the past two (2) years, because we have found that in order to -- to effect the best possible weather adjustment in the current year, weather coefficients need to be determined from the most recent data, ideally the previous year. However, twelve (12) months of data points were found to be insufficient to produce good estimates of the base -- the D -- the degree-day heating, and DD -- degree-day cooling coefficients, and so we moved to twenty-four (24) months.

(BRIEF PAUSE)

MS. LOIS MORRISON: And that explanation is outlined at page 23 of our rebuttal, between lines 18 and 36.

MR. SVEN HOMBACH: Okay. If I'm

looking at page 39 of the Board counsel book of documents, there is a -- a chart that Manitoba Hydro provided that shows the monthly degree-days heating in Winnipeg over the past fourteen (14) years.

And a high number of degree-days heating means you get an exceptionally cold year, does it not?

MS. LOIS MORRISON: That is correct.

MR. SVEN HOMBACH: And conversely, a high number of DDC means -- DDC days means you've got an exceptionally hot year? Or at least an exceptionally hot summer?

MS. LOIS MORRISON: Yes.

MR. SVEN HOMBACH: So let me take you to page 40 of the Board counsel's book of documents. There's a chart in front of you that shows the degree-days cooling. Now, what's apparent when you're comparing the DDH and the DDC charts is the degree-days cooling seem to be compressed into a significantly shorter time span year-over-year, no?

MS. LOIS MORRISON: That is correct.

MR. SVEN HOMBACH: It's rare that, for example, in April or in October anybody needs to run their air conditioner?

MS. LOIS MORRISON: I think that's a

very safe statement for Manitoba, yes.

MR. SVEN HOMBACH: Well -- so if, for example, on this chart in front of you, I was to look at the 2009 year where the total number of degree-days cooling is only a hundred and nineteen (119), that would indicate to me that it was a pretty cold and miserable summer?

MS. LOIS MORRISON: Yes.

MR. SVEN HOMBACH: Okay. The same for 2004, for example, where it was actually only seventy-two (72)?

MS. LOIS MORRISON: That is correct.

(BRIEF PAUSE)

MR. SVEN HOMBACH: Now...

(BRIEF PAUSE)

MR. SVEN HOMBACH: If I'm looking at what's happening after those very cold years -- and I'm taking you back to page 38 of the Board counsel book of documents -- where Elenchus provided the sensitivity coefficients -- again, we established 2004 and 2009 were very cold years. After 2009 the

kilowatt hours for DDC, the coefficient, is substantially higher.

Does that -- should I take that to mean that if you've got any summer that's just an outlier that's exceptionally hot or that's exceptionally cold, that that disproportionately skews the sensitivity coefficient?

MS. LOIS MORRISON: What we found is, after working with Elenchus -- Elenchus, was that when you have a large number of -- degree-day cooling is somewhat more difficult to determine within the Manitoba marketplace when we're dealing with a short period of time that's primarily heavily heat dominated and where you have -- sorry.

(BRIEF PAUSE)

MS. LOIS MORRISON: So there is difficulty in establishing the cooling coefficients in Manitoba because of the fact that we have a -- there's quite a bit of variation within the month -- month to month. And there's quite a bit of possibility for higher energy consumption in those months due to heating that may occur in the same month that you're cooling. And so when the coefficient -- when -- when

we were looking at our model, the way our -- our model picks the -- the data in, it'll pick in a month that may have large energy consumption tied to a low cooling degree-day.

There may be a cooling degree-day in there, but it'll pull in large energy consumption but won't pull in -- and then it'll compare it to a month that, say, had a high de -- degree-day cooling but then a -- but a low energy consumption. So we end up with variations within the designation for the cooling degree-days that -- that causes more bouncing around or -- or more variation from year to year within the cooling degree-day de -- coefficients.

MR. SVEN HOMBACH: Okay. And there is a -- a chart that was provided in response to Information Requests by Elenchus that seems to illustrate this quite well. It's at Elenchus Information Request 11. That takes the sensitivity coefficients that Manitoba Hydro provided and -- and charts them both for heating and for cooling.

Do you have the chart in front of you, Ms. Morrison?

MS. LOIS MORRISON: I -- I do, on the screen. Thank you very much.

MR. SVEN HOMBACH: Okay. Now --

MS. MARLA BOYD: Is that in your book of documents? I'm sorry, just to follow along.

MR. SVEN HOMBACH: I beg your pardon?

MS. MARLA BOYD: Is it in your book of documents?

MR. SVEN HOMBACH: Yeah -- no, it -- it is not, sorry.

CONTINUED BY MR. SVEN HOMBACH:

MR. SVEN HOMBACH: And -- and that shows a gradual, slow upward trend for heating, but shows the sensitivity coefficients really being all over the map for -- for cooling?

MS. LOIS MORRISON: Yeah.

MR. SVEN HOMBACH: Now, if -- if that's the case, does it actually make sense for Manitoba Hydro to adjust on a cooling basis when it predicts demand?

MS. LOIS MORRISON: Well, what we've determined after this analysis is that we -- overall, the impact to our weather adjustment for the year isn't affected, because either the cooling degree -- either the kilowatt hours for the cooling degrees go into heating, or they go into cooling. They don't disappear. They go to one (1) bucket or the other.

And what we've determined is that when we're going -- to -- to try and limit some of this variation, we should in the future when we're looking at our model, make sure that we aren't picking up months that have a heating component to them when we're doing our -- our calculation for degree-day cooling. So we wouldn't necessarily pick up a September that might have had a warm -- had a warm day and had some degree-days cooling, but then may have had heating attached to it also.

So what we're finding is that we are -- we believe that we'll be able to -- to -- there will still be variation, just because of the fact that cooling is a much smaller component of our overall load in terms of -- and we are only dealing with four (4) months of the year -- of -- of two (2) years of data for determining that cooling coefficient.

But we think that we can eliminate some of that variation by -- by focussing on months that don't have a high degree-day heating within the same month that a degree-day cooling is occurring.

MR. SVEN HOMBACH: Give or take, what -- what approximate range of cooling adjustments does Manitoba Hydro perform on an annual basis?

How many gigawatt hours are we talking

about?

(BRIEF PAUSE)

MR. SVEN HOMBACH: I'm just trying to get a handle on what the uncertainty is that this actually introduces.

MS. LOIS MORRISON: I'm -- could you clarify your question? Are you asking us to what effect a -- a change in degree-day cooling would affect our forecast?

MR. SVEN HOMBACH: I'm -- I'm asking on a cumulative basis over the year. You're providing in your load forecast the actuals for the year as well as the weather adjustment?

MS. LOIS MORRISON: Yes.

MR. SVEN HOMBACH: But that doesn't actually break it down. I'm just wondering, in a regular year, are we talking about an adjustment of 10 gigawatt hours, are we talking about 100 gigawatt hours, are we talking more than that attributable to a cooling-weather adjustment?

(BRIEF PAUSE)

MR. SVEN HOMBACH: If it makes more sense to deal with this by way of undertaking, I'll happily do that.

MS. LOIS MORRISON: I think that would be more appropriate. Thank you very much.

MR. SVEN HOMBACH: It's to provide an order of magnitude for the average degree-day cooling adjustment per year in the load forecast.

--- UNDERTAKING NO. 8: Manitoba Hydro to provide an order magnitude for average degree-day cooling adjustment per year in the load forecast

MR. SVEN HOMBACH: So we -- we've covered residential rates. Taking you back to page 18 of the book of documents, that just shows the total usage broken down into customer classes. Residential is one of the largest, but general service mass market is actually larger than that.

And it's my understanding that mass market is basically everything that is commercial and everything that is industrial, excluding the top consumers.

Do I have that right?

MS. LOIS MORRISON: That is correct.

MR. SVEN HOMBACH: Okay. And EnerNOC this morning provided a slightly different pie chart, but that's because EnerNOC actually distinguishes between industrial and commercial rather than just everything commercial and the top consumers.

MS. LOIS MORRISON: Yes. Our forecast is based on rate classifications. So anyone in the general service rate classification is included, is -- is forecast separately. We then exclude specific customers in our top consumers.

MR. SVEN HOMBACH: Now, to determine your mass market forecast, you take two (2) things into account, do you not?

You take the Manitoba population, as well as the projected GDP?

MS. LOIS MORRISON: That is correct. We -- to forecast our number of customers -- for the general service mass market sector, we forecast based on the change in pop -- there's a factor that aff -- accounts for the change in population, or the change -- actually the change in the number of residential customers, and the change in GDP.

MR. SVEN HOMBACH: And you provided a

Elenchus with a formula that's set out in the Elenchus report.

That's actually the correct formula that you use?

MS. LOIS MORRISON: That is correct.

MR. SVEN HOMBACH: The GDP numbers, are those coming from the same five (5) commercial forecasters that you used for population, or where do you obtain your GDP projections?

MR. IAN PAGE: Yes, it's the same five (5) forecasters.

MR. SVEN HOMBACH: And all in all, looking at the formula, the population level is about five (5) times as -- as influential in determining your mass market forecast as GDP, correct?

MS. LOIS MORRISON: That is correct.

MR. SVEN HOMBACH: What I am curious about is why there is no assumed impact from large industry, meaning the top consumers. Can you explain that to me? The formula that you provided looks at the GDP. It looks at the Manitoba population. But it doesn't look at the top consumers. So it doesn't assume that there's any trickle-down effect from large heavy industry, for example, on other commercial demand.

Why is that?

(BRIEF PAUSE)

MS. LOIS MORRISON: We haven't yet seen a relationship between the two (2) to be determined within our forecast. And their energy consumption has been -- we -- we separate them because their energy use is substantially different. And previously when we did include them within the overall -- many, many years ago, when we included them together, with the exception of two (2) top consumers, the outcome was that they were -- they were somewhat skewing the results of our models. So we pulled out the top consumers and forecasted them individually.

MR. SVEN HOMBACH: Now, you've also made some changes between 2012 and 2013. You were projecting annualized growth of about 1.5 percent for this customer group, which accounts for about 34 percent of total load. I'm sorry, you -- you're currently projecting 1.5 percent. You were projecting 1.7 percent.

That just follows the formula you've -- you've ...

MS. LOIS MORRISON: That's correct.

MR. SVEN HOMBACH: Okay.

(BRIEF PAUSE)

MR. SVEN HOMBACH: I'm showing you page 52 of the Board counsel book of documents. That is Table 5 from the 2013 load forecast. Sorry, I misspoke. Page 52 of the book of documents. And if you look at the middle of the page, you can see that your actual experience for residential growth was annualized growth of about 1.8 percent, less than that for the mass market group of about 1.4 percent, and really very little year over year growth for the top consumers.

You see that? Middle of the page, where it says that -- it shows you the ten (10) year average?

MS. LOIS MORRISON: Yes, that is correct.

MR. SVEN HOMBACH: Do you usually expect to see mass market growth to grow less quickly than residential? Or is this just an effect of the recession in 2008?

(BRIEF PAUSE)

MS. LOIS MORRISON: Okay. What we observed here was a higher residential growth due to the increased penetration of electric space heating and other -- and the adjustments to the -- and the increased end uses as opposed to the population and factors that are driving -- that are being observed in the mass market.

MR. SVEN HOMBACH: Is the increase in electric heating, though, something that you've just seen recently, or is that something that is incorporated into your overall formula for determining mass market growth?

MS. LOIS MORRISON: We don't factor electric space heating growth into the mass market forecast. I -- I'm speaking about the -- you asked about the -- the comparison between the residential market having 1.8 percent and the general service mass market having 1.4 percent.

And the 1.4 percent is -- the 1.8 percent reflects an increase -- what we would have -- we were supp -- we were a little more -- we had not yet anticipated that we were seeing in terms of the growth in electric heat, more so than -- we wouldn't -- we -- I guess I'm saying the converse to your -- your question where you said, Would we expect the

general service mass market to be growing at a slower rate than the residential sector.

MR. SVEN HOMBACH: So you're saying without the switch to electric heating, you might see -- might have seen less than the 1.8 percent residential growth, but it wouldn't have affected mass markets, because you're basing it on total population.

You're not tying it to the actual demand by --

MS. LOIS MORRISON: For --

MR. SVEN HOMBACH: -- the residential customers?

MS. LOIS MORRISON: Yes, that is correct.

MR. SVEN HOMBACH: Well, what -- what we're seeing here is you've got the highest growth for the past ten (10) years for residential customers, second highest for mass market, very little for top consumers. What you're projecting, though, for the next ten (10) years is the opposite.

If you look two-thirds (2/3s) down the page, you're projecting the highest growth for top consumers, second highest for mass market, lowest for residential.

So why the switch if that really hasn't been your experience over the past ten (10) years?

MS. LOIS MORRISON: Well, I think in looking, the -- the first thing we have to look at is the top consumers over the last ten (10) years, their growth over the last ten (10) years is not what you would have seen as their growth overall over the last twenty (20) years. The last ten (10) years, as we're all very aware of, saw an economic downturn that the industrial customers, or the large industrial customers, are now recovering -- appear to be recovering from.

And we also, during that period of time, saw the loss of one (1) very large top consumer entirely. And that will be reflected in that growth -- that overall growth over the last ten (10) years of -- of .5 percent as a -- as an average annual growth.

So going forward when we look into the future, for the top consumers we are looking at -- what we're anticipating to see is based on their short-term projected plans. And then what we're anticipating after that is average growth, which would be reflected by a period of -- a longer period of time, which is -- has periods of growth and recession.

MR. SVEN HOMBACH: Taking you back to

page 18 just for a second to -- to visualize this, top consumers, 23 percent of total amount right now?

MS. LOIS MORRISON: That is correct.

MR. SVEN HOMBACH: Really very broadly simplified, it's about a one-third (1/3), one-third (1/3), one-third (1/3) split between residential, mass market, and top consumers?

It's actually a bit less for top consumers.

MS. LOIS MORRISON: Yes, this is reflecting the loss of the one (1) top -- one (1) top consumer, which prior to that this split was more closer to the one-third (1/3), one-third (1/3), one-third (1/3).

MR. SVEN HOMBACH: Okay.

(BRIEF PAUSE)

MR. SVEN HOMBACH: Now, on the subject of top consumers, if you go to page 57 of the Board counsel book of documents, that is an answer to PUB-MH Information Request 1-102a revised. And that shows a chart of Manitoba Hydro's top consumer projections and how they changed between 2000 -- the 2007 forecast and the 2013 forecast.

MS. LOIS MORRISON: That is correct.

MR. SVEN HOMBACH: And that -- that large dip that you see occurring, Ms. Morrison, starting at about 2007, where actual top consumer demand declined by what appears to be about 750 gigawatt hours per year, is that primarily attributable to that loss of the one (1) top consumer you spoke about?

Or is this other consumer -- top consumers also reducing their demand?

MS. LOIS MORRISON: This period of time reflects reduction due to the loss of one (1) top consumer that was in the range of 500 to 600 gigawatt hours. And it also reflects the reduction in some other top consumers' operations as they optimized during the -- the economic downturn. They opim -- they optimized their operations, so they relied on existing inventories and such, and ran fewer shifts in order to -- to work through the recession.

MR. SVEN HOMBACH: Now, if I'm looking at this chart, it -- it seems that ever since the 2009 forecast you're moving the starting point? But otherwise the slope of your projected demand increase is basically the same.

Am I -- am I -- first of all, am I

reading that correctly?

MS. LOIS MORRISON: Yes, to a certain extent. Yes.

MR. SVEN HOMBACH: So given that Manitoba Hydro's appear -- experience appears to be that over the past five (5) years, the starting point keeps moving down.

What makes you think that ongoing demand is still going to take place at that same slope? Are you basically -- if -- if I had to simplify it, are you -- are you thinking that this is just a reset of the starting point, but that there hasn't been any actual shift with how companies do business in light of the recession?

MS. LOIS MORRISON: I -- I would agree with that, and Mr. Friesen can probably provide a little more insight.

MR. DANIEL FRIESEN: I think the question you have to ask yourself in some context around this is: Has the competitives -- competitiveness of the top consumers based in Manitoba, relative to the other -- the other companies they compete with world wide, changed as a result of the economic recession. And I would argue that it has not. In some ways, it's actually improved.

And, as a result, we expect once -- if you look at the -- the global recession as a market correction, and if you -- particularly if you look at the recovery over the last couple of years, the recovery over the last couple of years very much matches the load growth prior to the recession.

And we expect that, given that Manitoba industry remains competitive, in much the same way as it was before the recession, the growth is reasonable, and it -- it's in prox -- in proximity to what we've seen historically. So we don't expect the competitive position of Manitoba to change dramatically as a result of the global recession, so we don't foresee the reason to change the forecast dramatically either.

MR. SVEN HOMBACH: Okay. Two (2) issues on that. Now, when you say, "couple of years," can you see the cursor on the screen in front of you?

MR. DANIEL FRIESEN: Yes, I can.

MR. SVEN HOMBACH: This -- you're referring back to about 2011, 2012, when actually the amount kept increasing?

MR. DANIEL FRIESEN: If you look at the numerical data rather than the text, you'll see that the -- the lowest point was 2009/'10. And then we've seen con -- growth since 2009/'10 in our actual

consumptions.

MR. SVEN HOMBACH: But have you seen it at the same level that growth occurred before the recession?

MR. DANIEL FRIESEN: Yes, in -- in the -- over the -- over the last -- those two (2) -- that two (2) year period, it's been about an average of 2 percent per -- or an average of 2 percent per year.

MR. SVEN HOMBACH: Now, correct me if I'm wrong, sir, but top consumer demand is estimated in two (2) tranches if you will, right? You're looking at actual projections for specific consumers for about three (3) years out.

And after that you're relying primarily on what Manitoba Hydro calls PLIL, or potential large industrial load?

MR. DANIEL FRIESEN: That is correct. And I would say that period varies a little bit from industry to industry, that short-term period. But it's about two (2) to -- two (2) to five (5) years.

MR. SVEN HOMBACH: Now, with Manitoba Hydro's projections, does anything that extends beyond three (3) years automatically get lumped in as PLIL?

Or do you actually project for specific customer groups or industry groups beyond three (3)

years?

MS. LOIS MORRISON: If we have specific committed plans within that three (3) to five (5) year window, those committed plans go into the short-term forecast. It's in year 4 that we begin to introduce the -- the average annual growth that you mentioned, the potential large industrial, or the PLIL, gets introduced in year 4 to recognize that we don't necessarily -- and -- and that's to reflect growth for the overall sector based on past historic growth.

MR. SVEN HOMBACH: Now, on that subject of PLIL, you said "based on past historic growth." To determine PLIL, do you actually look at specific industry groups to determine, well, this industry group would probably grow beyond four (4) years while another one may not? Or do you just base it on what the slope has been historically?

MS. LOIS MORRISON: We look at the sector as a whole, and we take the average growth for that sector as a whole and -- and average that. We -- to -- to -- we -- we don't think that we can state that in ten (10) years from now, or twenty (20) years from now we'll know what industry is going to be here or grow. We do believe that the past history of

twenty (20) years, where we've had a period of growth, and we've had a period of significant recession or economic downturn, provides us with a reasonable benchmark, or -- or average to -- to project future growth.

It's -- it's a period that has, as I said, quite a bit -- a -- a period of growth and a period of -- of economic downturn.

MR. SVEN HOMBACH: Now, taking you to page 58 of Board counsel's book of documents, that's an excerpt from your 2013 load forecast that shows the projections for top consumers. And the orange line that keeps going up, that shows the potential large industrial load. And the green flat line, that would be the demand without the potential large industrial load; just based on what you currently know for specific industry sectors, correct?

MS. LOIS MORRISON: That is correct. It's -- the green line isn't what we know the customer will be doing. I -- I think what we're saying is that the green line is a bit misleading in that what we're showing is the -- is the short-term forecast. The green line depicts the short-term forecast, and we should probably, essentially, truncate it after the fifth year or the third year, and say -- and not show

any more dots going forward.

Because we -- what we're saying is, we don't know specifically what any one (1) of those top consumers is going to do five (5) years out. We do know, and we believe it's reasonable to expect, that there will be some growth overall in the top consumer sector.

And so what we're saying is that they're -- to -- to hold it flat into the future isn't realistic. We're not going to see a situation -- or we don't anticipate seeing a situation where there's absolutely no growth at all in the top consumer sector. However -- so -- so we do apply what we feel is a reasonable estimate of what the anticipated future growth is year-by-year.

MR. SVEN HOMBACH: Of the three (3) customer classes that we've covered, residential, mass market, and top consumers, is this really the one where there's the most uncertainty from Hydro's perspective in the long-term?

MS. LOIS MORRISON: We -- there's uncertainty in all forecasting. We have -- we are more -- there's -- there's more potential for var -- year-to-year variation because the load that is going to come on as a top consumer is going to come on at

year 8, maybe. Or maybe it's going to come in at year 10. We don't know what year it's going to come in, so -- but we -- we do believe that it's going to come in. It's going to come in around maybe a hundred -- what would be accumulating to a hundred gigawatt hours a year. But we just can't say when.

So if you were to look at a year-by-year basis, there will be uncertainty. But to look at it as a whole, and looking at the long-term, I don't believe there's any more uncertainty than -- than any other area of a forecast.

MR. SVEN HOMBACH: And you're basing that, essentially, on the rate of growth over the past twenty (20) years?

MS. LOIS MORRISON: That is what we've -- we've put our future forecast based upon, yes.

THE CHAIRPERSON: Let's talk about that in more detail, because it seems clear to me that a fairly large industrial customer arriving in Manitoba throws this whole thing out of whack, from a top consumer perspective.

MS. LOIS MORRISON: That is correct.

THE CHAIRPERSON: So -- so the reverse is also true; if somebody decides to leave the province, that also throws the load forecast out of

whack?

MS. LOIS MORRISON: Yes, it does.

THE CHAIRPERSON: Okay. Now, let's think about this positively. And -- and this morning we heard from Mr. Kuczek that the pipeline sector is a potential growth sector for the province, given what's going on with respect to the east-west movement of -- of commodity and so on.

So, in effect, if I -- if I read this correctly, we're -- we're beyond the bottom line now. If -- if we are successful in attracting pipeline users to use electricity as the basis -- as the -- as the method of energy, we're into the redline -- we're back into the redline, aren't we?

MS. LOIS MORRISON: Yes.

THE CHAIRPERSON: So if -- you know, if we get seventeen hundred (1,700) -- seventeen hundred (1,700) is the amount we saw this morning, we're into the redline?

MS. LOIS MORRISON: If -- if the pipeline loads were to come in, it would be similar to what MIPUG had asked us to look at in terms of a scenario under MIPUG Round 1, 43b -- or 'a' and 'b', where we would be looking at it -- where they asked us to advance all of the potential large industrial load

to be on the system by 2019/'20.

So, essentially, if we were to -- to use their scenario for what would be the pipe -- representing the pipeline load, you would take that redline and you would -- that's in 2031/'32, and you would move it to be back to -- you would be advancing the redline on the graph to -- to 2019 and -- and you would be hitting that peak. You would be hitting that at that time instead of '31/'32.

THE CHAIRPERSON: But just to explore that a little bit more. Inasmuch as there's some vagaries associated with the load forecast, the -- the principal vagaries are in relation to this particular class, the top consumer class. I mean, they -- they -- the resident -- residential customer is not going anywhere. I mean, the residential customer is -- is living in the province and, you know, there may be some slight changes around movement in and out of the province, but, I mean, they're staying here. And commercial classes, largely the same thing, with the exception of the top consumers who have said that if we increase rates -- if you increase rates we may think about going somewhere else.

Now, I guess what I'm getting at is, in terms of the load forecast, the behaviour of the top

consumers is -- is really what we need to be most cognizant of, in terms of assessing the risk associated with this load forecast.

MS. LOIS MORRISON: You are correct. In terms of the residential and the general service mass market areas, the forecast grows at a much more gradual basis. With top consumers, we are -- there -- there is the risk of the load coming in in a lar -- it comes in large chunks, or it drops off in large chunks.

And, as Mr. Friesen alluded to, it depends on how competitive they are on the global markets, it depends on what their options are, it depends on where -- where they can -- if they want to move their operations to another location, if they have that type of mobility, then all those factors come into play. You're correct, that we -- that -- that there is different drivers for their -- their purpose in being Manitoba, and their -- their use of energy.

MR. DALE FRIESEN: I'd like to also highlight, in respect to the mobility question, that we have to be very careful in how we characterize mobility. Most of the top consumers are resource-based companies, or they deal in a service, pipelines,

where they're resourced -- and the market have fixed locations. So in the case of the pipelines we're not, in particularly, attracting their load; we're in line with their load.

So we're -- we're not attracting that load to Manitoba. We just happen to be physically located between the resource and the market and, as a result, they're coming to us to request service of that load.

So we have to be a little character -- careful in how we characterize mobility, because rates alone may not be the primary driver to their mobility, or to that load growing or shrinking.

So it's just -- it's just something to keep in mind.

MR. LARRY SOLDIER: Could you tell me what the status of this smelter in Thompson is at? I know they announced a shutdown and then they delayed it a year. And what impact would it -- would that have on -- on Hydro if they were to shut down the smelter?

MS. LOIS MORRISON: The -- the smelter that you're referring to is still scheduled to be -- the smelter and refinery is still scheduled to be decommissioned in 2016. They are publicly on the

record that that will be continuing forward.

That load reduction is reflected in our load forecast already. We've already anticipated that. And I believe we are on the record for saying that it is in the same range of energy reduction as the top consumer that we lost in 2010. So it's around the 500 gigawatt hour range. But that has been reflected in the load forecast.

MR. DALE FRIESEN: And, as you mentioned, there is some variability in that date, as you've noted, over the past number of years. The -- that -- that date has been changing. And based on -- you know, there are a lot of factors that are going into that change. The primary one is regulatory, and it's related to the status of that smelter being able to continue operating for environmental reasons. So that's the primary driver there.

CONTINUED BY MR. SVEN HOMBACH:

MR. SVEN HOMBACH: Now, on page 67 of the book of documents, there's actually a chart on a sector-by-sector basis. And, Ms. Morrison, I will have some questions in the in camera session on CSI on this, as well.

But you indicated that the loss of the

smelter is already reflected here. That, I take it, would be the loss in the primary metal sector on this chart?

MS. LOIS MORRISON: That is correct.

MR. SVEN HOMBACH: And really, if we look at this chart, going out to 2020/'21, the only industry sector where you're currently projecting increased growth is the petroleum sector, is it not?

MS. LOIS MORRISON: The only sector that we are specifically in the short term projecting growth is the petroleum sector, that is correct.

MR. SVEN HOMBACH: Okay. Are you -- can you say, in the public session here, what that load is attributed to in the petroleum sector? Which expansions?

MS. LOIS MORRISON: No, I believe I cannot.

MR. SVEN HOMBACH: We will have an opportunity to explore this on Thursday.

Now, the last of the four (4) larger groups of losses that -- or loads that we discussed is the transmission and distribution losses. And again, to put that into perspective, that accounts for about 13 percent of total demand in Manitoba, according to the chart on page 18?

MS. LOIS MORRISON: That is correct.

MR. SVEN HOMBACH: And Manitoba Hydro advised, by way of an answer to Information Request, that it adds transmission losses of about 9.3 percent, distribution losses of 4.4 percent to domestic loads.

Do I have the numbers right?

MS. LOIS MORRISON: Those are -- yes, those are correct.

MR. SVEN HOMBACH: Are those allocated on an equal basis to domestic load and to export load per kilowatt hour or gigawatt hour?

(BRIEF PAUSE)

MS. LOIS MORRISON: We add transmission losses to the top consumers, and we add distribution and transmission losses to the other sectors.

MR. SVEN HOMBACH: Okay. And to export, is it transmission only?

MS. LOIS MORRISON: I am not able to answer how the -- how we account for the export.

MR. SVEN HOMBACH: Is -- is somebody else on the panel able to -- to speak to those issues?

MR. DANIEL FRIESEN: That is a cost of

service issue, so that would be han -- typically handled by our Rates and Regulatory Affairs group. So if it's pertinent that we provide you a response to that, it would probably have to be an undertaking.

MR. SVEN HOMBACH: I -- I -- well, but before I ask for the undertaking, perhaps, let me explore this issue just a little bit further and then we'll just have a single or -- or two (2) undertakings.

Now, at minimum, I believe, Mr. Wojczynski indicated yesterday that he's an electrical engineer, so I'm -- I'm confident that he can answer this.

Losses don't increase on a linear basis, right? It's an exponential function tied to the square of the current?

MR. ED WOJCZYNSKI: It's -- it's a squared function, yes.

MR. SVEN HOMBACH: Resistance times the square of the current?

MR. ED WOJCZYNSKI: Yes.

MR. SVEN HOMBACH: And you'll -- you'll see that as a lawyer I try to just grossly simplify this in atrocious writing. I actually passed little diagram to Mr. Simonsen earlier. Perhaps we

can put this on --

MR. DANIEL FRIESEN: It's actually -- it's actually IR squared.

MR. SVEN HOMBACH: Okay.

MR. DANIEL FRIESEN: It's resistance squared, current times resistance squared.

(BRIEF PAUSE)

MR. SVEN HOMBACH: So he said it's currents times resistance squared, not -- so it doesn't increase exponentially with the current? Just with the resistance?

MR. DANIEL FRIESEN: Obviously, the squaring the resistance creates a multiplier, but it isn't perfectly linear --

MR. SVEN HOMBACH: Okay.

MR. DANIEL FRIESEN: -- but you're right. Yeah.

MR. SVEN HOMBACH: So grossly simplified, then, if I -- if I were to double the amount of electricity flowing through this -- a line, is there any effect, or would it be more or less linear because the resistance itself in the line doesn't change?

MR. ED WOJCZYNSKI: Just -- just wait a second. Maybe we need a -- it's 'I' squared 'R'.

MR. DANIEL FRIESEN: Yes, yes.

MR. SVEN HOMBACH: So I did have that correct?

MR. DANIEL FRIESEN: We're -- we're all on the same page now. You -- every now and then you shouldn't listen to mechanical engineers.

THE CHAIRPERSON: Okay. We're going to have to -- I have to intervene here for a discussion amongst engineers for the non-engineers in the room.

Could you walk us through the -- the symbols here and so -- what we're discussing?

MR. SVEN HOMBACH: Now that I realize, Mr. Chairman, that venturing beyond high school math is an exceedingly bad idea for me, because I've been challenged on it.

CONTINUED BY MR. SVEN HOMBACH:

MR. SVEN HOMBACH: What I'm trying to get at is what -- if -- if it's tied to the square, there's a chart in front of you, Mr. Chairman, and -- and by all means, correct me if the chart isn't correct.

What that basically means is if you are doubling the amount of electricity flowing through a line, you're quadrupling the line losses, give or take; you're not doubling the line losses.

MR. ED WOJCZYNSKI: Yes.

MR. SVEN HOMBACH: So on an incremental basis, the more electricity you're showing through the line, it will have a -- a disproportionate effect?

MR. ED WOJCZYNSKI: Yes.

MR. SVEN HOMBACH: Mr. Simonsen, I don't need the chart any more. So Manitoba Hydro is a -- is an electric utility that meets domestic demand but that also exports a lot of electricity.

What I was trying to get at with the question, and you may have to deal with by way of undertaking is, if -- if you're adding a large amount of exports to the electricity that you are sending through the lines for domestic purposes, are you assigning the incremental transmission and distribution losses to export?

Or are you just assuming that on a percentage basis it's allocated fifty (50) fifty (50) to each of them?

MR. ED WOJCZYNSKI: When we do our

economic evaluations we -- sorry -- we use an -- an incremental value of 10 percent for the export losses. And what you have to keep in mind is the exports go over the high voltage system and don't use any of the lower voltage transmission.

So you -- you can't just look at the losses in our system and then think they're going to increase in the manner you are -- of a -- a -- the quad -- quadratic relationship, that 'I' squared relationship, because you are using the higher voltage system, which has less resistance on it.

So it's -- it -- so -- but -- but aside from that, we do account in our evaluations for the incremental losses due to exports.

MR. SVEN HOMBACH: So, sorry, Mr. Wojczynski, you said you're assuming that the incremental losses will be 10 percent for export?

MR. ED WOJCZYNSKI: Overall, that's what we tend to do. That would be accurate, plus or minus 1 percent. And again, I repeat, that's because we're using the high volt -- the high-voltage system. We don't use the entire grid.

So if you -- for exporting, let's say, additional power from the Nelson River, we're using the HVDC system, which has -- which has -- on an

incremental basis has relatively low losses compared to, say, 230 kV transmission. And then we're using the -- from, say, Dorsey, we would use the 500 kV line and the -- the 230s, but the 500 kV line carries the most. So the losses are lower on that than they would if they were on, say, a 230 kV.

The other thing is the DC system also has some fixed losses which don't vary by the current. When we answered yes to your question about the 'I' squared 'R', we were trying to keep it simple, but it's more complex in that there are fixed losses as well that don't vary by the current. The line losses are the ones, but there's other losses that don't vary by it.

MR. SVEN HOMBACH: Okay. Now, Mr. Wojczynski, we -- we covered this morning that, in its load forecast, Manitoba Hydro is assuming that there's no additional domestic load growth beyond 2047. So that gives us a good starting point beyond 2047. In its financial analysis, Manitoba Hydro's assuming load stays flat.

And what I'd like to know is if we go through the various financial analysis that Hydro has done and the various development plans, the line losses that Hydro's attributing to domestic customers,

not to export customers, are actually different between those plans.

And perhaps let me illustrate on -- on where I'm getting at. If you have a look at page 2 of Appendix 11.3 of Hydro's business case, that's the analysis of the all-gas plan. You should have it on the screen in front of you.

Underneath the highlight, you'll see that domestic losses that Hydro assumes are about 4,000 gigawatt hours per year, 3,927. And that stays flat, which makes sense considering that the load forecast stays flat.

MR. ED WOJCZYNSKI: Yes.

MR. SVEN HOMBACH: If you compare that with Manitoba Hydro's Preferred Development Plan, and let me just pull that up on screen, you'll see that for the same time period, you're attributing about 600 additional gigawatt hours per year to domestic losses, despite the fact that the domestic demand is actually the same.

Can you explain to me where that 600 gigawatt hours of difference comes from?

MR. ED WOJCZYNSKI: Could the person controlling this go the extreme left so we can see what the label is on that row?

MR. SVEN HOMBACH: Sure. That -- that person controlling it is me, if --

MR. ED WOJCZYNSKI: Okay. Okay.

MR. SVEN HOMBACH: I'd be happy to --

MR. ED WOJCZYNSKI: Oh, there.

MR. SVEN HOMBACH: -- to blow it up a bit.

MR. ED WOJCZYNSKI: Yeah.

MR. SVEN HOMBACH: It's the same excerpt, but from the --

MR. ED WOJCZYNSKI: Okay.

MR. SVEN HOMBACH: -- Preferred Development Plan.

MR. ED WOJCZYNSKI: You know, I -- I can't answer that question. I think we'll have to take that as an undertaking. It's -- it's not obvious to me at this moment.

MR. SVEN HOMBACH: Fine.

MR. ED WOJCZYNSKI: It's in the -- is it in the book?

MR. SVEN HOMBACH: I'll accept an undertaking, Mr. Wojczynski, but I'd like that to be a two (2) part undertaking. First of all, I'd like Manitoba Hydro to explain why that difference exists.

But I'd also like them to explain

whether this is simply because one (1) of the plans relies on a longer transmission line as opposed to building the load south, or whether you're actually attributing some incremental export losses to Manitoba Hydro domestic demand.

MR. ED WOJCZYNSKI: We'll accept that undertaking.

MR. SVEN HOMBACH: Thank you.

--- UNDERTAKING NO. 9: Manitoba Hydro to explain: a) attribution of 600 additional gigawatt hours per year to domestic losses; and b) whether this is because of longer transmission lines or whether incremental export losses are attributed to domestic demand

MR. ED WOJCZYNSKI: And this is actually probably a topic that is better addressed in the panel next week, which would be dealing with these evaluations and these calculations. So what I was doing today was trying to provide an -- a high-level

answer so we could keep the momentum going. But this -- this particular topic is actually better suited to next week's panel.

MR. SVEN HOMBACH: I appreciate that. Now, just -- just one (1) last question on this particular issue. On a year-over-year basis, approximately how many gigawatt hours does Manitoba Hydro export?

MR. ED WOJCZYNSKI: I'm not -- I don't have that number at the top of my head. Ms. Flynn would have that number in her head, or Mr. Cormie. I could look it up quickly, but I don't -- it's not -- it's not a number I carry in my head, sorry.

MR. SVEN HOMBACH: But you said that the incremental losses when you're exporting are about 10 percent?

MR. ED WOJCZYNSKI: That's what we typically use in our calculations, yes.

MR. SVEN HOMBACH: So that it -- it would follow then that if you weren't exporting electricity, those additional 10 percent are not something that you would have to generate to meet Manitoba demand, because those 10 percent wouldn't be lost?

MR. ED WOJCZYNSKI: If we didn't have

the exports and the -- then the transmission system, if that energy wasn't being used for domestic load, then -- then the -- the losses in our system would be less by that amount, yes.

(BRIEF PAUSE)

MR. SVEN HOMBACH: Now, we've covered the various adjustments to different customer groups between the 2012 and the 2013 load forecast, and perhaps you can recap just what that means for the earliest required in-service date for new generation?

MR. ED WOJCZYNSKI: I'm -- I'm sorry. I was still trying to read your book, and I don't have a magnifying glass, so I was trying to prepare for your question. You asked a different question than I was expecting. Sorry, could you repeat that?

MR. SVEN HOMBACH: Yes, I can. I -- I said we -- we covered the various adjustments today between the 2012 and the 2013 forecast, and the reductions. What exactly does that mean for when Manitoba Hydro is saying Keeyask will now be necessary, or some new generation in Manitoba would be necessary?

MR. ED WOJCZYNSKI: That actually is

an item for next week's panel, because of the -- that's that need panel which deals with that. But what I can tell you is that -- I do have this in my head, that going from the 12th -- 2012 forecast to the 2013 forecast, and with -- there were some other small changes in the overall assumptions, but the need for Keeyask in a -- a no-sale case, in a case with no new sales moves from 2022 to 2023.

MR. SVEN HOMBACH: So a one (1) year deferral, essentially?

MR. ED WOJCZYNSKI: Yes.

MR. SVEN HOMBACH: Now, before we move on to the subject of DSM, the last issue I wanted to canvas with the panel is the risk of disruptive technology. That was one (1) of the issues that Elenchus had identified in its expert report dealing with load forecasts, and I understand that Manitoba Hydro has looked at some potential future technologies like solar photo -- photovoltaic cells, and ultimately dismissed them at -- as not currently being financially feasible alternatives.

But has Manitoba Hydro had an opportunity to review Elenchus's evidence on disruptive technology and the example in Philippe Dunsky's expert report dealing with projected cost

decreases for solar photo -- photovoltaic and actually try to determine that impact on Manitoba Hydro's future load forecast?

MR. DALE FRIESEN: We have not evaluated it in the context of the forecast. We have evaluated it at a high level in the context of future potential DSM savings, yes.

(BRIEF PAUSE)

MR. SVEN HOMBACH: You've seen the evidence in Philippe Dunsky's report about grid parity, dealing with --

MR. DANIEL FRIESEN: Yes. I -- yes, I have.

MR. SVEN HOMBACH: And I'm -- I'm not trying to cover issues that will be covered by Intervenors, but does Manitoba Hydro agree with the potential time frames, or does it assume these are not realistic?

MR. DANIEL FRIESEN: I would say it's fair to say that those potential time frames reflect the uncertainty that's in the industry today. Manitoba Hydro hasn't done its own projection of when grid parity would occur, as there is a lot of

uncertainty as to where those solar prices will be in the future, and I think all you have to do is look at Mr. Dunsky's own evidence to support that there is a great deal of uncertainty.

So based on some of the industry projections for where those prices are headed, I believe that the range of time when we could see grid -- grid parity could be within the range that Mr. Dunsky projects. It could be later as well. It all depends on where the industry ends up going.

MR. SVEN HOMBACH: Now, does Manitoba Hydro have any tools at its disposal to either encourage the use of such technology or to discourage it?

Like, for example, encouraging people to feed into the grid or not permitting people to feed into the grid?

MR. DANIEL FRIESEN: We do, and if you look at -- we -- we currently have programs in place that would support the installation of solar. If you go to -- and you've looked at Cana -- Manitoba Hydro's current bio-energy optimization program, solar would be an eligible measure under that program.

So if a customer came forward with a solar project today, we would have the potential to

evaluate it under that project and determine whether, you know, what -- what type of incentive and what level of incentive we would provide. So we -- we don't explicitly discourage solar in any way today. We do believe that, today, that technology is not economic in Manitoba, but we do not discourage it.

MR. SVEN HOMBACH: Does Manitoba Hydro currently allow feeding into the grid? If, let's say, a commercial building wanted to install solar panels or other generation?

MR. DANIEL FRIESEN: We do allow it, and we have a policy that allows for it, yes.

MR. SVEN HOMBACH: So has Manitoba Hydro assessed the amount of uncertainty that this imposes on the load forecast?

MR. DANIEL FRIESEN: Like I said, we have looked at it from the standpoint of future DSM savings, and in general, I would say it's safe to assume that we would not expect significant savings to be -- to begin to develop until some time after the 2020 time frame. Even if you look at Mr. Dunsky's data and you look at a -- a grid parity date for Manitoba of 2018, if you assume that -- that to be correct, there would still be an implementation phase.

There would be a ramp-up stage over

which the industry would develop the resources to install the systems, and customers would begin to accept and -- and move forward with purchases of the systems. That -- that's going to involve a time lag, so grid parity is really just an indication at what point the technology -- the cost of generating power with the technology becomes equal to the price the customer is paying on the grid. It doesn't really tell you at what point the customer will begin adopting the technology.

And there are many factors that go into -- into that equation which would indicate that you would expect to see a gradual adoption rate develop after grid parity at some point, and then as momentum is gained, and the cost -- the economic advantage becomes greater, you're going to see an acceleration of that. But we would not expect to see an immediate -- it would be a very gradual impact on -- on the load in Manitoba. It wouldn't be a -- a step change in load.

MR. SVEN HOMBACH: And among the various development plans that Hydro is presenting, there are some long-lived options like hydroelectric power with a lifetime of likely in excess of a hundred years of -- Pointe du Bois, for example, is an

indication -- other technologies with a shorter lifetime, like gas or wind.

Once you've built an asset, Manitoba Hydro doesn't have a choice but to recover the cost of that assets in rates, does it not?

MR. DANIEL FRIESEN: Correct.

MR. SVEN HOMBACH: It's currently required to recover those costs under the Manitoba Hydro Act.

MR. DALE FRIESEN: Yeah.

MR. SVEN HOMBACH: So given the potential uncertainty about implementation and the time frames, how does that impact your decision making between choosing a long-lived asset like a hydro dam or a shorter-lived asset that might only have a quarter of the lifespan where you're not committed for an extended time frame?

MR. DALE FRIESEN: It would probably be better if Mr. Wojczynski answered that question.

MR. ED WOJCZYNSKI: There -- again, this is something we can address in more detail next week in the other panel. But as a first-cut answer, there are numerous uncertainties in -- in the load forecast in the short run and the long run.

We've already been talking about some

of those factors. And so we would view that as being one (1) factor that could cause a lower load forecast than we're looking at, and that's a risk and an uncertainty. And we do look at low load growth as well as high load growth as possibilities.

So we -- we consider it a risk and uncertainty that we'd address just like we do with the other uncertainties we're dealing with. So when we have a -- a -- we -- we do recognize and we do state it in the submission in Chapter 10 where we're dealing with uncertainty. We -- we looked at low load growth and high load growth, and the -- the natural gas plans do have some greater flexibility in the long run to deal with low load growth than the Preferred Plan.

There -- but there are some offsets from that as well in -- in that if you have the tie-line, you can deal with the lower load growth and -- and sell the exports from the additional surplus. But -- so we did assess that in our -- in our uncertainty and risk analysis, and that was included in our decisions and conclusions.

THE CHAIRPERSON: You talked about slow adoption of -- of solar technology; new technology, let's say. And it seems to me the early literature seems to suggest -- on this topic seems to

suggest that -- that large-scale applications are more -- more viable than, say, a -- a residential application would be.

So in a -- in a context where -- of consumers, that's such an important part of the load for Manitoba, do you -- do you think that's also the case for slow -- slow adoption would apply to those top consumers?

MR. DALE FRIESEN: If the you look at the consumption characteristic of a top consumer, a top consumer has a very high load factor. So their -- generally, their load factor is point eight (.8) or higher, often as high as point nine (.9). So they have a fairly continuous requirement for energy at or near their peak capacity requirements on an almost twenty-four (24) hour basis.

Solar's a very intermittent supply. As a result, I would not expect that a top consumer would choose solar as their first option in supplying their needs due to it -- due to its intermittency.

THE CHAIRPERSON: A follow-up question then would be: They would view electricity as being a supplement to their own internal generation source, wouldn't they?

MR. DALE FRIESEN: If you look at the

-- at the energy requirements of Manitoba's top consumers and you look at their opportunities for self-generation, in -- while there are opportunities for self-generation as a percentage of their total load, those opportunities are relatively small.

Like I said, they are available, but on a -- on an aggregate basis, they're -- they're relatively small. Generally, when you look at customers that pursue self-generation, particular large customers, they're taking advantage of either a low-cost or a no-cost waste stream of some type, whether it's biomass, whether it's hydrogen, whether it's flare gas in the oil field.

That really limits their access to low-cost self-generation or economical self-generation.

CONTINUED BY MR. SVEN HOMBACH:

MR. SVEN HOMBACH: So between those three (3) major customer classes -- residential, mass market, and top consumers -- which one of those has the largest variability between peak and off peak? You mentioned for a lot of the industrial consumers, they're actually operating fairly close to the limit?

MR. DANIEL FRIESEN: Yeah, the top consumer group would have the highest load factor.

The commercial and residential sectors would have lower load factors because of the variability in their demand over the course of the twenty-four (24) hour period, and on a seasonal basis. So I can't give you the exact numbers.

Our system load factor is in the or -- in -- in the range of about point six-three (.63), if you look at the information we've provided. So giving that the large consumers are in that point eight-two (.82), point eight-three (.83) range as a group, I would expect that -- that points to the residential and commercial classes being considerably lower.

MR. SVEN HOMBACH: So if you wanted to look at load shifting as opposed to load reduction to manage need, those are the classes you'd have to focus on?

MR. DANIEL FRIESEN: Load shifting is more of a challenge in the top consumer group than some people may initially believe. And the primary reason for that is their lo -- high load factor, yes.

MR. SVEN HOMBACH: Fine. But you -- you mentioned there's more variability with residential customers.

MR. DANIEL FRIESEN: Correct.

MR. SVEN HOMBACH: That's why I made

that comment.

MR. DANIEL FRIESEN: Yeah, but the question you have to ask yourself with the residential class, though, is: What is driving their consumption?

So what is typically driving the consumption, peak periods of consumption, in the resident -- residential sector, if you -- if you leave heat out of the equation, is the activities that occur at the beginning of the day and the end of the day. And I'm not sure about you, but I'd probably be a little resistant to deciding to cook my dinner at midnight as a load shifting initiative.

(BRIEF PAUSE)

MR. SVEN HOMBACH: Electric heating, though, has the largest influence, does it not? It's -- it's the largest component of at least those customers that use electric heating?

MR. DANIEL FRIESEN: Electric heat is a large component of energy consumption in the province, period. It -- it consumes about 50 percent of the energy that -- that we consume in this province is for heat in and of itself. The challenge with heat

is you will see load shifting programs in southern climates that are cooling dominated. They're quite common. They're typically characterized as demand response programs.

The problem we have with heat is that you're -- if you -- if you decide to curtail your -- your use of energy for heat for a period of time, you have to make it up in our climate. You can't do without it. At some point you have to replenish that supply. The longer you wait, and particularly in Manitoba, it's colder at night than it is during the day.

So if I curtail my heat requirement during the day, I'll have to add that plus an amount at night in order to make up for the heat loss, because I'm dealing with a colder climate at night. So it is -- curtailing heat and load shifting heat requirements is a very challenging exercise.

MR. SVEN HOMBACH: So explain this to me. Year over year Manitoba is a winter-peaking jurisdiction, with demand -- total peak demand being higher in winter than in the summer.

MR. DANIEL FRIESEN: That is correct.

MR. SVEN HOMBACH: And that's different from MISO, where it's summer peaking,

meaning you've got more demand during the summer air-conditioning season?

MR. DANIEL FRIESEN: Many jurisdictions within MISO are summer peaking, yes.

MR. SVEN HOMBACH: So on a -- on a day-to-day basis, let's say on a winter day and when you've got a lot of heating load, what time of day do you see the highest peak load in Manitoba?

MR. DANIEL FRIESEN: Traditionally we see the highest peak loads in Manitoba either in the early morning or later afternoon. So those correlate with the heaviest times of energy use for residential customers as well. So it -- the variability is probably largely created by residential customers, with the lar -- top consumers providing more of a base load component to that.

MR. SVEN HOMBACH: Okay. I'd like to address this issue a bit further in the DSM. But before we go there, I do have a question for Ms. Rohmund. I understand that EnerNOC, in preparing its demand potential study, or DSM Potential Study, prepared its own baseline load forecast.

Was that done using the LoadMAP model?

MS. INGRID ROHMUND: Yes, we --

MR. SVEN HOMBACH: Is -- is LoadMAP a

commer --

(BRIEF PAUSE)

MS. INGRID ROHMUND: Yes, we developed a baseline projection using LoadMAP.

MR. SVEN HOMBACH: Is -- is that a commercial program, or is that something that you developed yourself?

MS. INGRID ROHMUND: It's something we developed, yes.

MR. SVEN HOMBACH: And what's the reason for EnerNOC preparing its own load forecast rather than using that of Manitoba Hydro?

MS. INGRID ROHMUND: So just to be -- LoadMAP -- the tool LoadMAP was developed by Global Energy Partners when I was employed there before we were acquired by EnerNOC.

So we developed that tool -- oh, you asked why we used that to develop our projection. When I joined Global Energy Partners and their -- they had a framework for doing potential studies, but it was one that I was not completely enamoured with. So I was -- I come from a long history of end-use forecasting, which basically allows you to tell a

story of what -- about what's happening in the forecast, and allows you to explicitly account for lots of factors that drive the forecast -- or drive a projection.

And using an -- the approach that we developed in LoadMAP pre -- prevents us from overstating the savings that could happen through DSM. And in particular, there was an example in the -- I want to say -- it must be the early '90s, during the first wave of DSM in our industry, and ut -- utilities were doing potential studies.

And Xcel Energy, I think they were Xcel Energy at the time, in Colorado, did a -- did a study of potential and came out with estimates of lighting savings for -- that they could achieve through programs. And the savings that they said that they could achieve were larger than the consumption of lighting in total, and using the end-use forecasting framework, it was very, very embarrassing for them.

And we were doing end-use forecasting at the time and we said if you -- they had taken an end-use forecasting approach that accounts for -- starts with lighting energy use and then subtracts from that usage, then you will never find yourself in that position of overstating the savings in that way.

So that is --

MR. SVEN HOMBACH: Now, in term -- now, in terms of the methodology that you use, do you rely on the same statistical factors that Hydro uses, or do you rely on their input data? How do you arrive at your own load forecast?

MS INGRID ROHMUND: So our projection uses -- it is fundamentally different than what -- what Manitoba Hydro uses and also what many utilities in -- in the States use for their forecasting processes.

It -- when we can, we try to bring in the same growth assumptions and other drivers of the forecast that our clients use. And we are more or less able to do that, depending on the circumstances.

So for Manitoba Hydro, we were able to bring in some of the factors, but as you saw, the Manitoba Hydro forecast is based on rate classes. It's different groupings of customers, and -- and so it is -- the assumptions are not completely the same that drive both projections.

MR. SVEN HOMBACH: Now, you've heard the discussion, Ms. Rohmund, about the changes from Hydro's 2011 to the 2012 forecast where consumption went up and then back down.

MS. INGRID ROHMUND: M-hm.

MR. SVEN HOMBACH: The most recent amendment to your company's study that was filed with the November changes to the NFAT filing --

MS. INGRID ROHMUND: M-hm.

MR. SVEN HOMBACH: -- is that based on input data that reflects Manitoba Hydro's 2013 data, or did you make any changes to the baseline forecast?

MS. INGRID ROHMUND: It's -- it is based on the 2000 -- primarily based on the 2011 forecast.

MR. SVEN HOMBACH: Okay.

(BRIEF PAUSE)

MR. SVEN HOMBACH: I'd like to project again, but I see that my screen is down. There we go.

On the screen in front of you is an excerpt from First Round PUB/Manitoba Hydro Information Request. It's PUB-MH 1-248. And I apologize, that is not in Board counsel's book of documents.

That shows the difference between Hydro's 2011 load forecast and the one that was used for the baseline for this DSM potential study. And if

you go to the 2027/'28 column, there's a difference of over -- or of close to 3,000 gigawatt hours. Now, we've heard this morning that annual growth is in the vicinity of around 420 gigawatt hours. So that would represent about six (6), seven (7) years of growth.

How does that -- how do those discrepancies affect the DSM potential study? It appears that EnerNOC is -- sorry, Manitoba Hydro's projecting quite a bit more load than -- than you are.

Does that mean you'd see less potential for DSM than if you had started with Manitoba Hydro's higher forecast?

MS. INGRID ROHMUND: No, we don't believe that is a -- a conclusion that you can draw from that. When we -- as I explained this morning, we start with a -- a characterization of the market, and the pie charts and the bar charts that show how customers use energy in the base year, which was 2011, and then we apply the customer growth forecast and many other factors, the codes and standards that are -- are expected to be in place, or that we know are going to be in place. We have naturally occurring conservation. We have price effects.

We have -- probably the biggest -- the -- the two (2) biggest -- the biggest one is the

naturally occurring conservation, and so we do -- we apply those factors on an end-use and customer basis, and we -- we are confident that we have estimated those correctly. And then -- so the -- the fact that we differ from Manitoba Hydro's -- oh, let me back up for a second.

We developed this projection for the purposes of the study. It is an -- it is a stepping stone in the development of the potentials. It is not -- it -- it is never intended to be the load forecast. We don't own the load forecast. We're developing a projection for the basis of the study so that we can estimate the savings that come from all those end-uses and technologies.

So it is often the case that our potential study projections, baseline projections, are lower than the utility forecast, because there are factors that we are not taking into con -- account. We are not intimately familiar with all the details that go into the load forecast.

So that difference between the load forecast and our projection, I would argue could be put into a miscellaneous -- miscellaneous category to which no future DSM potential savings are attributed.

In cases where our clients have

required that we align with their forecast -- we have a few who have done that -- the question is what do we do with that difference? And we recommend, and -- and our clients generally agree that we will put that difference into the miscellaneous category wherein there are no future savings.

MR. SVEN HOMBACH: Okay. Now, this morning during Manitoba Hydro's presentation, there was one (1) particular slide that showed where the various jurisdictions where your company has done work, and I'll see if I can pull that --

MS. INGRID ROHMUND: Okay.

MR. SVEN HOMBACH: -- up on the screen for a moment. Do you have the slide in front of you? That's from today's presentations. The -- the difference between the Hydro load forecast and the one that you arrived at with the load forecast model, is that within the same zone of variation that you see when you're preparing your own baseline in other jurisdictions?

MS. INGRID ROHMUND: Yes, we have seen differences of the same magnitude in other jurisdictions. We've also seen less.

MR. SVEN HOMBACH: So you're saying this is not a difference that would concern you?

MS. INGRID ROHMUND: Not necessarily, no.

MR. SVEN HOMBACH: Now, on the issue, then, of DSM. Now, during Mr. Wojczynski's presentation yesterday, there was an indication that Hydro was increasing the DSM in its analysis and that it expected to file information within a week or two (2).

And I'm just wondering if you could elaborate, Mr. Wojczynski, what the nature of that information is that the Board should expect to be filed, and to what extent DSM will actually be expanded in -- in the new filings?

MR. ED WOJCZYNSKI: This is, again, the topic of the panel next week, but what I can say is that what we -- I had a little chart yesterday in my presentation --

MR. SVEN HOMBACH: This --

MR. ED WOJCZYNSKI: Yes, that one.

MR. SVEN HOMBACH: -- fifteen (15)?

MR. ED WOJCZYNSKI: Thank you.

MR. SVEN HOMBACH: You're welcome.

MR. ED WOJCZYNSKI: And so what we will -- we are finishing and have some preliminary results and -- and anticipate sharing at least some of

what's on this chart next week is we'll be having -- using 2013 assumptions, load forecast, and all the -- all the other assumptions, and starting with the 2013 load forecast and export prices and discount rate and everything else.

And we're ev -- evaluating using the Preferred Plan, the -- the base DSM, which is the old DSM level where -- which is called 2013 DSM here, and then the three (3) new DSM options that Mr. Kuczek was mentioning and talking about this morning.

So we will do a pow -- a -- a plan evaluation of that one (1) plan with our four (4) levels of DSM and compare those four (4) levels of DSM.

The other thing we're doing is, for the Preferred Plan, the Keeyask Gas 750 Plan, and the all-gas plan, evaluating those three (3) plans at the option 3 level of DSM, and also evaluating at the option 2 level of DSM.

And so that'll give us an indication of the impacts on the plan of the higher levels of DSM. They're also an indication, by going from option 2 to option 3, what the economics of those would be.

And what our finding was so far was in -- in -- on the economics -- we haven't done the

financials yet -- is that going from the -- the option -- option 1 DSM to the option 2 DSM, that was economic, but that going from option 2 DSM to option 3 DSM was not economic. So that's the information we will be presenting next week.

MR. SVEN HOMBACH: Do you intend to file financials when those will be ready as well?

MR. ED WOJCZYNSKI: Yes, but the financials always take longer, and the Financial Panel is the following week, and I -- I don't know at this point where their -- how far their analysis on the DSM options is right now.

I don't think they'll be able to do as much as the economics will. I expect they will do the levels of DSM on the Preferred Plan, that they will have that. I -- I can't say right now how much more they'll have.

MR. SVEN HOMBACH: Can you undertake to update the Board once you've canvassed with your staff to provide an estimated time for financials to be filed?

MR. ED WOJCZYNSKI: We can undertake to do that, yes.

--- UNDERTAKING NO. 10: Manitoba Hydro to indicate

an estimated time for financials to be filed

CONTINUED BY MR. SVEN HOMBACH:

MR. SVEN HOMBACH: Now, in chapter 12, you said that you were providing updates for five (5) plans that you were looking at. Are those financials ready yet, or do you anticipate having those ready soon?

MR. ED WOJCZYNSKI: Par -- could you repeat that question, please?

MR. SVEN HOMBACH: The -- the five (5) plans that were analyzed in chapter 12, have you done the financials for the update?

MR. ED WOJCZYNSKI: I don't believe those have been done. The update they were going to do were the same ones we just talked about here. They -- but I -- I'll -- is -- perhaps I could take another undertaking to get back to you on that.

MR. SVEN HOMBACH: Certainly. Thank you. Yes. The -- the undertaking is to advise when financial information relating to the plans outlined on page 15 of Mr. Wojczynski's presentation will be filed, and to advise when financial documentation relating to the five (5) plans analyzed in chapter 12

of the NFAT will be filed.

--- UNDERTAKING NO. 11: Manitoba Hydro to indicate when the plans on page 15 of Mr. Wojczynski's presentation, and financials for the five (5) plans will be filed

CONTINUED BY MR. SVEN HOMBACH:

MR. SVEN HOMBACH: Now, in the absence of -- of having some of this information available yet, Mr. Wojczynski, it would help to just have a visual of -- of what it means for Manitoba Hydro to be analyzing five (5) times DSM.

The document that I'm showing you is page 103 of the Board counsel book of documents, which is Figure 12 from the expert report of Mr. Dunsky. It's not a Board or Manitoba Hydro document.

This shows a chart that purports to project the year-over-year DSM over time from Manitoba Hydro (sic) latest Power Smart Plan, the one point five (1.5) times DSM scenario, and then the four (4) times DSM scenario.

First of all, has Manitoba Hydro had an

opportunity to -- to look at this chart, and does it accurately reflect the projected DSM?

MS. LOIS MORRISON: This representation does not fully characterize the new options that are being assessed currently. As Mr. Kuczek mentioned, there are a number of programs where the savings have been extended and have been increased, and if I could draw your attention to the rebuttal, specifically looking at page 31, if -- if we could pull that up?

(BRIEF PAUSE)

MS. LOIS MORRISON: The chart at the bottom, or the graph at the bottom. The graph at the bottom denotes the comparison of the option -- of the -- of the levels being assessed currently related to the -- 2013 Power Smart Plan. And the -- these are the -- these are the options being assessed by our resource planning group and will be discussed next week.

MR. SVEN HOMBACH: So the five (5) times DSM is -- the level 3, does that reflect the five (5) times DSM, or should we expect a similar charge just with a --

MS. LOIS MORRISON: Yeah.

MR. SVEN HOMBACH: -- a higher line?

MS. LOIS MORRISON: The level 3 that's being denoted here is what is comparable to what Mr. Wojczynski is referring to as that five (5) times.

MR. SVEN HOMBACH: Okay.

MS. LOIS MORRISON: I should note that what's being presented here is a year-by-year. If you cumulate it, and cumulate the savings over time, that's where the analo -- the -- the analogy of the five (5) times is.

You could also -- to give you a -- a perspective of what it -- the impact is to the load forecast, if you turn to page 32, you can see what -- what the different levels represent in terms of an adjustment to our load forecast.

(BRIEF PAUSE)

MR. SVEN HOMBACH: So again appreciating that not all of the information is available yet, EnerNOC draws the distinction between technical potential, achievable potential, market potential.

Are all three (3) levels what you, or

what EnerNOC would consider to be achievable potential?

MS. LOIS MORRISON: Mr. Kuczyk characterized it at the beginning that these levels that we've introduced, we are very confident in terms of the level 1 in terms of being achievable. There's a lot more analysis that has gone into those program charact -- program projections in terms of what the market uptake would be, what the different technologies included are, and such.

Level 2 requires more additional investigation. So in terms of the certainty of being able to attain those savings, I think when we're talking about the achievable versus the market, what you're getting into is that degree of certainty of being able to achieve it. The closer you get to market the more -- the more uncertainty there is attached to achieving it, and, so if you go through our levels, there's more uncertainty.

MR. SVEN HOMBACH: And are you in a position to state at this point what the deferral prospect for new generation are if you apply level 2 or a level 3? Has that analysis been done?

MR. LLOYD KUCZEK: That's not our panel.

MR. SVEN HOMBACH: So will the next panel be able to speak to that issue?

MR. ED WOJCZYNSKI: Could you repeat the question, please?

MR. SVEN HOMBACH: There's some new evidence with respect to the level 1, level 2, level 3. I'm wondering if Manitoba Hydro has analyzed to what extent this means new generation can be deferred if you're applying level 2 or if you're applying level 3?

MR. ED WOJCZYNSKI: Oh, yes. That's definitely part of that analysis.

MR. SVEN HOMBACH: Okay. And --

MR. ED WOJCZYNSKI: And that will be provided next week, on Monday. Now -- and -- and it -- I mean, it's -- it de -- will defer, in the no-sale case does defer the requirement for the next generation absolutely, yes.

MR. SVEN HOMBACH: This particular chart that's currently still on screen from page 32 of Hydro's rebuttal just goes to 2028. Has Manitoba Hydro analyzed the DSM potential going out further?

MS. LOIS MORRISON: We -- as Mr. Kuczek stated, we do a fifteen (15) year plan for the purposes of resource planning. We don't look out

beyond that period of time at this point.

MR. SVEN HOMBACH: M-hm. And I don't know if you're in a position to -- to answer the next question, but would you just assume that going forward it flatlines at a certain annual percentage basis, or would you assume that there is no further DSM potential beyond 2028, in your analysis?

(BRIEF PAUSE)

MR. LLOYD KUCZEK: It -- it's very difficult to project out that far in terms of what could be achieved. And we recognize a projection of zero beyond a certain point isn't realistic either. What we're going to try to do is come up with a projection at least in the fifteen (15) year period that we think is our best estimate of what it's going to be as opposed to having a conservative plan in the past.

So -- but -- be going -- going beyond '27, '28, you know, it really comes down to how many homes are left that need insulation, how much can you really expect technology changes after a certain point?

I'll just give you an example with

lights. Like you -- you know, substantial gains from a 60 watt to 11 watt, for example, well -- and if you think in terms of percentages, that -- that's huge. Where are you going to go from 11 watts? Like what's really realistic?

If you look at fridges, we went from 1,600 kilowatt hours a year down to 500 kilowatt hours a year. Now, what's realistic beyond that, you know? Natural gas furnaces from 60 percent up to 92, 94 percent. Well, where do you go from there, you know?

So -- so from -- if -- if there's anything to happen in the future, in my mind, I think there will be some opportunities that we could maybe capture. What they are, I think it's going to be diminishing as we move into time. I don't know if there's going to be additional end-use applications that are going to come into play. But when you certainly start to talk about the applications of solar, that -- that would be significant, relative to where I think some changes could occur with the technologies that we're currently looking at, or where there's improvements on efficiencies.

MR. SVEN HOMBACH: Well, you've indicated that Manitoba Hydro will file an economic analysis. And we've determined this morning through

testimony from Mr. Wojczynski that, for example, Manitoba Hydro extrapolates further load growth beyond twenty (20) years, but then stops projecting incremental load growth after 2047.

I'm just wondering what assumptions are you making for the economic analysis? Are you cutting off all DSM beyond fifteen (15) years, or are you continuing to assume that DSM is included?

(BRIEF PAUSE)

MS. LOIS MORRISON: Under the current plan -- or, sorry, under the options that are being looked at, we aren't introducing new programs or new technologies past the fifteen (15) years.

So what would happen is we wouldn't see any new additional reductions coming in on an annual basis. The reductions that are projected here would stay and continue on, but we wouldn't see new incremental ones coming in except -- sorry, so that would be it, yeah.

MR. SVEN HOMBACH: So no additional annual reductions?

MS. LOIS MORRISON: No additional annual reductions at the end of the -- the fifteen

(15) -- I think it's -- just a minute.

(BRIEF PAUSE)

MR. LLOYD KUCZEK: Like, certainly if you far enough into the future and homes get torn down and rebuilt, they're going to be rebuilt to more efficient standards, so you know, you're going to -- you're going to achieve some opportunities there.

MR. SVEN HOMBACH: Right. And, again, perhaps I can simply ask that when the economic analysis is filed that the assumptions that are going into DSM are confirmed with that analysis, to the extent that what you indicated on the record today may not be the case.

MS. LOIS MORRISON: We will confirm the assumptions going into the analysis for DSM.

--- UNDERTAKING NO. 12: Manitoba Hydro to confirm assumptions going into DSM analysis

MR. SVEN HOMBACH: Thank you. Now, Mr. Chairman, it's 4:30. I promised that we would break at 4:30 today. I do have a few additional

issues with respect to DSM to cover in the morning, but it hopefully will not take much more than an hour. So if the panel is prepared to adjourn for the day, we may wish to do so.

THE CHAIRPERSON: Yes, I think we are prepared to adjourn for the day.

Now, I wonder are there any administrative matters to attend to before we recess? I'm looking -- it doesn't appear that we have anything.

MR. SVEN HOMBACH: Nothing further that I'm aware of, Mr. Chair.

THE CHAIRPERSON: Okay. Well, thank you very much, everyone. We'll see each other again tomorrow morning at nine o'clock. Thank you.

(PANEL RETIRES)

--- Upon adjourning at 4:33 p.m.

Certified Correct,

_____

Cheryl Lavigne, Ms.

$

$1,000 476:10

$10 473:18

$100M 349:17

$178 486:16

$2,000 476:11

$20,000 451:19

$3,500 450:11 451:23

$4,000 451:23

$4,300 450:18

$5,000 450:21

$500 446:8 476:9

$700 458:22 481:18,20

$709 486:12

$800 449:10

$887 486:14

0

0.3 526:21

01 515:14

08 513:23

09 392:17 444:21

1

1 324:3 325:24 326:17,19 342:9,25 351:23 352:23 357:7 358:24 360:17 362:16 364:8,19 365:14 366:15 367:9,22 368:7,25 369:25 370:17 371:14 396:23 400:7,11 401:15,17 421:11 422:19 424:11 425:12 426:5 429:24 430:7 433:23 435:2 438:8 445:5 448:18 450:7 453:5 457:8 468:10 471:3,19 475:14,15,18 476:18 479:14 482:1,4 483:21 486:4 487:23 489:15 492:18 493:14 495:2,15,20 513:8 515:24 521:13,14,18 523:11 525:3 528:22 538:13 543:16,17,20 554:6 555:4 558:21 565:25 575:14 576:11 577:7,12 583:3 585:23 596:20 600:1 601:5 603:9,15 609:2 622:9 624:12 625:2 630:6 631:6

1,000 458:9

1,100 415:3

1,159 495:7

1,250 447:10

1,600 633:7

1,700 393:9 585:17,18

1.0 426:4,11

1.1 522:2

1.14 391:18

1.2 522:1

1.4 390:14 392:1 422:18,20 525:20,23 526:1 572:12 573:18,19

1.5 390:11,17 391:25 422:17 571:18,21 627:23

1.6 390:22 391:24

1.7 571:22

1.8 572:11 573:17,19 574:5

1/2 414:16

1/3 576:5,6,13,14

1:00 485:6,7

10 325:3 327:8 353:9 357:16 359:10 361:3 362:25 365:5,23 366:24 367:18 368:16 369:11 370:11 371:3 373:20 390:8 392:18,20 423:8 442:10 458:25 459:3 465:18 479:11 482:9,10 525:18 526:18 556:3 567:19 572:16 574:18,21 575:2,5,6,8,16 581:23 584:2 596:2,17 601:16,21,23 609:10 625:25

100 331:24 550:19 551:9 567:20

101 331:25

102 332:3

103 332:4 627:17

104 332:5

105 332:6

106 332:7

107 332:9 452:22

108 332:11

109 332:12

11 324:18 325:5 327:9 353:10 357:17 359:11 361:4 363:3 365:6,24 366:25 367:19 368:17 369:12 370:12 371:4 374:3 564:18 627:3 633:2,4

11.3 499:4 598:5

11:14 465:24

11:28 465:25

11:54 485:9

110 332:13

1-102a 576:22

111 332:14

112 332:15

113 332:16

114 332:17

115 332:18

116 332:19

117 332:20 524:21 551:24

118 332:21

119 332:22 562:5

119/13 326:3

12 325:8

327:10
353:11
357:18
359:12
361:5
363:4
365:7,25
367:3
368:18
369:13
370:13
374:8
489:10,17
494:23
495:3
509:3
513:22
523:6
525:11
552:10
560:13
626:5,13,25 627:18
635:19

12:54 485:10

120 332:23

121 332:24

122 332:25

123 333:3

124 333:4

1-248 619:20

125 333:5

126 333:6

126/13 326:5

127 333:7

127/13 326:7

128 333:8

128/2013 324:3

129 333:9

12th 603:4

13 325:11
327:11
345:8
351:13,22
353:12
357:19
359:13
361:6
363:5
365:8
366:3
367:4
368:19
369:14
370:14
504:23
512:9
513:22
590:24

130 333:10

131 333:11

132 333:12

133 333:13

134 333:14

135 333:15

136 333:16

137 333:17

138 333:18

139 333:19

14 325:14
327:12
353:13
357:20
359:14
361:7
363:6
365:9
366:4
367:5
368:20
369:15
413:11
489:25
514:1
557:16,20
558:4,11
561:4

14,714 519:18

140 333:20

141 333:21

142 333:22

143 333:23

144 333:24

145 333:25

146 334:3

147 334:4

148 334:5

149 334:6

15 325:17
327:13
353:14
357:21
359:15
361:8
363:7
365:10
366:5
367:6
368:21
369:16
374:4
465:18
484:8,15
623:20
626:23
627:4
631:24
632:16
634:7,15
635:1

15,2013 351:25

150 334:7

151 334:8

152 334:9

153 334:10

154 334:11

155 334:12

156 334:13

157 334:14

158 334:15

159 334:16

16 324:8,10,12,13
325:20
327:15
353:15
357:22
359:16
361:9
363:8
365:11
366:6
368:22
369:17
412:8
416:3

16(b 457:1

16,901 552:24

160 334:17

161 334:18

162 334:19

163 334:20

164 334:21

165 334:22

166 334:23

167 334:24

168 334:25

169 335:3

17 324:4,7
325:23
327:16
353:16
357:23
359:17
361:10
363:9
366:7
369:18
415:4

170 335:4

171 335:5

172 335:6

173 335:7

174 335:8

175 335:9

176 335:10

177 335:11

178 335:12

179 335:13

18 326:3
327:17
353:17
357:24
359:18
361:11
363:10
366:8
369:19
412:13
504:15
557:11,20
558:1,11
559:22
560:24
568:17
576:1
590:25

18,500 549:11,19

180 335:14

181 335:15

182 335:16

183 335:17

184 335:18

185 335:19

186 335:20

187 335:21

188 335:22

189 335:23

19 326:5
327:18
353:18
357:25
359:19
361:12
363:11
366:9
369:20
518:12
521:5

190 336:3

191 336:5

192 336:7

193 336:8
194 336:9
195 336:10
196 336:11
197 336:12
198 336:13
199 336:14
1993 380:16
1st 531:18

2

2 324:5
326:20
351:16,25
352:24
357:8
358:25
360:18
362:17
364:9,20
365:15
366:16
367:10,23
368:8
369:3
370:3,18
371:17
417:23
420:4,8,17
,19,22
422:8
434:21
445:5
454:19
462:8
470:19
471:3,4,21
472:15
473:12
476:12
477:2
482:1
483:15
486:8
490:1
491:4
492:17
493:14
495:3
496:2,7
499:5
509:25
513:6,12
516:1
518:24,25
520:11
527:7
537:17
541:19
549:12
552:20
560:4,9
566:16
569:14
571:6,12
579:15
580:6,7,8,
11,20
592:8
598:4
599:23
620:25
623:8
624:19,22
625:2,3
630:11,22
631:6,9
2,000 415:16
2,287 519:23
524:20
2.1 491:4
2.4 455:4
456:22
2.77
510:5,6,18
515:13
2.79 509:24
510:3,7,9,
18 516:25
2.8 509:22
2.9 456:21
2.93 512:21
513:4
515:11
516:10,25
517:4
2/3s 574:22
2:27 556:6
2:45 556:7
20 326:7
327:19
352:22
353:19
357:6
358:3,23
359:20
360:16
361:13
362:15
363:12
364:7,18
365:13
366:10,14
367:8,21
368:6,24
369:21,24
370:16
371:7,9
390:13,18,
23 413:23
422:17
465:21
495:8,23
496:8,10,1
4,21,23
497:11
498:8
504:3
526:22
528:25
539:19,24
549:7
575:8
581:23
582:1
584:14
634:3
200 336:16
2000
412:3,5,8
576:24
619:10
2004
562:10,24
2004/08
349:7
2005 507:24
2006 469:19
2006/'07
512:19
2007 384:7
513:23
576:24
577:4
2007/'08
474:14
2008 392:17
444:21
572:23
2008/'09
469:22
2009 345:5
385:13
539:9
540:14
562:4,25
577:21
2009/'10
579:24,25
201 336:17
2010 384:11
470:14
508:5
589:6
2011 345:5
385:14
395:23
398:22
399:7,16
407:18
410:1
412:5,20
413:9,12
470:15
507:10,23
508:1,8
513:22
579:20
618:24
619:10,24
620:18
2012 480:8
489:5,8,16
494:25
507:11
508:3,7,22
509:7
518:5,15
519:16
522:25
523:2
524:19
525:15
550:24
551:21
552:9,21
553:1
571:17
579:20
602:10,20
603:4
618:24
2012/'13
490:5
2013
324:4,7,8,
10,12,13,1
6,18,20,23
,25
325:4,7,9,
10,13,16,1
8,19,22,24
,25
326:4,6,8,
11,14,16,1
8
351:8,10,1
3,15
424:17
473:5,8
489:9,22
490:1
495:1,6,20
,24 496:7
504:5
507:11
508:9,18
509:2
518:4,15
519:17
525:11,16
537:3,14,1
9 551:22
552:9,21
553:2
554:22
571:17
572:7
576:25
582:11

602:10,20
603:5
619:7
624:2,3,8
628:18

2014 321:24
351:17,19,22
352:5,8,11,13,16,18,20,22
357:6
358:23
360:16
362:15
364:7,18
365:13
366:14
367:8,21
368:6,24
369:24
370:16
371:7,9
393:1
394:12
471:14,16
489:18
508:13
530:2,5,17,23 531:4

2016 588:25

2018 606:23

2019 586:7

2019/'20
586:1

202 336:18

2020 606:21

2020/'21
590:6

2022 603:8

2023 603:8

2027/'28
620:1

2028 486:9
631:21
632:7

203 336:19

2031 399:8

2031/'32
399:9
413:22
414:15
415:4,18,25 495:8
586:5

204 336:20

2047 497:16
498:10,14
499:5,23
597:18,19
634:4

205 336:21

206 336:22

207 336:23

208 336:24

209 336:25

20-year
549:4

21 326:6,8,9
327:20
353:20
358:4
359:21
361:14
363:13
366:11
369:22

210 337:3

211 337:4

212 337:5
553:6

213 337:6

2130 399:9

214 337:7

215 337:8

216 337:9

217 337:10

218 337:11

219 337:12

22 326:12
327:21
353:21
358:5
359:22
361:15
363:14
366:12
380:17
559:2

220 337:14

221 337:16

222 337:18

223 337:19

224 337:20

225 337:21

226 337:22

227 337:23

228 337:24

229 337:25

23
326:11,14,15 327:22
351:10
352:5
353:22
358:6
359:23
361:16
363:15
504:21
560:23
576:2

23,000 549:9

230 338:3
597:2,6

230s 597:4

231 338:4

232 338:5

233 338:6

234 338:7

235 338:8

236 338:9

237 338:10

238 338:11

239 338:12

24 326:17
327:3,24
328:3
329:3
330:3
331:3
333:3
334:3
335:3
336:3
337:3
338:3
339:3
340:3
341:3
342:3
343:3
344:3
345:3
346:3
347:3
348:3
349:3
350:3
351:3,13
353:23
358:7
359:24
361:17
363:16
384:4
559:7,15,17 560:17
610:16
612:3

24,400
389:10

24,404
490:5,17

24,759 490:9

240 338:13

241 338:14

242 338:15

243 338:16

244 338:17

245 338:18

246 338:19

247 338:20

248 338:21

249 338:22

25 324:20
325:18,19
328:3
351:6
353:24
358:8
359:25
361:18
363:17
381:19
386:18
415:24
419:21
421:11
465:22
481:17

250 338:23

251 338:23

252 338:24

253 338:24

254 338:25

255 338:25

256 339:3

257 339:3

258 339:4

259 339:4

26 325:22
328:4
349:11
351:9
353:25
358:9
360:3
361:19
363:18
385:10
412:4

260 339:5

261 339:6

262 339:7

263 339:8

264 339:9

265 339:10
266 339:11
267 339:12
269 339:14
27 328:5 351:11,15 352:8 354:3 358:10 360:4 361:20 363:19 632:21
27/'28 394:25 395:11
270 339:15
271 339:16
272 339:17
273 339:18
274 339:19
275 339:20
276 339:21
277 339:22
278 339:13,23
279 339:24
28 328:6 351:14 352:11 354:4 358:11 360:5 361:21 363:20 467:3,4 632:21
280 339:25
281 340:3
282 340:4 552:25
283 340:5
284 340:6
285 340:7
286 340:8
287 340:9
288 340:10
289 340:11
29 324:16 325:7 326:16 328:7 351:8,16 354:5 358:12 360:6 361:22 363:21 411:25 504:19 513:3 540:19 546:21
290 340:12
291 340:13
292 340:14
293 340:15
294 340:16
295 340:17
296 340:18
297 340:19
298 340:20
299 340:21

3

3 323:6 324:8 326:21 352:25 357:9 359:3 360:19 362:18 364:10,21 365:16 366:17 367:11,24 368:9 369:4 370:4,19 379:17 391:22 394:25 415:2,16 417:9 421:20 428:6 430:22 438:7,10 463:3 468:13 470:23 471:4 472:4,12 473:1 474:9 476:23 478:6 484:6,14 486:5 487:24 495:25 507:10 515:25 528:3,8 552:11,12 553:7 580:13,23, 25 581:3 583:16 611:19 624:9,17,1 8,23 625:3 628:23 629:3,25 630:23 631:7,10
3,000 490:24 491:6 620:2
3,400 549:2,7
3,500 450:18
3,927 598:10
30 325:24,25 328:8 351:18 354:6 358:13 360:7 361:23 363:22 383:3 387:2 415:23 481:17 504:19 532:19
300 340:22 393:15
301 340:23
302 340:24
303 340:25
304 341:3
305 341:4
306 341:5 521:6 551:23
307 341:6
308 341:7
309 341:8
30th 484:20
31 328:9 351:20 354:7 358:14 360:8 361:24 363:23 628:9
31/'32 586:9
310 341:9
311 341:10
312 341:11
313 341:12
314 341:13
315 341:14
316 341:15
317 341:16
318 341:17
319 341:18
31st 484:3,17 531:18
32 328:10 351:23 354:8 358:15 360:9 361:25 363:24 629:14 631:20
320 341:19
321 321:25 341:20
322 341:21
323 341:22
324 323:3 341:23
325 341:24
326 341:25
327 342:3
328 342:4
329 342:5
33 328:12 352:3 354:9 358:16 360:10 362:3 363:25 373:4 550:12 551:13
330 321:22 342:6
331 342:7
332 342:8
333 342:9
334 342:10
335 342:11
336 342:12 486:4
337 342:13
338 342:14
339 342:15
34 328:14 352:6 354:10

358:17
360:11
362:4
364:3
456:15
504:20
547:24
549:3,8
571:19

340 342:16

341 342:17

342 342:18

343 342:19

344 342:20

345 342:21

346 342:22

347 342:23

348 342:24

349 342:25

35 328:15
352:9
354:11
358:18
360:12
362:5
364:4
473:19
497:5,20,22 498:9
553:18

350 343:3

351 343:4

352 343:5

353 343:6

354 343:7

355 343:8

356 343:9

357 343:10

358 343:11

359 343:12

36 328:16
352:12
354:12
358:19

360:13
362:6
554:20
560:24

360 343:13
481:12

361 343:14

362 343:15

363 343:16

364 343:17

365 343:18

366 343:19
547:1
548:4
550:18
552:1,6,18
553:10

367 343:20

368 343:21

369 343:22

37 328:18
352:14
354:13
358:20
360:14
362:7

370 343:23

371 343:24

372 343:25

373 323:4
344:3

374 344:4

375 344:5
371:19

376 344:6
371:20,22,24

377 344:7
372:4

378 344:8

379 323:13
344:9

38 328:20
352:17

354:14
358:21
362:8
558:23
562:22

380 344:10

381 344:11

382 344:12

383 344:13

384 344:14

385 344:15

386 344:16

387 344:17

388 344:18

389 344:19

39 328:21
352:19
354:15
362:9
561:1

390 344:20

391 344:21

392 344:22

393 344:23

394 344:24

395 344:25

396 345:3

397 345:4

398 345:6

399 345:7

3F 506:16
517:9

4

4 321:24
324:11
325:9,10
326:4,22
353:3
357:10
359:4
360:20
362:19
364:11,22

365:17
366:18
367:12,25
368:10
369:5
370:5,20
400:4,10
414:11
415:20
417:9
453:2
456:18
491:4
509:18
513:5
516:1
566:16
581:5,8,16
590:20
624:12,13
627:23

4,000 598:10

4,400 490:19

4,600 491:16

4,650 491:14

4.4 591:5

4.6 449:7,8

4:30
635:24,25

4:33 636:19

40 328:22
352:21
353:3
354:3,16
355:3
356:3
357:3
362:10
448:21
561:15

400 321:22
345:8
381:23

401 345:9

402 345:10

403 345:11

404 345:12

405 345:13

406 345:14

407 345:15

408 345:16

409 345:17

41 328:24
354:17
357:5
358:3
362:11

410 345:18

411 345:19

412 345:20

413 345:21
495:21
521:18

414 345:22

415 345:23

416 345:24
521:15

417 346:3

418 346:5

419 346:6

42 329:3
354:18
358:22
359:3
360:3
362:12

420 346:7
495:16
620:4

421 346:8

422 346:9

423 346:10

424 346:11

425 346:12
549:14

426 346:13

427 346:14

428 346:15

429 346:16

43 329:5
354:19
360:15
361:3
362:3,13
440:23
430 346:17
431 346:18
432 346:19
433 346:20
434 346:21
435 346:22
436 346:23
437 346:24
438 346:25
439 347:3
43b 585:23
44 329:7
354:20
362:14
363:3
364:3
440:23
466:7
440 347:4
441 347:5
442 347:6
443 347:8
444 347:9
445 347:10
446 347:11
447 347:12
448 347:13
449 347:14
45 329:9
354:21
364:5
450 347:15
451 347:16
452 347:17
453 347:18
454 347:19
455 347:20
456 347:21
457 347:22
458 347:23
459 347:24
46 329:10
354:22
364:17
365:3
460 348:3
461 348:5
462 348:7
463 348:8
464 348:9
465 348:10
466 348:11
372:7
467 348:13
372:8
468 348:14
469 348:15
47 329:11
354:23
365:12
366:3
470 348:16
471 348:17
472 348:18
473 348:19
474 348:20
475 348:21
476 348:22
477 348:24
478 349:3
479 349:5
48 329:13
354:24
366:13
480 349:6
481 349:8
482 349:9
483 349:10
484 349:11
485 349:12
486 323:14
349:15
487 349:16
488 349:17
489 349:18
49 329:15
354:25
367:7
490 349:19
491 349:20
492 349:22
493 349:23
494 349:24
495 349:25
496 350:3
497 350:5
498 350:6
499 350:7

5

5 324:14
326:23
352:13,16
353:4
357:11
359:5
360:21
362:20
364:12,23
365:18
366:19
367:13
368:3,11
369:6
370:6,21
374:6
386:25
390:8
392:5,6
393:23
423:22,24
424:3,18
462:6
506:25
570:7,11,14 572:7
575:17
578:6
580:20
581:4
583:4
626:6,12,25 627:8,15
628:22,24
629:5,11
5,300 516:12
50 329:17
355:3
367:20
429:19
430:17
440:22
448:20
453:1
595:23
613:23
500 350:8
447:4
478:18
479:4
577:13
589:7
597:3,4
633:7
501 350:9
502 350:10
503 350:11
504 350:12
505 350:13
506 350:14
507 350:15
508 350:16
509 350:17
50-kilovolt
505:14
51 329:19
355:4
368:5
510 350:18
511 350:19
512 350:20
513 350:21
514 350:22
515 350:23
516 350:24
517 350:25
518 351:3
519 351:4
52 329:21
355:5
368:23
369:3
572:6,8
520 351:5
53 329:22
355:6
369:23
370:3
54 329:23
355:7
370:15
371:3
55 329:24
355:8
371:5
551 373:7
56 329:25
355:9
371:8
568 373:11
57 330:3
355:10
371:10
576:20
570 414:14
58 330:4
355:11
371:13
582:10
58-2 375:19
504:16

59 330:5
355:12
376:5
491:4

6

6 324:17
327:3
353:5
357:12
359:6
360:22
362:21
364:13,24
365:19
366:20
367:14
368:4,12
369:7
370:7,22
414:16
424:4
470:2
620:5

6.69 480:8

60 330:6
355:13
376:11
633:2,9

60,000
448:19

600
373:13,19
393:24
577:13
598:17,21
600:11

61 330:7
355:14
376:19
419:23

62 330:8
355:15
491:8

625 373:22

627 374:7

63 330:9
355:16
612:7

635 374:10

636 321:25
323:16

64 330:10
355:17

65 330:11
355:18

66 330:13
355:19
505:20

67 330:14
355:20
589:20

67/13 324:17

68 330:15
355:21

69 330:16
355:22

7

7 324:19
327:5
352:18,20
353:6
357:13
359:7
360:23
362:22
364:14,25
365:20
366:21
367:15
368:13
369:8
370:8,23
373:3
433:12
458:11,16
459:4
462:7
480:1
551:12
620:5

7.27 459:6

7.4 433:8,9

7.5 433:14

70 330:17
355:23
458:13

70s 509:17

71 330:18
355:24

72 330:19
355:25
562:11

73 330:20
356:3

74 330:21
356:4

75 330:22
356:5

750 577:5
624:16

76 330:23
356:6

77 330:24
356:7

78 330:25
356:8
498:7

79 331:3
356:9

8

8 324:21
327:6
353:7
357:14
359:8
360:24
362:23
364:15
365:3,21
366:22
367:16
368:14
369:9
370:9,24
373:8
412:15
415:18
416:3
433:14
475:19
476:19
484:25
485:1
509:5
515:12
568:10
584:1
610:12

80 331:4
356:10
459:7
514:6,11
515:16

81 331:5
356:11

82 331:6
356:12
612:10

83 331:7
356:13
612:10

84 331:8
356:14

85 331:9
356:15
513:3

86 331:10
356:16
377:10

87 331:11
356:17
377:16
388:23

875 550:25

88 331:12
356:18

89 331:13
356:19

9

9
324:23,24,
25
325:4,13,1
6 327:7
351:19
353:8
357:15
359:9
360:25
362:24
364:16
365:4,22
366:23
367:17
368:15
369:10
370:10,25
373:12
476:25
600:10
610:13

9.3 591:4

9:10 375:1

90 331:14
356:20

90s 509:22
617:9

91 331:15
356:21

91/13 324:24
325:6

92 331:16
356:22
413:24
633:9

92/13 325:3

93 331:17
356:23

94 331:18
356:24
633:9

942 548:5

95 331:19
356:25

96 331:20
357:3

97 331:21
357:4

98 331:22

99 331:23

A

A.1 509:6

a.m 375:1
465:24,25

485:9
ability 488:9,15 494:17
able 452:16 475:9 485:16 524:6 529:18 532:25 551:4 566:12 589:15 591:21,24 618:15,16 625:13 630:13,16 631:2
absence 399:18 408:5 627:11
absolute 418:17 423:18
absolutely 516:2 583:12 631:18
academic 383:7
accelerate 406:11
acceleration 607:16
accept 387:23 512:16 524:23 532:16 599:21 600:6 607:3
acceptable 444:13 476:4
acceptance 409:6,7,12,23
accepted 387:16
access 324:22 336:8 337:19 342:13,14,15 349:18,19 611:14
accessing 447:1
accommodate 494:13
accommodation 538:9
accordance 400:3
according 484:18 590:24
accou 461:8
account 381:24 392:9 408:6,7 412:4 413:24 414:3 418:12 421:25 432:10 440:8,9 441:25 442:22 443:11,16 444:1,3,20 447:5 453:9 461:5 463:22 471:12 478:3 500:19 539:22 569:15 591:22 596:13 617:2 621:18
accountant 385:7
accounting 381:18
accounts 569:22 571:19 590:23 617:22
accumulating 584:5
accuracy 390:7 392:2,3 423:9,23 424:2 463:23
accurate 520:20 596:19
accurately 423:16,18 628:2
ACEEE 420:1 440:18
achievable 400:6,12,13 402:19 403:5 409:8,10 413:22 414:13,19 415:4,7,17 416:2,16,17 629:23 630:1,6,14
achievables 426:15
achieve 396:21 419:6,9 420:6,23 437:11,13 442:18 445:6 456:7 462:23 471:10 476:14 535:25 547:15,16 617:15,17 630:16 635:9
achieved 392:3 402:17 403:1 414:20 419:8 437:18,19 446:25 463:9 464:5,6,11 632:13
achievement 419:13
achievements 463:6
achieving 437:2 443:12 630:18
acquired 616:18
across 381:3 387:3 413:1,7,8 414:10 415:15,25 421:20 427:1 439:23 478:19,24 503:5
Act 484:2 608:9
Action 388:3
actions 407:7
active 380:23 415:11 417:13 463:21
activities 327:17 383:14 613:9
activitities 348:18
activity 404:12 480:23
actual 403:10 405:17 482:24 490:8 504:3 521:5 554:18 572:10 574:9 577:4 578:13 579:25 580:12
actually 385:11 393:19 394:18,21 395:9 396:18,23 402:17 419:8 422:15 428:21 434:11 435:14 441:10 447:12,16 448:7,12 459:23 460:6 468:1 469:12,18 474:11,14 483:14,19 489:7 492:17 494:20 499:18 501:7,17 509:24 510:17 511:18 515:22 517:6 525:2

526:18
540:21
543:11,17
550:17,24
554:23
562:10
565:16
567:7,18
568:21
569:5,23
570:3
576:8
578:25
579:20
580:24
581:14
589:21
592:24
593:2,3
598:1,19
600:3,22
601:2
602:25
604:1
611:23
623:12

actuals
424:1
558:16
567:14

add 417:15
440:21
461:12
500:4,25
501:23
591:15,16
614:14

added 410:22
425:10
447:24
467:3

adder 442:7

adders
348:12

adding
442:7,10
500:10
525:1
527:10
549:24
595:17

addition
387:8
505:8
512:20
514:22
526:13
527:12
537:20
542:11

additional
348:7
373:13
421:7,10
428:5
446:19,25
486:7
497:17
499:9
501:14
503:15
527:1
596:24
597:18
598:18
600:12
601:21
609:18
630:11
633:16
634:17,22,
24 635:25

additions
510:16

additive
552:4

address
423:2
424:14
425:4
430:25
457:6
531:21
608:21
609:7
615:18

addressed
529:2
600:22

addressing
382:22
430:4

adds 591:4

adjourn
636:3,6

adjourning
636:19

adjust
391:17
540:3
565:17

adjusted
390:2
490:3
518:2
522:5,6
523:18
553:5

adjusting
490:11

adjustment
326:21,22
373:10
424:1
490:10
530:5,7
552:13
553:3
556:24
560:11
565:21
567:15,19,
22
568:8,13
629:16

adjustments
531:24
532:1
552:8,20
566:23
573:4
602:9,19

adjusts
556:25

administrati
ve 636:8

admit 531:23

adopt 401:20
421:7

adopted
408:18

adopting
607:10

adoption
401:18
402:4
404:13
417:6
607:13
609:23
610:7

advance
448:5
585:25

advanced
447:22,23

advancing
586:6

advantage
607:15
611:10

advantages
418:24

adversarial
419:11

advertising
541:3,9,17
,19

advice
377:24

advise 551:8
626:21,24

advised
591:3

adviser
554:5

advisors
362:14
371:20
376:6,9
512:13

aff 569:21

Affairs
592:2

affect 508:7
532:12
567:11
620:7

affected
565:22
574:6

affects
501:10
529:9

Affidavit
325:17

Affirmed
323:7
379:18

afternoon
486:21
487:12
615:11

against
432:22
434:4
441:11,15
476:18
480:15
558:16

age 511:6

agencies
506:20

aggregate
459:25
516:17
611:7

Aggregated
342:21

aggressive
419:5
448:25
467:24
469:10
470:15,18
472:23
474:17,19
483:12
541:17

aggressively
541:3

aging 538:7

ago 417:10
442:3

465:9
514:5
517:22
558:1,4
571:11

agreement
347:7

agreements
340:14

ahead 375:14
478:3
487:6

aid 532:25

air 400:24
413:16
561:24
615:1

align 622:1

aligned
558:6

alignment
420:20
421:9

all-electric
521:22
523:11
551:22,24

all-gas
486:13
502:18,25
503:3
551:22
598:6

allocated
591:9
595:23

allow
606:8,11

allowance
545:5
546:7

allowances
546:1,4,13
,16 547:19

allowed
420:24

allows 409:9
520:15
606:12
616:25
617:2

alluded
416:23
528:17
543:20
587:11

alone 588:12

already
393:7
415:11
416:23
417:5,13
443:22
445:21
449:14
462:25
483:11
503:19
514:15,25
545:19
546:8
589:3
590:1
608:25

alternative
327:24
345:13,16
348:3
349:8,10
402:15
459:14
537:8

alternatives
321:8
324:6
354:7,8,9,
10,11,12,1
3,14,15,16
,17,18,19,
20,21,22
488:7
603:21

am 381:21
385:6,14
386:21
517:2
570:17
577:25
591:21

amendment
619:3

Ameren 387:6

America
387:3
391:4
397:21
398:4
400:10
402:8
403:23
425:1
531:22

American
387:18
391:2,12

among 456:20
463:14
607:21

amongst
594:11

amount
401:24
405:17
416:24
417:2
418:3
459:21
461:25
479:17
490:9
493:19
494:18
500:1,3
507:25
535:3
576:2
579:21
585:18
593:22
595:2,17
602:4
606:14
614:14

amounts
442:5

analo 629:10

analogy
629:10

analysis
330:14
334:8
335:14
352:23,24,
25
353:3,4,5,
6,7,8,9,10
,11,12
356:9,10,1
1,12,13,14
,15,16,17,
18,19,20,2
1,22,23,24
357:3
374:10
378:22
385:15,22
386:1,12
387:11,17
392:25
395:17
396:18
397:13
399:13
403:7,15
405:4,14,1
7,25
406:22
419:2
420:21
429:7
463:19
465:13
467:17
468:3
497:10,15
498:11,14
501:8
502:3,7
503:8,18,1
9,22
523:4,6
553:5
558:7
559:9
565:20
597:20,23
598:6
609:20
623:6
625:11
630:7,23
631:12
632:7
633:25
634:6
635:12,13,
17,21

analytical
499:8

analyzed
411:24
501:17
502:1
515:2
523:9
626:13,25
631:7,22

analyzes
418:1

analyzing
501:11
627:15

and/or
418:10

Anderson
322:16
388:4

anecdotal
492:22

Angeles
387:4

angry 466:5

announced
473:17
588:18

annual
328:12
390:4
418:4
423:17
433:17
488:17
507:6
521:5
522:1,2
549:8
558:15
566:24
575:17

581:6
620:3
632:5
634:17,23,25

annualized 571:18
572:11

annually 389:18
395:6
422:8

ano 420:15

answer 455:6
485:24
487:3,10,11 488:13
489:1
491:25
496:25
533:9
536:24
540:17
543:1,10
547:20
551:5
576:21
591:3,22
592:12
599:15
601:1
608:22
632:3

answered 597:9
608:19

answering 494:8

answers 531:11

anticipate 487:25
583:11
623:25
626:8

anticipated 522:4,7
523:19
525:14
526:14
573:22
583:14
589:3

anticipating 527:25
540:5
575:20,22

Antoine 322:13
387:25

anybody 375:21
387:20
561:23

anymore 470:3

anyone 569:9

anything 487:14
500:17
538:4
580:22
633:12
636:10

anyways 447:24
468:1,21

anywhere 586:16

apart 516:17

apartment 538:14
555:8,9

apartments 538:20
539:13

apologies 466:23

apologize 375:4
388:12
559:14
619:21

apparent 561:17

Apparently 465:14

appeal 325:12

appear 575:11
578:5
636:9

APPEARANCES 322:1

appears 497:14
508:17
513:13
577:5
578:5
620:8

Appendix 489:23
499:4
509:6
598:5

appliance 399:20
417:4
528:14
553:4

appliances 413:2,3
528:6
544:23

applicability 411:10

applicable 425:1

application 324:20
477:4
493:7
530:22
531:8
610:3

applications 384:13
402:8
453:14
610:1
633:16,18

applied 479:23
532:22
540:14
545:11
546:7

apply 478:17
539:7
583:13
610:7
620:19
621:2
630:22

applying 631:9

appointed 558:22

appreciate 514:20
533:6
548:16,22
549:14
601:4

appreciating 543:8,10
548:7
629:21

approach 396:12
406:23
418:15,16
419:10
420:16
428:7
436:25
440:16
469:4
470:15,18
472:23
474:19
483:12
503:11,17
617:5,22

approaches 417:24

appropriate 377:7,22
390:3,4
421:23
435:11
437:5
443:11
473:4
487:3
530:12
532:13
534:13
541:22
568:5

appropriately 408:2

appropriateness 385:21

approval 471:25
483:7

approvals 477:13

approve 435:15,16
483:6

approved 351:21
473:9
483:7,13

approximate 552:23
566:23

approximately 381:19
392:6
412:14
446:12
495:15,21
549:9
601:7

April 324:4,7
484:20
531:18
561:23

area 385:11
393:25
412:1
415:3
431:2
437:11
447:17
450:14
453:5
463:3
467:16

523:11,17,
19,21,22
540:7,9
541:5,7,18
,21 544:24
548:20
549:3
584:11

areas 380:2
382:16
383:18
384:24
385:20
386:14
397:10,22,
25 412:22
429:14
430:24
523:16,25
524:7
540:5,10,1
3 544:19
587:6

aren't 432:5
453:7,13
460:22
566:4
585:14
634:14

argue 458:18
578:24
621:22

argument
460:1
477:19
511:14

argument's
458:11,17

Armstrong
379:4

arrangement
469:25

arrive 618:5

arrived
516:21
622:17

arriving
584:19

arrow 407:9

article
514:1,2

aside 553:24
596:12

aspect
535:17

assess 400:2
424:24
443:6
446:21
474:18,19
476:1,13
488:6
492:6
609:19

assessed
424:22
434:4
606:14
628:5,17,1
9

assessing
393:2
408:11
464:15
473:3
493:6
587:2

assessment
386:16,24
387:13
397:24
398:24
410:16
418:23
420:11
432:3
447:5
471:4,6,7
475:17
483:4

assessments
386:15
421:15

asset
498:19,20
503:24
608:3,14,1
5

assets 332:8
608:5

assign 537:6

assigned
377:25

assigning
595:20

assist
447:12
462:15

assisting
524:10

associated
414:1
434:18
447:11
457:21,23
461:9
469:24
476:2,25
586:12
587:3

Association
381:8
383:10,11

assum 549:23

assume
400:22
489:19
498:15
499:22
517:22
523:25
570:23
604:19
606:19,23
632:4,6
634:8

assumed
549:1
557:3
570:18

assumes
400:18
401:19
598:9

assuming
498:12
501:9
533:18
536:22
537:1
548:18
595:22
596:16
597:17,20

assumption
481:1
498:23
499:8,15
501:18
513:24
524:4
554:12,15

assumptions
329:25
330:3,4
348:5
374:9
411:16
498:4
548:23
554:7
603:6
618:13,20
624:2,3
634:5
635:12,17,
20

asterisks
398:12

atrocious
592:24

attached
545:6
566:10
630:18

attaches
545:7

attachment
544:22

attachments
545:2,4

attain
630:13

attempt
498:25

attempting
498:14

attend
542:13
636:8

attending
542:16

attention
628:8

attest
516:23

attracting
585:11
588:3,5

attractive
523:23

attributable
514:7
554:25
567:21
577:7

attribute
510:25

attributed
373:19
590:14
600:18
621:24

attributing
513:5
546:23
552:2
597:25
598:17
600:4

attribution
373:13
600:11

August
324:23,25
325:4,7

Authority
387:5

**automaticall
y** 580:23

availability
333:3
349:25

available
389:19
400:20
412:7,23,24 428:5
440:8
448:22
464:18
484:22
489:19
492:16
495:1
500:2
508:3
517:13
524:1
531:5
541:18
544:19
548:20
611:6
627:12
629:22

Avenue
321:22

average
341:4
373:9
391:7,8
421:16,20
455:8,14
459:8
480:4
490:18
491:11,18
493:2
506:25
507:3,6
509:24
510:11
522:1
526:20
528:2
549:10,19,20,23
554:18
557:9,15
559:21
568:7,12
572:17
575:17,22
580:7,8
581:6,20,21 582:4

averaging
476:5

avoided
331:22,23
345:20
426:25
427:16

aware 393:12
452:2
475:5
487:7
528:14
542:18
545:15
575:9
636:12

away 438:13
475:14
524:1
538:8

B

bachelor
380:13
383:8

backbench
487:6

background
395:21

bad 594:17

bailiwick
528:21

balance
429:19,22
436:20

balanced
410:11

ballpark
548:8

ban 524:12

band
392:6,19

bar 412:18
413:4
414:12
620:17

barrier
402:5
404:21

barriers
443:7
444:8
445:8
453:15

bars 407:9

bas 549:8

base
332:17,18
350:12
399:16
407:16,17
434:3
438:2
459:1
460:19
478:11
482:23
560:15
581:17
615:15
620:18
624:7

based 373:6
417:25
418:7,20
428:23
431:21
456:6
463:1
469:23
470:1,2
471:3
476:16
483:4
488:16
489:5,8
497:9,10
499:7
505:15
508:11
509:13
516:21
519:17
530:23
534:6
538:16,21
540:3,14
545:5
547:10
551:8,15
553:4
557:4
559:8,9
569:9,20
575:20
578:21
581:10,13
582:16
584:16
587:25
589:12
605:5
618:18
619:6,10

baseline
399:12,19
408:4,16
414:15,23
415:5,18
416:12,17
464:24
474:23
615:22
616:6
619:8,25
621:16
622:19

baselines
463:23
464:23

basically
417:23
432:3
436:15
440:11
545:7
553:24
557:14
568:23
577:24
578:10
595:1
616:25

basing 574:7
584:12

basis 390:4
393:21
422:3
484:11
488:17
490:3,11
504:17
507:6
508:25
510:14
515:6
516:17
517:3
520:12
527:9
549:8
557:1
558:16
565:17
566:24
567:13
584:8
585:12
587:7
589:22
591:10
592:15
595:7,23
597:1
601:6
610:16
611:7
612:4
615:6
621:2,12
632:5
634:18

bath 452:4

bathrooms
402:12

BC 456:21
470:17

became 495:1

become
452:2,3,11,15 501:3
534:25

becomes
447:25
464:12
475:23
607:7,16

becoming
528:5

beg 565:3

begin 388:22
531:16,17
581:5
606:20
607:2,9

beginning
545:11
559:14
613:10
630:4

begins
485:13

behalf
387:22

behaviour
537:12
586:25

behind
379:3,4
396:2
554:20

bel 321:16
378:8
427:23
485:13,20
544:7

belabour
533:21

believe
375:4
389:22
395:11
412:12
422:2
429:8
445:2
447:11
456:17
466:1
473:5
476:24
487:10
489:24
490:23
495:9
506:5
517:3
523:14
525:10,18
526:24
531:8
533:11
540:23
550:23
556:9
559:6
566:12
581:25
583:5
584:3,10
589:4
590:16
592:10
605:7
606:5
612:19
620:14
626:15

benchmark
394:25
463:14
582:4

benchmarking
463:1,4

beneficial
486:14

benefit
401:14
427:6,7,14
439:5,15,17 440:1
462:3,9
479:1,19
480:20
493:20
501:6,14
503:15,16
535:9,19

benefit-cost
401:17
426:2,4

benefiting
440:12

benefits
338:17,18,19 426:24
435:22
438:25
441:1,23
442:8
454:10
480:25
500:22

best 389:25
407:25
430:18
440:7
443:4
444:24
475:25
517:25
542:17
543:7
546:14
560:10
632:17

better
421:19
423:1
475:9
486:23
489:1
518:20
542:23
558:5
600:22
601:2
608:19

beyond
463:5,8
476:24
496:20,23
497:16
498:8,9,10,14
499:5,23
500:17
580:22,25
581:16
585:10
594:16
597:18,19
632:1,7,14,20 633:8
634:2,7

bias 402:11

biennium
420:8

bigger 436:2

biggest
620:24,25

bill 458:23
460:14
535:10,16
542:12

billed
520:16,17

billing
384:9
407:14
410:1
520:15,20
539:5

bills
458:17,18,20
459:7,8,10,11,24
460:1,6,7,18,23

bio-energy
605:22

biomass
382:5
611:12

bit 378:12
410:14
411:6,18
417:15
423:14
442:16,19
465:15
468:14
472:6
494:15
495:6
503:25
510:22
512:6
520:22
531:20
534:25
536:18
540:16
551:3
563:21,22
576:8
580:18
582:7,21
586:11
592:7
599:7
615:18
620:9

blow 599:6

blue 391:23
397:22
407:9
412:25
416:12
446:9
455:22

blue-shaded
412:1

board
321:3,14,15,16,17,21
322:2
324:17,24
325:3
326:3,5,7
371:13,19
375:9,13,16,19,25
378:7
380:7
382:19
383:1,22
385:2,18
386:9
387:20
388:23
396:24
424:13
451:5,6
471:25
485:13,19
486:22
488:6
504:14
506:21
509:6
512:9
514:1
518:12
531:8
539:18
540:19
545:14
546:22
547:25
550:12
553:18

558:22,23
561:1,15
562:22
572:6
576:20
582:10
619:21
623:11
625:19
627:17,19

Board's
373:5
551:14

Bob 322:2

Bois 607:25

bold 481:1

Bond 347:20

book
371:13,19
372:8
373:5
375:18,25
467:1,6
504:15
509:6
512:9
518:13
540:19
546:22
547:25
550:12
551:14
553:18
558:23
561:1,15
562:23
565:1,4
568:18
572:6,8
576:21
582:10
589:21
599:20
602:14
619:21
627:17

bottom
406:23
441:20
585:10
628:15,16

bottom-up
406:22
417:25
418:23
419:1
421:15

bouncing
564:11

bound 402:17

Boyd 322:6
323:13
377:4,10
378:5,6,9
379:25
380:1
382:15,25
383:15
384:21
385:25
386:4,8
387:14
388:20
429:17
465:14,19
466:17
467:12
484:21
485:12
487:13
533:18
550:5
551:1,7,10
565:1,4

brain 464:16

break 377:23
389:11
413:16
429:21
465:17
481:21
485:2
556:1,3
567:18
635:25

brief 388:10
397:6
405:6
406:18
422:23
423:11
427:11,21
428:17
453:19
454:25
474:5
487:12
491:1
494:5
496:18
499:12
508:20
518:9
519:10
521:1
524:14
525:8
526:3
529:11
533:1,16
539:1
540:1,20
541:13
548:10
550:8,21
553:15
555:22
556:16
557:23
558:25
559:11
560:6,20
562:14,18
563:16
567:3,24
571:3
572:3,25
576:17
591:13
593:8
602:6
604:9
613:15
616:3
619:14
628:12
629:18
632:9
634:10
635:3

briefly
506:18
556:23

bring 396:9
398:19
399:2,4
514:16
532:24
618:12,17

bringing
477:13
524:6

brings 396:7
471:16

broad 381:3
383:3
481:5,6
504:16

broader
463:5
471:22

broadest
400:5,15

broadly
504:8
576:4

broag 481:5

broken
390:13
525:15
541:19
568:19

brought
430:25
458:12

bubble
433:23

bubbles
475:21

bucket
468:7,8,10
,25 470:10
565:25

buckets
438:8

budget
351:15
352:3,12
479:21

budgets
371:5
418:11

build 429:7
457:24

builder
544:11
545:18,23
546:2,9

builders
541:8
542:13
543:12,25
544:23
546:15,19

builder's
544:2

building
387:12
399:20
412:12
523:21
527:14
536:3
538:14,21,
23 540:13
544:23
600:3
606:9

buildings
406:5
410:6
429:15
555:9

built 608:3

bulb 473:18

bulbs 528:5

bullet
405:19

Bureau
506:23

burning
520:7

business
380:11
384:1,8
385:6
386:17
578:14
598:5

buy 404:15
475:14

buying
451:20

buzzer
487:14

Byron 322:8
377:21
387:22
466:4

C

C25/750
332:8

CAC 322:8
352:19
372:6
387:23
466:7,10

CAC/MMF
352:17

CAC-44 372:5
466:9

CAC's
371:22,24
376:12,16,
20,24

calculate
409:1,9
442:10
454:4
497:21
503:23
510:4
512:19

calculated
550:11

calculates
509:9
548:1

calculating
503:21
558:13

calculation
332:10
373:4
460:10
478:16
510:23
511:18
513:9,18
515:12
516:22
542:4
548:5
551:8,13
566:6

calculations
326:21,22
345:15
404:17
411:5
600:24
601:18

calibrate
539:4

camera
589:23

campaign
469:2
522:5,14,1
7,22,24
525:15,21
526:6,14
541:3,10,1
7 547:15

campaigns
523:21

Cana 605:21

Canada 381:1

Canadian
381:7
383:9,11
391:7
424:13
451:4
529:7

cancelled
469:22

canvas
603:14

canvassed
625:19

cap 420:24
508:4

capabilities
345:23

capacity
340:22
341:9
381:6
479:19,24
494:1,3
610:15

capita
554:24

capital
332:7
334:3,4
335:16
344:3,4,12
,13 345:8
346:8
347:11,12,
13,14
349:15
350:12,13
358:24,25
359:3,4,5,
6,7,8,9,10
,11,12,13,
14,15,16,1
7,18,19,20
,21,22,23
360:8,9,10
,11,12,13,
14
363:10,21,
22,23,24
370:8,10
428:3
479:12,16

Capra 352:21

capture
474:3
475:10
633:14

captured
445:15
449:4

car 451:20

Carbon
340:24
341:5
344:5,6

Carbon/GHG
335:15

Care 378:20
380:10
382:21
383:25

careful
464:3
488:3
587:23
588:11

carefully
401:25
471:24

Carolina
419:20

carries
597:4

carry 516:10
601:13

case
332:17,18
429:2
430:10
431:12
437:25
444:5
446:4
457:16
458:21
460:19
472:11
481:13
483:23
487:14
531:14
534:1
535:7,10
542:25
565:16
588:2
598:5
603:7
610:7
621:15
631:17
635:15

cases 417:19
434:3
472:24
544:19
621:25

categories
389:13

category
413:11
438:22
468:22
470:6,11,1
2 471:1
504:22
621:23
622:5

cause 459:12
549:22
609:2

causes
564:11

caution
392:24
463:18
468:4
471:11

CCCT 327:13

CCGT
332:14,25

CCGT/C
349:11

CCGT/SCGT
350:6

CEF 345:8

cells 603:19

Celsius
557:11,17

Centre 388:3

cents 428:6
433:8,14
455:4
458:11,16,
25
459:3,4,7
462:6,7,8
475:19
476:19,25
480:1,8
532:19

cents-per-kilowatt-

hours
479:7

CEO 371:15
487:16
530:20

certain
494:17
503:7
532:11
539:11
544:22
545:8
578:2
632:5,14,23

certainly
387:23
393:25
395:19
450:22
626:20
633:18
635:5

certainty
630:12,15

Certificate
323:16

certified
385:6
636:21

cetera 410:7
536:3

chair 377:21
378:7
381:10
387:15
388:3
429:17
465:15
466:23
484:22,25
636:12

chaired
451:5

chairman
375:9
378:1
380:6
382:19
383:22
385:2
451:5
555:24
556:12
594:16,23
635:24

Chairperson
321:13
375:3
378:4
388:8,14,18
394:8,13,16 395:3
403:16,19,25 404:10
416:5
424:20
425:12
429:16,23
430:15
432:24
433:4,11
465:16,20
466:1,13,21 467:9
477:2,8
485:4
492:10
493:6
526:5
531:19
533:20
556:2,9
584:17,23
585:3,16
586:10
594:9
609:22
610:21
636:5,13

challenge
451:13
612:18
613:25

challenged
594:18

challenges
473:25

challenging
453:17
614:18

chance
536:12

change
336:10
395:1
440:14
444:17,19
449:15,25
456:8
469:12
473:20
477:16
478:22
484:12
493:1
496:2
503:8
511:20,21,24,25
512:2
513:5,6
514:12,25
521:25
525:13
535:25
536:1,15
537:4,5
567:10
569:21,22,23,24
579:12,14
589:14
593:25
607:19

changed
442:6
446:2
472:15
576:24
578:23

changes
392:14
393:13
476:1
494:25
495:4
510:25
511:2,9
513:21
517:20
518:2
521:24
523:9
526:8
537:23
538:23
539:19,21,23 542:15
552:7
553:9
571:17
586:18
603:6
618:23
619:4,8
632:23
633:20

changing
414:7
513:22
538:23
589:12

chapter
489:10,17
491:4
494:23
495:3
509:3
523:6
609:10
626:5,13,25

charact
630:8

character
588:10

characterise
411:9

characteristic 610:10

characteristics 389:24
442:21
532:12
534:11
536:8

characterization
407:24
408:3
410:1
414:23,24
620:16

characterize
399:15
407:6,12,16 408:21
587:23
588:11
628:4

characterized 400:13
412:16
614:3
630:4

characterizing 409:21

charge
546:18
628:25

charging
544:4

chart 371:20
376:5,8
412:18
413:8
414:12
512:8,12
518:11
519:1
521:4
524:17
547:25
554:4,5,21
561:2,16
562:3
564:15,21
569:4
576:23
577:21
589:21
590:3,6,25
594:23,24
595:12
623:16
624:1
627:20
628:1,14
631:20

charts
510:13
518:25

553:10
561:18
564:20
620:17

cheaper
404:15
528:5
542:24

check 505:19
512:17
521:9,11
524:23,24

Cheryl 379:7
636:24

choice
384:17
394:2
420:9
469:2,6,8
540:25
542:4
554:10
608:4

choices
542:5,20
553:24

choose 403:6
487:2
523:22
537:7,8
542:8,9
549:3,10
554:8
610:19

choosing
527:7
552:17
608:14

chose 406:11
458:14
460:21
469:7

chosen 402:1
554:3

Christian
322:20
388:16

chunks
587:9,10

circulated
376:6

circulating
377:14

circumstances 402:23
502:8
618:15

cities 529:8

City 387:4

claimed
428:4

clarification 553:13

clarify
395:3
403:19
405:19
430:20
492:10
526:5
567:9

clarity
431:1,10
438:5

class 504:7
505:22
586:14
613:4

classes
504:6,18
505:24
568:19
583:17
586:20
611:19
612:12,15
618:18

classification 569:10

classifications 569:9

classify
413:13

classifying
403:20

clear 487:23
491:18
584:18

clearly
434:3
442:1
455:15
484:17

client 407:4
425:7
426:9

clients
398:11,17,18 403:13
406:25
410:4
411:13
417:18
482:16
618:14
621:25
622:4

climate
336:10
492:25
535:5,21
614:8,16

climates
614:2

close 495:19
521:15
611:23
620:2

closely
399:1

closer 475:7
529:22
576:13
630:16

clothes
413:2

co 381:13
461:17

coal 524:12

coalition
451:4,6,8

code 520:16
528:12

codes 380:24
381:2
382:10
391:20,23
393:12,13
394:24
399:20
408:6
437:1,9,12,22
463:7,9
527:15
528:9
620:20

coding
445:25

coefficient
563:1,7,25
566:17

coefficients
558:15,18,20
559:4,17,20
560:4,11,17 562:24
563:19
564:13,19
565:12

cognizant
587:2

cold 490:12
557:2
561:6
562:6,21,25 563:5

colder
532:17
614:11,16

coldest
557:15

colleagues
487:5
528:22

collections
384:10

Colleen
379:6

colleges
410:7

Colorado
617:13

coloured
445:25

column
513:5,6,8
515:8,10
620:1

combination
441:6

combine
406:8

combined
336:14
419:18
431:8
433:19
434:6
436:8,20
437:20
440:2
446:2

combining
434:13

comes 416:25
443:1
536:18
544:7,13
587:9
598:22
632:21

comfort
431:10
435:20
527:9

comfortable
392:2

coming
457:25
521:6
531:8
570:7
587:8
588:8
634:17,20

commencing
375:1

comment

396:13,23
463:12
481:10
482:11
613:1

commented
530:20

comments
397:2
450:25
453:22
463:3

commer 616:1

Commerce
384:2

commercial
378:19
380:9,20
381:18,22
384:20
407:20
410:2,3,5,6 412:11
415:1
416:23
429:14
568:23
569:6,7
570:7,24
586:20
606:9
612:1,12
616:8

commercially
487:8
506:13,15

committed
533:12
581:3,4
608:16

committee
381:8,11
383:10,12
483:6

commodity
585:8

common
426:12
614:3

commonly
554:2

communities
452:9,23,25 453:3,5
474:2
541:10

community
452:13
453:1,12
473:23

compact
402:6,11,13 404:22
417:7

companies
387:6
578:13,22
587:25

company
458:1,13
558:3
622:10

company's
619:3

comparable
449:1
629:4

comparative
454:22
463:19
464:3

compare
424:1
433:24
445:11
456:10
461:16,17
480:15
550:18
558:16
564:7
598:14
624:13

compared
456:12,17
486:16
511:21,25
520:2
524:18
529:5,16
543:13
549:16
597:1

compares
390:25
391:3
456:16
490:18

comparing
502:17
503:5
561:18

comparison
330:14
334:5
435:23
573:16
628:16

comparisons
334:4

compete
578:23

competitive
579:8,11
587:12

competitiveness 578:21

competitives
578:20

complete
484:2,18
531:17

completed
484:20

completely
466:19
616:23
618:20

complex
456:23
503:19
597:11

complexity
546:11

complicated
448:1
462:11
464:13
475:23

component
328:21
437:3,4,10
439:7
443:2
447:16,19
457:12
478:7,8,9
479:3,8
537:2,15
549:21
566:5,14
613:19,22
615:16

components
478:6
527:24
532:21
534:8
537:17,23
553:7

composed
505:10

comprehensive 411:3
436:24

compressed
561:19

compressors
413:17

computer
478:3
556:18

con 527:8
548:21
579:25
621:18

Conawapa
328:22
332:16
338:11
370:12
491:13

conc 502:9

concept
396:2
436:4
557:4
559:19

concern
430:24
431:3
460:3
482:14
622:25

concerned
444:14,15
476:21
482:17

conclude
397:16
447:20

concludes
484:21
485:5

conclusion
436:5
442:12
499:2
502:9
534:4
620:14

conclusions
338:3,4
339:24
609:21

concrete
428:8

concurrently
394:10

condition
492:4

conditional
553:5

conditioner
561:24

conditioners
400:25

conditioning
615:2

conditions
370:11
402:2,21
426:24

444:21
conduct
397:12,14
406:21
414:6
conducted
397:13
398:1
416:8
422:7
501:8
502:2
conducting
386:19
397:11
498:6,11
conference
324:9,11,15 325:9
424:13
506:21
confident
501:23
592:12
621:3
630:5
confirm
374:8
377:6
393:16
519:6
551:3
635:16,19
confirmed
377:12
635:13
confused
430:19
confusion
438:14
connecting
546:3
connection
377:5
544:4,22
545:19
546:17,18
cons 412:3
418:25
conscious
534:25
consensus
424:16
517:5
consequenes
331:4
conservation
378:21
380:11
382:11,21,24 384:1
399:21
417:3
420:6,10
464:7
470:13,16
471:23
477:10
620:23
621:1
conservative
473:6
498:1,19,22
499:16,22
503:11,17
632:18
conserving
535:18
consider
393:22
418:13
430:12
443:10
459:9
463:4
505:17
534:19
541:23
609:6
630:1
considerably
455:13
612:12
considerate
436:21
consideration 382:8
471:22
514:23
535:5
536:7
considerations 328:3
352:11
457:8
477:22
534:18
considered
327:25
428:9
442:2
444:9
543:11,23
considering
430:8
477:3
543:16
547:14
598:11
considers
505:17
consistent
409:20
415:25
417:14
439:23
442:14
constant
522:11
constitute
492:13
constraints
327:15
340:12
347:23
constructed
412:3,7
527:16
construction
336:14
363:5
constructions 346:8
consult
487:4,5
consultant
396:4,7
403:2
533:7
consultations
484:3
consultations 484:6
consulting
386:20
consume
613:24
consumed
494:20
505:9
consumer
378:24
383:25
384:10
480:5,10,11,12,21,24,25 504:10
575:14
576:12,23
577:4,7,9,13 580:10
583:6,12,25 584:21
586:14
589:6
610:10,11,18 611:25
612:18
consumer/industry
327:3
consumers
327:5
347:22
349:5
381:16,17
382:8
389:13
390:21
504:22
534:22
568:25
569:7,12
570:19,22
571:12,15
572:14
574:20,24
575:5,19
576:2,7,9,20
577:10,15
578:21
580:12
582:12
583:4,18
586:21
587:1,7,24
591:16
610:5,8
611:2,20,22 612:9
615:15
consumes
613:23
consuming
504:18
consumption
381:20
389:10
423:19
424:7,8
470:22
506:1
527:3,20,21,23
553:19,22
554:18,24
555:19
563:23
564:3,6,9
571:8
610:10
613:4,7,22
617:17
618:24
consumptions
553:4
580:1
cont 414:5
Con't 325:1
326:1
327:1
328:1
329:1
330:1

331:1
332:1
333:1
334:1
335:1
336:1
337:1
338:1
339:1
340:1
341:1
342:1
343:1
344:1
345:1
346:1
347:1
348:1
349:1
350:1
351:1
352:1
353:1
354:1
355:1
356:1
357:1
358:1
359:1
360:1
361:1
362:1
363:1
364:1
365:1
366:1
367:1
368:1
369:1
370:1
371:1
372:1
374:1

contained
382:13

CONTENTS
323:1

context
396:15
454:2
535:21
578:19
604:5,6
610:4

contingent
499:17

continue
498:24
533:5
556:1
589:16
634:19

continued
467:12
498:15
501:2
503:1
526:16
533:3
539:16
550:10
551:19
556:22
565:9
589:19
594:20
611:17
626:4
627:10

continuing
500:4
524:5
589:1
634:8

continuous
435:17
527:9
610:14

contract
333:4
335:22
337:11
348:16
395:23

contracts
328:6,7,8,9 339:25
340:3,4,5,6,7,10,11
341:15,16,17,18,20,22,23,24,25
342:10,12,16
355:21,22,23

contributes
455:21,23

contributing
528:1

contribution
447:20
545:9,11

contributions 432:20

contributor
414:6

control
545:22
546:2

controlling
598:24
599:2

controversial 487:25

converse
573:24

conversely
561:9

conversions
524:8
548:21

convert
443:19
527:4

convince
469:4

cook 613:12

cooling
373:10
412:25
413:14
532:14
557:5,9,20
558:2
559:22
560:16
561:17,19
562:5
563:10,19,25
564:4,5,8,10,13,20
565:13,17,22,23,24
566:7,9,14,17,21,23
567:10
568:7,12
614:2

cooling-weather
567:22

coordinate
520:17

copies
375:20,21

copy 375:22

core 382:1

Cormie
601:11

corporate
344:14,15,18 379:1
385:4,5,12,14,15

Corporation
385:5
391:13
433:2

Corporation's 384:16
436:10
443:12

correct
395:2
403:24
424:9
428:6
430:14
490:6,7,15
494:21,22
495:12
496:3,5
499:10
504:12
512:11
513:24
514:11
519:25
520:3,9
521:13
525:6
537:2
553:23
557:7,12,18 559:7
561:8,21
562:12
569:2,18
570:3,5,15,16 571:25
572:19
574:15
576:3
577:1
580:9,17
582:17,18
584:22
587:4,17
590:4,11
591:1,8
594:5,24,25 606:24
608:6
612:24
614:23
636:21

correction
478:1
579:3

correctly
502:14
578:1
585:10
621:4

correlate
615:11

Cory
388:6,12,13

cost
328:20,22
331:4,22,23
332:15,16
334:4
335:16
345:20
346:6
347:8

349:11
358:24,25
359:3,4,5,6,7,8,9,10,11,12,13,14,15,16,17,18,19,20,21,22,23
360:8,9,10,11,12,13,14
363:10,21,22,23,24
400:21
401:11,13,14
404:1,2,7,9 408:21
411:9
421:8
426:1,21,25
427:14,15,17 428:3
430:1,11
432:5,7,8,12,14,17,22 434:4,14
436:18
438:23,24
439:4,5,6,7,10,15,16,17 440:1
441:1,2,5,6,7,8,11,15,16 442:3
443:1,5
444:18
445:1,5
446:19,23
447:1
451:15,17,22
452:5,6,15,16,18,19,20 453:13
454:15,18
455:3,4,8
456:1,3,11
457:10,11
458:6,25
459:4,12
470:25
474:25
479:1
480:5,11,24 500:24
502:22
527:22
532:7
537:5
544:25
545:23
546:3,4
554:11
591:25
603:25
607:6,15
608:4
611:15

cost-benefit 426:16,18

cost-effective 401:20
420:6
436:16
443:13
447:7
455:7

costing 501:4

costly 434:5

costs 326:24
328:17,19,21 332:18
334:3
336:12
344:19,20
345:12
346:5,8,21,22
347:11,12,13,14
348:23
363:5
370:5,8,10
426:23
427:17
434:18
435:22
440:10
441:1
442:25
454:10,14
455:17
456:17
457:4
459:2,3
468:18
478:23
500:22
502:24
503:2
542:1,2,6,7,19
545:16
608:8

Council 324:3
383:10
391:2

counsel 322:2
371:6,11,12,13,19
375:13,19,25 387:20
486:21
509:6
512:9
514:2
518:12
547:25
550:12
553:18
561:1
562:22
572:6
576:21
627:17

counsel's 504:15
540:19
546:22
558:23
561:15
582:10
619:21

countries 514:9

couple 382:7
419:18
450:6
452:9
453:21
474:8
579:4,5,16

course 387:7
392:13
403:18
448:7
460:24
549:4
559:24
612:3

cover 391:10
489:15
546:4
604:17
636:1

covered 493:21
568:17
583:17
597:16
602:8,19
604:17

create 484:15

created 484:7,9
559:4
615:14

creates 593:15

credit 331:8,9
447:11

criteria 462:21
493:15

critical 411:15

cross 484:23

cross-examination 323:14
371:11
375:13
467:2
485:13
486:19

crude 453:23,24
461:5
530:13
534:6

CSI 487:9,10,12 589:23

cumulate 629:9

cumulative 395:18
413:21,25
414:14
529:5
567:13

curiosity 538:4

curious 570:17

current 381:13
385:13
389:18
392:24
423:25
449:9
469:3
476:18
477:5
507:21
517:24
547:10
560:11
592:16,20
593:6,12
597:8,12
605:22
634:12

currently 389:9,11
393:11,23
399:15
452:21
470:5
471:14
483:14
499:5
523:25
529:6
532:7
539:21
544:3

571:21
582:16
590:7
603:20
605:19
606:8
608:7
628:5,17
631:20
633:21

currents
593:11

cursor
579:17

cursory
529:17

curtail
614:6,13

curtailing
614:17

curve
443:17,18,22,25
444:2

cus 534:22

custom 379:5
448:17

customer
326:20
378:20
379:5
380:10
382:3,4,21
383:10,25
401:2,18
402:2,5
403:8
404:21
406:4
409:6,12
411:24,25
435:6
439:14,16
440:2
441:8
444:4
446:6
455:21
458:21
459:1,7,8,9 470:1
478:13
480:15,16,17 481:16
504:7
509:13,18,20
511:2,10
513:21
520:2,12
526:20
527:11
535:9,16,18,24 536:5
542:23
543:4
549:10
555:18
568:19
571:19
580:25
582:19
583:17
584:19
586:15,16
602:9
605:24
607:8,9
611:19
620:19
621:2

customers
381:24
399:15
400:18
407:17
408:18
409:13
415:10
428:13
432:14,16,20 436:22
439:19
446:1,3,10
447:2,13,23
448:5,17,21
449:4,5,18,19,22
450:22
451:11,21
455:18,20
458:18,20
459:7,10,25
460:6,8,12,15,19,22,23
469:5,12,19
470:18,21
477:17
481:6,23
482:7
504:20
509:10,11,15 510:16
511:1,21,25 516:12
518:14,20
519:2,19,21,24
520:22,23
522:12
523:11,16
524:17,20
527:2,4
529:9
532:15
542:18
552:16,25
554:24
555:6
569:12,19,24
574:13,18
575:10,11
597:25
598:1
607:2
611:9,10
612:23
613:20
615:13,14
618:19
620:18

customer's
439:17
505:8

Customers
449:20

cut 400:23

cutoff
505:14

cutting
634:6

cycle 336:14
489:12,15
542:1

D

daily 557:10

Dale 323:7
378:17
379:18
380:5,8
534:15,16
587:21
589:9
604:4
608:10,18
610:9,25

dam 608:14

DANIEL
536:23
578:18
579:18,22
580:5,17
591:25
593:2,5,14,18
594:3,6
604:14,21
605:18
606:11,16
608:6
611:24
612:17,24
613:2,21
614:23
615:3,9

D'Arcy 352:9

dark 397:22

dark-blue
397:25

data 390:25
403:20
407:13,15,16
408:7,22,24 410:1
427:2
490:6
497:10
559:17
560:12,14
564:2
566:17
579:23
606:22
618:5
619:7

database
411:11

date
324:4,7,10,13,16,18,20,23,25
325:4,7,10,13,16,19,22,25
326:4,6,8,11,14,16,18
351:8,10,13,15,17,19,22,25
352:5,8,11,13,16,18,20,22
357:6
358:23
360:16
362:15
364:7,18
365:13
366:14
367:8,21
368:6,24
369:24
370:16
371:7,9
394:14,23
395:8,13,14 529:17
530:14
531:9
534:6
589:10,12
602:12
606:22

dates
394:17,19
395:10

day 325:21
375:6

432:21
434:16
437:20
443:8
486:24
557:10,15,16
559:23,25
566:8
613:10
614:12,14
615:6,7
636:3,6

days 382:7
430:22
451:1
558:1
559:21
561:10,17,19

day-to-day
615:6

DC 597:7

DD 560:16

DDC 558:17
559:21
561:10,18
563:1

DDH 558:17
559:21
561:18

de 564:8,13
631:16

Deacon
352:10

deal 478:1
505:21
568:2
587:25
595:16
605:4
609:14,17

dealing
488:8
504:3
524:16
563:12
566:15
600:23
603:16,25
604:13
609:8,10
614:16

deals 462:12
603:2

debt
331:13,15
344:17

Debt-equity
336:16,17,18,19,20

dec 351:15
552:22

decelerate
406:12

December
351:10,12,13

decide 440:6
464:21
614:6

decided
418:7
441:22
442:25
443:4
468:19,21
473:7
503:16

decides
584:24

deciding
613:12

decision
439:25
441:13
458:5
462:22
543:5,7
608:13

decisions
440:4
441:17
609:21

decline
448:13

declined
448:12
509:21
577:5

declining
345:4
417:3
509:16

decommissioned 588:25

decrease
421:24
507:14

decreased
507:11

decreases
604:1

decreasing
552:22

deemed 390:4

defer
631:16,17

deferral
521:14
603:10
630:21

deferrals
346:6

deferred
479:22
631:8

define 408:1
432:25

defined
400:7
410:8

definitely
631:12

definition
327:23
400:6,15
404:20
410:3
492:15

definitions
399:10

degree
380:14
383:8
460:13
558:1
561:16,18
565:22
630:15

degree-day
373:9
557:5,8
558:8,13
559:3
560:16
563:10
564:4,5,8,13
566:6,20,21 567:10
568:7,12

degree-days
559:22
561:3,5
562:4
564:11
566:9

degrees
557:11,16
558:1,4,11,12 559:22
565:23

delay 331:4

delayed
588:18

deliver
378:3
398:17
425:6
494:3

deliverables
407:10

delve 397:15

demand
327:12
328:24
362:20
363:3
373:19
386:14,22
398:10
488:10
490:4
491:23
495:9
498:12
499:9
502:12
533:23
536:19
547:1
553:5
565:18
570:25
574:10
577:5,10,23 578:9
580:10
582:15
590:24
595:13
598:19
600:5,19
601:23
612:3
614:3,21
615:1,21

demands
382:11
490:14

demand-side
382:9
383:5,13
384:18
388:25
389:5
480:19

demographic
514:24
540:13

demonstrate
445:23

demonstrates
483:22

denominator
439:4,7

denote
525:12

denoted
629:4

denotes

628:16

Department
387:4

depend 480:6

dependable
327:22
345:12
490:20,23
491:10,12,14,19
492:8,13,15 493:9,15
500:18

depending
443:6
445:13,14
479:25
545:1
618:15

depends
446:6
510:10
587:12,13,14 605:10

depicts
582:23

derive
529:18
537:24

derived
555:11
559:16

deriving
549:25

describe
386:9
398:15
399:17
409:24

described
404:22
409:3
492:11
501:11,13

describes
420:1

description
324:2
325:2
326:2
327:2
328:2
329:2
330:2
331:2
332:2
333:2
334:2
335:2
336:2
337:2
338:2
339:2
340:2
341:2
342:2
343:2
344:2
345:2
346:2
347:2
348:2
349:2
350:2
351:2
352:2
353:2
354:2
355:2
356:2
357:2
358:2
359:2
360:2
361:2
362:2
363:2
364:2
365:2
366:2
367:2
368:2
369:2
370:2
371:2
372:2
373:2
374:2
540:24

design
386:16
405:23
406:16
422:4
440:4,14
443:9,11
444:13
454:12
462:23

designation
564:10

designed
405:25
473:8

designing
474:22

designs
445:18
454:6
464:14
467:23,25
468:5,11,16
475:24,25

desk 543:19

desks 543:21

despite
598:19

detached
538:17,18
539:8,14
540:9

detail 393:3
411:19
414:21
463:24
464:20
467:15
476:21
497:3
515:4
527:1
584:18
608:21

detailed
396:18
421:15
497:1,24
498:17
503:22
504:1
540:24

details
621:19

determine
418:3
479:1,13,15 512:7
529:18
546:14
554:18
559:17
560:4
563:11
569:13
581:14,15
604:2
606:1

determined
427:6
436:7
461:20
478:2
501:10
509:11
558:4,8,18
560:12
565:20
566:1
571:7
633:25

determines
488:15
558:15

determining
505:25
559:19
566:17
570:14
573:11

devel 544:11

develop
396:5,20
398:13,22
400:3,4,10
403:10,13
406:1,2,7
407:10
408:3,8,20
409:6
410:17
411:15
417:18,20,22 418:10
420:10
422:11
435:4
467:19
484:13
606:20
607:1,13
616:20

developed
398:16
399:8,22,25 410:18
411:8,11
415:19
416:13
435:21
436:4
475:18
616:5,9,11,16,19
617:6
621:7

developer
542:14,16
544:7,10,12,13,20,25
545:8,17,20,22
546:6,7,8

developers
541:9
542:14
544:1

developing
415:11
417:24
421:22,23
621:11

development
321:10
347:6
380:23
381:14
383:11
387:10
488:7
544:8,9,18
545:19
597:24

598:15
599:13
607:22
621:9

deviation
515:10,11,14

device
556:14

diagram
431:15
455:18
592:25

dialogue
383:12
430:21

die 444:6

differ 621:5

difference
424:2
461:25
519:16,21
525:12
545:10
558:10
559:8
598:22
599:24
619:23
620:1
621:21
622:3,5,16,25

differences
463:15
518:15
536:14,16
545:12
622:22

different
389:11,21
391:15,19
392:14
403:22
404:5
408:13,14
410:4
416:9
420:16
426:10
438:11
442:22
444:8
445:4,18,25
449:19,20,21,23,24
454:16,19
455:20
456:3
457:18
458:14
461:7
464:17
465:8
468:16,23,25 471:15
476:13
479:10
483:25
488:3
502:8
503:25
504:6,18
505:24
517:1
534:8,10
539:7
541:20
542:7,19,20 569:4
571:9
587:18
598:1
602:9,16
614:25
618:8,19
629:15
630:9

differential
558:8

differentiate 544:10

differentiated 412:20

differently
427:5
443:6
498:1

difficult
420:23
442:8
451:25
551:3
563:11
632:12

difficulties
383:21
556:13

difficulty
563:19

digit 515:24

diminishing
448:16
633:15

dinner
613:12

dip 577:3

diplomatic
543:10

direct
386:13
484:22
494:11

directed
387:9

direction
546:15

directional
454:7

director
378:22
386:1

disagree
502:11
512:23

disagreeing
513:2,4

disappear
565:25

disclose
506:12

discontinued
469:21

discount
335:7
350:10,11
370:7,9
385:21
624:4

discourage
536:5
605:13
606:4,6

discouraging
535:17

discrepancies 620:7

discuss
462:13
473:4
553:19

discussed
428:1
467:15
477:14,15
540:15
547:9
590:21
628:20

discussing
453:2
522:17
594:14

discussion
393:7
434:9
438:4
472:3
594:11
618:23

dishwashers
413:3

disincentives 543:12

dismissed
603:20

displacement
382:11
469:16,17
470:6,9
471:22

displacements 329:5

displacing
500:15

disposal
605:12

disposing
482:18

disproportionate 595:8

disproportionately
563:6

disruptive
603:14,24

distinct
399:22
408:12

distinction
491:18
494:2
519:15
629:22

distinguish
505:13

distinguishes 569:5

Distress
363:19,20,25

distribution
478:8
479:9,20,21
505:6,14,18 523:9
590:22
591:5,17
595:21

diverse
398:11

divide
479:5,17

divided
513:3

dividing
441:4

division
378:18,24
379:1

380:9,10
382:1
383:24
384:8,11
385:4,12

divorced
511:7

document
420:1
489:25
490:2
499:5
509:1
511:19
512:16,18
514:2
554:6,20
627:16,19

documentation 517:11
626:24

documents
371:13,19
372:8
373:5
375:18
376:1
467:1,6
504:15
509:6
510:4
512:10
518:13
528:24
540:19
546:22
547:25
550:13
551:15
553:19
558:23
561:2,15
562:23
565:2,5
568:18
572:6,8
576:21
582:10
589:21
619:22
627:17

dollar
405:17

dollars
446:8,14,19 449:10
450:11,18,21
451:19,23
458:22
473:18
476:9,10,11 479:18
481:18,19

dollars-per-megawatt-hour 479:6

domestic
373:15,19
381:19,25
477:21
486:10
499:6
502:12,20
591:5,10
595:13,19
597:18,25
598:9,18,19
600:5,13,19 602:2

domestically
462:2,6

dominated
532:15
534:20
563:13
614:2

done 390:3
397:18
398:5,8
399:6
411:22
422:11
425:23
426:6
473:3
483:4,16
497:3,25
499:15
502:7
511:18
513:19
517:22
529:13
530:14
536:10
540:11
541:16
545:24
597:24
604:24
615:23
622:2,10
624:25
626:13,16
630:23

door 481:12

Dorsey 597:3

dots 583:1

double
593:21

doubling
595:2,4

downside
419:3

downturn
575:9
577:16
582:3,8

DR 423:6,13
424:6,10
426:13
427:4
477:18
480:3,18
536:17
538:1,22

dramatically
579:12,14

draw 502:9
534:4
620:14
628:8

draws 629:22

drill 434:25
453:10
467:22

drive 452:15
494:9
534:8
617:3
618:21

driver
588:12
589:17

drivers
390:15,19
587:18
618:13

driving
543:5
573:6
613:4,6

dropped
468:19
473:16

drops 587:9

drought
328:15
336:9,21,22 345:4,7
349:16
491:20
492:3,12,16
493:7,10,16

droughts
493:4,17

drove 447:16

dryers
413:18

DS 435:5

DSM 328:5
331:19,20,21,24,25
337:3,4,5,6,7,8,9
338:20,21,22
339:6,7,8,9,10,11
344:22,23
347:8
358:10,11,12,13,14,15,16,17,18,19,20,21
368:7,8,9,10,11,12,13,14,15,16,17,18,19,20,21,22
369:7,8,9
370:13,14
371:18
372:4
374:9
375:13
377:15,19
378:10
382:13
386:5
387:17
391:14,20,21 392:1
396:19,22
397:20
404:13
405:22
422:18
427:5
430:18,21
431:5,8,20,21
432:1,8,11,16,18,21
433:17
434:7,16,19 435:5
436:8,9,14,16
437:13,23
438:1,7,17
439:21
440:7
442:13,20
444:11
445:6
455:3
457:4,7,18,19,22
458:6
459:15,16
460:13,25
461:9,10,18 462:8,21
463:3,4,14
467:18
471:17,19,21 472:4
474:9

477:2
482:9
483:2
525:20
533:9
603:13
604:7
606:17
615:18,21
617:7,10
619:25
620:7,11
621:24
623:4,6,12
624:7,8,9,
13,14,18,1
9,21
625:2,3,4,
11,15
627:15,21,
23,24
628:2,23,2
4 631:22
632:6
634:7,8
635:13,17,
20 636:1

DSM-related
533:10

du 607:25

ducting
429:5

due 393:13
394:5
513:13
514:12,13
518:5
521:25
563:23
573:2
577:12
596:14
610:20

Dunsky 368:5
605:9
627:18

Dunsky's
456:15
603:25
604:12
605:3
606:21

duration
489:13
533:13

during
445:1,15
488:11
490:5
491:20
575:13
577:16
614:11,14
615:1
617:9
622:8
623:4

dwellers
555:8

dwellings
538:13

dynamics
516:15

E

earlier
409:3
432:10
448:7
463:6
464:13
475:20
489:10
496:6
503:10
555:1
556:24
592:25

earliest
602:12

early 418:6
509:17,22
609:24
615:11
617:9

earth 429:10

easier
494:11

east-west
585:7

ec 392:15

eco 446:13
448:25

economic
334:10,20,
21,22,23,2
4,25
335:3,4,5,
10,11,12,2
0 336:25
337:20,21,
22,23,24,2
5 339:5
346:7
347:5,21
350:9
356:9,10,1
1,12,13,14
,15,16,17,
18,19,20,2
1,22,23,24
357:3
370:11
385:22
398:23
401:8,9,15
,16,23
409:2
415:23
416:4
431:12
432:4
433:17,25
434:8
435:12,23
436:1,3,9
437:5,6
438:12
447:21
462:3,9
468:8,11
471:2,3,4
472:14
474:18
476:19
486:1,12,1
6 507:5,9
509:7
523:4
524:6
575:9
577:16
578:24
582:3,8
596:1
606:6
607:15
625:3,4
633:24
634:6
635:11

economical
385:15
611:15

economically
523:23

economics
364:17
438:10
469:24
476:2,15,1
7 506:22
624:23,25
625:14

economist
379:13

economy
390:20
392:14,15

Ed 323:12
379:23
478:4
480:6
485:19
488:12,19,
22 489:7
490:20
491:7,15,2
1,25
492:9,14
493:12
494:7,14
496:24
497:8,12,1
9 498:3,13
499:10,20,
24 500:21
501:12,19,
22
502:4,15
503:9
592:17,21
594:1
595:5,10,2
5 596:18
598:13,23
599:3,5,8,
11,14,19
600:6,21
601:9,17,2
5
602:13,25
603:11
608:20
623:14,19,
21,23
625:8,22
626:10,15
631:3,11,1
4

educate
469:5

education
394:3
437:4
463:10
469:4
522:4,14,1
7,20,22
523:20
525:14,21
526:14
540:25
541:3
547:15

educational
547:11

effect
501:17
560:10
567:10
570:23
572:22
585:9
593:23
595:9

effective
434:14
437:2
446:19
452:16,19,
20 453:13
456:7
462:22

548:2
effectively 535:2
effectiveness 401:12
effects 399:20 463:21 620:23
efficiencies 633:22
efficiency 381:2,9 382:12 386:14,22 387:2 398:9 399:18,24 400:2,4,16 402:4 408:17 415:12 419:17,19,22 421:8,10,15 443:20 468:24 527:5,6 528:4
efficient 400:19 401:1 417:6 428:24 448:19 481:16 528:6 635:8
effort 394:6 396:10 437:20 535:19
efforts 391:20 392:1 394:3 422:5 463:4,10,14 464:12
eight 412:14 433:14 449:10 475:19 476:19 484:25 485:1 509:22 515:12 610:12
eighteen 412:12 549:18 557:20 558:11
eight-three 612:10
eight-two 612:9
eighty 513:2 515:16
eighty-seven 519:23 524:20
either 388:3,17 447:21 453:13 458:5 483:14 495:22 520:16 523:4 550:14 565:22,23 579:14 605:12 611:10 615:10 632:14
Either's 465:19
elaborate 623:10
elastic 530:11
elasticity 393:19 395:4 528:20
529:2,19 530:11,17 531:20,22 532:12,22 533:23 534:5,8,23 535:23 536:7,10,13,22 537:1,3
elec 412:23
electric 350:5 380:25 384:15 385:18 390:16 391:2,12 398:7,9 428:2,14 429:2,3 504:4 518:19 519:2,18 520:2,5,12,17,21 522:6,12 524:2 527:18,25 535:10 537:7 538:19 542:9,24 543:13 544:17 545:13 546:5 548:19,21 549:4,10,21 552:17 553:22,23 554:8,11 555:6,7,9,14 573:3,9,14,23 574:4 595:13 613:17,20,21
electrical 383:8,10 384:13 470:22 592:11
electrically 412:6 519:21 523:16 532:9 549:20 555:18
electric-heat 520:16
electric-heated 538:17
electrici 544:17
electricity 344:9,10 412:5,16,22 419:23 469:7 487:19 488:10 494:18 505:5 520:23 527:10,19,21,23 531:22 535:9 537:5 545:1,2,4 558:6 585:12 593:22 595:2,7,14,18 601:21 610:22
electronic 375:20
electronics 413:5
Elenchus 558:21 562:23 563:9 564:16,17 570:1 603:16
Elenchus's 603:23
elicit 487:8,14
eligible 605:23
eliminate 566:18
else 375:22 387:20 409:21 494:8 586:23 591:24 624:5
elsewhere 399:6 403:23 413:13 425:16 532:2
embarrassing 617:19
embedded 459:4
emerging 339:22 437:8 463:11
emissions 335:15
emphasis 380:20
employed 404:24 405:3 616:17
enamoured 616:23
encourage 405:12 523:22 546:15 605:13
encouraging 605:15
end-of-life

482:17
end-use
381:4
382:2
386:15
387:11
412:17,20
413:9
616:24
617:18,20,22 621:2
633:16
end-uses
621:13
ener 491:10
energy
327:9,12,22
328:4,5,14,18 342:24
343:23,24
344:25
345:12
348:13
349:25
350:4
378:20,22
380:10,25
381:2,9,19,25
382:12,21,24 384:1
386:1,12,14,20,22,23
387:1,2,11
399:15,17,18,23
400:2,4,16
402:4
407:16,17
408:5
410:12
415:11
416:19
419:17,18,19,22
421:7,10,15 428:5,24
431:18
433:2
437:2
440:9
443:3
445:9,13
446:14,24
449:1
455:25
458:22
459:20
463:19,20,21 468:24
470:13,25
471:9,23
472:20,25
477:9
479:6,19
484:1,2
490:4,20
491:11,12,14,19
492:13,15
493:2,9,13,15,19,25
494:3,9,19
495:6
500:2,13,18 505:3,9
520:18
527:3
528:2,4,11
532:7
535:12,16,18 539:4
553:4,6
555:19
563:23
564:3,6,9
571:7,9
585:13
587:20
589:5
602:2
610:14
611:1
613:22,24
614:7
615:12
616:17,21
617:12,13,23 620:18
Energy/ Energy
327:21
energy's
445:14
EnerNOC
378:23
386:2,13
387:1
395:22
397:23
410:18
569:3,5
615:20
616:13,18
620:8
629:22
630:1
Eng 379:5
engage
403:14
engaged
480:22
engagements
386:20
engineer
380:15
592:12
engineering
379:6
380:13,14
383:8
engineers
364:5
594:8,11
Enhanced
345:23
ensure
542:18
entails
487:10
540:22
enter
538:6,10
entering
444:16
entire 443:5
448:14
456:1,2
596:22
entirely
575:15
entirety
537:16
entities
397:15
envelope
536:3
environment
355:13,14,15,16,17,18,19,20
532:14
environmental
333:17,18
542:21
589:16
equal 410:12
458:8
461:25
591:10
607:7
equate
524:21
equation
440:25
441:21,23
607:12
613:9
equipment
381:1,4,12
400:19
401:5
408:17
413:17
414:2
equivalent
495:16,20
ERA 517:8
ERA-MH
506:16
ergo 425:16
erroneous
513:10
error 444:14
escalation
328:20,23
332:15
especially
419:12
essentially
433:23
468:15
494:17
495:8
497:3
499:6
536:19
582:24
584:13
586:2
603:10
establish
409:5,12
established
398:15
445:3
562:24
establishing
563:19
estimate
394:1
400:12
401:9,18
413:9
414:17
471:9,11
503:24
583:14
621:13
632:17
estimated
373:21
413:22
415:16
472:18
580:10
621:3
625:20
626:1
estimates
331:22,23
398:22
399:8
403:12
409:4
470:24

560:15
617:14

estimating
399:23

et 410:7
536:3

ev 624:6

evaluate
428:11
446:23
447:18
493:20
500:22
606:1

evaluated
604:5,6

evaluating
624:6,17,18

evaluation
334:10
335:4,5
336:25
347:21
348:4
350:9
362:16,17
364:4
379:8
397:25
478:20,21
480:22
497:24,25
504:1
624:12

evaluations
478:25
596:1,13
600:24

eve 382:20

evening
376:6

evenly
478:20

event 538:2

events
517:25

everybody
375:23
459:11

everyone
401:20
636:14

everything
400:23
402:3
409:21
478:24
481:9
568:23,24
569:7
624:5

evidence
352:20
382:7
384:15,17
385:19,24
387:17
441:9
525:18
603:23
604:12
605:3
631:6

evolved
385:13

ex 514:15

exact 444:12
480:7
549:14
550:15
612:5

exactly
393:9
414:22
602:21

examination
484:22

Examination-in-chief
323:13
379:25

example
394:16
400:1
402:6
403:25
405:13
406:11
409:18
423:21
427:24,25
428:8
441:24
442:23
443:19
444:19,21
457:2,13,15 458:2,8
461:2,3,6
476:8
478:11
481:8
549:1
561:23
562:3,10
570:24
603:24
605:15
607:25
617:8
632:25
633:2
634:1

examples
420:4
445:22
474:9
475:12

exceedingly
594:17

exceeds
559:22

excellent
402:6

except
436:19
634:20

exception
571:12
586:21

exceptionally
490:12,13
557:1,2
561:6,11,12 563:5

excerpt
489:22
582:11
599:10
619:19

excess 525:3
607:24

Exchange
327:10
350:4

exclude
391:13,21
569:11

excluded
401:17
410:23
426:5

excludes
404:12

excluding
568:24

exclusive
456:18
525:20

executive
483:6,13

exemplify
483:10

exercise
413:17
614:18

exercised
463:18

exhaustive
411:4

exhibit
325:2
326:2
327:2
328:2
329:2
330:2
331:2
332:2
333:2
334:2
335:2
336:2
337:2
338:2
339:2
340:2
341:2
342:2
343:2
344:2
345:2
346:2
347:2
348:2
349:2
350:2
351:2
352:2
353:2
354:2
355:2
356:2
357:2
358:2
359:2
360:2
361:2
362:2
363:2
364:2
365:2
366:2
367:2
368:2
369:2
370:2
371:2
372:2
375:19,25
376:4,5,8,11,15,19,23
377:6,10,16,18,24
388:23
466:7,9
467:3,4,6
489:24,25
504:16

exhibits
323:3
324:1
325:1
326:1
327:1

328:1
329:1
330:1
331:1
332:1
333:1
334:1
335:1
336:1
337:1
338:1
339:1
340:1
341:1
342:1
343:1
344:1
345:1
346:1
347:1
348:1
349:1
350:1
351:1
352:1
353:1
354:1
355:1
356:1
357:1
358:1
359:1
360:1
361:1
362:1
363:1
364:1
365:1
366:1
367:1
368:1
369:1
370:1
371:1
372:1
375:17
377:2,5

existence
429:4

existing
406:5
452:1
458:15
467:21
469:13
472:13
475:2
577:18

exists
599:24

exogenous
404:18

expand
352:7,14

expanded
623:13

expansions
590:15

expect
394:18
429:18
448:15
471:18
477:5
483:20
487:11,13
544:21
572:21
573:25
579:1,7,11
583:5
606:19
607:13,17
610:18
612:11
623:11
625:14
628:24
632:23

expected
408:4
416:18
523:10
524:18
546:23
620:21
623:7

expecting
437:11,13
524:1
525:19
602:17

expenditures
332:7
344:3,4
349:15
350:12,13
479:12

expense
331:5

expensive
419:9
453:11
536:4

experience
383:3
386:19
387:8
397:10,20,23 398:10
399:2
417:17
463:2
572:10
575:2
578:5

experienced
392:17

expert
352:4,23,24,25
353:3,4,5,6,7,8,9,10,11,12
386:21
387:16
430:2
477:25
532:23
534:5
603:16,25
627:18

expertise
382:2
395:25
396:4

experts
425:13
430:2
536:13
558:22

explain
373:12
394:13
423:14,21
435:14
436:17,23
463:24
477:20
494:1
496:21
499:21
504:24
506:18
507:13
509:10
521:20
531:25
542:17
557:19
570:19
598:21
599:24,25
600:10
614:19

explained
441:20
461:17
620:15

explanation
478:11
560:23

explicitly
606:4
617:2

explode
464:16

explore
512:6
531:19
586:10
590:19
592:7

exponential
592:15

exponentially 593:12

export
327:8,10,21
328:6,7,8,9 330:5
333:4,19,20
334:14,15,16,17,18,19
335:17,18,19,21,22
337:10,11
338:8,9,10
339:25
340:3,4,5,6,7,9,10,11,12,13,17,18
341:4,7,11,12,15,16,17,18,20,22,23,24,25
342:10,12,16,21,23
343:12,14,25
345:9,15,23 346:18
347:19
348:5,8,11,14 349:13
355:21,22,23 356:25
370:8,10
373:18
444:23
461:14,19,21
462:1,5,6
469:21,24
477:22
500:20
501:10,17
502:13,21
591:10,20,22 595:21
596:2,17
598:1
600:4,17
601:8
624:4

exporting
596:23
601:15,20

exports
327:6,7
348:20
362:18,19

363:4,14,15,16,17,18
478:23
499:17
595:14,18
596:3,14
602:1
609:18

expressed
431:4

ext 446:19

extend 524:6

extended
472:16
503:12
544:8
608:17
628:7

extending
544:17

extends
580:22

extension
351:9
472:20
543:24
546:12

extensions
547:18

extensive
383:6
411:23

extent
425:21
515:2
524:2
539:12
578:3
623:12
631:8
635:14

external
396:1
506:8
533:7

extrapolate
497:4

extrapolates
634:2

extrapolation 497:7
516:21

extreme
598:24

extremely
450:12
456:12

F

F&PP 349:14

facilities
410:9

facing
524:11

fact 405:15
499:25
530:20
534:20
545:6
555:5
563:20
566:13
598:19
621:4

factor
392:12
554:17
569:21
573:13
609:2
610:11,12
611:25
612:6,20

factored
525:24

factors
391:18
393:2
409:23
538:10
573:6
587:16
589:13
607:11
609:1
612:2
617:3
618:4,17
620:20
621:2,18

Faculty
380:13
384:2

fail
400:24,25
430:8
481:21

failed
400:19
430:13
482:22

fair 460:12
523:24
533:14
604:22

fairly
410:11
419:24
452:7
475:25
480:17
584:19
610:14
611:23

fairness
460:4
461:5
462:17

fall 382:23

false 510:23

familiar
506:22
621:19

family
412:2,6
538:13

fan 527:4

fans
527:5,6,7
555:13

fashion
412:10

faster
465:10

favourable
402:3

feasible
603:21

February
352:13,16,18,20,22
357:6
358:23
360:16
362:15
364:7,18
365:13
366:14
367:8,21
368:6,24
369:24
370:16
371:7,9

federal
446:4,13,20 447:19
448:24
450:16,17
451:7

federally
508:5

fee 544:4

feed 605:16

feedback
390:5
410:21,22
425:9

feeding
606:8

feel 407:24
411:19
461:3
528:22
583:13

felt 469:6
503:18

fewer 516:12
519:23
577:18

field 611:13

fifteen
465:18
484:8,15
623:20
631:24
632:16
634:7,15,25

fifth 582:25

fifty 429:19
430:17
440:22
447:10
448:20
452:25
595:23

fifty-three
516:12

figure
451:10
627:18

file 517:6
530:21
531:2
623:7
625:7
633:24

filed 373:22
374:7
375:18
377:7
489:23
497:16
523:14
528:23
531:13
619:3
623:12
625:21
626:2,24
627:1,8
635:12

filing 380:4
383:19
384:25
489:4,24
491:4
494:24
495:3
619:4

filings
623:13

filter 432:4
435:12
436:2
438:17
471:2
475:21

filtered
433:18
436:9
468:9

filtering
434:7
475:21

filters
434:21

final 409:5

finally
378:25
402:18

finance
331:5
344:14,15,
18 352:4
385:7

financial
329:21,22,
23,24,25
330:3,4,7
331:7,10,1
1,12,14
344:7,8,16
345:19
385:11
497:15
597:20,23
625:9
626:22,24

financially
603:21

financials
373:21
374:6
625:1,7,9,
20
626:2,7,14
627:7

financing
428:3
429:9,11

finding
566:11
624:24

findings
416:1

fine 423:5
465:19
551:6,9
599:18
612:21

finger
487:13

finished
420:25
466:19

finishing
623:24

firm 398:9

first
347:10,16,
17,18
350:7
395:19
399:11,14
407:6
421:18
431:2
442:20
446:8
452:9,10
455:24
457:9
467:16
476:8
486:14
505:22
547:2
548:25
553:21
575:4
577:25
599:23
610:19
617:10
619:19
627:25

first-cut
608:22

Firstly
375:18

first-year
456:16

fiscal 399:8
531:17

fiscally
436:21
443:13

Fisher
452:10
474:1

five 374:6
386:25
390:8
392:5
423:22,24
424:3,18
433:13
446:8
447:4
450:20
451:23
462:6
476:9
478:18
479:4
506:25
513:3
549:14,19
570:7,10,1
4 578:6
580:20
581:3
583:4
626:6,12,2
5
627:7,15,2
3
628:22,24
629:5,11

fixed 511:5
588:1
597:8,11

fixing 500:3

flare 611:13

flash 400:23

flat 478:12
480:9
498:4
501:6
502:21
503:7,18
509:23
582:14
583:9
597:21
598:11,12

flatlines
632:5

flexibility
420:2
609:13

florescent
404:23

flow 494:17
500:7,13

flowing
593:22
595:2

flows 328:11
347:24
349:24
478:24
492:23

Flows/
hydraulic
328:12

fluorescent
402:7,12,1
3

fluorescents
417:7

Flynn 601:10

focus 416:15
482:7
505:25
524:10
541:6
612:15

focussed
397:17
541:20
543:13

focusses
543:9

focussing
384:19
566:19

follow-up
610:21

forced
402:14

fore 390:1

forecast
326:10,19
332:3
338:23,24,
25
339:3,4,23
343:3,4,5,
6,7,8,9,10
,11,13,15,
16,17,18,1
9,20
344:7,8
350:17,18,
19,20,21,2
3,24
351:3,4,5,
7
357:7,8,9,
10,11,12,1
3,14,15,16
,17,18,19,
20,21,22,2
3,24,25
358:3,4,5,
6,7,8,9
367:9,10,1
1,12,13,14
,15,16,17,
18,19
370:4
371:17
372:3
373:11
375:12
377:15,19
378:10
379:11
384:16
385:24
386:15
389:2,5,14
,15,17,20
390:2,8,10
,24
391:5,10,1
5,16,17,19

,21,22,24,25
392:3,18
393:1,4,14,15
394:5,12
399:22
401:11
408:8,13,15,16
416:25
418:19
420:18
423:7,9,17,18,23,24
424:15,17
479:16
488:16
489:5,8,9,11,16,19,22 490:1
492:8
494:25
495:1,20,24 496:7,13
497:2
498:25
499:15
504:5,6
505:23
506:4
507:11
508:3,9
509:13,14
510:1,10
512:7
515:18
517:6,15,16,21
518:5,15
519:16,17
521:24,25
522:11,25
523:2
524:19
525:11,13,16 526:20
528:10
530:2,5,18,24 531:4
533:6
536:22
537:15,19
538:7,16,17,21,22,24,25
392:3,18
393:1,4,14,15
394:5,12
399:22
401:11
408:8,13,15,16
416:25
418:19
420:18
423:7,9,17,18,23,24
424:15,17
479:16
488:16
489:5,8,9,11,16,19,22 490:1
492:8
494:25
495:1,20,24 496:7,13
497:2
498:25
499:15
504:5,6
505:23
506:4
507:11
508:3,9
509:13,14
510:1,10
512:7
515:18
517:6,15,16,21
518:5,15
519:16,17
521:24,25
522:11,25
523:2
524:19
525:11,13,16 526:20
528:10
530:2,5,18,24 531:4
533:6
536:22
537:15,19
538:7,16,17,21,22,24,25
539:20
549:5
551:22
552:8,11,21,22
553:1,2
554:22
557:3
567:11,14
568:8,14
569:8,11,14,19,20
570:15
571:7
572:7
573:15
576:24,25
577:22
579:14
581:5
582:11,22,23
584:11,16,25
586:12,25
587:3,6
589:3,8
597:17
598:12
602:10,20
603:4,5
604:3,5
606:15
608:24
609:2
615:22
616:13
617:2,3
618:6,14,18,24
619:8,11,24
620:12,19
621:10,11,17,20,22
622:1,16,17 624:2,4
629:14,16

forecasted
389:20
571:15

forecasters
507:20
570:8,11

forecasting
330:11
382:24
383:5
386:23
387:11
389:22
390:1,11,22 392:10
423:16,25
504:4
506:20
516:2,16
529:24
531:16,18
536:19
538:3
558:5
583:22
616:25
617:18,20,22 618:10

forecasts
327:11
329:21,22,23,24,25
330:3,4,5,7 331:7
332:16
334:14,15
338:8,9,10
341:7,11,12 345:8
346:18
348:8,9,10,14 390:6
391:3,4,6
424:12,17,18 437:22
488:21
496:2,11
506:8,12,25 511:23
517:10,12
603:17

forecasts/CO2 348:11

forecasts/Top 347:22

foresee
579:13

forget
469:22

form 406:23
419:24

formed
508:25

formula
427:1,2
570:1,3,13,20 571:23
573:11

formulas
403:22

forty 448:21

forty-four
440:23

forty-three
440:23
450:18

forward
392:5
395:1,20
399:17
403:13
408:1,2
477:13
539:7,10
540:4
575:18
583:1
589:1
605:24
607:3
632:4

fourteen
519:17,18
557:20
558:10
561:4

FR 325:6

fraction
416:4

frame 369:25
475:6,10
606:21
608:17

frames
604:19,22
608:13

framework
391:10
616:22
617:19

free 463:25
475:14,15
514:3
528:22

fridge
404:15,16

fridges
400:24
633:6

Friesen
323:7
378:18
379:18
380:1,5,8
534:15,16
536:23
578:16,18
579:18,22
580:5,17
587:11,21
589:9
591:25
593:2,5,14,18
594:3,6
604:4,14,21 605:18
606:11,16
608:6,10,18 610:9,25
611:24
612:17,24
613:2,21
614:23
615:3,9

front 375:21
394:3
481:12
489:25
491:5
503:25
521:4
526:19
542:2

545:1,17
546:6
548:3
551:4
554:5
561:16
562:3
564:21
579:17
594:23
598:7
619:18
622:14

fuel 348:24
368:25
369:3,4,5,6 373:7
384:16
394:2
469:2
472:2
520:6
522:16,20
525:22
526:6,8,11,12 537:6
540:16,25
542:3,19
546:24
550:24
551:17
552:2

fuels 407:22

full 425:1
504:1

fully 480:25
487:13
536:13
542:18
545:15
628:4

fumbled
485:24

function
592:15,18

functional
329:3
383:6

functions
385:16

fundamentally 555:10
618:8

funding
429:11

funds 331:6

furnace
429:4
444:5
481:17,25
482:20
520:3
527:3
535:11
542:24
550:4
553:23
554:8,11

furnaces
400:25
443:19,23
448:18,20
633:9

future 346:5
395:2,14
399:18
408:6
417:8
422:4
449:21
465:6
470:8
475:10
493:25
500:1
506:1
522:6
528:17
529:22,23
530:3
566:3
575:19
582:4
583:9,15
584:16
603:18
604:3,6
605:2
606:17
621:24
622:6
633:12
635:6

G

G&T 328:16

G.S 332:16
345:18

GAC 322:10

gained
535:13
607:15

gains 633:1

Gange 322:10
388:2

gap 416:16

gas
327:11,13
329:5,9,10
332:13,14,17,22,24,25 383:11
384:13
412:2,7,24
428:2
443:18
469:7,13
481:16
485:15,21,22
486:6,8,13,16,17
500:4,11,15 502:23
503:14
520:3
523:23,25
524:6,7
527:22
535:7,8
537:5,8
538:18
541:18
542:8,24
543:12
544:18,19,21
545:10,13
548:20
549:3
553:22,23
554:8,9
558:3,5,7
608:2
609:12
611:13
624:16,17
633:9

gas/Conawapa
332:21

gas-available
523:16,17
540:7
541:4,7

gases 412:23

gas-Keeyask
485:23
486:12

Gaudreau
367:21

GDP 390:19
569:17,24
570:6,9,15,21

gen 479:12

gender
402:10

general
381:16
389:12
390:17,19,20,21
391:5,10
439:9,22,23 442:16
464:22
504:9,21
530:21
538:5
542:12
568:20
569:10,20
573:17
574:1
587:5
606:18

generally
392:21
396:17
403:6
419:1,3
438:11
439:25
442:4,13
448:14
456:18,19,20
462:4,16
480:4
501:15
502:10
546:4
610:12
611:8
622:4

generate
408:19
428:5
601:22

generated
331:6

generating
607:6

generation
327:13
328:3,10,13,18 332:5
347:25
354:7,8,9,10,11,12,13,14,15,16,17,18,19,20,21,22
457:8,23,24
458:5,8,10,24
459:3,12,17,22
460:16,20,21
461:10,18
478:7,9,22,25 479:5
492:8
500:5,10,11,15,23,25
505:4
602:12,23
606:10
610:23

630:22
631:8,18

GeoExchange
451:4

geographic
523:9

George
322:15

geothermal
428:2,9,10,12,15,20
429:9,13
450:4,5,6,7,24,25
451:1,3,10,12,13,15,17,18,25
452:6,12,14,18
453:4,15
473:23,25
542:10

geothermals
453:16

gets 418:7
435:13
509:11
554:9
581:8

getting
377:22
451:11
453:16
489:11
510:22
516:5,6
528:6
533:24
546:1,10
547:23
586:24
598:4
630:15

GHG 337:5

Gibson
367:20

gigawatt
373:14
389:10

393:15,24
394:5
414:14
415:3,16
418:18
458:9,10
478:18
479:4
490:5,9,19,24 491:14
494:20
495:7,16,21 521:6
524:22
547:1
548:5
550:18,25
551:23,25
552:1,6,19
553:1,6,11
566:25
567:20
577:6,13
584:5
589:7
591:11
598:10,18,22 600:12
601:7
620:2,4

gist 442:16

given 377:11
393:20
397:3
424:23
436:6
438:3
454:3
473:25
482:5
488:10
494:18
499:25
502:1
529:1,20
534:2,20
554:11
578:4
579:7
585:6
608:11

gives 408:10

409:3
483:22
513:3
549:8
597:19

giving
385:23
541:21,22
612:8

glass 602:15

glitches
375:5

global 387:1
506:22
579:2,13
587:12
616:16,21

globally
430:7

go/no 439:25

goal 398:21
403:3

goals 415:12
420:7,8,10,12,14
421:4,5,24
422:12

go-forward
393:20
484:11

gone 459:2
515:4
630:7

goods 413:3

Gosselin
321:13

Gotham 367:8
371:22
376:13,17

gov 446:20

governing
380:25

government
346:24,25
347:3
362:22
364:3

404:12,14
446:4,13,20 448:25
450:16,17
451:2,7,8
472:3
477:15

governments
330:20

GRA 461:13

gradual
395:16
565:11
587:7
607:13,18

graduate
380:12
384:1

Grant 321:17
378:8
423:6,13
424:6,10
426:13
427:4
477:18
480:3,18
536:17
538:1,22

Grant's
539:18

granular
407:19
408:5
409:23
412:10
413:13

graph 456:16
471:8
586:7
628:15

great 605:4

greater
401:15
440:1
454:10
480:21
493:1
513:19
515:17

540:6
607:16
609:13

green 388:3
413:3
419:16
437:10
447:17
450:14
455:21
582:14,19,21,23

Greenhouse
329:5,9,10

grey 407:9

grid 596:22
604:12,25
605:7,8,16,17
606:8,22
607:5,8,14

gross 463:20
464:4,9

grossly
592:23
593:20

ground
430:23

grounded
419:2
421:14

group 482:7
496:15
504:9,10
521:22
571:19
572:12
581:16
592:2
611:25
612:10,18
628:20

grouped
403:9

groupings
618:19

groups
520:12

580:25
581:15
590:21
602:9

grow
390:11,22
526:21
572:21
581:16,25

growing
391:24
574:1
588:13

grows 500:11
587:6

growth
326:20
327:4,12
333:16
349:3,6
385:24
390:11,20
392:14
394:22
416:18,20
422:17
423:17
424:8
479:15
486:10
495:15,20,25 496:22
497:17
498:15,24
499:1,23
501:2,3,9
503:1,13
504:7
511:11
512:4
513:13
514:7
521:14
522:1,2
525:4,19
540:6,12
571:18
572:10,11,13,21
573:2,12,14,23
574:6,17,23
575:6,7,15,16,17,22,24
579:6,9,25
580:3
581:6,10,11,14,20
582:1,5,7
583:6,12,15 584:13
585:6
590:8,11
597:18
609:4,5,11,12,14,17
618:13
620:3,5,19
634:2,4

growth's
393:10

guess 391:11
425:19
456:9
480:18
506:20
507:24
549:22
573:24
586:24

guidance
403:11
406:1,14
407:2

guideline
461:23

guidelines
442:15,17

Gunn 366:13

Gwh/yr 349:4

H

ha 532:18

Hacault
322:13
387:25

hair 413:17

half 412:21
414:4

hallmark
398:14

han 592:1

handle 515:1
549:15
550:16
567:6

handled
592:2

happen
448:15
458:14
464:24
465:2
512:4
588:6
617:7
633:12
634:16

happened
446:11,22
447:21
449:12
464:8
492:21
495:5
513:23

happens
459:17
460:5

happily
568:3

happy
485:1,3
494:12
548:13
599:4

hard 443:7
482:4

Harper
371:24
376:21,25

hav 448:3

haven't
501:16,19
502:1
515:3,4
529:13
536:12
537:23
571:5
624:25

having
383:4,21
440:15
462:18
470:13
476:4
486:15,22
487:15
541:9
551:4
556:13
573:17,18
624:1
626:8
627:12
632:18

Hawaii 387:7
419:20

head
601:10,11,13 603:4

headed 605:6

heading
508:13

heads 451:9

hear 378:14
429:21
433:7
445:12

heard 422:21
427:25
487:15
506:6
528:5
585:5
618:22
620:3

hearing
375:6
385:19,20
441:10

heartening
547:7

heat 390:16
428:2,13,15,20
429:9,13
518:19
519:2
520:3,4,17,22,23
522:12
524:2
527:16,17
534:20
535:3,4,7,8,10,13
537:7
549:4,10,21 555:1,6
563:13
573:23
613:9,21,25
614:5,7,13,15,17

heat-dominated
532:8
535:5

heated 412:6
519:21
523:16
527:2,11,19 532:9
538:19
542:9
548:19,21
549:21
555:13,18

heater
348:22
553:23
554:9,10

heating
326:23
350:5
384:16
412:2,21
413:14
414:1,2
428:14
429:3
451:22
522:4,7,14,22 523:22

525:14,21
526:13
528:1
536:2
537:8
540:25
541:24
542:3,6
547:15
549:1,24
552:18
553:20
554:3,18
557:5,13,21
558:2,9,12,13 560:16
561:3,6
563:24
564:20
565:11,24
566:5,10,20
573:3,9,14
574:4
613:17,20
615:7

heatings
555:7

heaviest
615:12

heavily
532:8
563:13

heavy 570:24

held 321:20
522:10

Hello 428:19

help
420:11,13
435:19
457:15
559:18
627:13

helps 548:14

here's
416:22
419:15

he's 379:4
531:2
592:11

high 392:25
421:5
436:12
443:20
450:15
451:16
471:8
474:25
500:7,13
508:2
515:22
516:4
527:6
534:9
546:24
557:10
561:5,10
564:8
566:20
594:16
596:4,21
604:6
609:5,12
610:11,13
612:20

higher 391:6
393:21
418:6
419:6
426:4
445:22
455:5
458:6,25
459:23
460:8,20
472:24
480:4,12
493:2
500:5,8
502:22,23
510:17
527:25
529:8
557:11
563:2,23
573:2
596:10
610:13
614:22
620:12
624:21
629:2

highest
415:1
574:17,19,23,24
611:25
615:8,10

high-level
396:16
397:11
470:24
471:11
600:25

highlight
587:22
598:8

highlights
495:4

highly
500:13

high-voltage
596:21

Hill 351:9

hired 395:22

historic
581:10,13

historical
509:14

historically
492:22
579:11
581:18

history
491:23
581:25
616:24

history/ forecasts
349:4

hitting
586:8

hold 380:8
383:24
385:3
583:9

holding
380:13

Hombach
322:3
323:14
375:7,8
376:4,11,19 377:1,9
378:1
387:19
466:18
484:24
485:13
486:19,20,21 487:22
488:5,14,20,23
489:4,18,21
490:8,16,22
491:3,13,17,22 492:5
493:23
494:10,16,23
495:13,22
496:3,6,20
497:6,9,14
498:2,5
499:3,14,21 500:17
501:7,16,21,25
502:10
503:4
504:2,13
505:12,21
506:5,11,17,24
507:4,8,18
508:12,22
509:4
510:2,12
511:13
512:5,12,15,24
513:11,25
514:5,20
515:19
516:3,7
517:5,14
518:1,11,22,24
519:6,14,22
520:1,7,10,21
521:3,12,20
522:15,24
523:3,8,24
524:16
525:1,17
526:16,17
528:3,19
529:25
530:19
531:6,11
533:3,4,14
539:16,17
540:15
542:22
543:8
544:2
545:21
546:21
547:6,24
548:12,17,24
550:2,10,11,23
551:1,6,19,20
553:12,17
554:4,16
555:14,24
556:11,12,18,22,23
557:8,13,19 558:14
559:1,18
560:2,25
561:9,14,22
562:2,9,16,20
564:14,25
565:3,6,9,10,15
566:22
567:5,12,17
568:1,6,16
569:3,13,25
570:6,12,17 571:16

572:1,5,20
573:8
574:3,12,16 575:25
576:4,15,19 577:2,20
578:4
579:15,19
580:2,9,21
581:12
582:9
583:16
584:12
589:19,20
590:5,12,18
591:2,9,19,23
592:5,19,22
593:4,10,17,20
594:4,15,20,21
595:6,11
596:15
597:15
598:14
599:1,4,6,9,12,18,21
600:8
601:4,14,19 602:8,18
603:9,12
604:11,16
605:11
606:7,13
607:21
608:7,11
611:17,18
612:13,21,25 613:17
614:19,24
615:5,17,25 616:7,12
618:2,22
619:2,6,12,16
622:7,13,24
623:3,18,20,22
625:6,18
626:4,5,12,20
627:10,11
628:22
629:2,6,20
630:20
631:1,5,13,19 632:2
633:23
634:22
635:10,23
636:11

home 445:24
449:23
450:1
452:1,20
453:6
505:8
527:19,20
535:8,10
537:9
538:8
541:8
542:13
544:4,11,23
546:2,9,18
549:1,20,23 555:18

homes
412:2,4,6
413:9
449:25
453:6,8
511:8
527:15
528:13
532:10
539:9,14
540:8,9
541:20,21
544:23
548:19
549:2,7,9
555:12,13
632:22
635:6

hook 544:5

hopefully
431:1,10
434:8
457:2
636:2

hoping 474:1
484:19

horizon
416:25
468:17
496:14
498:9

horizontal
407:9

hospitals
406:10
410:7

hot 490:13
557:1
561:11,12
563:5

hottest
557:16

hour 393:24
428:6
429:18
478:18
480:2
532:19
550:18
589:7
591:11
610:16
612:3
636:2

hours 373:14
389:10
393:15
394:5
414:14
415:3,17
418:18
458:9,10
479:5
490:5,10,19,24
491:14
494:20
495:7,16,21 521:7
524:22
547:1
549:11
550:25
551:24,25
552:1,6,19
553:1,6,11
563:1
565:23
566:25
567:20,21
577:6,14
584:5
598:10,18,22 600:12
601:7
620:2,4
633:7

house
532:17,18
545:7
546:3

household
412:19
512:21

housekeeping
375:15

houses
545:3,5

housing
511:1
538:19

HRV 527:16
555:19

HRVs 555:12

huge 633:3

Hugh 321:17
423:6,13
424:6,10
426:13
427:4
477:18
480:3,18
536:17
538:1,22

hundred
381:23
393:9
394:5
446:8
447:4,9
449:10
450:11,17,18 452:22
458:22
476:9
478:18
479:4
481:18,19
490:17
491:16,23
492:19,24
516:12
519:18,23
521:15,18
524:19
538:12
548:2,6
549:2,6,13,19 552:24
562:5
584:4,5
585:17,18
607:24

HVDC 328:24
329:3
332:6
345:24
596:25

hyd 503:13

hydraulic
327:22
328:10
347:25
502:6

hydro 321:7
322:5
323:6
324:21,22
325:20,23
326:9,12,15,17
351:6,11,12,14,16,18,20,23
363:25
371:10
373:3,8,12,20
374:3,8
375:10,20
378:2
379:13,17
380:17,22
383:4
384:3
385:9

386:6
387:7
397:14
398:2
399:2
403:22
404:24
405:3,11
406:1
407:3,14,15 408:8,22
410:21
411:22
418:1,14
424:24
425:3,8,14,23
426:19,22
427:3,7
428:3
429:9
431:4,9,19
435:17
438:2
443:5
446:3
451:9
454:1,8
455:2
460:2
462:19
466:19
470:17
482:25
484:4
486:4
487:17
488:15
489:24
492:6
493:24
494:13,24
495:14
496:9
500:3,10,11 501:3,6
502:17,18,19,22,25
503:14
505:13,16
506:7,25
507:5
508:23
509:8
511:13
512:16
515:1
517:14
521:8
523:8
525:19
528:23
530:21
540:17
543:9,11
544:4,5,14
545:21
549:16
550:17
551:7,12
552:1,15
554:6
556:25
558:14
561:2
564:19
565:17
566:24
568:10
580:15
588:20
591:2
595:12
597:17,23
598:9
599:24
600:5,10
601:8
602:22
603:18,22
604:18,24
605:12
606:7,14
607:22
608:4,9,14
616:14
618:4,9,16,18 619:19
622:16
623:6
625:25
627:3,14,19,22,25
631:7,22
633:24
634:2
635:19
Hydro/ Minnesta 350:3
Hydro-1 457:1
hydroelectric 607:23
hydrogen 611:12
Hydro's 321:9
371:15,17
375:12,15
380:4
381:7,15,17,22
382:3,14
383:5,19
384:12,15,18 391:5
426:25
436:7,14
447:4
448:11
456:16,21
457:10
487:16
488:7
489:5,23
491:23
497:15
504:7
518:13
520:11
542:23
548:4
554:13
560:3
576:23
578:5
580:22
583:19
597:20,25
598:5,15
604:2
605:21
618:24
619:7,24
620:8,11
621:5
622:8
631:21
I
Ian 323:10
378:25
379:21
385:1,3
424:14
506:9,14,19
507:2,7,16,19
508:15,24
509:12
510:8,20
511:16
512:11,14,22
513:1,14
514:4,10
515:3,21
516:5,14
517:8,18
518:4,18,23 540:23
570:10
ICF 330:16,17,18,19
I'd 396:13
406:20
411:17
430:25
431:7
466:5
485:2,23
486:24
489:21
493:12
496:6
505:21
512:5
528:19
548:12
587:21
597:22
599:4,22,23,25
613:11
615:17
619:16
idea 556:3
594:17
ideal 402:1,21,24 431:12
433:15,16
435:25
436:10
457:20
ideally 560:13
identificati on 414:25
identified 396:19
471:18
603:16
identify 407:10
411:1
425:14
435:1
530:11
IEC 322:20
324:21
351:10,14
371:10,11
IECs 326:13
388:17
IFF 478:17,25
489:12
IFFR 528:24
ignored 537:16
ignoring 513:9
II 373:6
551:15
I'll 384:14
398:15
399:10
413:10
417:15
423:20
430:17
431:22
432:6
435:14

436:17,22
438:1
439:2,12
442:16,19,23
448:12,23
450:7,24
453:24
456:24
458:13,16
461:12
468:3,14
478:10
481:7
485:1
486:23
488:13
494:12
505:22
536:23
548:24,25
556:19
568:2
599:21
614:14
622:11
626:18
632:25

Illinois
420:15

illustrate
564:17
598:3

illustration
509:5

I'm 378:9
380:12
383:9
384:1
388:14
394:14
395:7
412:23
415:24
422:25
424:21,22
425:19,20
430:16,19
432:24
434:1
437:15
465:12
471:25
474:14
477:25
480:9
483:16
486:21
487:7,9,14
495:2
499:4
502:14
504:5
506:21
509:5
512:16
513:1,4,6
516:7
518:11
521:5
522:20
528:20
529:1
533:24
534:5
538:7
549:22
550:15
555:24
558:19
560:25
562:20,22
565:2
567:5,8,12,18 571:20
572:5
573:15,24
577:20
580:10
586:24
592:12
594:21
598:4
601:9
602:13
604:16
613:11
614:16
623:9
627:16
631:7
634:5
636:9,12

immediate
378:17
607:17

Immediately
379:4

immigrants
518:6

immigration
508:1,7
513:13
514:8,13,19

impact
385:22
392:13
395:6
437:24
439:12
454:7,8
458:4
460:14
470:20
512:7
516:9
526:9
535:15,23
554:11,17
565:21
570:18
588:19
604:2
607:18
608:13
629:13

impacted
448:8
460:22

impacting
381:4

impacts
328:15
329:9,10
333:17,18
334:6,7
336:13,23
337:20,21,22,23,24,25
338:5,6,7,16
345:4,14
346:11,12,14,19
349:9
350:15,16
362:22,25
363:6,7,8,9,11,12,13
364:3
394:18
439:11
460:14
624:21

implement
381:2
482:9
483:7
535:24

implementation
402:1,23
606:24
608:12

implemented
421:25
483:21

implementing
432:7
483:14,15
536:5

implications
348:16
542:20

import 333:3
502:6,22

important
392:22
396:7
407:25
422:2
437:3,4,10,16 438:9
444:10
445:10
458:19
462:16,17
463:7,18
513:22
534:19
535:5,23
543:4
610:5

imports
327:7
362:18,19
363:4,18
500:14,15

imposed
419:10
420:18

imposes
606:15

impression
472:8

improved
528:12
578:25

improvements
390:3
536:3
633:22

improving
528:14

inadvertentlly 509:19

Inasmuch
586:11

inc 378:23
386:2
447:8

incenting
435:6,7

incentive
435:6
445:18
447:25
448:11
449:7
450:10
469:11
606:2,3

incentives
429:13
436:25
445:22
446:1,2,15,18
449:3,14,15,17
450:8,16,20 472:24

476:15
543:12

include
383:7
386:15
387:10
391:14,19
428:20
431:5
441:22
468:20
473:8,10
510:10
520:6
522:15
528:4
530:16
547:8,17
571:10

included
391:11
401:16
405:14,16
415:9
426:3
428:22
429:7
437:22
468:5,24
469:14
470:10,12,16 473:13
509:3
514:1,18
522:25
525:23
552:15
569:10
571:11
609:20
630:10
634:8

includes
399:19
413:2,12

including
381:16
382:4,9,23
383:4
384:9
387:4
411:4
415:10
431:11
435:5
438:25
481:24
488:11
531:9

income
409:14
442:24
456:2

inconclusive
529:4

incorporate
432:18
512:2

incorporated
393:14
555:5
573:11

incorporating 529:23
530:5,14

incr 531:3

increase
352:3,12
394:2
395:16
421:23
447:9
498:12
502:23
503:3
507:14,25
513:16
527:3,21,22 528:2
554:23
555:11,15
573:8,20
577:23
586:22
592:14
593:12
596:8

increased
449:2
450:20
502:12,20
503:2
507:10
510:14,15
523:15
540:7
573:3,5
590:8
628:8

increases
351:15
370:3
393:20
395:5
528:24
529:6,15,21 532:5

increasing
449:8
457:24
501:1
513:17
579:21
623:6

increasingly
500:12

incredible
515:8

incremental
328:18
346:3
373:18
435:22,24
446:21,24
447:19,24
459:3
464:15
474:20,25
476:15
510:16
512:20
514:22
526:9
595:7,20
596:2,14,17 597:1
600:4,17
601:15
634:4,20

independent
398:19
424:16
427:15
558:21

in-depth
530:8

index 504:5

indicate
373:20
374:3
526:19
562:6
607:12
625:25
627:3

indicated
398:12
416:5
425:13
430:3
485:23
493:13
494:24
495:15
525:19
589:25
592:11
633:24
635:14

indicates
446:1

indication
483:22
607:5
608:1
623:5
624:20,22

indifferent
460:2

indivi
435:24

individual
421:24
430:5,11,13 435:1,16
487:1
516:18

individually
571:15

individuals
523:21

industrial
349:6
378:18
380:9,20
381:11,12,18
382:10,11
394:11
407:21
410:3,4,5,8,13,15
411:14
412:14
415:6,9,10,13 417:11
478:13
568:24
569:6
575:10
580:16
581:7
582:14,15
584:19
585:25
611:22

industries
412:15

industry
349:3
386:21
400:3,9
438:6
442:14
452:17
457:5
463:2
464:1
570:19,24
579:8
580:19,25
581:15,16,24 582:17
590:7
604:23
605:5,10
607:1
617:10

inefficient
444:6

inevitable
489:14

infinite
434:23
464:20
475:24

inflation
393:21
532:5

influence
449:17
470:21
532:21
613:18

influenced
447:3
449:5

influencing
447:13

influential
570:14

Infometrica
506:23

information
324:23
326:17
342:9,25
351:16
352:21
357:5
358:22
360:15
362:14
364:5,17
365:12
366:13
367:7,20
368:5,23
369:23
370:15
371:21,23
376:12,15,20,23
383:13
389:19
396:15
402:22
403:12
406:7
409:1
411:13,23
417:16,20
418:2,8
422:11
427:16
440:17
454:5,18
463:16
472:7
485:25
486:3
487:9
489:10
492:22
506:13
508:2,10,14,16
520:15,19
530:15
539:5
540:18
542:3,4,12
543:6,9,14
544:16
564:16,18
576:22
591:3
612:8
619:20
623:7,11
625:4
626:22
627:12
629:21

informed
475:4
480:25
481:23

Ingrid
323:11
378:21
379:22
386:3,7,11
396:24
397:8
403:18,24
404:3,19
405:8,15,24 406:20
409:17
416:7
425:5,24
426:20
427:13
428:12
430:14
432:9
436:19
615:24
616:5,10,15 618:7
619:1,5,9
620:13
622:12,21
623:1

Ingrid's
397:3

inherent
392:10
455:9

ini 473:12

initial
552:3

initially
612:19

initiative
373:7
435:11
447:9
452:14
453:2
469:10
483:6
522:16,21
525:22
526:9
535:2
540:16,21,25 546:24
551:17
552:3
613:13

initiatives
380:19
382:4
384:6,17,19 391:21
455:9
468:25
470:4
471:21
472:4,13
474:9
477:3
481:2
547:11,13
552:14

inner 463:21

input 506:4
618:5
619:7

inserts
542:12

in-service
330:8,22,23 331:4
332:9,11
346:3
602:12

inside
409:15

insight
395:24
454:6,13
461:8
578:17

Insights
506:22

insignificant 450:12

install
452:17,24,25 606:9
607:2

installation
605:20

installed
401:6
447:23
452:4,22
453:16
544:21

installing
451:3,15,22 452:6,12
555:18

instance
498:23

instances
480:20

instead
447:10
502:20
516:25
586:9

Institute
398:8,9

insufficient
560:14

insulate
449:23

insulation
401:4
405:12
414:3
443:1
445:24
476:7
481:9
632:22

integrate
434:20

integrated
431:3,8,16,24 432:21
436:8
437:21
438:20
462:12
471:5
482:25
483:9
502:6

Integration
369:10,11,12,13,14,15,16,17,18,19,20,21,22

intend 625:6

intended
458:2
466:24
621:10

intends
530:21

intensities
413:7

intensity
412:19

intention

533:5
inter 452:11
interconnected 457:20 458:4
interconnections 332:4
interest 330:11,13 472:1
interested 451:2 452:12
interesting 482:15
interests 542:17
interim 407:10
intermittency 610:20
intermittent 610:17
internal 326:10 343:3,4,5,6,7,8,9,10,11 346:13,15,16 350:17,18,19,20,21,23,24 351:3,4,5,7 352:23,24,25 353:3,4,5,6,7,8,9,10,11,12 391:18 396:4,8 477:12 484:10 610:23
internally 331:6 477:14 492:6
international 380:24
interplays 535:20
interrogatories 523:14
Interrogatory 486:3
intervene 465:1 594:10
Intervenors 375:11 380:7 383:23 385:2 472:1 604:18
intervention 352:7,15 401:25 547:17
intimately 621:19
introduce 379:3 411:6 581:6
introduced 375:17 377:3 378:15 581:8 630:5
introduces 567:7
introducing 377:4 634:14
introduction 378:11
introductory 430:9
invaluable 399:4
inventories 577:18
invest 455:2 456:12 457:7 460:13,25
investigation 630:12
investment 432:19
involve 607:4
involved 384:11 421:3 451:4 474:22 476:22 516:15 540:24
involves 418:9
IR 351:18 593:3
IRR 331:3 334:8
irrespective 438:16 512:4
IRs 325:24
isI 375:5
isn't 389:25 444:11 451:16 480:9 555:4 557:3 565:22 582:19 583:9 593:16 594:24 632:14
isolated 412:15
issue 436:2 460:4 462:17 463:25 502:3 512:6 513:12 531:20 547:7 556:19,24 592:1,7 601:6 603:13 615:18 623:3 631:2
issued 488:24 489:2
issues 332:6 382:22 430:18,20 462:13 475:5 579:16 591:24 603:15 604:17 636:1
item 603:1
items 513:7
it'll 394:22 395:19 455:19 459:6 531:3 542:6 564:2,6,7
it's 392:1,4,8,11 393:17 395:19 396:6,7,10,16,25 397:18 400:11 407:19,24 408:12,13 409:2,20 411:14,23 412:2 414:16 422:2,15 426:12 427:16 431:14 432:8,21 433:14,23 434:23,24 435:12,17 436:15,18,25 437:3,16,19,21,24 438:9,20 439:10,23 441:15 442:7,10,13 443:9 444:6 445:16,20 446:6,17 448:20 449:14 451:14,17,20,24 452:4,5,6 453:22,23,24 454:11,22 455:9 456:18 458:20 459:12 461:13 462:10,15 470:18,19 475:25 476:5,22 477:16 478:1,12 479:19,25 482:25 483:23 484:12,13,25 489:7,14 491:5 492:1,19,20 493:25 494:11 495:3,5,6,19 497:23,24,25 498:16 499:22 500:4

502:7
504:15,19
505:20
508:17
509:23
510:22
512:12,15,17 513:16
514:2
515:25
517:19
519:22
521:14,17
522:3
523:3,23
524:3,5
525:19,22
528:25
531:12
533:5
534:16
537:15
538:3
539:11
540:18
542:23
543:18,19
544:6
546:25
547:20
548:3
549:7,14,20,21,23
550:3,14,15 551:3,8
557:14
559:4,9,25
561:22
564:17
568:6,22
570:10
576:5,8
578:25
579:10
580:7,20
581:5
582:6,19
583:5
584:1,2,3,4 588:14
589:6,15
592:3,15,17
593:2,3,5,10
594:2,22
595:23
596:12
597:11
599:9,16,19
601:12,13
604:21
606:18
608:7
611:12,13
613:18,19
614:11,25
616:10
618:19
619:9,20
627:19
631:16
632:11,17
633:14
635:1,24

IV 490:2

I've 377:12
387:9
431:15
436:5
441:9,19
449:13
450:25
451:3
462:25
463:23
481:9
501:13
510:2
519:4,12
524:17
594:17

J

Jan 351:25

January
351:17,19,22
352:5,8,11

JARED 488:25

Jersey 387:6

Jessica
322:18

466:22,23

JKDA
330:9,10,25

joined
616:21

joint 347:6
352:17

judgement
448:1,4

judgment
418:3
434:14
437:6
444:12
464:1,23
465:7
474:21
476:22
502:9
503:10

juggling
378:12

jump 466:24

jumping-off
408:11

June
324:18,20
489:3
531:5

jurisdiction
529:16
534:9
614:21

jurisdiction-by-jurisdiction 529:14

jurisdictions 505:15
529:7
533:24
534:2
536:6
615:4
622:10,20,23

justification 389:23

K

K19/C25/250
349:12

K19/C25/750
349:12

K19/gas/250
332:23

K19/Sales
332:7

Kapitany
321:14
378:8
405:1,10,18 409:11
422:14
423:4
474:7

Keeyask
328:22
345:17,18
347:6
485:15,21,22
486:6,8,9,13,14,15,17
490:18,23
602:22
603:7
624:16

Keeyask/Conawapa
332:19,20

Kessler
379:10

key 381:23
454:9
457:17

kids 511:8

kilowatt
428:6
479:18
480:2
494:20
532:19
549:11
563:1
565:23
591:11
633:7

Kleer 324:14
325:5,14

Knight
351:21

knowledge
399:3
422:1

known 381:9

KPMG 330:6

Kuczek 323:8
378:20,21
379:19
382:15,18
383:2,16
394:9,15,17 395:9
422:15,25
423:20
424:9
433:1,6,13
453:21
455:1
466:15
474:7,11
477:7,9,24
481:4
482:22
487:20
488:2,25
505:19
506:7
526:13
528:17
530:15
543:20
585:5
624:9
628:6
630:24
631:24
632:11
635:5

Kuczyk
388:21,24
430:16
467:10,13
630:3

Kuczyk's 429:18
Kuruluk 379:7
kV 505:20 597:2,3,4,6

L

la 452:5
label 598:25
lag 508:6 607:4
Lake 347:23 349:23
lamps 402:7,12,13,14 404:23
landscaping 452:7
lar 532:9 587:8 615:15
large 380:20 394:11 409:13 415:10 478:13 503:15 514:13 516:15 532:9 538:13 563:10 564:3,6 570:18,23 575:10,14 577:3 580:15 581:7 582:13,15 584:19 585:25 587:9 595:17 611:10 612:9 613:22
largely 586:20 615:14
larger 381:18 459:1 568:21 590:20 617:17
large-scale 386:19 610:1
largest 381:16,25 410:13,15 411:25 412:6 416:24 478:8 568:20 611:21 613:18,19
Larry 321:15 588:16
last 405:19 445:17 452:23 471:13 483:25 484:5 492:23 509:17,25 575:5,6,7,8,16 579:4,5 580:6 590:20 601:5 603:13
lately 524:10
later 400:1 435:14 436:17,23 444:18 446:12 513:19 558:6 605:9 615:11
latest 627:22
latter 497:13
launch 476:8
launched 473:24
launching 444:25
Lavigne 636:24
lawyer 516:4 592:23
LC 486:3
leader 386:12
leading 397:19
learnt 449:12
least 422:9 431:12 436:1 452:25 460:13 463:2 466:14 468:20 561:11 613:19 623:25 632:16
leave 325:12 535:1 584:24 613:8
leaving 553:24
led 381:14 387:2 465:3,6 468:18 473:10,14 528:5 553:7
legislation 484:1,18
legislators 418:19
legislatures 417:21
length 395:6
less 401:17 418:7 426:5 448:21 455:11,12,13 492:18 502:21 534:1 540:22 546:2 557:16 572:11,21 574:5 576:8 593:23 596:11 602:4 618:15 620:10 622:23
lessons 449:11
Lest 466:4
let's 465:20 500:4 502:17 513:11 529:7 534:23 541:10 550:18 556:3 559:22 584:17 585:3 596:23 606:8 609:24 615:6
letter 324:14,21 325:5,14,20 326:9,12 351:6,9,11,12,14,18,20,23 352:3,6,9,12,14,17,19 371:5,8,10
level 392:25 400:11 401:22 402:25 407:19 415:7 416:14 423:18 430:4,5 436:12 449:7 450:8 468:10,13 471:3,4,9,21 472:4 474:9 475:18 476:18,23 477:2 483:13,21 492:18 506:1 509:9 527:8 544:22 570:13 580:3 604:6 606:3 624:8,18,19 628:23 629:3 630:6,11,22,23 631:6,9
levelized 439:3,6,9 445:1,5 454:15,18 455:3 456:11 458:11,17
levels 328:25 400:4,10 414:12 415:20 435:6

445:19
450:10
471:15
474:23
508:7
624:13,21
625:15
628:17
629:15,25
630:4,19

liberty
506:12
529:25

license
347:23

life 334:12
449:25
498:20
542:1

lifespan
608:16

lifetime
411:10
607:24
608:2

light 387:4
388:21
397:22
457:2
578:14

lighting
414:5
465:3,6
468:18
473:3,10,13,14,15
475:13
528:12
535:14
617:14,18,23

lights
534:24
535:1,2
633:1

likelihood
492:25

likely 394:4
472:4
474:10
477:13
483:23
486:23
555:11
607:24

limit 400:17
401:8
420:19
566:2
611:23

limited
417:17
447:12,15
448:4
453:15

limits
611:14

line
329:12,14,16,18,20
335:24
336:4,6
337:13,15,17 349:21
391:23
416:12,16
582:12,14,19,21,23
585:10
588:3
593:22,24
595:3,4,8
597:3,4,12,24 600:2
609:17
629:2

linear 497:7
592:14
593:16,24

lined 481:11

lines 373:17
391:22
416:13
470:17
505:3
560:24
595:19
600:16

linked
482:25

list 323:3,4
324:1
325:1
326:1
327:1
328:1
329:1
330:1
331:1
332:1
333:1
334:1
335:1
336:1
337:1
338:1
339:1
340:1
341:1
342:1
343:1
344:1
345:1
346:1
347:1
348:1
349:1
350:1
351:1
352:1
353:1
354:1
355:1
356:1
357:1
358:1
359:1
360:1
361:1
362:1
363:1
364:1
365:1
366:1
367:1
368:1
369:1
370:1
371:1
372:1
408:20
410:17,21,23 411:3,9
425:6,7,8,10,11
558:20

listed
426:15
546:22

listen 594:8

literally
421:18

literature
609:25

little
378:12
388:20
417:15
446:12
456:23
463:24
531:20
534:25
556:14
572:13
573:21
574:19
578:17
580:18
586:11
588:10
592:7,25
613:12
623:16

live 450:1

living
538:12
539:13
586:17

Lloyd 323:8
378:19
379:19
382:18
383:2
388:24
394:9,15,17 395:9
397:8
422:25
423:20
424:9
430:16
433:1,6,13
453:21
455:1
467:13
474:11
477:7,9,24
481:4
482:22
487:20
488:2
505:19
630:24
632:11
635:5

LLP 352:10

lo 612:20

load
326:10,19
327:3
332:3
333:16
338:23,24,25
339:3,4,23
343:3,4,5,6,7,8,9,10,11,13,15,16,17,18,19,20
347:22
348:9,10
349:3,6
350:5,17,18,19,20,21,23,24
351:3,4,5,7
357:7,8,9,10,11,12,13,14,15,16,17,18,19,20,21,22,23,24,25
358:3,4,5,6,7,8,9
367:9,10,11,12,13,14,15,16,17,18,19
370:4
371:17
372:3

373:11
375:12
377:15,18
378:10
382:10,24
383:5
384:16
386:22
389:2,5,9,
20 390:11
391:3,10,1
5,17,24
392:3
393:4,9,14
394:4,11,1
2 396:5
399:13,22
408:13,14
420:18
422:17
423:7
437:22,24
457:24
458:8,9
469:16,17
470:6,9
471:22
478:11,12,
18
479:2,13,1
4,15,17,22
480:9,15
486:10
488:11,16,
20
489:5,8,9,
16,18,22
490:1
492:4,8
496:13,22
498:15,23
499:1,15,2
3 500:5,11
501:1,2,5,
9 502:20
503:1,6,13
504:4,7
505:23
512:7
517:16
524:19
525:2,11
528:10
530:2
531:4,16
533:6
536:21
538:6
554:22
557:3
566:15
567:14
568:8,14
571:20
572:7
579:6
580:16
582:11,14,
16 583:24
584:25
585:25
586:4,12,2
5 587:3,8
588:3,4,6,
9,13
589:2,3,8
590:14
591:10
597:17,18,
20 598:11
600:3
602:2,10
603:17
604:3
606:15
607:18,20
608:23
609:2,4,5,
11,12,14,1
7
610:5,11,1
2 611:5,25
612:2,6,14
,17,20
613:13
614:1,17
615:7,8,16
,22 616:13
618:6
619:24
620:9
621:10,11,
20,21
622:16,17
624:2,4
629:13,16
634:2,4

LoadMAP
399:12
615:23,25
616:6,16
617:6

loads 413:16
585:21
590:21
591:5
615:10

local 399:2
408:23
411:13
426:24
451:8

locally
499:19

locate
485:16

located
486:2
588:7

location
505:15
587:15

locations
588:2

Lois 323:9
378:23
379:20
383:20,23
428:19
482:19
489:2,20
490:7,15
494:22
495:11,19
496:1,4,12
504:12
505:1
506:3
519:4,8,12
,20,25
520:4,9,14
,24
521:10,17,
23 522:19
523:1,5,13
524:3,24
525:5,10,2
5
526:11,24
528:8
529:13
530:4
531:1,7,15
532:3
533:11
534:3
536:25
538:15
539:3
540:3
541:15
543:1,15
544:6
545:25
547:4,12
548:15,18
549:18
552:5
554:1,14
555:3,17
557:7,12,1
8,25
559:1,13,2
5 560:8,22
561:8,13,2
1,25
562:8,12
563:8,18
564:23
565:14,19
567:8,16
568:4
569:2,8,18
570:5,16
571:5,25
572:18
573:1,13
574:11,14
575:3
576:3,10
577:1,11
578:2,15
581:2,19
582:18
583:21
584:15,22
585:2,15,2
0 587:4
588:22
590:4,9,16
591:1,7,15
,21
628:3,14
629:1,3,7
630:3
631:23
634:12,24
635:16

long 344:17
430:6
467:14
489:13
532:6
608:24
609:13
616:24

longer
373:16
422:9
446:12
496:15
503:13
535:11
537:12,13
575:23
600:2,15
614:10
625:9

long-lived
607:23
608:14

long-term
444:15
535:22
583:20
584:9

loop 390:5

loops 453:10

Lorenz's
429:8

Los 387:4

loss 462:2
505:5
575:14
576:11
577:7,12
589:25
590:2
614:15

losses

345:10
373:15,18
504:23
505:1,2,7
590:21,22
591:4,5,16
,17 592:14
595:3,4,21
596:2,7,14
,17
597:1,5,8,
11,12,13,2
5 598:9,18
600:4,14,1
8 601:15
602:3

lost 464:19
589:6
601:24

lot 398:10
430:18
434:14
437:6
439:19
443:23
448:1
450:9
464:1,2,23
465:7
467:15
472:9
473:24
476:25
506:21
511:5,9
515:20
524:9
589:13
595:14
604:25
611:22
615:7
630:7

lots 500:7
617:3

Louis 379:10

low 421:6
442:23
450:13
456:12
492:18
517:23
532:7
557:10
564:3,9
597:1
609:4,11,1
4 611:14

low-cost
611:11

lower 391:7
412:18
426:9
430:6
452:18
455:15
456:2
460:6,23
480:4
492:24
495:6,10
502:13
508:8,11
518:5,6
527:8
534:2
554:23
596:5
597:5
609:2,17
612:2,12
621:17

lower-income
481:8

lowest 415:6
574:24
579:24

lumped
413:18
580:23

lunch
485:2,5

lunchbreak
485:3

M

Macro-economic
346:10

macro-environmental
366:15,16,
17,18,19,2
0,21,22,23
,24,25
367:3,4,5,
6

Macro-environmental
360:17,18,
19,20,21,2
2,23,24,25
361:3,4,5,
6,7,8,9,10
,11,12,13,
14,15,16,1
7,18,19,20
,21,22,23,
24,25
362:3,4,5,
6,7,8,9,10
,11,12,13

magnifying
602:15

magnitude
363:19,20
373:9
568:7,11
622:22

mailers
542:12

maintain
411:12

maintained
410:18

maintains
410:18

major 328:16
381:24
553:21
611:19

majority
381:17
384:4
385:10
404:8
489:15
509:1
541:6
555:10

Man 455:21

manage
612:15

management
331:13,15
333:5,6,7,
8,9,10
381:21
382:9
383:5,14
384:19
385:6
389:1,5
399:13
480:19

manager
378:18,24
379:1,5,7,
9,11 380:9
383:24
384:8
385:4,12

managing
386:19

mandate
420:7

Manitoba
321:3,7,9,
23 322:5
323:6
324:21,22
325:20,23
326:9,12,1
5 350:3
351:6,11,1
2,14,18,20
,23 362:20
363:25
371:10,15,
17 372:7
373:3,8,12
,20
374:3,8
375:10,12,
14,19
378:2
379:13,17
380:4,13,1
6,17,22
381:4,6,15
,17,22
382:3,14
383:3,4,19
384:2,3,12
,15,18
385:8,9
386:6
387:7
389:9
390:12,20
391:5
397:14
398:2
399:2
403:21
404:24
405:3,11
406:1
407:3,14,1
5 408:8,22
410:20
411:22
416:6
418:1,13
424:24
425:2,7,14
,15,18,23
426:22,25
427:3,7,18
428:25
429:8
431:4,9,18
435:17
436:7,14
437:25
438:2
443:4
446:3
447:3
448:10
451:2,9
454:1,8
455:2
456:16
457:10
460:2
462:19
466:7,11,1
9 470:22
482:25
484:4
486:4
487:16,17
488:7,10,1

5
489:5,23,24 490:4
491:22
492:5,7,23
493:23
494:13,21,24 495:14
496:9
497:15
498:12
499:9,18
504:6
505:12,16
506:2,7,23,24 507:5
508:1,23
509:8
510:15
511:13
512:15
514:16
515:1
517:14
518:13
520:10
521:8
523:8,17
525:18
527:15
528:23
530:9,12,21 531:24
532:1,3,13
533:23
534:1,13,18 535:6
536:9
540:17
542:22
543:9,11
544:4,14
545:21
548:4,20
550:17
551:7,12
552:15
554:6
556:25
558:14
560:2
561:2
562:1
563:12,20
564:19
565:17
566:24
568:10
569:16
570:21
576:23
578:5,22
579:7,12
580:15,21
584:20
587:19
588:6
590:24
591:2
595:12
597:17,20
598:15
599:24
600:4,10
601:7,23
602:22,23
603:17,22
604:2,18,24
605:11,21
606:6,7,13,23 607:19
608:3,8
610:6
614:11,20
615:8,10
616:14
618:9,16,18 619:7
620:8,11
621:5
622:8
625:25
627:3,14,19,21,25
631:7,21
633:24
634:2
635:19

Manitobans
438:20
487:19
493:20,24

Manitoba's
381:19,24
382:8
415:2
514:12
611:1

manner 498:1
596:8

manners
382:22

manufacturing 410:8,9

map 397:21
419:16
565:13

mar 401:22
445:10

March 321:24
484:3,13,17 531:18

margin
431:18
433:3
434:13
447:5
468:12
475:18

marginal
345:20,21,22 347:8
431:17
432:2,23,25 433:1
435:18
436:7
441:4,12
442:11
444:18
445:11
454:1
455:4,10
461:13
468:9
477:19,20,21,24
478:2,5,6
479:4
480:3,20,22 483:5

Marilyn
321:14
405:1,10,18 409:11
422:14
423:4
474:7

marked
377:15
388:23
466:7

market
327:5,12,14,16,17,18,19,20
329:6
348:17,18,19 356:25
379:11
381:5
383:11
386:15,24
389:12,15
390:12,15,17 395:22
396:3,5,14,25
397:20,24
399:1
400:14,20
401:23,25
402:1,16,20,21 403:5
404:11,20,25 406:10
407:7,12,16,20,24
409:7,9,24,25
414:17,23
416:2,19
422:1
425:18
428:25
442:24
443:16,17,20
444:2,21,23
448:16,22
451:14,15
461:14,19,21
462:1,5,6
469:21,24
470:3
472:10
504:9,21
532:8
534:18
536:9
539:6
568:20,23
569:14,20
570:15
572:12,21
573:7,12,14,17,18
574:1,19,24 576:7
579:2
583:18
587:6
588:1,7
611:20
620:16
629:23
630:9,14,17

market-attainable
398:23

marketed
400:11

marketing
378:25
379:7
383:25
384:10
391:21
437:19
463:10

marketplace
395:25
396:9
443:23
444:7,16
453:17
464:7,25
465:1,4,10
530:9
532:4,6,22
534:14
563:12

markets
333:19,20
335:21
337:10
384:20

574:7
587:13

market's
442:21

Markowsky
379:12

Marla 322:6
323:13
377:4,10
378:6,8
379:25
380:1,5
382:15,25
383:15
384:21
385:25
386:4,8
387:14
388:20
429:17
465:14,19
467:12
484:21
485:12
533:18
550:5
551:1,10
565:1,4

married
511:7

mass 327:5
389:12
390:17
504:9,21
568:20,22
569:14,20
570:15
572:12,21
573:7,12,14,17
574:1,6,19,24 576:6
583:17
587:6
611:19

matches
579:6

material
485:16
551:4

558:10

math
459:1,6,13,22 516:4
524:21
546:24
547:3,4
554:20
555:4
594:16

mathematical
515:6

mathematically 510:21
516:24

mathematics
513:2

maths 515:23

matter
427:19
432:11
437:23
502:2
503:6

matters
371:9
375:16
432:22
466:25
528:4
555:2
636:8

mature
451:14,15

maximize
440:9

may
324:8,10,12,13,16
378:14
402:23
406:11
410:5
412:23,24
418:5,6,20
419:5,7,10
421:9,16,19,23
435:19

442:6
445:6,18
449:15,16
461:3
509:19
531:23
535:9,16,17,22
536:4,6
554:8
563:24
564:3,5
566:9
581:17
586:17,22
588:12
595:16
612:19
635:14
636:4

maybe 423:2
449:24
473:4
501:22
543:1
584:1,4
594:2
633:13

MBA 383:7
385:7

mean 404:16
416:6
445:18
454:8
488:9
493:4
498:10
509:19
536:1
548:12,24
563:3
586:14,16,19 602:21
620:10
631:16

meaning
410:11
478:23
559:21
570:19
615:1

meaningful
515:18

meaningless
516:19,22,23

means 425:16
436:23
464:9
487:2
490:10
491:19
494:17
495:23
516:11
523:3
528:22
561:6,10
594:24
595:1
602:11
627:14
631:8

meant 474:13

measurable
441:22

measure
401:10
402:6
406:4
410:16,21
411:3,5,8
414:24
421:24
424:2
425:6,7,8,25
427:5,17,24
428:8,9,13
430:5
432:12
439:12
441:11,15
442:8
446:18
454:9,22
462:21
482:16
534:24
536:2
605:23

measured
436:17
442:1
468:12

measures
382:13
401:3,5,11,14,20
403:8
406:9
408:18,20,21 409:6
410:17,22,24 411:1
413:23,24
414:2,3,10,25 421:25
424:23,24
425:1,2,3,9,11,14,17,21,24
426:3,23
428:21
429:6
430:4,8,12
443:13
446:7
447:24
455:7
464:3
482:9
534:21
535:24
536:4
547:8

measuring
432:22

mechanical
380:14
594:8

mechanism
404:24
419:12
421:9

meet 420:3
487:18
488:15
492:3,7
601:22

meeting
415:12
500:19

meets 543:7
595:13

member
321:14,15,16,17
383:9
451:6
485:13,19
539:18

members
375:9
378:7
380:6
382:19
383:22
385:2

memory 491:8
531:2

mention
413:10

mentioned
417:11
422:16
426:14
432:9
437:9
439:1
441:2,7
445:21
449:13
450:4
453:23
455:25
456:4
463:25
464:13
469:3
475:20
483:20
499:14
512:25
524:9
526:7
529:17
534:11
540:6
541:6,16
552:5,10
555:12
581:7
589:10
611:22
612:22
628:6

mentioning
436:19
624:10

Merci 388:16

messaging
541:22

Messr
388:14,16

met 403:3
418:11
491:24
492:2

metal 590:2

metering
384:9

meth 427:18

method
417:25
419:1,7
499:16
585:13

methodologies 389:21

methodology
330:12
496:22
618:3

methods
390:2
418:25

metric
453:23,25
461:22
463:13

metrics
420:19
434:17
438:2,7,10
439:9,21
440:5,21
442:13,14
443:12
454:2,5

MH 327:10

MH-87 372:3
377:18

M-hm 519:8
543:15
619:1,5
632:2

MH's 348:14

Michael
322:16,21
388:4

microphone
375:7

middle
572:9,15

mid-efficiency
527:5

midnight
613:13

Miller
322:11

million
458:13
459:8
486:12,16

mind 403:20
407:1
441:16
447:1
477:23
482:12
526:6
588:15
596:3
633:12

mindful
429:18

minds 414:18

minimal
535:17

minimum
493:19
528:10
592:10

Minister
484:4

Minnesota-Manitoba
329:11,13,15,17,19
335:23
336:3,5
337:12,14,16 349:20

minor 504:10

minus 596:20

minuses
393:5

minute
485:17
528:20
553:20
635:1

minutes
429:20
430:17
465:18
484:25
485:1
556:4

MIPUG 322:13
352:3
388:1
585:22,23

miscellaneous
413:4,11,19 621:23
622:5

miserable
562:7

misleading
463:15,20
582:21

MISO
327:6,7,8,9,12,14,16,17,18,19,20 329:6,8
333:14
340:8
341:6
348:11,13,15,16,17,18,19,20,21,22
364:19,20,21,22,23
365:9,10,11 614:25
615:4

misspoke
572:8

mitigation
328:15
345:7

MKO 322:15
352:6,14
371:5
388:5

MMF 322:18
352:12
372:8
388:7
467:4,6

MMF-28 372:8
467:6

mobility
587:16,22,24
588:11,12

model 389:25
408:9
435:21
452:14
453:12
478:3
537:11,12,13,14
538:2
553:5
559:5,6,8
564:1
566:4
615:23
622:17

modelling
386:23
406:12
421:18

models
387:11
390:2
537:21,25
571:14

modification s 471:20
modified 436:17,19 438:24 439:1,24 441:3
moment 465:17 488:8 599:17 622:14
momentum 601:1 607:14
Monday 631:15
money 449:24
monitor 390:6,9
monitoring 436:6 437:7
Monnin 322:20 388:15,16
month 470:2 559:23,24 560:1 563:21,22, 24 564:2,7 566:21
monthly 328:10 561:3
months 530:25 559:17 560:14,18 563:23 566:5,16,1 9
morning 375:3,5,8, 9,10 377:2,13 378:4,7,9 380:6 382:18,20 383:20,22 385:1 429:20,21 478:4 487:17 506:7 526:8 528:5,18 569:4 585:4,18 597:16 615:11 620:3,15 622:8 624:10 633:25 636:1,15
Morrison 323:9 378:24 379:20 383:17,20, 24 384:22 428:19 482:19 483:17 489:2,20 490:7,15 494:22 495:11,19 496:1,4,12 504:12 505:1 506:3 518:20 519:3,4,8, 12,20,25 520:4,9,14 ,24 521:10,17, 23 522:19 523:1,5,13 524:3,24 525:5,10,2 5 526:11,24 528:8,21 529:13 530:4 531:1,7,15 532:3 533:11 534:3,16 536:11,24, 25 538:15 539:3 540:3,21 541:15 543:1,15 544:6 545:25 547:4,9,12 548:3,15,1 8 549:18 550:14 551:20 552:5 554:1,14 555:3,17 557:7,12,1 8,25 558:19 559:1,13,2 5 560:8,22 561:8,13,2 1,25 562:8,12 563:8,18 564:22,23 565:14,19 567:8,16 568:4 569:2,8,18 570:5,16 571:5,25 572:18 573:1,13 574:11,14 575:3 576:3,10 577:1,3,11 578:2,15 581:2,19 582:18 583:21 584:15,22 585:2,15,2 0 587:4 588:22 589:22 590:4,9,16 591:1,7,15 ,21 628:3,14 629:1,3,7 630:3 631:23 634:12,24 635:16
motion 325:11,15, 21,23
motors 527:4
move 395:1,20 403:13 404:6 408:1 448:20 449:21 450:19 456:8 465:12 474:8 511:8 538:13 539:10 546:15 586:6 587:15 603:12 607:3 633:15
moved 384:7 385:11 465:10 475:4 560:17
movement 585:7 586:18
moves 603:8
moving 407:8 408:2 450:1 527:6 577:22 578:7
mud 452:3
multi 555:12
multi-attached 538:19
multiplier 593:15
multiply 549:6
multiplying 549:12
MW 332:23 349:12

N

narrowly 400:7
Nation 452:9,10
national 380:24 398:6,7
Nations 347:10,16, 17,18 350:7
natural 327:11,13 332:21,22 381:1 384:13 443:18 464:7 469:7,13 481:16 523:23 527:22 537:8 538:18 542:8 544:18 558:3 609:12 633:9
natural-gas-heated 527:20
naturally 399:21 417:3 472:19 620:22 621:1
nature 392:10

623:10

necessarily
389:25
411:4
440:16
444:24
472:11
537:1
566:7
581:9
623:1

necessary
534:4
602:23,24

negative
454:8
460:22

negotiation
418:9
420:25

neighbourhood 433:11

neighbouring
418:21

Nelson
349:24
596:24

net 328:13
334:5
347:9
385:22
427:6,7
437:24
463:21
464:10
498:7
528:7
535:15,19
553:8

Nevada
419:19

newer 508:9

NFAT 324:6
325:8,21
332:17,18
489:4,23
491:4
494:24
495:3,14
497:16
498:6
499:4
508:23
509:1
519:16
523:4
531:13
619:4
627:1

niche 553:25

night
614:11,15,16

nine 456:21
476:24
509:24
510:3,7,9,18 512:21
513:4
515:11
516:10,24,25 517:3
552:24
610:13
636:15

nineteen
562:5

no-cost
611:11

nominee
507:23
514:8,14
517:21,23
518:7

non 401:4
468:11
520:16

non-cust
460:14

non-energy
438:25
441:23

non-engineers
594:11

non-gas-available
429:14

non-gassable
540:10

non-participating
460:7,18

noon 484:25

norm 535:12

normal
478:25
497:23

normalized
556:25

normally
535:13
538:1
546:20

North
387:3,18
391:1,4,12
397:21
398:4
400:10
402:8
403:23
419:20
425:1
531:22

no-sale
603:7
631:16

note 484:25
629:7

noted 523:6
559:14
589:11

notes 548:16

nothing
474:25
636:11

notice 324:8
325:11,15
448:13

November
326:18
351:8
619:4

NPV
335:6,8,9
338:12,13,14,15
344:21,24
370:6
439:13

nuance 555:4

nuances
546:13

number's
455:15
514:11
521:13

Numeral
490:2

numerical
579:23

numerous
608:23

O

objection
388:4,6

objections
387:19,25
388:2,17
407:4

objective
392:19
407:5
443:12

objectives
397:12
407:1
462:24

obs 537:11

observation
463:12

obtain 570:9

obtained
401:24

obtains
506:8

obvious
534:23
599:16

obviously
502:1
517:23
526:10
593:14

occur 394:18
505:2
563:24
604:25
613:9
633:20

occurred
580:3

occurring
399:21
417:3
566:21
577:3
620:22
621:1

o'clock
636:15

October
326:4,6,8,11,14,16
561:23

odd 378:14

offer 393:8
429:9,11
448:3
449:16
450:24
461:2
463:3
476:9
477:17
481:11

offered
446:1,3,20
450:8
468:7
469:11
476:10
481:18

offering
436:25
437:1

445:18
446:5,14,17 470:17
472:17

offers
416:24

offhand
480:13

office 410:6
483:16,18

official
391:25

off-peak
329:7
345:11

offset
460:24

offsets
416:18,20
609:15

oh 394:15
433:6
478:3
491:7
502:15
516:5,6
599:5
616:19
621:5
631:11

oil 520:8
611:13

okay 388:24
397:19
401:21
406:6,20
413:20
415:15
417:15
424:6,10
429:16
430:15
441:15
465:12,20,21 466:21
476:3
482:23
486:17
501:25
502:15
504:2
506:11,17
507:4
512:5
531:6
543:8
546:25
553:12
556:9
560:25
562:9
564:14,25
569:3
572:1
573:1
576:15
579:15
585:3
590:12
591:19
593:4,17
594:9
597:15
599:3,11
615:17
619:12
622:7,12
629:6
631:13
636:13

Olanguju
366:14

old 481:18
624:7

older 511:8

Olthuis
324:14
325:5,14

ones 393:3
407:13
426:5
468:8
493:4
503:14
504:11
528:17
597:13
626:17
634:20

one-third
576:5,6,13

ongoing
422:3
501:9
578:8

On-peak
329:7

onto 442:11

opening
372:6
466:6,10

operate
527:8,9
535:11

operating
589:16
611:23

operation
345:24
478:23
500:16
501:5

operational
429:5

operations
349:23
524:11
545:13,14
577:15,17
587:15

opim 577:16

opinion
442:18

oppor 444:4

opportune
465:17

opportunities 382:9
396:19
398:25
399:1
431:12
432:3
433:18
434:9
435:2,5
436:1,3,9,16
438:17,19
440:7
445:7
454:19
455:10
462:8
464:21
467:21
469:14
470:9,10
472:9
473:9
474:2,3,12
475:6
477:1
528:16
543:24
546:19
611:2,3,5
633:13
635:9

opportunity
441:14
442:20
443:6
445:7
448:8,16
460:25
464:25
473:21
483:2
546:16
590:19
603:23
628:1

opposed
424:7
430:5
442:17
450:3
459:3
461:18
473:19
475:14
476:5
481:20
493:10
501:10
532:13,17
538:9
573:5
600:2
612:14
632:18

opposite
574:21

optimal
431:6

optimization
605:22

optimized
577:15,17

optimum
440:16
445:17

option 332:5
400:19
401:1
428:2
432:13,16
451:24
458:24
459:14
471:19
474:17
475:18
610:19
624:18,19,22,23
625:1,2,3
628:16

options
362:21,23,24 408:17
431:5
433:24
434:5,22,23 435:23
444:3
457:19,22
458:6
460:16
461:10
464:17
467:18,19
468:22
475:8
476:13
554:3
587:13
607:23
624:9
625:12
628:5,19

634:13

orange
448:24
450:20
582:12

order
324:3,17,24 325:3,6
326:3,5,7
373:9
480:1
537:6
560:10
568:7,11
577:19
614:15

organi
524:11

orient
446:10

Orle 322:15

others 380:7
381:2
382:19
383:23
385:3
453:23
463:22

otherwise
381:9
430:8,13
448:6
577:23

ours 442:9

outcome
460:17
474:24
475:16
536:15
571:13

outlier
563:4

outline
380:2
382:16
383:1,17
384:23
559:15

outlined
400:5
528:11
560:23
626:22

outlines
559:3

outlook
339:5
347:5
507:5,9
509:7

output
490:18,23

outside
398:5
404:24
409:15
416:6
511:10
546:20

outstanding
466:25

overall
389:15
390:12
448:13
517:16
528:2
539:9
554:22
555:16,20
565:20
566:14
571:10
573:11
575:7,16
581:10
583:6
596:18
603:6

overshadowed
537:22

overstating
617:7,25

overview
397:12
406:21
504:16

540:20

ownership
538:8

P

p.m 485:10
556:6,7
636:19

package
433:19,22
434:8,17
435:13
468:20
469:15
470:16

packages
470:23

page
323:2,10
324:2
325:2
326:2
327:2
328:2
329:2
330:2
331:2
332:2
333:2
334:2
335:2
336:2
337:2
338:2
339:2
340:2
341:2
342:2
343:2
344:2
345:2
346:2
347:2
348:2
349:2
350:2
351:2
352:2
353:2
354:2
355:2
356:2
357:2
358:2
359:2
360:2
361:2
362:2
363:2
364:2
365:2
366:2
367:2
368:2
369:2
370:2
371:2
372:2
373:2,4
374:2,4
378:25
379:21
384:23
385:1,3,25
424:14
456:15
490:2
491:4
495:3
499:5
504:15
506:9,14,19
507:2,7,16,19
508:15,24
509:5,12
510:8,20
511:16
512:9,11,14,22
513:1,14
514:1,4,10
515:3,21
516:5,14
517:8,18
518:4,12,18,23
519:15
521:5
525:10,18
526:18
527:14
540:19,23
546:21
547:24
550:12
551:13
552:10,12
553:18
554:20
558:23
559:2,7,15
560:23
561:1,15
562:22
568:17
570:10
572:6,8,9,15 574:23
576:1,20
582:10
589:20
590:25
594:7
598:4
626:23
627:4,17
628:9
629:14
631:20

pages 321:25
495:3
519:5

paid 432:17
458:18,22

panel 323:6
371:18
375:10,20
377:5,15
378:2,10,13
379:14,17
385:23
462:11
466:13
478:1
483:17
485:2,5
487:1
493:22
494:2
496:25
533:7
555:25
591:24
600:23

601:3
603:1,2,14
608:22
623:15
625:9
630:25
631:2
636:3,17

panels 606:9

paper
375:21,22
543:18
547:9

Par 626:10

pardon
485:22
493:8
501:2
565:3

parity
604:13,25
605:8
606:22
607:5,14

Park 362:14

participant
380:23
439:16

participate
419:3
448:6,7,18
449:5,18
451:11
481:7

participated
446:11
447:2
450:22

participating 383:13
432:20
440:13
455:17
460:5,15,23

participation 446:16
448:11
449:8
450:9,12,15 465:5
472:19
474:23

particular
389:24
395:8,13
396:19
402:11
415:19
435:11
445:7
447:19
448:16
462:21
464:25
469:9
482:15
515:13
535:21
557:10
586:13
601:2,6
611:9
617:8
622:9
631:19

particularly
411:14
412:22
507:22
535:4
544:19
579:3
588:3
614:10

parties
371:8
377:2

Partners
387:1
616:17,21

partnership
340:14
345:17

party 396:1

pass 401:15

passed
426:15
435:13
496:14
546:8
592:24

passes
545:23

past 386:25
390:6,8
392:4
393:22
438:4
507:9
510:13
560:3,9
561:4
574:18
575:2
578:6
581:10,13,25 584:13
589:11
632:19
634:15

path 403:7
451:25
470:14

paths 458:14

pathway
485:21

pathways
485:20

pattern
415:22

patterns
538:5,6,23

Patti 322:5

Paupanakis
325:17

PAUSE 388:10
397:6
405:6
406:18
422:23
423:11
427:11,21
428:17
453:19
454:25
474:5
491:1
494:5
496:18
499:12
508:20
518:9
519:10
521:1
524:14
525:8
526:3
529:11
533:1,16
539:1
540:1
541:13
548:10
550:8,21
553:15
555:22
556:16
557:23
558:25
559:11
560:6,20
562:14,18
563:16
567:3,24
571:3
572:3,25
576:17
591:13
593:8
602:6
604:9
613:15
616:3
619:14
628:12
629:18
632:9
634:10
635:3

pay
432:14,17
442:25
443:5
445:8,15
455:18
456:1,2
458:20
460:25
480:5
481:8
544:9,21
545:1,18
546:4

payback
439:18
451:16

paying
432:11
445:21
534:2
607:8

Payments
330:20
346:24,25
347:3

pays 427:15
429:12
438:16
545:17
546:6

PDP 345:7

peak 328:24
348:13
488:11
494:1,3,8,16 495:9
586:8
610:15
611:21
613:7
614:21
615:8,10

peaking
614:25
615:4

peaky 480:11

Peguis
452:10
474:1

pellet 520:8
553:24

penetration
522:6
539:8
540:4
573:3

penetrations
539:6

people
405:12
409:14
428:9
431:24
432:10
433:21
434:22
438:9
439:13
441:10
447:22
449:17,25
450:1,3
455:1
457:16
458:18
461:14
481:11,14
506:21
509:18
510:15
511:2,6,7,8,10
512:3,21
514:15
520:16
538:12
539:13
541:21
544:12
555:8,16
605:15,16
612:19

per
373:10,14
390:22
412:19
420:17
422:20
453:1
479:18
490:19
509:18,19
511:1,2,10
512:3,21
526:20
546:18
549:11,19
550:25
551:24
554:24
568:8,13
577:6
580:8
591:11
598:10,18
600:13

perceive
531:25

percent
381:19
390:11,14,18,22
391:18,24
392:1,7,20
412:4,8
413:11,24
414:16
415:5,18,23,24 416:3
419:23
420:17,22
422:17,18,20 442:10
482:10
504:19,20,21,23
514:6,11
522:1,2
525:20,23
526:1,21
528:4,8
548:2,6
549:3,8
550:19
551:9
571:18,20,21,22
572:11,12
573:17,18,19,20
574:5
575:17
576:2
580:8
590:24
591:4,5
596:2,17,20
601:16,21,23 613:23
633:9,10

percentage
414:15
418:18
504:17
549:16
550:16
595:23
611:4
632:5

percentages
633:3

perfect
402:22

perfectly
593:16

perform
411:5
566:24

performance
380:25
381:8
528:11

performing
398:24

perhaps
406:8
533:25
551:1
592:6,25
598:3
602:11
626:18
635:11

period
334:11
348:13
383:6
422:12
439:19
446:8
448:4,9,14,23 449:15
451:16
470:2
472:17
495:8
496:8,10,16,23
497:5,13,21,23 498:7
504:3
532:6
535:11
539:20
563:13
575:13,23
577:11
580:7,18,19
582:1,2,6,7,8 598:17
612:4
613:23
614:7
632:1,16

periodically
422:7
479:11

periods
392:15
511:17
575:24
613:7

permitting
605:16

pers 487:3

person
481:24
487:3
598:23
599:2

perspective
389:8
399:5
416:11
435:24
438:8,13,15,21
439:8,14,18 440:2
446:22
461:4,22
463:5
464:16
474:20
495:14
504:14
537:19
542:1,21,23 543:25
554:13
583:20
584:21
590:23
629:13

perspectives
438:11

pertains
504:24

pertinent
592:3

Peter 322:11

Peters 322:2

petroleum
590:8,11,14

phase 606:24

Philippe
603:24
604:12

Philips
473:17

photo 603:19
604:1

photovoltaic
603:19
604:1

physically
531:15
588:6

pick 516:17
564:2
566:7

picked
395:8,11

picking
566:4

picks 564:2

picture
419:15

pie 413:8
569:4
620:17

piece 486:2

pieces
516:18

Piesold
351:22

358:22
Pilek 379:8
pilot 469:18
pilots 473:4
Pimicikamak
324:19
325:11
pink 450:10
pipe 586:3
pipeline
393:6
394:20,22
585:5,11,21 586:4
pipelines
394:21
587:25
588:2
plan 321:10
345:21,22
362:16,17
364:4
395:12
403:10
431:3,6,13,21,23
433:20
434:3,19
435:11
436:10
444:15
455:14
471:14,17
473:5,6,8
478:16,17,19 483:19
484:2,6,8,9,14,15,19
486:6,7,12,13 488:8
493:8
502:17,18,19,22,23,25 503:1
598:6,15
599:13
609:14
624:7,11,12,16,17,21
625:15
627:22
628:18
631:24
632:18
634:13
planning
353:13,14,15,16,17,18,19,20,21,22,23,24,25
354:3,4,5,6 378:23
379:1,8
385:4,11,15
386:2,12,17,22 387:9
393:24
394:2
397:24
399:13
407:3
422:4,7,12
431:9,17,24,25
433:21
434:21
435:13
437:21
452:24,25
462:12
468:2
471:6
484:10
496:15,16
497:24
531:2
533:8
628:20
631:25
plans
354:23,24,25
355:3,4,5,6,7,8,9,10,11,12
374:4,6
389:6
403:14
485:20
486:5
493:18
503:6,8,13
575:21
581:3,4
597:24
598:2
600:1
607:22
609:12
624:17
626:7,13,22,25
627:4,8
play 587:17
633:17
please 377:9
379:15
380:2
382:16,25
383:17
384:23
386:8
388:22
465:21
467:4
494:1
496:21
504:24
519:13
540:21
626:11
631:4
pleased
378:9
PLIL
580:15,23
581:8,13,14
plug 413:16
plus 381:23
393:6
441:7
475:6
483:25
596:19
614:14
plus/minus
392:20
pluses 393:5
po 401:19
point
393:17,23
405:19
408:11
423:3
424:11
426:4,11
432:6
433:8,9,12,13 444:10
445:17,20
446:15
448:12
449:6,7,8
450:15
455:4
456:9,21,22 459:6
460:4
461:12
462:13
463:17
471:13
477:12
480:8
488:10
498:16
503:7
505:7
509:22,24
510:3,5,6,7,9,18
512:20
513:4
514:21
515:11,12,13,14
516:10,24,25 517:3
530:7
533:21
534:4,10
541:2
552:11,12
557:15,16
577:22
578:6,12
579:24
597:19
607:6,9,14
610:12,13
612:7,9,10
614:9
625:11
627:22
630:21
632:1,14,24
Pointe
607:25
pointed
530:15
points
493:14
497:10
527:13
560:14
612:11
policies
546:12
policy
382:22
543:25
606:12
pop 569:21
popular
419:24
population
326:20
385:24
390:15,19
424:12,15
506:1,4,8
507:17
509:9,13,16
511:3,4,11,22
512:1,4
513:8,12,16,20,21
514:6,12,24 516:16
517:15
521:25
522:11
525:13
538:7
552:22
569:16,22
570:8,13,21 573:5
574:7
Portage

321:22
481:12

portfolio
430:4,6

portion
380:3
383:19
460:25
513:14
514:13

pose 427:4

posed 543:2

position
380:8
383:24
385:4
459:15
579:12
617:25
630:21
632:3

positively
585:4

possibilitie s 609:5

possibility
547:14
563:22

possible
411:4
485:7
503:20
560:10

possibly
393:3,8
440:10,14
457:3
481:21
547:17

post-2047
501:1
502:20

potential
382:13
386:5,16
387:3,9,18
394:11
395:22
396:3,5,14 ,25 397:20
398:1,13,1 9 399:24
400:2,4,13 ,16,17,18
401:7,8,9, 16,19,23
402:16,19, 20 403:1,5
404:11,20, 25 408:11
409:2,8,10
413:20
414:12,17, 19
415:2,4,8, 17,21,23,2 4
416:2,14,1 6,17,19
417:2,8
420:11
422:21
424:23
425:18
426:11
469:11
470:8
472:10
516:9
549:17
580:15
581:7
582:13,15
583:23
585:6,25
603:18
604:7,19,2 2 605:25
608:12
615:21
616:22
617:11,14
619:25
620:7,10
621:16,24
629:23,24
630:2
631:22
632:7

potentially
427:7
444:5
471:10
493:11

potentials
621:9

pow 624:11

power 327:24
345:13,16, 21,22
348:3,21
349:8,10,1 7 350:3
379:8
380:19
382:3,4,14
384:5
387:5
395:12
398:8
413:17
429:11,12
433:20
471:14
478:16
500:20
596:24
607:6,24
627:22
628:18

PowerPoint
372:5
377:23
466:6,9

practical
434:24

practicality
411:7

practice
386:12
400:3,9
408:24
422:9
426:7
434:23
435:9

pre 617:6

precision
515:20
517:15,17

predicting
537:12

predicts
565:18

prefer
400:12
429:20

preference
402:2,5
404:21

preferred
321:10
395:10
402:9
419:1
488:7
598:15
599:12
609:14
624:7,16
625:15

prefers
485:2

prehearing
324:9,11,1 5 325:8

pre-hearing
351:24

preliminary
425:7
496:25
508:16
623:24

premise
510:23

preparation
386:5

prepare
508:23
602:15

prepared
371:20
376:5,8
388:25
484:5
488:21
496:13
512:13
615:22
636:3,6

prepares
488:16
507:5

preparing
615:20
616:13
622:19

prepay 545:7

pres 498:18

present
347:9
378:9
380:7
382:19
383:23
385:3,22
397:4
498:7

presentation
372:3,5
374:5
375:12,15
377:6,11,1 4,18 378:3
388:22,25
389:1
396:24
397:1
422:16
423:2
427:25
428:4
429:8,19,2 2
466:6,9,20
487:15,17
528:18
530:16
622:8
623:5,17
626:23
627:6

presentation s 622:15

presented
403:8
552:8
629:8

presenting
454:17
607:22
625:5

president
371:15
378:20
382:20
388:17

Press 514:3

pressure
421:6

pretty
390:13
416:21
521:15
562:6

prevents
617:6

previous
450:3
525:2
559:16
560:13

previously
323:12
327:25
379:23
385:17
387:1
571:10

price 330:5
334:14,15
338:8,9,10
341:7,9,11
,12 346:18
348:8,11,1
4 393:19
395:4
421:8
473:16,20
477:21,22
528:20
529:2,15,2
1 530:17
531:20,22
533:23,25
534:5,8,22
535:23
536:7,9,13
,19,22
537:1,3,6,
16,21,23
607:7
620:23

prices
327:14
334:16,17,
18,19
340:17,18
341:4
344:9,10
348:13,21
370:8,10
444:23
529:6
605:1,6
624:4

pricing
340:22,24
341:5
342:23

primarily
388:25
397:17
410:9
505:10
532:14
541:2,18
563:13
577:6
580:14
619:10

primary
389:13
390:15,19
462:21
487:18,24
505:25
506:4
588:12
589:14,17
590:2
612:19

principal
586:13

principles
457:17
502:5

prior 381:13
424:5
459:4
486:8
531:5,8
537:3,19
576:12
579:6

priority
482:6

pro 407:1
453:25
508:25

prob 477:10

Probabilisti c 335:14

probably
392:22
423:21
437:1
447:21
463:17
476:11
498:18
502:19
554:10
578:16
581:16
582:24
592:4
600:22
608:18
613:11
615:14
620:24

problem
481:4
491:8
614:5

proc 431:8
484:10

proceed
379:15

proceeding
382:17
384:12
387:17
466:15

proceedings
466:2
556:10

process
375:6
398:15
399:5
406:15
407:2,3
408:13,19
410:25
411:7,20
414:22
418:12
421:2
425:5,9
426:1
431:9,25
432:1
434:7
435:17
436:6,8
437:21
462:13
482:24
483:1,9,15
,25 505:5
531:16,18

processes
484:10
618:11

produce
491:20
500:7
560:15

produced
424:15
558:21

production
478:23
501:4
503:2

products
553:25

profes
380:15

professional
380:15
506:20

profiles
407:16

proging
444:11

program
386:16
397:24
402:22
403:10,14
405:22
406:7,10,1
6 407:3,15
422:4
429:11,12
435:4
440:4,7,15
443:2,3,4
444:13
445:9,18,2
4 446:5,14
447:2,18
449:1,9,13
452:13
454:6,9,11
,12
455:8,14
456:1,4,7
462:23
464:14,21
467:23
468:4,11
469:11,23
473:23
475:23
476:7,8,18
481:8,11,1
3,14
507:23
514:8,14
517:21,23
518:2,7
522:8,18
526:12
548:2
605:22,23
616:8
630:7,8

programmable
401:4

programming
380:21
382:10,12,
14 437:5
444:11
463:5

464:8,12
528:15

programs
379:7
399:18
403:7
406:1,2,9
408:6
414:20
417:7
421:23
435:15,16
437:1,14,19,23
440:13
444:25
445:4
455:20
464:13
467:21
468:7,15,16,17
471:18
472:7,11,13,18,21,23
473:1
474:16,22
475:2,7
483:11,13,20 514:17
605:19
614:1,4
617:16
628:6
634:14

Progression
328:16

project
328:16
333:5,6,7,8,9,10
338:17,18,19 349:11
399:3,16
408:4
421:1
465:5
496:10,15,22 580:24
582:4
605:25
606:1
619:16
627:21
632:12

projected
490:18
492:7
495:10
529:15
558:17
569:17
575:21
577:23
603:25
628:2
634:18

projecting
493:24,25
497:17
504:7
528:25
529:6
539:19,23
549:16
550:17
552:2
554:19,23
571:18,21
574:20,23
590:7,10
620:9
634:3

projection
399:12,19,25 408:14
414:16,24
415:5,19
416:12,17
465:2,8
495:6,24
496:8
508:10
540:7,8
548:5
604:24
616:6,20
617:4
618:7
621:7,12,22
632:13,16

projections
357:4
416:11,14
489:6
499:6
505:23
518:14
540:5,11
570:9
576:23
580:12,22
582:12
605:6
618:21
621:16
630:8

projects
386:13
500:11
501:3
605:9

promised
635:24

promising
471:23

promoting
421:10

prompted
473:21

proposal
352:17

pros 418:24

prospect
630:22

prospective
488:16

provide
373:3,8
377:24
396:24
397:1
403:11
405:25
406:14
407:2
410:20
411:13
417:19
431:1,10,20,23
433:7,20
434:7,21
435:22
438:5
454:4
456:24
493:18
501:4,6
526:25
527:9
540:20
543:6
544:15,16
551:12
568:6,10
578:16
592:3
600:25
606:3
625:20

provided
385:19
410:20
418:8
432:2
441:10
457:1,13,15 458:7
471:5
486:4,7
489:17
506:10,15
540:17
561:3
562:23
564:15,19
569:4,25
570:20
612:8
631:15

providers
506:18

provides
382:1
392:23
435:20
453:25
454:3,6,13
456:15
461:7
504:16
582:3

providing
382:7
384:14,17
387:16
389:3
567:13
615:15
626:6

province
380:16
427:8
492:7
514:7
523:12
584:25
585:6
586:17,19
613:23,24

province-by-province
529:14

provinces
398:1

provincial
507:22
514:8,14
517:21,22
518:7

prox 579:10

proximity
579:10

proxy
393:8,11
433:7
445:12

prudent
421:16

PUB
324:15,17,21,24
325:3,20
326:3,5,7,9,12,15
327:3
328:3
329:3
330:3
331:3
333:3
334:3
335:3

336:3
337:3
338:3
339:3
340:3
341:3
342:3
343:3
344:3
345:3
346:3
347:3
348:3
349:3
350:3
351:3,6,9,
11,12,14,1
6,18,20,23
352:3,6,9,
12,14,17,1
9,21 353:3
354:3
355:3
356:3
357:3,5
358:22
359:3
360:3,15
361:3
362:3,14
363:3
364:3,5,17
365:3,12
366:3,13
367:7,20
368:5,23
369:3,23
370:3,15
371:3,5,8,
10,13,20,2
2 372:3
376:5,8,12
,16 377:18
504:15
512:13
554:5

PUB/CAC
366:13
367:7,20
368:5

PUB/Elenchus
357:5

PUB/GAC
368:23

PUB/Knight
358:22

PUB/La
352:21

PUB/Manitoba
326:17
351:16
456:25
457:1
619:19

PUB/MIPUG
369:23

PUB/MKO
370:15

PUB/MNP
360:15

PUB/Morrison
362:14

PUB/Potomac
364:17

PUB/Power
364:5

PUB/Typlan
365:12

PUB-253B
541:1

PUB-58-2
371:19
375:25

PUB-59
371:20
376:8

PUB-60
371:21
376:15

PUB-61
371:23
376:23

public
321:3,21
324:8
352:4
375:16
385:18
471:25
486:22
590:13

publicly
588:25

published
531:21

PUB-MH
576:21
619:20

PUB-MH-1-253A
540:18

PUB's 371:23
376:20,23

pull 564:6,7
598:16
622:11
628:10

pulled
571:14

pulling
444:17

pump
429:9,13

pumps
428:13,15,
20

punt 528:23

pur 358:3
458:5

purchase
424:17
558:2

Purchased
344:25

purchases
607:3

purchasing
541:21,23

pure 515:6

purely
547:10

purple 448:9

purports
627:20

purpose
385:23
587:19

purposes
387:16
399:23
496:16
498:5,11
499:8
509:5
595:19
621:8
631:25

pursing
467:22

pursuant
516:11

pursue
432:16
436:16
438:18
440:3,7
441:14
454:9
455:6
457:19
458:5,6,24
461:10
468:2,19
474:2
476:6
611:9

pursued
460:16
471:19
472:5
474:10

pursues
432:13

pursuing
435:5
442:23
448:15
454:11
455:9
459:15
468:21
470:5
483:12
528:16

push 419:5
421:5,8

pushed
479:16

pushing
421:7

putting
508:16
544:3

Q

quad 596:9

quadratic
596:9

quadrupling
595:3

qualificatio ns 380:2
383:1,7,18
384:24
386:9
387:23

qualify
559:20

quality
382:4

quantitative
398:24

quantity
494:18

quarter
446:11
485:6,7
608:16

question
403:16
404:10
405:2,9
422:15
424:20
425:19
429:24
455:2
461:15
485:14
487:9,21
488:1
506:16

517:8
519:13
528:23
531:12
533:9
538:3
539:18
543:2
547:7,20
567:9
573:25
578:19
587:22
595:16
597:9
599:15
601:5
602:16
608:19
610:21
613:3
615:19
622:2
626:11
631:4
632:4

questions
371:14
422:13
466:3,14
482:8
486:23,25
487:1,4
494:12
533:5,10
538:2
589:23

quick 390:24
515:9

quickly
389:7
391:9
572:21
601:12

quite 431:14
447:25
450:5
468:2
487:23
495:6
508:2
520:22
521:13
546:1
563:21,22
564:17
582:7
614:2
620:9

quote 451:18
544:17

R

radar 473:2

raise 459:5

raised
450:17

Ramage 322:5
388:19

ramping
418:7
483:11

ramp-up
606:25

ran 577:18

range 381:3
391:5
392:21
393:17,24
400:12
403:4,5
414:19
416:1,2
425:1
456:19,21
462:16
481:6
500:1
532:19
566:23
577:13
589:5,7
605:7,8
612:7,10

rare 561:22

rarely 548:7

rate 327:10
330:11,13
335:17,18,19
336:13,23
346:13,15,16
350:10,11
370:3,7,9
373:6
381:15
385:18
393:20
423:17
424:7
439:11
458:10
477:4
480:7
482:10,13
510:17
523:19
526:21
528:24
530:21
532:4,5,18
534:10
536:6
550:19
551:9,16
569:9,10
574:2
584:13
607:13
618:18
624:4

ratepayer
334:6,7
338:5,6,7,16 345:14
346:11,12,14,19
349:9
350:15,16
362:25
363:6,7,8,9,11,12,13
432:13

ratepayers
436:22
440:12

rates 348:7
382:11
385:21
395:5
409:7
421:6
432:15,18
458:16,19
459:5,17,18,22 462:5
470:13,16,20 471:23
477:10
480:16
529:8
534:2
544:22
568:17
586:22
588:11
592:2
608:5

rather
400:23
418:23
421:17
442:15
451:16
569:6
579:23
616:14

rating
331:8,9

ratio
336:16,17,18,19,20
401:14,17
426:2
436:18
439:4,6,15
441:2
456:8
509:14,15
537:4,5

rationale
395:23

ratios 426:4

re 321:7
324:15,21
325:6,14,20,24
326:9,12
351:6,9,11,14,18,20
352:3,10,12,14,17
371:5,8,11
385:12
401:6
452:6
481:6
527:16
533:21

rea 534:19

reached
477:20

reading
578:1

ready 375:4
379:14
466:2
530:24
556:10
625:7
626:8

real 402:4
457:14
461:7
462:10
508:6
535:25
536:1

realistic
583:10
604:20
632:14
633:5,8

reality
434:22

realizable
428:25

realize
535:9,16,19 594:15

realizing
547:22

really
423:14
432:11,22
434:24
435:3
437:23
441:13
446:21
454:11,23

464:11
476:20
482:15
508:6
515:22,24
536:12
565:12
572:13
575:1
576:4
583:18
587:1
590:5
607:5,8
611:14
632:21,23
633:5

realm 476:3

re-announced
449:2

reason
395:13
445:9
455:16
459:18
480:18
484:8
507:13
520:11
560:3
579:14
612:20
616:13

reasonable
392:5,8
524:3
529:18
554:12,15
579:9
582:3
583:5,14

reasoned
551:5

reasons
445:5
449:23
481:6
482:4,5
521:21
589:16

rebuilt
635:7

rebuttal
473:6
511:14
525:18
526:18,25
529:3
559:3,15
560:23
628:9
631:21

recall 451:2
470:1
473:17

recap 551:23
602:11

receive
545:8

received
508:14
517:11

receiving
477:12

recent 518:2
539:6
560:12
619:2

recently
392:16
411:22
468:18
573:10

recess 636:8

recessing
465:24
485:9
556:6

recession
444:22
572:23
575:24
577:19
578:14,24
579:2,6,9,
13 580:4
582:2

recessions
392:16

recognize
396:8
437:16
461:8
517:24
529:20
530:6
532:20,23
534:17
535:22
536:6,13,1
5 581:8
609:9
632:13

recognized
386:21

recognizes
402:20
538:16

recognizing
530:9
539:12

recommend
421:14
422:6
622:3

record
482:20
485:17
487:11
491:20
492:3,12,1
7
493:10,16
512:8
517:7
518:25
589:1,4
635:14

recover
608:4,8

recovering
575:11,12

recovery
527:17
555:1
579:4,5

red 388:21
412:20
434:11
437:12
450:10
455:22
475:22
476:4

redline
585:13,14,
19 586:5,7

reduce 394:4
527:19
536:2
552:16

reduced
470:22
479:22
522:2,10

reducing
479:2
522:13
535:3
577:10

reduct
479:14

reduction
478:18,21
479:14,17,
23 495:7
521:6,19,2
1 522:12
523:11
524:18,21
525:3
548:1
550:18
552:25
553:11
555:16,19
577:12,14
589:2,5
612:14

reductions
551:21
602:21
634:17,18,
23,25

refer 433:19
489:22
491:3
504:14
517:7
559:2

reference
324:5
399:7
456:25
486:5
519:13

referenced
371:14
524:5
525:11
526:6,13
552:11

referred
429:1
509:2
517:9

referring
495:2
496:1
507:16
511:17,18
512:9
522:20,23
558:20
579:20
588:23
629:5

refine
393:25
396:20
406:2

refined
398:16

refinery
588:24

reflect
389:18
409:7,8
426:24
522:7,13
528:12,13,
15 552:13
553:10
581:9
604:22
628:2,23

reflected
508:9
523:2,4,6

526:1
528:9
530:1
552:6
558:22
575:15,23
589:2,8
590:1

reflecting
522:3
531:10
537:3
540:12
576:11

reflection
521:24

reflects
528:9,10
573:20
577:12,14
619:7

refresh
531:1

refrigerators 400:24
413:2
444:7

refugee
514:17

refute 559:2

regard
396:10
434:15
471:12
472:2

regarding
385:24
485:14

regardless
400:20
464:6

regards
390:7
467:18

region
437:18

regional
398:6
463:15

regions
390:25
398:20
439:23
440:20
456:20
536:11

Regis 321:13

registered
380:15

regression
497:10
559:9

regression-based
559:5

regular
542:14
567:19

regulation
381:3

regulators
417:21
418:10,20
419:12

regulatory
402:2,23
419:12
421:9
589:14
592:2

re-landscape
452:5

related
382:22
384:12
468:17
473:14
499:25
527:3
552:21
555:5
589:15
628:17

relates
422:20
523:15

relating
626:22,25

relation
404:11
493:7,10
586:13

Relations
385:6

relationship
381:23
419:11
537:14,24
571:6
596:9,10

relative
446:23
461:14,18
462:1
463:20
532:1
533:23
536:9
578:22
633:19

relatively
509:23
532:7
536:4
597:1
611:5,8

relatives
514:16

relevance
441:18

relevant
411:2
425:10
432:12
441:14
458:21
460:1
461:22

reliability
336:7
337:18
349:22
391:2,12

relied
577:17

relies 600:2

rely 404:8
411:12
424:12
529:20
618:4,5

relying
396:6
580:14

remain 511:5

remainder
413:4

remained
509:23

remaining
467:14

remains
579:8

removed
537:14

renewable
419:19

renewables
348:15
381:9
382:5

rental 538:9

rentals
349:13

repeat 405:9
519:13
596:20
602:17
626:11
631:3

replace
400:18
481:20,24

replaced
400:23
401:1
482:20
535:4

replacement
535:8

replenish
614:9

report
330:6,16,17,18,19
352:23,24,25
353:3,4,5,6,7,8,9,10,11,12
440:18
489:14
550:24
570:2
603:16,25
604:12
627:18

reported
463:19

reports
351:10
430:3

represent
381:24
397:23
419:23
620:5
629:15

representation 530:17
628:4

representative 381:7
416:3,4

represented
552:25

representing
586:4

represents
552:18

request
352:6,14
371:6
564:18
576:22
588:8
591:3
619:20

requested

428:22

Requests
326:18
342:9,25
351:17
352:21
357:5
358:22
360:15
362:15
364:6,18
365:12
366:13
367:7,20
368:5,23
369:23
370:15
371:21,23
376:12,15,20,23
540:18
564:16

require
404:4,5
471:25
484:9
527:15

required
420:23
471:21
531:24
602:12
608:8
622:1

requirement
330:8,22
332:9
420:5,17
536:2
610:14
614:13
631:17

requirements
332:11
345:6
346:4
348:6
419:25
420:3
528:13
610:15
611:1
614:18

requires
392:25
472:2
630:11

requirment
330:23

research
379:9
386:20
398:8

reserved
375:11

Reservoir
328:14

reset 578:12

residence
509:19
512:3

residences
428:1

resident
511:1
586:15
613:8

residential
384:19
389:12
390:14
407:20
409:19
410:2
411:18,21
414:10
416:25
417:2,8
429:10,12
473:14
480:5,10,12,21,24
504:9,20
505:22
506:1
509:10,11,12,15,18,20
511:1,2,24,25 518:14
519:1,2
520:18
538:5,6,16
539:4
552:9
568:17,19
569:23
572:10,22
573:2,16
574:2,6,12,18,25
576:6
583:17
586:15,16
587:5
610:2
611:19
612:1,11,23 613:3,8
615:12,14

residents
509:15

residual
346:9
497:21,25
503:24

resistance
592:19
593:5,6,11,13,15,24
596:11

resistant
613:12

resistence
402:14
428:14
429:3

resolved
556:19

resource
327:24
332:5
345:13,16
348:3
349:8,10
353:13,14,15,16,17,18,19,20,21,22,23,24,25
354:3,4,5,6,23,24,25
355:3,4,5,6,7,8,9,10,11,12
362:21,23,24 386:15
401:12
404:1,9
419:17,22
426:1,21
427:14,15
430:1,11
431:3,6,8,13,16,23,25 432:5,6
433:21,24
434:3,21
435:13,23
436:8,18
437:21
438:8,15,23,24
439:3,5,6
441:1,2,5,6,15 442:3
454:14,15
457:10
462:12
471:6
478:16
483:1,9
496:15
497:24
587:24
588:7
628:20
631:25

resourced
588:1

resources
327:9
343:21,22
381:1
396:8
607:1

respect
380:3
382:8,17
383:19
384:15,18,25 386:9
398:6
403:20
423:8
477:21
521:22
533:6
585:7
587:22
631:6
636:1

responded
440:24

response
382:12
386:14,22
398:10
456:25
506:16
517:6
533:25
541:1
564:15
592:3
614:4

responses
351:19
534:23

responsibilities 383:6
384:9,24

responsibility 380:3
382:16,23
383:4,18
487:18
545:20

responsible
381:14,21
385:14
386:5
436:21
443:14
484:4

result
396:10
431:6,11
433:16
436:8
450:9
463:15
502:12
510:21
525:12,14

535:15
536:14
578:23
579:1,13
588:8
610:18

results
406:3,6,13
408:14
411:20
413:20
416:10
421:18
422:3
426:2
456:7
507:21
508:6
526:10,14
571:14
623:25

resume
465:21
466:2
485:6
556:10

resuming
465:25
485:10
556:7

retirement
511:8

RETIRES
636:17

return
346:13,15,16
482:10,13

returning
384:10

revenue
328:13
330:8,22,23 332:9,11
334:5
343:12,14,25
345:6,9,15,17 346:3
348:5,6,7
439:11
457:21,23,25 461:9
462:2
499:6
501:10,17
502:21

revenues
327:8,10
335:17,18,19 340:13
342:21
347:19
349:13
458:12
502:13

reverse
557:14
584:23

review 321:9
324:19
379:2
385:5,13,15 394:11
397:11
410:22
433:17
483:16
529:15,17
530:13
534:6
603:23

reviewed
425:8
467:25

revised
351:24,25
576:22

revor 483:1

Richard
321:16
427:23

ride 413:6

ridership
463:25

right-hand
515:8

RIM 438:3
453:22
454:4,21

risk
330:13,14
336:9,21,22 345:7
346:17
402:10
493:7
587:2,8
603:14
609:3,6,20

river 328:11
452:11
474:1
596:24

rivers
492:23

road 516:13

roadway
473:3,13

Rob 379:4

rock 453:10

Roddick
352:9

Rohmu 378:21

Rohmund
323:11
378:22
379:22
386:1,3,7,11 387:15
397:8
403:18,24
404:3,19
405:8,15,24 406:20
409:17
416:7
424:21
425:5,24
426:20
427:13
428:12
429:1
430:14
533:8,12
615:20,24
616:5,10,15 618:7,23
619:1,5,9
620:13
622:12,21
623:1

role 381:13
384:7
385:12,14
386:11

roles 380:18
384:5

roll 459:13

Roman 490:2

room
375:11,23
535:1
594:12

roughly
389:10
395:12
410:12
433:5,9
469:19

round 325:24
326:17
342:9,25
351:16
486:4
506:16
585:23
619:19

rounding
444:14

routine
422:10

row 378:13
379:3
538:19
598:25

rudimentary
530:7

rules
442:15,17
443:7
445:2

run 401:11
440:19
561:23
608:24
609:13

running
500:24

RWACC 330:15
334:13
336:24

S

safe 562:1
606:18

sake
458:12,17

sale 349:17

sales 329:7
345:11
378:25
383:25
384:11
486:9
603:8

SaskPower
349:17

sat 467:25

saturation
411:22
522:13
523:19
527:25

Saunders
322:18
466:22,23

save 527:21

Savers 443:3
445:9
456:1

saving
479:1,7

savings
398:23
401:24
408:19,22
411:9
413:21,22,25
414:1,4,6,8,13,16,20
415:7,13,1

7
416:21,24
418:4
420:17,22
421:16,17,
24 422:21
426:22
427:17
428:24
437:2
440:9
441:24
446:24
453:7
463:19,20,
21
464:4,10
470:25
471:9
472:20,25
475:8
479:18
484:2
546:8,23,2
4 604:7
606:18,19
617:7,15,1
6,25
621:13,24
622:6
628:7
629:9
630:13

saw 508:17
522:9
575:9,14
585:18
618:17

scale 504:1

scenario
332:14,23,
24,25
349:11
485:15
486:5
501:8
546:2
585:23
586:3
627:23,24

scenarios
327:25
332:13,17,
19,20,21

SCGT 332:18

scheduled
475:7
588:23,24

school
515:23
516:4
546:24
594:16

schools
410:7

science
380:14
383:8
444:12
549:15
550:15

scope 326:13
351:21
352:7,15

SCOPEER
381:10

Scott 487:16
488:4

scratching
451:9

screen
401:15
427:24
473:2
489:25
491:5
511:20
515:7
526:19
548:3
564:24
579:17
598:7,16
619:17,18
622:13
631:20

screened
425:17
427:9
428:23

screening
347:8
401:12
425:25
431:22
438:1

screening-out 425:22

scrolled
515:7

se 546:18
559:3

season
445:13
615:2

seasonal
454:15
612:4

seated
378:13

Seattle
387:4

second 375:6
376:4
378:13
412:5
417:1
421:19
463:12
471:1
479:8
493:16
531:12
547:7
574:19,24
576:1
594:2
621:6

secondary
408:10

sector 327:3
349:3
352:4
380:20
389:16,20,
22,23
390:13,15
393:6
394:20
409:19,22
410:8,12,1
3,15
411:14,18,
21
412:11,14
414:11
415:1,6,9,
10,14
416:22,23,
25
417:2,8,11
,12 505:11
552:10
569:20
574:2
581:10,20,
21
583:7,13
585:5,6
590:2,7,8,
9,11,14
613:8

sector-by-sector
589:22

sectors
381:4
389:12
390:1,14
407:22
414:22
415:2,16,2
5 539:7
582:17
591:18
612:1

security
493:13,19

seeing
521:23
522:9
523:15
524:7
526:10
527:2
540:12
573:22
574:17
583:11

seek 395:25
483:7

seem 430:19
556:13
561:19

seems 510:4
564:16
577:21
584:18
609:24,25

seen 441:9
493:5
510:2
522:11
532:4
571:6
573:10
574:5
575:7
579:11,25
580:2
604:11
622:21,23

segment
401:10
406:4
407:20
409:19,22
480:17

segmentation
409:25
412:9

segmented
409:19
410:2

segments
403:9
407:21
408:5
411:24,25
412:16,21
413:1

self-generation
469:20
611:3,4,9,
15

sell 609:18

selling
459:20

sending
595:18
senior
379:13
sense 395:15
426:22
436:15
438:21
440:3
442:19
445:6
449:15,16
453:8,11
454:12
457:19
461:4
464:22
474:18
475:1,9
476:11
482:11,12
483:4
533:24
565:16
568:2
598:11
sensitive
487:8
506:13,15
sensitivity
465:13
467:17
558:15,18
562:24
563:6
564:18
565:12
separate
399:21
424:18
520:12
571:8
separately
389:21
411:24
413:16
493:21
569:11
September
325:9,10,13,16,18,19,22,24,25
566:8
sequence
503:3
ser 546:11
seriously
473:22
serve
381:6,10
438:19
488:9
served
380:16
532:24
545:20
serves
546:25
service
325:15
345:3
381:16
382:3
389:12
390:17,20,21 391:14
410:10
411:2
413:7
415:3
504:9,21,23 505:2
506:18
543:24
544:8,14,17,18
545:8,9,12,18 546:11
547:18
568:20
569:10,20
573:17
574:1
587:5,25
588:8
592:1
serviced
544:9
services
379:6
384:8
542:15
session
482:7
487:12
589:23
590:13
sessions
542:14,16
setting
397:2,17
405:21
406:16
417:16,17
421:13
543:11
547:16
settings
398:11
seven
433:8,9,12,13 452:22
458:11,16,22 459:4,6
462:7
480:1
481:18,19
509:24
510:3,5,6,7,9,18
515:13
516:25
519:18
620:5
seventeen
393:8
585:17
seventy
562:10
seventy-eight
498:7
several
384:12
387:10
397:9,10
398:5,11
420:12
503:5
510:3
528:24
shaded
397:22
437:11
447:17
shape 480:15
share 383:12
390:16
440:17
455:17
467:19
472:6
474:13
537:6
shared
440:10,11
455:19
shares
410:12
sharing
456:3,5
623:25
sharper
554:23
shave 546:25
shaves
495:24
shed 457:2
Shefman
388:6,12,13
S-H-E-F-M-A-N 388:13
shell 414:3
She's 378:22
shift 539:12
578:13
shifting
538:6
612:14,17
613:13
614:1,17
shifts
514:24
577:18
shop 434:7
444:14
short 389:1
563:12
590:10
608:24
shorter
561:20
608:1
shorter-lived
608:15
shortly
477:8
short-term
469:25
470:3
575:21
580:19
581:5
582:22,23
showed
524:18
622:9
showing
402:10
419:16
499:5
504:5
518:12
537:13
572:5
582:22
595:7
627:16
shows 408:15
412:19
413:8,21
415:20
437:11
441:21
456:14
471:8
490:4
496:7
512:18
554:21
561:3,16
565:11,12
568:18
572:16

576:22
582:11,13
619:23
627:20

show's
518:13

shrinking
588:13

shut 588:20

shutdown
588:18

shy 521:18

sic 385:19
541:18
627:22

side-by-sides
538:20

sided 382:5

sign
481:12,14

signed
395:22

significant
392:13
393:6
414:5
416:21
417:6
450:23
451:17
452:7
453:16
470:20
473:20
476:1
477:16
492:25
501:14
515:24
521:21
523:10
524:2
532:4
537:22
582:2
606:19
633:19

significantly 561:20

similar
448:18
508:17
517:16
519:1
555:15
585:21
628:24

similarly
479:20

Simonsen
466:5
592:25
595:11

simple
431:15
436:15
439:5,18
440:25
455:6
457:14,15
458:3,7
461:3
481:7
503:20
597:10

simplest
423:21
478:11

simplified
576:5
593:21

simplify
578:11
592:24

simply 497:2
503:23
506:25
507:3
600:1
635:11

Simpson
367:7

simulation
387:12

Singh 377:13

single
412:2,6
463:13
538:12,17,18
539:8,14
540:8
592:8

single-stage
527:6

sir 465:19
506:12
510:2
512:25
514:21
516:8
518:16
580:10

sit 536:12

sitting
543:19,21

situation
345:19
443:7
458:15
492:2
539:21
583:10,11

six 424:4
449:7,8
470:1
480:8
491:16
620:5

six-nine
480:8

sixteen
521:15
552:24

six-three
612:7

sixty 448:19

sixty-two
491:8

size 448:16

skew 490:13
557:2

skewing
571:14

skews 563:6

slated 477:6

slide 390:24
392:22
405:20
406:23
409:18
413:21
414:9
415:20
423:8,15
441:21
456:14
463:1,24
622:9,14

slides 389:7
400:1
467:14

slight 492:1
586:18

slightly
391:6,7,19
436:19
490:9
508:8
525:3
532:16,17
569:4

slope 577:23
578:10
581:18

slow 444:23
565:11
609:23
610:7

slower 574:1

small 413:1
424:11
453:6
603:5
611:5,8

smaller
395:20
417:9
566:14

smallest
415:14
417:12

Smart
345:21,22
379:8
380:19
382:3,14
384:5
395:12
429:12
433:20
471:14
627:22
628:18

smelter
588:17,21,22,24
589:15
590:1

social
426:18

societal
438:23
442:2

socio-economic
331:16,17,18 346:23
347:4
352:10,19
365:14,15,16,17,18,19,20,21,22,23,24,25
366:3,4,5,6,7,8,9,10,11,12
370:17,18,19,20,21,22,23,24,25
371:3,4,8

software
387:10,11,12,13

solar 382:5
603:19
604:1
605:1,20,22,25
606:4,9
609:23
610:19

633:19
Solar's 610:17
Soldier 321:15 378:8 588:16
solid 403:12
Solutions 378:19 380:10 386:13
Solutions's 397:23
somebody 436:13 438:12 494:8 520:2 553:22 554:7,9 584:24 591:23
someone 532:24
Something's 438:12
somewhat 468:23 485:23 498:1,22 563:11 571:13
somewhere 403:6 586:23
sorry 380:6 381:12 388:14 412:23 432:25 494:7 506:9 534:16 538:18 545:3 551:24 559:7,13 563:14
565:2,7 571:20 572:7 596:1,15 601:13 602:13,17 620:8 634:13,20
sort 426:16 475:15 476:21 508:5
sound 389:22
source 520:5,6 550:5 610:23
sources 407:13 408:10,25
south 523:17 540:6 541:4,6,18 600:3
southern 614:1
space 326:23 348:22 407:14 412:2,20 414:1 449:20 522:6 528:1 535:3 548:19 549:1,24 552:17 555:6 573:3,14
span 561:20
spares 375:22
Spatial 506:22
speak 485:18 518:18,21 527:14 528:19
591:24 631:2
speaking 438:11 439:25 442:5 462:4 478:5 504:8 534:17 553:10 573:15
specific 403:7,13 405:22 406:3,9,10 407:4,23 412:13 421:12 422:1 426:19,21 427:3,18 480:14,16,17 494:12 569:11 580:12,24 581:3,15 582:17
specifically 399:23 406:7 424:21 426:25 428:22 429:2 462:20 521:22 523:20 525:15 527:1 541:4 558:19 583:3 590:10 628:9
specifics 397:16
specified 418:16
speed 555:13
spend 457:3 459:16 460:3 461:24,25 462:7,20 543:21
spending 420:19,24 461:18
spent 457:4 459:16,21
spike 447:15,16
split 442:25 576:6,12
spoke 555:1 577:8
spring 509:7
square 592:16,20 594:22
squared 592:18 593:3,6,11 594:2 596:9 597:10
squaring 593:15
stable 512:1
staff 324:22 399:2 431:17,21 443:8,10 454:17 465:4 467:17,22 471:6 474:15 475:4 625:20
stage 449:25 508:16 527:7 606:25
stakeholder 421:2
stakeholders 418:10 419:4 421:3,4
standard 400:9 419:17,19 426:7 443:20 448:19 481:16 515:10,11,14 519:1,24 520:1,13,23 524:17 527:2,4,11 551:25 554:24 555:13
standards 380:24 381:3,7 382:10 391:20 393:12,13 394:24 399:20 408:7 417:4 419:22 437:1,9,12,22 463:7,9 528:9,11,14 620:20 635:8
standpoint 606:17
stands 399:13 413:11
start 375:4 389:2 406:25 407:25 425:6 440:5 450:8,9 457:12 458:9 464:15 485:3 532:21

555:25
620:16
633:18

started
434:2
446:4
470:14
486:24
620:11

starting
397:10
532:18
534:10
577:4,22
578:6,12
597:19
624:3

starts
431:14
491:9
617:23

startup
345:18

state
387:6,7
419:16,25
420:5,13,15 581:22
609:9
630:21

stated
392:11
473:5
631:24

statement
372:6
466:6,10
562:1

states
391:25
397:18,25
404:4,6
418:21,22
419:18,21,24 420:3
421:2,5,11
440:22,23
552:12
618:10

static
440:15

station
391:13
504:23
505:1

stations
505:4,9

statistical
618:4

statistically 559:16

Statistics
506:23

StatsCan
424:13

status
588:17
589:15

stay 533:12
634:19

stayed 475:1

staying
499:7
586:19

stays 597:21
598:10,12

steady
507:25

Steering
381:8

step 396:18
399:14
406:3
407:6
409:5
410:16
476:23
607:19

stepping
621:8

stone 621:9

stop 498:17
500:14

stopping
500:14

stops 634:3

storage
328:14
345:3

story 421:12
617:1

stove 520:8

stoves 520:8
553:25

straightforward 409:3

strategic
379:1
385:5,12
386:16

strategies
396:21
547:17

strategy
386:17
436:13,14,24
437:3,5,10
438:18
469:3

stratified
409:16

stratify
409:12

stream
611:11

strictly
507:17

structure
381:15

struggle
481:13

studies
387:3,9
396:17
397:11,16,21
398:1,4,6,8,13,17
399:4
404:2,4,8
410:14,19
411:11
414:6
415:8
416:1,6,8
417:1,10,14 422:7
426:6,8,12
427:2
489:13
498:17
531:21
536:10
616:22
617:11

Sturgeon
336:11

subdivision
544:3

subject
456:23
477:12
478:1
505:19
512:17
521:9,11
524:23,24
576:19
581:13
603:13

submission
486:7
609:10

submissions
387:21

subpoena
326:15

subsequent
448:9,23
484:7

subsequently
447:8

subset
401:7,23
402:19

subsidies
405:2,11

subsidize
404:13,14

subsidy
404:16,23
405:13,16

substantial
633:1

substantially 473:16
563:2
571:9

substation
505:8,16

substations
505:4

subsumed
552:3

subtract
392:1

subtracts
617:23

success
373:6
507:22
522:4,8
549:16
550:16,19
551:9,16

successful
452:8
473:25
548:6
585:11

successive
417:7

suddenly
538:13

suggest
378:2
430:6
447:6,15
458:16
461:21
468:3
477:11
515:15
609:25
610:1

suggested
514:6

suggests
395:7

suited 601:2

summarizes
420:2

summary
414:10
415:15
416:22

summer 393:1
452:10,23
473:24
478:19
490:13
495:2
557:1
561:12
562:7
563:4
614:22,25
615:1,4

sunk 336:12
344:19,20
346:5,21,22 370:5

supp 573:21

supplement
408:9,24
484:15
610:23

supplemental
484:8,9,19

suppliers
435:7

supply
327:11,21
457:18
492:4
610:17
614:10

supplying
610:19

supply-outside
457:22

supply-side
432:13

support
382:2
384:8
419:13
429:13
534:15
605:3,20

supporting
380:19
384:5
437:7
463:11
542:2

suppose
427:5

supposed
433:18
443:9

sure 423:4
430:16
434:1
472:1
474:14
491:23
506:6,21
509:12
518:22
520:19
528:21
534:12
543:7
566:4
599:1
613:11

surplus
500:20
609:18

surprise
414:1
536:18

survey
391:2,13
411:23
440:22
539:4
540:14

surveys
407:15
520:19

Sustainability
367:22,23,24,25
368:3,4

Sven 322:3
323:14
375:8
376:4,11,19 377:1,9
378:1
387:19
466:18
484:24
486:19,20,21 487:22
488:5,14,20,23
489:4,18,21
490:8,16,22
491:3,13,17,22 492:5
493:23
494:10,16,23
495:13,22
496:3,6,20
497:6,9,14
498:2,5
499:3,14,21 500:17
501:7,16,21,25
502:10
503:4
504:2,13
505:12,21
506:5,11,17,24
507:4,8,18
508:12,22
509:4
510:2,12
511:13
512:5,12,15,24
513:11,25
514:5,20
515:19
516:3,7
517:5,14
518:1,11,22,24
519:6,14,22
520:1,7,10,21
521:3,12,20
522:15,24
523:3,8,24
524:16
525:1,17
526:16,17
528:3,19
529:25
530:19
531:6,11
533:3,4,14
539:16,17
540:15
542:22
543:8
544:2
545:21
546:21
547:6,24
548:12,17,24
550:2,10,11,23
551:6,19,20
553:12,17
554:4,16
555:14,24
556:12,18,22,23
557:8,13,19 558:14
559:18
560:2,25
561:9,14,22
562:2,9,16,20
564:14,25
565:3,6,9,10,15
566:22
567:5,12,17
568:1,6,16
569:3,13,25
570:6,12,17 571:16
572:1,5,20
573:8
574:3,12,16 575:25
576:4,15,19 577:2,20
578:4
579:15,19
580:2,9,21
581:12
582:9
583:16
584:12
589:19,20
590:5,12,18
591:2,9,19,23
592:5,19,22
593:4,10,17,20
594:4,15,20,21
595:6,11
596:15
597:15
598:14
599:1,4,6,9,12,18,21
600:8
601:4,14,19 602:8,18
603:9,12
604:11,16
605:11
606:7,13
607:21
608:7,11
611:17,18
612:13,21,25 613:17
614:19,24
615:5,17,25 616:7,12
618:2,22
619:2,6,12,16
622:7,13,24
623:3,18,20,22
625:6,18

626:4,5,12
,20
627:10,11
628:22
629:2,6,20
630:20
631:1,5,13
,19 632:2
633:23
634:22
635:10,23
636:11

switch 428:9
524:1
574:4
575:1

switching
348:24
368:25
369:3,4,5,
6 373:7
428:1,14
472:2
522:16,20
525:22
526:6,12
540:16
550:24
551:17
552:2

sworn
323:8,9,10
,11,12
325:17
378:16
379:14,19,
20,21,22,2
3

symbols
594:14

synonymous
405:21
406:15

system
328:12
345:10,24
429:5
435:22,24
451:18,22
470:19
493:3
500:3,6
502:6
520:15,20
535:14
539:5,9
542:8,9,10
586:1
596:4,7,11
,21,25
597:7
602:1,3
612:6

systems
422:2
429:10,14
452:18
469:13
541:24
542:6
555:2,7
607:2,4

T

tab 518:12

table 323:1
396:7
414:13
490:1
491:4
496:7
555:5
572:7

tabled 477:6

taking
396:11
405:16
421:17,24
441:3
443:11
452:14
461:5
471:12
476:23
478:3
505:3
509:5
539:21
562:22
568:17
575:25
582:9
611:10
621:18

talk 389:14
436:12
437:6
438:1,9
439:2,12
441:11
442:16,19
443:18
450:5
453:1
455:7
467:16
468:14
542:15
584:17
633:18

talked 453:6
463:1
471:1
476:7
609:22
626:17

talking
397:17
438:14
457:11
480:9
502:19
526:8
566:25
567:19,20,
21 608:25
624:10
630:14

talks 464:4

tallied
560:1

tally 559:24

tank 520:8

tanks 555:9

target 397:2
417:16,17
421:13,21
442:21,24
448:22

targeted
541:10,17

targeting
523:20
541:4,5

targets
331:10,11,
12,14
344:16
396:20,22
397:17
405:22
406:16
417:19,20,
22,24
418:2,4,6,
10,16
419:6,8,9,
14
421:14,22
522:5
523:18
541:20
547:13,21

tax 447:11

team 381:14
396:10

technical
375:5
381:11,22
382:2
383:21
398:23
400:5,16
401:7,19
409:2
415:23
534:18
556:13
629:23

technologies
339:22
407:23
413:14
417:6
437:8
463:11
603:18
608:1
621:14
630:10
633:21
634:15

technology
386:23
387:12
398:25
402:5
404:22
414:7
435:1
482:15
603:15,24
605:13
606:5
607:6,7,10
609:23,24
632:23

temperature
532:16,17

ten 390:8
392:18
458:25
459:3
465:18
473:18
479:11
556:3
572:16
574:18,21
575:2,5,6,
8,16
581:23

tend 421:4
500:12
596:19

tendency
501:15

tends 537:22

Tennessee
387:5

tentative
377:11

ter 461:16

term 344:17
590:10
618:2

terms 324:5
389:4,8
390:10
392:2
395:17

396:21
397:2
408:21
409:21
414:23
418:17
420:3
422:21
435:20
438:6
439:20
440:4
442:13
444:13
454:7
457:3
461:6
462:20,23
463:6
464:20
466:25
470:22,24
472:7
476:4
477:17
480:19
483:11,24
500:14
553:21
558:12
566:15
573:22
585:22
586:25
587:2,5
618:3
629:15
630:5,6,8,12 632:12
633:3

territory
410:11
411:2
413:7

test 401:13
403:20
404:5,7,9
426:1,16,21 427:14
430:1,9,13
436:18
439:16
441:1,3
442:3

testified
385:17

testimony
382:6
384:14
456:15
634:1

testing
423:22

tests 425:13

text 579:23

tha 452:16

thank 378:6
380:5
382:14
383:15
384:20,21
385:25
387:13,14
397:8
467:4,9,13
482:20
484:20,24
485:7
486:20
553:12
564:24
568:5
600:8
623:21
626:20
635:23
636:13,15

Thanks 423:5

that'll
393:14,16
463:24
477:15
530:1
624:20

that's
377:14
393:10
395:11,17
399:14
410:14,18
412:19
413:1
415:4,18
418:8
420:18
426:16
428:21
432:17
433:6
434:12
438:16
439:15,16
440:5
441:3
446:10
447:21
448:14
452:13
454:22
457:11
458:21
461:25
462:2
464:5,9,24
465:1
469:13,14
470:11,23
472:10
474:17
475:23
477:6,11
481:13
484:1
486:9
490:6
491:7
493:8,19
495:17
497:4,21
501:15
502:18
504:2,23
507:5
509:25
512:9,11,22
513:10,24
514:25
515:15,16
516:1,16,21 517:12
521:12
522:22
527:10
528:21
530:1
533:18
535:4
541:17
543:19
545:19
547:6
551:6,9
554:5,14
561:25
563:4,5,13
565:16
569:5
570:1,3
571:25
581:9
582:10
586:5
589:17
596:18,20
598:5
601:17
603:2
604:23
607:4
609:3
610:5,6
612:25
614:24
622:15
625:4
629:3,10
630:24
631:11,20
633:3

themselves
505:10

theoretical
400:17
401:8
402:16

theory
434:20
435:25

therefore
406:15

there'll
471:20

there's
389:22
392:10,14,16 393:5,6
404:6
413:6
429:3
430:18,24
433:16
434:11,22
435:4,7
438:6,10,14
439:3,15,22
443:2,22,23 444:8
448:13,21
449:19
450:6
453:7
455:11
456:19
457:25
459:10
462:8
463:13,20,21,25
464:1,23
465:6
467:15
468:16
470:4
473:24
474:21
475:22
476:25
478:6,7
481:5
490:12
499:9
500:21
504:8,22
505:6,9
506:20
507:8
511:9
513:6,25
514:16,17
515:19,23
516:15
517:3,19,20 518:24
527:13
534:17
539:13
544:20
545:12

548:19
555:3,4
557:1
561:16
563:20,22
569:21
570:23
583:11,19,21,23
584:10
586:11
589:21
594:23
597:13,17
612:22
620:1
630:6,19
631:5
633:11,16,22

thermal
328:3
414:3
478:23
502:6

thermostats
401:4

they'd 377:2

they'll
507:20
545:5
625:13,17

they're
404:17
420:8
433:19
444:5
449:23,24
452:11,19,23
455:12,19
458:16
468:15,23
471:6
474:11
480:25
489:2
506:14,19
540:12
541:23
545:19
583:9
586:19
588:1,8
596:7
611:7,10,23 614:2,3
624:22
635:7

they've
450:2

think's
465:2

third 401:22
416:18
421:19
456:2
463:17
470:12
479:9
576:14
582:25

thirteen
521:18

thirty 383:2
387:2
451:22
481:17
532:19

thirty-five
450:11,17
473:19
497:5,20,22 498:9

thirty-four
549:2,6

Thompson
588:17

Thomson
371:16
467:2
487:16,21
488:4
524:4
543:2

thousand
446:14,19,25
447:3,10
448:19
450:21
451:19,23
476:10
490:17
491:6,16
519:18,23
524:19
549:9,19
552:24

threaten
516:4

three-sixty-six 548:4

threshold
426:10

threw 468:11

throughout
380:22
385:20
391:4,6
399:11
416:24
448:14

thrown
481:9,10

throws
584:20,25

Thursday
427:25
487:12
533:19
590:19

tie 609:16

tied 564:3
592:15
594:22

tiered
470:19

time-frame
496:21

time-limited
449:16

time-lines
483:24

Time-line's
484:17

time-of-use
381:15

timetable
351:24,25

today 375:11
382:6
465:8
467:22
481:20
495:18
512:20
528:15
533:10
600:25
602:19
604:23
605:25
606:4,5
635:14,25

today's
622:15

tomorrow
533:9
636:15

tool 398:16
399:12,14
542:4
616:16,19

tools 387:10
413:17
605:12

top 327:3
349:5
381:17
382:8
389:13
390:21
406:24
413:23
414:25
416:12
445:25
482:12
487:23
504:10,21
568:24
569:7,12
570:19,22
571:12,15
572:13
574:19,23
575:5,14,19
576:1,7,8,11,20,23
577:4,7,9,12,15
578:21
580:10
582:12
583:3,6,12,18,25
584:21
586:14,21,25
587:7,24
589:6
591:16
601:10
610:8,10,11,18
611:1,20,24 612:18
615:15

top-down
418:15
419:7,10

topic 423:7
438:3
543:19
555:25
600:22
601:2
609:25
623:15

topics
397:10
543:20

torn 635:6

total 328:14
401:12
404:1,9
424:7
426:1,21
427:13
430:1,11
432:7,12,14,17
436:18
438:24
439:5
441:1,2
443:1
454:14

457:9
458:12,20
459:7,24
460:1,6,7
490:4
493:25
494:19
499:17
513:8
514:18
547:1
549:17
562:4
568:18
571:20
574:7
576:2
590:24
611:4
614:21
617:18

totally
452:4

touch 431:2
436:22
438:2,5
482:23,24

touched
463:6
556:23

towards
402:3
404:7,21,22 538:8

Townsend
324:14
325:5,14

TR 401:12

track 422:3
517:15
520:11

tracking
410:5

tracks
517:16

traditionally 496:13
615:9

tranches
580:11

Transcript
323:16
324:11
325:8,23

transformation
443:16,17,22 444:2

translate
521:4

transmission
327:15
328:24
329:3,11,13,15,17,19
332:4,6
333:11,12,13,15,21,22,23,24,25
335:13,23
336:3,5,7,8
337:12,14,16,18,19
342:3,4,6,7,8,13,14,15 345:10
346:20
347:15
349:18,19,20,22
350:8,14
355:24,25
356:3,4,5,6,7,8
364:8,9,10,11,12,13,14,15,16
373:17
478:7
479:9,12
505:3,13,17 590:22
591:4,16,17,20
595:20
596:5
597:2
600:2,16
602:1

TRC 439:24
441:19

trend 503:12
538:8
565:11

trends
507:21
540:12

trickle-down
570:23

tried
474:14,17
482:11

tries 457:6

triple
446:16

tripled
446:15

trouble
388:21

true 441:2
536:21
584:24

truncate
582:24

trust 556:20

try 392:19
411:2
423:2
430:20
469:4
474:16
476:1,13
494:13
516:17
550:16
551:2
554:16
566:2
592:23
604:2
618:12
632:15

trying
394:14
424:22
425:19,20
440:6,8
443:19
451:10
462:14,15
465:5
487:8
492:6
498:3
503:10,19,23 510:25
515:5
516:8
517:24
521:3
546:14
567:5
594:21
595:15
597:10
600:25
602:14,15
604:17

turbine
336:15

turbines
486:8

turn 375:7
378:5
534:24
535:2
629:14

turning
491:8

twelve 447:9
560:13

twenty
390:12,18,23 413:23
422:17
451:19
465:21
490:16
495:8,23
496:8,10,13,21,23
497:11
498:8
504:3
526:21
528:25
539:19,24
549:7,13
575:8
581:23
582:1
584:14
634:3

twenty-five
386:18
419:21
421:11
465:22
481:17

twenty-four
384:3
559:16
560:17
610:16
612:3

twenty-nine
411:25
513:3

twenty-six
385:10

twenty-three
549:9

twenty-two
380:17

twice 414:18

twist 492:1

two-point-seven
510:17

two-thirds
574:22

tying 574:9

Tyler 379:12

type 405:13
513:8
520:6
587:16
606:2
611:11

types
397:11,20
412:12
538:21,24

typical
326:23

348:22
415:7
446:5
473:17

typically
417:25
446:7
592:1
601:18
613:6
614:3

U

ultimately
603:19

un 502:4

unbiased
398:19

uncertainties 608:23
609:8

uncertainty
335:10,11,12,20
476:25
567:6
583:19,22
584:8,10
604:23
605:1,4
606:14
608:12
609:4,7,11,19
630:17,19

underlying
499:8
502:5
511:9
512:2
548:23

Underneath
598:8

understand
394:14
396:8
423:15
424:22
425:21
429:25
439:13
457:16,18
462:15
502:5
559:19
603:17
615:20

understanding 435:19
495:5
502:14
550:3
568:22

undertake
389:25
393:1
396:17
404:13
431:24
432:3
481:2
530:8
534:22
551:2
625:18,22

undertaken
391:1
396:16
440:18,22
523:7
552:14

undertaking
395:24
396:3
467:18
469:20
471:7
517:7
551:7,12
568:2,10
592:4,6
595:17
599:16,22,23
600:7,10
625:25
626:19,21
627:3
635:19

undertakings
323:4
373:1
374:1
592:9

undertook
391:3
395:21

underway
420:25

uni 442:20

uninfluenced
425:22

unique
389:24
442:21
530:10
532:1
536:8

unit 327:8
345:12
380:11
384:1
385:6
527:17
553:4

United
397:18

University
380:12
384:2
385:8

unless
402:14
512:17

unusual
410:14
415:13

upcoming
524:12

update 389:3
392:23
431:17,21
489:10,17
509:3
523:7
625:19
626:14,16

updated
389:18
398:22
484:14
559:6

updates
626:6

updating
471:15

upfront
428:3

upon 375:1
378:2
424:12
465:24,25
485:9,10
529:20
534:6
556:6,7
559:8
584:16
636:19

upper 349:24
400:17
401:8
402:16
412:1
413:8

uptake 630:9

upward
565:11

usage 329:4
413:9
494:3,19
521:5
568:19
617:24

useful
347:24
425:15
482:18
485:18

users
381:18,25
585:12

usual 496:9
557:3

usually
410:4
418:8,19
488:24
520:22
572:20

ut 617:10

utilities
321:3,21
375:16
383:13
387:3,18
391:1
397:23
403:6
419:1,3,6,11,16
420:7,9,13,20
432:8,18
440:20
442:4
456:11,12,17,19
457:3,7,21
463:14,22
486:22
617:10
618:9

utility
385:18
386:13
404:7
418:9
432:13
438:19
439:8,9
440:2,11
441:4,7,11,16
445:1,5
452:14
453:12
454:18
455:3,22
456:11
457:11
458:3
459:1
460:3,11
462:3,9
471:25
595:13
621:17

utility's

441:5
458:10
461:4,22
463:4

utilize
408:22

V

vagaries
586:12,13

Valley 387:5

valuable
396:11
454:20
500:12

value
345:21,22
346:5,9
347:9
385:22
394:11
396:9
431:17,18,20,22
432:2,23,25 433:1,2
434:18
435:18,20,24 436:7
441:4,12
442:11
445:11
453:24
454:1,4
455:10
461:13,20
462:1
468:9,12
470:2
477:19,21
478:2,5,6
479:4
480:4
483:5
497:22,25
498:7,18,19,20 500:8
501:4
503:24
515:5
596:2

valued
500:13

values 332:8
342:24
403:22
411:10
454:16

var 583:23

variability
589:10
611:21
612:2,22
615:13

variable
536:20
537:22

variables
334:20,21,22,23,24,25 335:3
346:7

variation
507:9
511:5
515:9,16
516:1
563:21
564:12
566:3,13,19 583:24
622:18

variations
456:20
564:10

varied
479:25

varies 433:9
580:18

variety
407:13
413:6,7
440:21

various
380:18
384:5
435:6
597:23,24
602:9,19
607:22
622:10

vary 324:19
419:25
597:8,12,13

vast 404:8

ventilation
527:10,17
555:1

venturing
594:16

verify
520:18

verison
439:24

version
438:24
439:1

versus 494:3
502:18
503:14
505:17
520:13
537:7
539:13
630:14

viable 610:2

vice 378:20
382:20

vicinity
620:4

view 403:4
416:9
438:17
493:14
533:25
609:1
610:22

views 397:2

visual
627:14

visualize
576:1

voice 378:14

Vol 371:14

volatility
493:1,3

volt 596:21

voltage
596:4,5,10

Volume 372:8
373:5
467:1,7
551:15

Volumes
340:9,13

vs 327:13
349:13

W

WACC 344:11

wait 594:1
614:10

waiting
481:20
543:21

walk 397:9
399:10
400:7
411:17
458:13
548:13,25
594:13

warm 566:8

warmer
532:16

washers
413:2

Washington
420:5,13

wasn't
470:3,15
471:5
475:10
482:17
485:21,25
487:22
506:6
511:16
602:2

waste 611:11

water 326:23
348:22
349:13
387:5
441:25
443:3
445:9
455:25
500:7
522:7
528:1
548:21
549:24
552:17
553:19,23
554:8,9,17
555:6,7,9

Watershed
347:24

watt 633:2

watts 633:4

wave 617:10

Waverley
451:1,3

ways 435:5,8
578:25

weather
326:21,22
424:1
490:3,10
556:24,25
560:10,11
565:21
567:15

weather-normalized
490:11

website
542:3,5

we'd 412:9
422:8
425:3
443:24
511:5
609:7

wedge 417:12

week 493:22
496:25
600:23
608:22

623:7,15
624:1
625:5,10
628:21
631:15

weeks 514:5

week's 601:3
603:1

weight
513:19

Weinstein
322:21

welcome
388:8
623:22

we'll 377:23
389:2,14
394:10
395:17
397:16
400:7
404:15
409:18,24
437:6
442:25
444:20
484:14
493:1
494:14
507:20
521:10
529:23
530:14
551:10
566:12
581:24
592:8
599:15
600:6
624:1
636:14

well-vetted
399:5

we're 375:4
390:10,21
392:2,20
393:10,12,23,24
394:2,4,20
404:14
408:1,2
413:13
422:10
423:7
430:22
434:10
437:11,13,17
444:13,14
445:2,3,4,15 449:9
452:21
453:1
454:14
456:21
457:11
462:20
466:1,15
467:21
468:21
471:14
472:11,17
474:1
476:19
483:10,11,24
484:12,19,22 498:17
501:23
502:17,19
508:15
510:22
511:23
516:5,6,18
517:24
518:19
522:22
523:15
524:6
526:8,10
527:2
528:16
529:21
532:6,8,23
534:2,12
540:12
541:5,18,20 542:2
545:25
546:13
550:15
556:10
563:12
566:2,3,6,11 574:17
575:8,20,21
582:20,21
583:2,8,10
585:10,13,19
588:2,3,5
594:6,9,14
596:21,24
597:2
609:3,8,10
621:11
624:6,15
630:13
632:15
633:21

West 451:1,3

we've
398:8,16
416:8
420:12
422:11
426:6,11
441:22
442:25
453:5
468:25
469:2,17
470:5
472:14,16
473:2,3,5
475:3
483:3,13
492:17
493:4
502:7
517:19
522:21
523:13,14
528:9
529:16,20
530:14
537:16,21
540:15
541:15,16
542:11,15
565:19
566:1
568:16
579:10,25
582:1,2
583:17
584:15,16
589:3
602:8
608:25
612:8
620:3
622:23
630:5
633:25

wha 444:3

whack 584:20
585:1

whatever
482:16
483:3
525:22

WHELAN
488:25

whenever
390:2,4

whereas
457:22
511:23

whereby
421:3

wherein
622:5

whether
373:15,17
414:2
436:3
437:21
441:14
447:3
464:6
474:18
487:23,24
498:15
499:1
529:1
530:1
531:3,12
539:12
545:22
600:1,3,14,17 606:1
611:12

white 407:14
413:3
543:18
547:9

whole 478:12
497:13
539:9
581:20,21
584:9,20

whom 426:17

who's 378:18
379:7,12
432:11

wi 421:16

wide 413:6
500:1
578:23

widespread
402:7

wilderness
378:14

William
322:10
388:2

Williams
322:8
377:21,22
387:22
466:3,4,24

willing
445:3,4,15
449:22
450:2
461:24
462:7,20
482:8
532:16

wind 328:4
343:23,24
344:25
345:3
349:25
350:3
369:10,11,12,13,14,15,16,17,18,19,20,21,22 608:2

window 581:4

Winnipeg

321:23
347:23
349:23
409:15
514:2
540:9
541:5
561:4

winter
478:19
490:12
557:2
614:22
615:6

winter-peaking
614:20

wintertime
445:15
481:21

wireless
556:14

wisely 485:1

wish 387:20
636:4

witness
371:22,24
376:13,16,20,24
387:24
494:12

witnesses
487:2

Wojczynski
323:12
377:12
378:12,15
379:12,23
478:4,5
480:6
485:14,15,19
488:12,19,22 489:7
490:20,22
491:7,15,21,25
492:9,14
493:12
494:7,11,14 496:24
497:8,12,19 498:3,13
499:3,10,20,24
500:21
501:12,19,22
502:4,15
503:9
509:1
523:5
592:11,17,21 594:1
595:5,10,25
596:16,18
597:16
598:13,23
599:3,5,8,11,14,19,22 600:6,21
601:9,17,25
602:13,25
603:11
608:19,20
623:10,14,19,21,23
625:8,22
626:10,15
627:13
629:5
631:3,11,14 634:1

Wojczynski's
374:5
623:4
626:23
627:5

women 402:11

wonder
466:15
504:24
636:7

wondering
395:8
422:25
529:1
549:22
567:18
623:9
631:7
634:5

wood 520:7

work 326:13
351:21
386:10
393:16,25
398:20
403:21
411:15
417:18
451:10
453:4
469:17
482:4
489:16
502:6
536:13
546:13,14
577:19
622:11

worked
380:18
398:3,12
399:1
420:12

working
381:1
383:3
384:4
406:23
450:25
452:8,17
453:1
463:3
471:14
541:8
542:13,16
543:25
563:9

world
433:15,16
435:25
436:11
457:14,20
461:7
462:10
578:23

worse
492:2,12
493:4,17

worst 491:20
492:3,11,12,16
493:10,11,15

worth
445:13,16
495:25
521:13,14
525:4

worthless
516:2

writ 409:13

write 489:14

writing
592:24

wrong 392:11
580:10

Wuskwatim
328:20,21
330:21,24
332:15

X

Xcel 617:12

Y

yard 452:3

year-by
584:7

year-by-year
517:9
583:15
629:8

yearly
458:22

year-over-year
561:20
601:6
627:21

year's
479:14
525:3

year-to-year
501:5
583:24

yesterday
376:6
377:7,12
378:15,16
392:12
466:25
467:2
485:14,20
487:16,21
493:13
530:20
543:2
592:11
623:5,16

yet 482:18
489:19
508:14
534:4
571:5
573:22
625:1
626:8
627:13
629:22

yields
347:20

you'll 433:7
434:10
446:9
448:13
451:18
452:2
513:15,16
515:10
579:23
592:22,23
598:8,16

yourself
578:19
613:3
616:9
617:24

you've
423:17,18
461:15
492:12
498:19
501:8
502:1
508:14

511:19
513:18
515:7,25
529:1,2,3
543:13
546:22
561:10
563:4
571:16,23,
24 573:9
574:17
589:11
604:11
605:21
608:3
615:1,7
618:22
625:19
633:23

Z

zero
426:4,11
515:14
536:22
537:1
548:19,20
632:14

zone 622:18

Tab 52

REFERENCE: Appendix C 2012 Electric Load Forecast and Appendix 4.2

QUESTION:

Please provide supply and demand tables for the "no new resources" and for the Preferred Plan showing the situation if the PLIL projected to arise by 2031/32 had fully arrived on the system by 2019/20 (6 years from today) and no further growth in PLIL arrives after that time through 2031/32 such that for all periods after 2031/32 the load forecast is unaffected.

RESPONSE:

Provided below are the requested Supply and Demand Tables with the 2012 Electric Load Forecast altered such that the PLIL growth that was previously forecast over the 17 years at 100 GWh per year starting from 2015/16 to 2031/32 has now been added to the forecast from years 2014/15 to 2018/19 such that total growth of the 1700 GWh for the PLIL group are now completely added by 2019/20. This equates to approximately 370 GWh and 50 MW per year growth from 2014/15 to 2018/19 and 0 from that point on such that the 2031/32 fiscal year and beyond remains the same as the original Load Forecast. No changes to the amount and timing of new resources for the Preferred Development Plan Supply and Demand Tables were made to reflect these load changes.

Date: October 4, 2013

System Firm Winter Peak Demand and Capacity Resources (MW) @ generation
NFAT 2012 Reference
MIPUG-0043b No New Resources with modified load

	Fiscal Year	2030/31	2031/32	2032/33	2033/34	2034/35	2035/36	2036/37	2037/38	2038/39	2039/40	2040/41	2041/42	2042/43	2043/44	2044/45	2045/46	2046/47	2047/48
	Power Resources																		
	New Power Resources																		
	New Hydro																		
	Conawapa																		
	Keeyask																		
1	**Total New Hydro**																		
	New Thermal																		
	SCGT																		
	CCGT																		
2	**Total New Thermal**																		
	New Imports																		
	Contracted																		
	Proposed																		
3	**Total New Imports**																		
4	**Total New Power Resources** 1+2+3																		
	Base Supply Power Resources																		
	Existing Hydro	5 177	5 177	5 177	5 177	5 177	5 177	5 177	5 177	5 177	5 177	5 177	5 177	5 177	5 177	5 177	5 177	5 177	5 177
	Existing Thermal																		
	Brandon Coal - Unit 5																		
	Selkirk Gas	132	132	132	132	132	132	132	132	132	132	132	132	132	132	132	132	132	132
	Brandon Units 6-7 SCGT	280	280	280	280	280	280	280	280	280	280	280	280	280	280	280	280	280	280
	Contracted Imports																		
	Proposed Imports																		
	Pointe du Bois Rebuild	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43
	Bipole III Reduced Losses	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90
5	**Total Base Supply Power Resources**	**5 722**	**5 722**	**5 722**	**5 722**	**5 722**	**5 722**	**5 722**	**5 722**	**5 722**	**5 722**	**5 722**	**5 722**	**5 722**	**5 722**	**5 722**	**5 722**	**5 722**	**5 722**
6	**Total Power Resources** 4+5	**5 722**	**5 722**	**5 722**	**5 722**	**5 722**	**5 722**	**5 722**	**5 722**	**5 722**	**5 722**	**5 722**	**5 722**	**5 722**	**5 722**	**5 722**	**5 722**	**5 722**	**5 722**
	Peak Demand																		
	2012 Modified Load Forecas	5 963	6 032	6 116	6 200	6 284	6 368	6 452	6 537	6 621	6 705	6 789	6 873	6 957	7 042	7 126	7 210	7 294	7 378
	Less: 2012 Base DSM Forecast	- 190	- 189	- 185	- 178	- 172	- 166	- 161	- 154	- 146	- 138	- 131	- 124	- 117	- 110	- 102	- 95	- 88	- 81
7	**Manitoba Net Load**	5 773	5 843	5 931	6 022	6 112	6 202	6 291	6 383	6 475	6 567	6 658	6 749	6 840	6 932	7 024	7 115	7 206	7 297
	Contracted Exports																		
	Proposed Exports																		
8	**Total Exports**																		
9	**Total Peak Demand** 7+8	**5 773**	**5 843**	**5 931**	**6 022**	**6 112**	**6 202**	**6 291**	**6 383**	**6 475**	**6 567**	**6 658**	**6 749**	**6 840**	**6 932**	**7 024**	**7 115**	**7 206**	**7 297**
10	Reserves	693	701	712	723	733	744	755	766	777	788	799	810	821	832	843	854	865	876
11	**System Surplus/(Deficit)** 6-9-10	**(744)**	**(822)**	**(921)**	**(1 023)**	**(1 123)**	**(1 224)**	**(1 324)**	**(1 427)**	**(1 530)**	**(1 633)**	**(1 735)**	**(1 837)**	**(1 939)**	**(2 042)**	**(2 145)**	**(2 247)**	**(2 349)**	**(2 451)**
12	Less: Brandon Unit 5																		
	Exportable Surplus 11+12																		

1

Date: October 4, 2013

System Firm Energy Demand and Dependable Resources (GWh) @ generation
NFAT 2012 Reference
MIPUG-0043b No New Resources with modified load

	Fiscal Year		2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30
	Power Resources																			
	New Power Resources																			
	New Hydro																			
	Conawapa																			
	Keeyask																			
1	**Total New Hydro**																			
	New Thermal																			
	SCGT																			
	CCGT																			
2	**Total New Thermal**																			
	New Imports																			
	Contracted																			
	Proposed																			
3	**Total New Imports**																			
4	New Wind																			
5	**Total New Power Resources**	1+2+3+4																		
	Base Supply Power Resources																			
	Existing Hydro		21 697	21 950	21 940	21 930	21 910	21 890	21 880	21 860	21 850	21 840	21 830	21 830	21 820	21 810	21 810	21 800	21 790	21 790
	Existing Thermal																			
	Brandon Coal - Unit 5		811	811	811	811	811	811	811	592										
	Selkirk Gas		953	953	953	953	953	953	953	953	953	953	953	953	953	953	953	953	953	953
	Brandon Units 6-7 SCGT		2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354
	Contracted Imports		2 705	2 705	1 949	1 549	1 639	1 639	1 639	1 639	1 639	1 639	1 639	1 639	1 639	271				
	Proposed Imports				781	936	936	936	936	936	936	936	936	936	936	155				
	Hydro Adjustment		340	340	373	784	844	844	844	844	844	844	844	844	844	139				
	Market Purchases		363	363	338	583	493	493	493	493	493	493	493	493	493	2 641	3 068	3 068	3 068	3 068
	Existing Wind		766	777	777	777	777	777	777	777	777	777	777	777	777	777	777	777	777	777
	Pointe du Bois Rebuild																			
	Bipole III Reduced Losses							239	239	239	239	239	239	239	239	239	239	239	239	239
6	**Total Base Supply Power Resources**		**29 989**	**30 253**	**30 276**	**30 677**	**30 717**	**30 936**	**30 926**	**30 687**	**30 085**	**30 075**	**30 065**	**30 065**	**30 055**	**29 339**	**29 201**	**29 191**	**29 181**	**29 181**
7	**Total Power Resources**	5+6	**29 989**	**30 253**	**30 276**	**30 677**	**30 717**	**30 936**	**30 926**	**30 687**	**30 085**	**30 075**	**30 065**	**30 065**	**30 055**	**29 339**	**29 201**	**29 191**	**29 181**	**29 181**
	Manitoba Domestic Load																			
	2012 Modified Load Forecas		24 961	25 734	26 071	26 763	27 416	28 236	29 094	29 283	29 651	29 996	30 346	30 689	31 035	31 373	31 707	32 049	32 394	32 738
	Construction Power - Hydro															10	20	30	30	35
	Less: 2012 Base DSM Forecast		- 62	- 173	- 271	- 356	- 436	- 509	- 583	- 643	- 693	- 740	- 782	- 805	- 820	- 841	- 865	- 866	- 850	- 832
8	**Manitoba Net Load**		**24 899**	**25 561**	**25 800**	**26 407**	**26 980**	**27 727**	**28 511**	**28 640**	**28 958**	**29 256**	**29 564**	**29 884**	**30 215**	**30 542**	**30 862**	**31 213**	**31 574**	**31 941**
	Contracted Exports		3 293	3 156	3 156	2 115	2 012	2 012	2 012	2 012	2 012	2 012	2 012	2 012	2 012	249	145	145	145	145
	Proposed Exports					162	162	162	162	162	162	162	162	162	162					
	Less: Adverse Water		- 91			- 309	- 370	- 370	- 370	- 370	- 370	- 370	- 370	- 370	- 370	- 61				
9	**Total Net Exports**		**3 202**	**3 156**	**3 156**	**1 968**	**1 804**	**1 804**	**1 804**	**1 804**	**1 804**	**1 804**	**1 804**	**1 804**	**1 804**	**188**	**145**	**145**	**145**	**145**
10	**Total Energy Demand**	8+9	**28 101**	**28 717**	**28 956**	**28 375**	**28 784**	**29 531**	**30 315**	**30 444**	**30 762**	**31 060**	**31 368**	**31 688**	**32 019**	**30 730**	**31 007**	**31 358**	**31 719**	**32 086**
11	**System Surplus/(Deficit)**	7-10	**1 888**	**1 536**	**1 320**	**2 302**	**1 933**	**1 405**	**611**	**243**	**(677)**	**(985)**	**(1303)**	**(1623)**	**(1 964)**	**(1 391)**	**(1 806)**	**(2 167)**	**(2 538)**	**(2 905)**
12	Less : Brandon Unit 5		- 811	- 811	- 811	- 811	- 811	- 811	- 811	- 592										
13	Adverse Water		- 91			- 309	- 370	- 370	- 370	- 370	- 370	- 370	- 370	- 370	- 370	- 61				
	Exportable Surplus	11+12+13	**986**	**725**	**509**	**1 182**	**752**	**224**												

1

Date: October 4, 2013

System Firm Energy Demand and Dependable Resources (GWh) @ generation
NFAT 2012 Reference
MIPUG-0043b No New Resources with modified load

	Fiscal Year		2030/31	2031/32	2032/33	2033/34	2034/35	2035/36	2036/37	2037/38	2038/39	2039/40	2040/41	2041/42	2042/43	2043/44	2044/45	2045/46	2046/47	2047/48
	Power Resources																			
	New Power Resources																			
	New Hydro																			
	Conawapa																			
	Keeyask																			
1	**Total New Hydro**																			
	New Thermal																			
	SCGT																			
	CCGT																			
2	**Total New Thermal**																			
	New Imports																			
	Contracted																			
	Proposed																			
3	**Total New Imports**																			
4	New Wind																			
5	**Total New Power Resources**	1+2+3+4																		
	Base Supply Power Resources																			
	Existing Hydro		21 780	21 780	21 770	21 760	21 760	21 750	21 740	21 740	21 730	21 730	21 720	21 710	21 710	21 700	21 690	21 690	21 680	21 670
	Existing Thermal																			
	Brandon Coal - Unit 5																			
	Selkirk Gas		953	953	953	953	953	953	953	953	953	953	953	953	953	953	953	953	953	953
	Brandon Units 6-7 SCGT		2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354
	Contracted Imports																			
	Proposed Imports																			
	Hydro Adjustment																			
	Market Purchases		3 068	3 068	3 068	3 068	3 068	3 068	3 068	3 068	3 068	3 068	3 068	3 068	3 068	3 068	3 068	3 068	3 068	3 068
	Existing Wind		777	777	777	777	777	777	777	777	777	777	777	777	777	777	777	777	777	777
	Pointe du Bois Rebuild		60	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150
	Bipole III Reduced Losses		239	239	239	239	239	239	239	239	239	239	239	239	239	239	239	239	239	239
6	**Total Base Supply Power Resources**		**29 231**	**29 321**	**29 311**	**29 301**	**29 301**	**29 291**	**29 281**	**29 281**	**29 271**	**29 271**	**29 261**	**29 251**	**29 251**	**29 241**	**29 231**	**29 231**	**29 221**	**29 211**
7	**Total Power Resources**	5+6	**29 231**	**29 321**	**29 311**	**29 301**	**29 301**	**29 291**	**29 281**	**29 281**	**29 271**	**29 271**	**29 261**	**29 251**	**29 251**	**29 241**	**29 231**	**29 231**	**29 221**	**29 211**
	Manitoba Domestic Load																			
	2012 Modified Load Forecas		33 081	33 425	33 882	34 340	34 798	35 255	35 713	36 170	36 628	37 085	37 543	38 001	38 458	38 916	39 373	39 831	40 288	40 746
	Construction Power - Hydro		30	10																
	Less: 2012 Base DSM Forecast		- 816	- 803	- 779	- 743	- 711	- 682	- 657	- 628	- 598	- 568	- 540	- 516	- 487	- 459	- 431	- 404	- 377	- 349
8	**Manitoba Net Load**		**32 295**	**32 632**	**33 103**	**33 597**	**34 087**	**34 573**	**35 056**	**35 542**	**36 030**	**36 517**	**37 003**	**37 485**	**37 971**	**38 457**	**38 942**	**39 427**	**39 911**	**40 397**
	Contracted Exports		145	145	145	145	145	145	145	145	145	145	145	145	145	145	145	145	145	145
	Proposed Exports																			
	Less: Adverse Water																			
9	**Total Net Exports**		**145**	**145**	**145**	**145**	**145**	**145**	**145**	**145**	**145**	**145**	**145**	**145**	**145**	**145**	**145**	**145**	**145**	**145**
10	**Total Energy Demand**	8+9	**32 440**	**32 777**	**33 248**	**33 742**	**34 232**	**34 718**	**35 201**	**35 687**	**36 175**	**36 662**	**37 148**	**37 630**	**38 116**	**38 602**	**39 087**	**39 572**	**40 056**	**40 542**
11	**System Surplus/(Deficit)**	7-10	**(3 209)**	**(3 456)**	**(3 937)**	**(4 441)**	**(4 931)**	**(5 427)**	**(5 920)**	**(6 406)**	**(6 904)**	**(7 391)**	**(7 887)**	**(8 379)**	**(8 865)**	**(9 361)**	**(9 856)**	**(10 341)**	**(10 835)**	**(11 331)**
12	Less : Brandon Unit 5																			
13	Adverse Water																			
	Exportable Surplus	11+12+13																		

1

Date: October 4, 2013

System Firm Winter Peak Demand and Capacity Resources (MW) @ generation
NFAT 2012 Reference
MIPUG-0043b Preferred Development Plan with modified load

	Fiscal Year		2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30
	Power Resources																			
	New Power Resources																			
	New Hydro																			
	Conawapa															520	1 040	1 300	1 300	1 300
	Keeyask									90	450	630	630	630	630	630	630	630	630	630
1	**Total New Hydro**									90	450	630	630	630	630	1 150	1 670	1 930	1 930	1 930
	New Thermal																			
	SCGT																			
	CCGT																			
2	**Total New Thermal**																			
	New Imports																			
	Contracted																			
	Proposed																			
3	**Total New Imports**																			
4	**Total New Power Resources**	1+2+3								**90**	**450**	**630**	**630**	**630**	**630**	**1 150**	**1 670**	**1 930**	**1 930**	**1 930**
	Base Supply Power Resources																			
	Existing Hydro		5 166	5 177	5 177	5 177	5 177	5 177	5 177	5 177	5 177	5 177	5 177	5 177	5 177	5 177	5 177	5 177	5 177	5 177
	Existing Thermal																			
	Brandon Coal - Unit 5		105	105	105	105	105	105	105											
	Selkirk Gas		132	132	132	132	132	132	132	132	132	132	132	132	132	132	132	132	132	132
	Brandon Units 6-7 SCGT		280	280	280	280	280	280	280	280	280	280	280	280	280	280	280	280	280	280
	Contracted Imports		550	550	385	385	385	385	385	385	385	385	385	385	385					
	Proposed Imports				220	220	220	220	220	220	220	220	220	220	220					
	Pointe du Bois Rebuild																			
	Bipole III Reduced Losses							90	90	90	79	79	79	79	79	79	18	18	18	18
5	**Total Base Supply Power Resources**		**6 233**	**6 244**	**6 299**	**6 299**	**6 299**	**6 389**	**6 389**	**6 284**	**6 273**	**6 273**	**6 273**	**6 273**	**6 273**	**5 668**	**5 607**	**5 607**	**5 607**	**5 607**
6	**Total Power Resources**	4+5	**6 233**	**6 244**	**6 299**	**6 299**	**6 299**	**6 389**	**6 389**	**6 374**	**6 723**	**6 903**	**6 903**	**6 903**	**6 903**	**6 818**	**7 277**	**7 537**	**7 537**	**7 537**
	Peak Demand																			
	2012 Modified Load Forecast		4 491	4 609	4 676	4 789	4 895	5 025	5 162	5 210	5 280	5 348	5 416	5 485	5 554	5 622	5 689	5 757	5 826	5 894
	Less: 2012 Base DSM Forecast		- 12	- 36	- 58	- 77	- 95	- 111	- 127	- 142	- 154	- 165	- 176	- 181	- 185	- 189	- 194	- 195	- 193	- 191
7	**Manitoba Net Load**		4 479	4 573	4 618	4 712	4 800	4 914	5 035	5 068	5 126	5 183	5 240	5 304	5 369	5 433	5 495	5 562	5 633	5 703
	Contracted Exports		605	605	605	358	358	358	358	358	633	880	880	880	880	385	385	275	275	275
	Proposed Exports				119	119	119	119	119	119	119						220	330	330	330
8	**Total Exports**		605	605	724	477	477	477	477	477	752	880	880	880	880	385	605	605	605	605
9	**Total Peak Demand**	7+8	**5 084**	**5 178**	**5 342**	**5 189**	**5 277**	**5 391**	**5 512**	**5 545**	**5 878**	**6 063**	**6 120**	**6 184**	**6 249**	**5 818**	**6 100**	**6 167**	**6 238**	**6 308**
10	Reserves		463	483	508	565	576	590	604	608	615	622	629	636	644	652	659	667	676	684
11	**System Surplus/(Deficit)**	6-9-10	**686**	**583**	**449**	**545**	**446**	**408**	**273**	**221**	**230**	**218**	**154**	**83**	**10**	**348**	**518**	**703**	**623**	**545**
12	Less: Brandon Unit 5		- 105	- 105	- 105	- 105	- 105	- 105	- 105											
	Exportable Surplus	11+12	**581**	**478**	**344**	**440**	**341**	**303**	**168**	**221**	**230**	**218**	**154**	**83**	**10**	**348**	**518**	**703**	**623**	**545**

1

Date: October 4, 2013

System Firm Winter Peak Demand and Capacity Resources (MW) @ generation
NFAT 2012 Reference
MIPUG-0043b Preferred Development Plan with modified load

	Fiscal Year		2030/31	2031/32	2032/33	2033/34	2034/35	2035/36	2036/37	2037/38	2038/39	2039/40	2040/41	2041/42	2042/43	2043/44	2044/45	2045/46	2046/47	2047/48
	Power Resources																			
	New Power Resources																			
	New Hydro																			
	Conawapa		1 300	1 300	1 300	1 300	1 300	1 300	1 300	1 300	1 300	1 300	1 300	1 300	1 300	1 300	1 300	1 300	1 300	1 300
	Keeyask		630	630	630	630	630	630	630	630	630	630	630	630	630	630	630	630	630	630
1	**Total New Hydro**		1 930	1 930	1 930	1 930	1 930	1 930	1 930	1 930	1 930	1 930	1 930	1 930	1 930	1 930	1 930	1 930	1 930	1 930
	New Thermal																			
	SCGT													245	245	245	490	490	735	735
	CCGT																			
2	**Total New Thermal**													245	245	245	490	490	735	735
	New Imports																			
	Contracted																			
	Proposed																			
3	**Total New Imports**																			
4	**Total New Power Resources**	1+2+3	**1 930**	**1 930**	**1 930**	**1 930**	**1 930**	**1 930**	**1 930**	**1 930**	**1 930**	**1 930**	**1 930**	**2 175**	**2 175**	**2 175**	**2 420**	**2 420**	**2 665**	**2 665**
	Base Supply Power Resources																			
	Existing Hydro		5 177	5 177	5 177	5 177	5 177	5 177	5 177	5 177	5 177	5 177	5 177	5 177	5 177	5 177	5 177	5 177	5 177	5 177
	Existing Thermal																			
	Brandon Coal - Unit 5																			
	Selkirk Gas		132	132	132	132	132	132	132	132	132	132	132	132	132	132	132	132	132	132
	Brandon Units 6-7 SCGT		280	280	280	280	280	280	280	280	280	280	280	280	280	280	280	280	280	280
	Contracted Imports																			
	Proposed Imports																			
	Pointe du Bois Rebuild		43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43
	Bipole III Reduced Losses		18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18
5	**Total Base Supply Power Resources**		**5 650**	**5 650**	**5 650**	**5 650**	**5 650**	**5 650**	**5 650**	**5 650**	**5 650**	**5 650**	**5 650**	**5 650**	**5 650**	**5 650**	**5 650**	**5 650**	**5 650**	**5 650**
6	**Total Power Resources**	4+5	**7 580**	**7 580**	**7 580**	**7 580**	**7 580**	**7 580**	**7 580**	**7 580**	**7 580**	**7 580**	**7 580**	**7 825**	**7 825**	**7 825**	**8 070**	**8 070**	**8 315**	**8 315**
	Peak Demand																			
	2012 Modified Load Forecast		5 963	6 032	6 116	6 200	6 284	6 368	6 452	6 537	6 621	6 705	6 789	6 873	6 957	7 042	7 126	7 210	7 294	7 378
	Less: 2012 Base DSM Forecast		- 190	- 189	- 185	- 178	- 172	- 166	- 161	- 154	- 146	- 138	- 131	- 124	- 117	- 110	- 102	- 95	- 88	- 81
7	**Manitoba Net Load**		5 773	5 843	5 931	6 022	6 112	6 202	6 291	6 383	6 475	6 567	6 658	6 749	6 840	6 932	7 024	7 115	7 206	7 297
	Contracted Exports		275	275	275	275	275													
	Proposed Exports		330	330	330	330	330	330												
8	**Total Exports**		605	605	605	605	605	330												
9	**Total Peak Demand**	7+8	**6 378**	**6 448**	**6 536**	**6 627**	**6 717**	**6 532**	**6 291**	**6 383**	**6 475**	**6 567**	**6 658**	**6 749**	**6 840**	**6 932**	**7 024**	**7 115**	**7 206**	**7 297**
10	Reserves		693	701	712	723	733	744	755	766	777	788	799	810	821	832	843	854	865	876
11	**System Surplus/(Deficit)**	6-9-10	**509**	**431**	**332**	**230**	**130**	**304**	**534**	**431**	**328**	**225**	**123**	**266**	**164**	**61**	**203**	**101**	**244**	**142**
12	Less: Brandon Unit 5																			
	Exportable Surplus	11+12	**509**	**431**	**332**	**230**	**130**	**304**	**534**	**431**	**328**	**225**	**123**	**266**	**164**	**61**	**203**	**101**	**244**	**142**

1

Date: October 4, 2013

System Firm Energy Demand and Dependable Resources (GWh) @ generation
NFAT 2012 Reference
MIPUG-0043b Preferred Development Plan with modified load

	Fiscal Year		2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30
	Power Resources																			
	New Power Resources																			
	New Hydro																			
	Conawapa															2 198	4 650	4 650	4 650	4 650
	Keeyask									493	2 974	3 003	3 003	3 003	3 003	3 003	3 003	3 003	3 003	3 003
1	**Total New Hydro**									**493**	**2 974**	**3 003**	**3 003**	**3 003**	**3 003**	**5 201**	**7 653**	**7 653**	**7 653**	**7 653**
	New Thermal																			
	SCGT																			
	CCGT																			
2	**Total New Thermal**																			
	New Imports																			
	Contracted										928	1 113	1 113	1 113	1 113	1 113	1 113	1 113	1 113	1 113
	Proposed																742	1 262	1 336	1 336
3	**Total New Imports**										**928**	**1 113**	**1 113**	**1 113**	**1 113**	**1 113**	**1 855**	**2 375**	**2 449**	**2 449**
4	New Wind																			
5	**Total New Power Resources**	1+2+3+4								**493**	**3 902**	**4 116**	**4 116**	**4 116**	**4 116**	**6 314**	**9 508**	**10 028**	**10 102**	**10 102**
	Base Supply Power Resources																			
	Existing Hydro		21 697	21 950	21 940	21 930	21 910	21 890	21 880	21 860	21 850	21 840	21 830	21 830	21 820	21 810	21 810	21 800	21 790	21 790
	Existing Thermal																			
	Brandon Coal - Unit 5		811	811	811	811	811	811	811	592										
	Selkirk Gas		953	953	953	953	953	953	953	953	953	953	953	953	953	953	953	953	953	953
	Brandon Units 6-7 SCGT		2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354
	Contracted Imports		2 705	2 705	1 949	1 549	1 639	1 639	1 639	1 639	1 639	1 639	1 639	1 639	1 639	271				
	Proposed Imports				781	936	936	936	936	936	936	936	936	936	936	155				
	Hydro Adjustment		340	340	373	784	844	844	844	844	844	844	844	844	844	139				
	Market Purchases		363	363	338	583	493	493	493	493	957	1 050	1 050	1 050	1 050	3 198	2 882	2 363	2 288	2 288
	Existing Wind		766	777	777	777	777	777	777	777	777	777	777	777	777	777	777	777	777	777
	Pointe du Bois Rebuild																			
	Bipole III Reduced Losses							239	239	239	243	243	243	243	243	243	151	151	151	151
6	**Total Base Supply Power Resources**		**29 989**	**30 253**	**30 276**	**30 677**	**30 717**	**30 936**	**30 926**	**30 687**	**30 553**	**30 636**	**30 626**	**30 626**	**30 616**	**29 900**	**28 927**	**28 398**	**28 313**	**28 313**
7	**Total Power Resources**	5+6	**29 989**	**30 253**	**30 276**	**30 677**	**30 717**	**30 936**	**30 926**	**31 180**	**34 455**	**34 752**	**34 742**	**34 742**	**34 732**	**36 214**	**38 435**	**38 426**	**38 415**	**38 415**
	Manitoba Domestic Load																			
	2012 Modified Load Forecast		24 961	25 734	26 071	26 763	27 416	28 236	29 094	29 283	29 651	29 996	30 346	30 689	31 035	31 373	31 707	32 049	32 394	32 738
	Construction Power - Hydro			10	25	50	50	80	100	70	55	50	55	80	100	100	50	35	30	35
	Less: 2012 Base DSM Forecast		- 62	- 173	- 271	- 356	- 436	- 509	- 583	- 643	- 693	- 740	- 782	- 805	- 820	- 841	- 865	- 866	- 850	- 832
8	**Manitoba Net Load**		**24 899**	**25 571**	**25 825**	**26 457**	**27 030**	**27 807**	**28 611**	**28 710**	**29 013**	**29 306**	**29 619**	**29 964**	**30 315**	**30 632**	**30 892**	**31 218**	**31 574**	**31 941**
	Contracted Exports		3 293	3 156	3 156	2 115	2 012	2 012	2 012	2 012	3 048	4 191	4 314	4 314	4 314	2 031	1 887	1 472	1 389	1 389
	Proposed Exports				448	699	699	699	699	699	699	252	162	162	162		829	1 410	1 493	1 493
	Less: Adverse Water		- 91			- 309	- 370	- 370	- 370	- 370	- 370	- 489	- 513	- 513	- 513	- 85				
9	**Total Net Exports**		**3 202**	**3 156**	**3 604**	**2 505**	**2 341**	**2 341**	**2 341**	**2 341**	**3 377**	**3 954**	**3 963**	**3 963**	**3 963**	**1 946**	**2 716**	**2 882**	**2 882**	**2 882**
10	**Total Energy Demand**	8+9	**28 101**	**28 727**	**29 429**	**28 962**	**29 371**	**30 148**	**30 952**	**31 051**	**32 390**	**33 260**	**33 582**	**33 927**	**34 278**	**32 578**	**33 608**	**34 100**	**34 456**	**34 823**
11	**System Surplus/(Deficit)**	7-10	**1 888**	**1 526**	**847**	**1 715**	**1 346**	**788**	**(26)**	**129**	**2 065**	**1 492**	**1160**	**815**	**454**	**3 636**	**4 827**	**4 326**	**3 959**	**3 592**
12	Less : Brandon Unit 5		- 811	- 811	- 811	- 811	- 811	- 811	- 811	- 592										
13	Adverse Water		- 91			- 309	- 370	- 370	- 370	- 370	- 370	- 489	- 513	- 513	- 513	- 85				
	Exportable Surplus	11+12+13	**986**	**715**	**36**	**595**	**165**				**1 695**	**1 003**	**647**	**302**		**3 551**	**4 827**	**4 326**	**3 959**	**3 592**

1

Date: October 4, 2013

System Firm Energy Demand and Dependable Resources (GWh) @ generation
NFAT 2012 Reference
MIPUG-0043b Preferred Development Plan with modified load

	Fiscal Year		2030/31	2031/32	2032/33	2033/34	2034/35	2035/36	2036/37	2037/38	2038/39	2039/40	2040/41	2041/42	2042/43	2043/44	2044/45	2045/46	2046/47	2047/48
	Power Resources																			
	New Power Resources																			
	New Hydro																			
	Conawapa		4 650	4 650	4 650	4 650	4 650	4 650	4 650	4 650	4 650	4 650	4 650	4 650	4 650	4 650	4 650	4 650	4 650	4 650
	Keeyask		3 003	3 003	3 003	3 003	3 003	3 003	3 003	3 003	3 003	3 003	3 003	3 003	3 003	3 003	3 003	3 003	3 003	3 003
1	**Total New Hydro**		**7 653**	**7 653**	**7 653**	**7 653**	**7 653**	**7 653**	**7 653**	**7 653**	**7 653**	**7 653**	**7 653**	**7 653**	**7 653**	**7 653**	**7 653**	**7 653**	**7 653**	**7 653**
	New Thermal																			
	SCGT													1 857	1 857	1 857	1 857	3 714	3 714	3 714
	CCGT																			
2	**Total New Thermal**													**1 857**	**1 857**	**1 857**	**1 857**	**3 714**	**3 714**	**3 714**
	New Imports																			
	Contracted		1 113	1 113	1 113	1 113	1 113	186												
	Proposed		1 336	1 336	1 336	1 336	1 336	1 336	223											
3	**Total New Imports**		**2 449**	**2 449**	**2 449**	**2 449**	**2 449**	**1 522**	**223**											
4	New Wind																			
5	**Total New Power Resources**	1+2+3+4	**10 102**	**10 102**	**10 102**	**10 102**	**10 102**	**9 175**	**7 876**	**7 653**	**7 653**	**7 653**	**7 653**	**9 510**	**9 510**	**9 510**	**9 510**	**11 367**	**11 367**	**11 367**
	Base Supply Power Resources																			
	Existing Hydro		21 780	21 780	21 770	21 760	21 760	21 750	21 740	21 740	21 730	21 730	21 720	21 710	21 710	21 700	21 690	21 690	21 680	21 670
	Existing Thermal																			
	Brandon Coal - Unit 5																			
	Selkirk Gas		953	953	953	953	953	953	953	953	953	953	953	953	953	953	953	953	953	953
	Brandon Units 6-7 SCGT		2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354
	Contracted Imports																			
	Proposed Imports																			
	Hydro Adjustment																			
	Market Purchases		2 289	2 289	2 289	2 289	2 289	3 216	3 546	3 569	3 618	3 666	3 715	3 763	3 812	3 860	3 909	3 957	4 006	4 054
	Existing Wind		777	777	777	777	777	777	777	777	777	777	777	777	777	777	777	777	777	777
	Pointe du Bois Rebuild		60	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150
	Bipole III Reduced Losses		151	151	151	151	151	151	151	151	151	151	151	151	151	151	151	151	151	151
6	**Total Base Supply Power Resources**		**28 364**	**28 454**	**28 444**	**28 434**	**28 434**	**29 351**	**29 671**	**29 694**	**29 733**	**29 781**	**29 820**	**29 858**	**29 907**	**29 945**	**29 984**	**30 032**	**30 071**	**30 109**
7	**Total Power Resources**	5+6	**38 466**	**38 556**	**38 546**	**38 536**	**38 536**	**38 526**	**37 547**	**37 347**	**37 386**	**37 434**	**37 473**	**39 368**	**39 417**	**39 455**	**39 494**	**41 399**	**41 438**	**41 476**
	Manitoba Domestic Load																			
	2012 Modified Load Forecast		33 081	33 425	33 882	34 340	34 798	35 255	35 713	36 170	36 628	37 085	37 543	38 001	38 458	38 916	39 373	39 831	40 288	40 746
	Construction Power - Hydro		30	10																
	Less: 2012 Base DSM Forecast		- 816	- 803	- 779	- 743	- 711	- 682	- 657	- 628	- 598	- 568	- 540	- 516	- 487	- 459	- 431	- 404	- 377	- 349
8	**Manitoba Net Load**		**32 295**	**32 632**	**33 103**	**33 597**	**34 087**	**34 573**	**35 056**	**35 542**	**36 030**	**36 517**	**37 003**	**37 485**	**37 971**	**38 457**	**38 942**	**39 427**	**39 911**	**40 397**
	Contracted Exports		1 389	1 389	1 389	1 389	1 389	353	145	145	145	145	145	145	145	145	145	145	145	145
	Proposed Exports		**1 493**	**1 493**	**1 493**	**1 493**	**1 493**	**1 493**	**249**											
	Less: Adverse Water																			
9	**Total Net Exports**		**2 882**	**2 882**	**2 882**	**2 882**	**2 882**	**1 846**	**394**	**145**	**145**	**145**	**145**	**145**	**145**	**145**	**145**	**145**	**145**	**145**
10	**Total Energy Demand**	8+9	**35 177**	**35 514**	**35 985**	**36 479**	**36 969**	**36 419**	**35 450**	**35 687**	**36 175**	**36 662**	**37 148**	**37 630**	**38 116**	**38 602**	**39 087**	**39 572**	**40 056**	**40 542**
11	**System Surplus/(Deficit)**	7-10	**3 289**	**3 042**	**2 561**	**2 057**	**1 567**	**2 107**	**2 097**	**1 660**	**1 211**	**772**	**325**	**1 738**	**1 301**	**853**	**407**	**1 827**	**1 382**	**934**
12	Less : Brandon Unit 5																			
13	Adverse Water																			
	Exportable Surplus	11+12+13	**3 289**	**3 042**	**2 561**	**2 057**	**1 567**	**2 107**	**2 097**	**1 660**	**1 211**	**772**	**325**	**1 738**	**1 301**	**853**	**407**	**1 827**	**1 382**	**934**

1

Tab 53

M A N I T O B A	**)**	**Order No. 73/15**
	)	
THE PUBLIC UTILITIES BOARD ACT	**)**	**July 24, 2015**

BEFORE: Régis Gosselin, B ès Arts, MBA, CPA, CGA, Chair
Richard Bel, B.A.,M.A.,M.Sc., Member
Hugh Grant, Ph.D., Member
Marilyn Kapitany, B.Sc. (Hon), M.Sc., Member

FINAL ORDER WITH RESPECT TO MANITOBA HYDRO'S 2014/15 and 2015/16 GENERAL RATE APPLICATION

TABLE OF CONTENTS

1.0 Executive Summary 3
2.0 Overview 11
3.0 Rate Increases for 2014/15 and 2015/16 15
4.0 Bill Affordability 25
5.0 Operation, Maintenance & Administration Expenses 31
6.0 Depreciation and Amortization 37
7.0 Finance Expense 47
8.0 Risks and Financial Targets 51
9.0 Capital Expenditures 58
10.0 Load Forecast and Demand-Side Management 69
11.0 Power Resource Plan 81
12.0 Export Markets 84
13.0 Special Rates 88
14.0 Presenter Submissions 92
15.0 IT IS ORDERED THAT: 96

1.0 Executive Summary

By this Order, the Public Utilities Board of Manitoba (Board) approves rates for Manitoba Hydro for the April 1, 2014 to March 31, 2015 fiscal year and also for the April 1, 2015 to March 31, 2016 fiscal year.

The Board approves a total 3.95% increase in Manitoba Hydro consumers' billed rates effective August 1, 2015. This will increase the monthly bill of an average residential customer without electric space heat (using 1,000 kWh per month) by $3.20 and an average customer with electric space heat (using 2,000 kWh per month) by $6.11.

However, of the 2015/16 rate increase, only the revenues from a 1.8% rate increase will flow to Manitoba Hydro's general revenues to improve its financial position.

The revenues generated from a 2.15% rate increase are to be placed in the previously established deferral account to mitigate rate increases when the Bipole III Transmission Reliability Project (Bipole III), including the Riel Converter Station, comes into service in 2018/19. Because very significant rate increases will be needed at that time, the Board sees a compelling policy reason to gradually increase rates to avoid rate shock for consumers three years from now.

This Order also finalizes the previously approved interim 2.75% rate increase for Manitoba Hydro's 2014/15 fiscal year. Because this increase was previously granted and is already being collected, there will be no additional impact on ratepayers.

Reasons for the Rate Increases

Manitoba Hydro is making very large capital investments to meet its projected energy and capacity requirements and to replace its aging assets. These investments, which will double Manitoba Hydro's assets and associated costs, will be funded mostly by debt and the remaining balance funded by monies generated from its ongoing operations. Including the refinancing of old debt, Manitoba Hydro projects that it will borrow $2.4 billion in 2015/16 and approximately $3 billion annually between 2016/17 to 2018/19.

Manitoba Hydro has advised that its investments will place pressure on its financial strength and will require significantly higher electricity rates to support its increased costs.

The 1.8% portion of the total rate increase will generate additional revenues that will strengthen Manitoba Hydro's finances and support its borrowing plans. The increase is broadly aligned with the anticipated inflation rate.

The funds set aside in the Board-ordered deferral account, including the revenues from the 2.15% portion of the total rate increase, will be used to smooth the significant rate increases that may otherwise be required when the Bipole III Transmission Reliability Project (Bipole III) is completed, mitigating the resulting rate shock. The capital costs of Bipole III have increased by $1.4 billion (or 44%) in the past year, resulting in a total projected capital cost of $4.6 billion. The project is currently expected to increase Manitoba Hydro's annual costs by $384 million in 2020 and will not generate any related offsetting incremental revenues. A rate increase in excess of 20% would be needed to support this annual cost.

Furthermore, Manitoba Hydro has forecasted lower export revenues, largely because of continued lower export prices. Because export revenues are decreasing, domestic rates will need to increase.

Manitoba Hydro announced that successive increases of 3.95% are indicated until 2031. Despite those rate increases, the utility still projects losses from 2019 to 2025 (the total to exceed $980 million) and deterioration in its financial condition.

While the Conawapa Generating Station is no longer part of Manitoba Hydro's Capital Expenditure Forecast, the combination of higher capital expenditures than initially planned, increased investments in energy efficiency measures and declining export revenues means that significant rate increases will be needed for the next decade.

The Board is extremely concerned about the impact of successive and significant rate increases on ratepayers. However, in setting just and reasonable rates, the Board must balance the interests of ratepayers with the financial health of the utility.

Manitoba Hydro has advised that rate increases in excess of inflation are required into the future. The Board will scrutinize all future requested rate increases and approve rates that are justified by the evidence examined. Because financial projections are highly variable, regular applications and reporting by Manitoba Hydro will allow the Board to be better informed and responsive to changing conditions.

The Board previously advised Manitoba Hydro that it would not consider new rates for April 1, 2016 in the Hearing. Manitoba Hydro is studying the financial targets that are embedded in its integrated financial forecasts. The Board will consider various options regarding a process to review rates for April 1, 2016. The Board does not expect to award any further rate increases until a Cost of Service Study (COSS) Application has been filed and the Board has sufficient time to review the COSS Application.

Bill Affordability

The Board recognizes that higher electricity rates will have an impact on all Manitobans but especially lower income Manitobans. In this Order, Manitoba Hydro is directed to file Terms of Reference for a collaborative process led by Manitoba Hydro to develop a bill affordability program harmonized with Manitoba Hydro's other programs supporting low-income ratepayers. The goal of the process should be to develop a program for implementation within one year from the Board's approval of the Terms of Reference.

The Board continues to support the implementation of Manitoba Hydro's Affordable Energy Program (AEP) which offers assistance to lower income homeowners who are in need of energy efficient upgrades such as insulation. The Board approves the proposed increased budget to the AEP for 2015 and directs Manitoba Hydro to consider additional measures to increase participation rates and to assist all-electric customers, particularly those living in communities without access to natural gas heating options,

and to provide regular reports on the implementation of the Program and any additional measures developed.

The Board recommends to the Consumer Coalition, the Green Action Centre, the Manitoba Métis Federation and Manitoba Keewatinowi Okimakanak that these interveners encourage their eligible members to take advantage of potential savings that can be generated by the AEP along with other energy efficiency measures. The Board is encouraged by Manitoba Hydro's increased efforts to identify customers eligible for the AEP, and believes that these interveners may have additional valuable information to contribute.

Manitoba Hydro's Capital Expenditures

In addition to investing in major new capital projects, such as the Keeyask Generating Station and Bipole III, Manitoba Hydro also intends to increase its investment in base or sustaining capital (i.e., electric service replacements and expansions), and Demand-Side Management (DSM).

Manitoba Hydro is bringing several major new generation and transmission projects, including the two projects discussed above, into service in Manitoba Hydro's fiscal years 2018/19 and 2019/20, respectively. The Keeyask Generating Station was reviewed by the Board at the NFAT Review in 2014, while Bipole III was excluded from that review. Manitoba Hydro advised that Bipole III, which is currently under construction, is intended to increase system reliability and decrease the risk of outages by providing a third transmission line from northern Manitoba to the south.

When these projects enter service, they will increase Manitoba Hydro's revenue requirement, as Manitoba Hydro will need to recover depreciation, finance costs, operations, maintenance, and administration costs (OM&A), and other expenses related to these projects on an annual basis. As Manitoba Hydro's rates are set to recover its revenue requirement, rates would need to increase by the amounts shown in the following table if these projects were considered in isolation. Manitoba Hydro is

indicating that 3.95% annual rate increases may be sought for the next 15 years, a concept known as rate smoothing, instead of large, lump-sum increases when these projects enter service. Manitoba Hydro projects to incur losses beginning in 2018/19 which will temper the need for rate increases in the near term, such that the cumulative rate increase proposed by Manitoba Hydro is 42% by 2024, even though larger rate increases would be required to avoid the projected losses. The rate increases approved by the Board for 2014/15 and 2015/16 reflect a policy decision by the Board to mitigate rate shock to consumers by phasing the rate increases in over time.

The following table illustrates Manitoba Hydro's new revenue requirements attributable to new major projects, starting in 2019:

Revenue Requirement Impacts ($ Million)

Year Ending March 31	**2019**	**2020**	**2021**	**2022**
Bipole III Transmission Reliability Project	234	384	382	377
Keeyask Generating Station	28	80	316	462
Manitoba/Minnesota Transmission Project / Great Northern Transmission Line	1	5	85	115
Conawapa Sunk Costs	35	34	34	33
Additional Annual Revenue Required for New Projects	298	503	817	987
Cumulative Indicative-Only Annual Rate Increase Required to Pay New Costs	20%	34%	54%	65%

Sources: Application Appendix 11.15, Exhibit MH-118

Although all of Manitoba Hydro's new major capital projects have been approved by the Province, the Board is very concerned about possible cost escalations associated with these projects. Any future capital cost increases have a direct impact on domestic rates. Over the past year, the projected cost of Bipole III has increased by $1.4 billion to $4.6 billion and projected cost of the Great Northern Transmission Line has increased from $507 million to $676 million US dollars.

The Board expects Manitoba Hydro to demonstrate cost control efforts with respect to its capital expenditures, including its staffing for these projects. Furthermore, in order to

obtain timely and transparent information on the evolution of Manitoba Hydro's capital projects, the Board directs Manitoba Hydro to file quarterly progress reports on its major capital projects. These reports are to outline the proposed budget (at time of contract), budget changes and the reasons for such changes, and the revised projected in-service costs. Where capital costs have increased materially, Manitoba Hydro is to explain how such increases will impact domestic revenue requirements and projected impacts on Manitoba Hydro's financial forecasts and targets.

Given the significant risks Manitoba Hydro ratepayers are facing during this decade of large capital expenditures, the Board reiterates its recommendation to the Province of Manitoba that the Board should be provided with the statutory jurisdiction to review and approve Manitoba Hydro's major capital projects.

Sustaining capital expenditures address aging utility assets, improve the capacity of the existing system and maintain system reliability. The Board is approving the recovery, through rates, of increased sustaining capital investments during the 2013/14 and 2014/15 fiscal years. However, the Board directs Manitoba Hydro to file terms of reference for a more comprehensive asset condition assessment report before approving the rate impacts from increased sustaining capital spending for future years.

Operating Expenditures

The Board is encouraged by Manitoba Hydro's plans to slow the growth of its operating and maintenance costs to 1% annually, since this is below the expected increase in inflation. The Board directs Manitoba Hydro to provide quarterly reports on its current OM&A expenditures so as to demonstrate that its target is being met.

Accounting Changes

The Board accepts some of the proposed accounting changes, but denies Manitoba Hydro's request to calculate depreciation expense using the Equal Life Group (ELG) method and requires Manitoba Hydro to continue to utilize the existing Average Service

Life (ASL) method for rate-setting until a full comparison study has been filed for the Board's consideration.

Load Forecast, Demand-Side Management and Power Resource Plan

Manitoba Hydro's load forecast predicts reduced load growth in the future, largely as a result of decreases in the projected pipeline load. This further erodes any potential business case for the Conawapa Generating Station and pushes back the need for new post-Keeyask generation for Manitobans to more than 20 years from now.

Demand side management (DSM) is another way to mitigate the impact of rate increases. While the Board recommended to the Government of Manitoba that Manitoba Hydro be divested of its responsibilities for DSM, this recommendation has yet to be implemented and Manitoba Hydro continues to be responsible for DSM. The Board supports plans and the associated expenditures to enhance DSM programs, such as improved codes and standards, and to increase investments in energy efficiency measures by $0.9 billion over the next 20 years as a means of mitigating the impacts of future rate increases.

DSM reduces the utility's revenues but defers the need for new generation and provides ratepayers with a means to reduce their electricity bills.

The Board is encouraged by Manitoba Hydro's increased DSM efforts but notes that the utility's 2014/15 DSM budget was underspent by approximately $19 million, while Manitoba Hydro is planning to significantly increase expenditures for 2015/16. As a result, the Board orders Manitoba Hydro to retain the DSM deferral account and place the 2014/15 underspent funds in that account, to be utilized for Board-approved ongoing DSM expenditures.

Special Rates

By this Order, the Board further addresses a number of special rates, namely Light-Emitting Diode rates for Area and Roadway Lighting, the Curtailable Rate Program and the Surplus Energy Program.

2.0 Overview

Previous Rate Increases

In Order 43/13, the Board approved a 3.5% increase in Manitoba Hydro consumers' billed rates effective May 1, 2013. However, the revenues from a 1.5% rate increase were to be placed into a deferral account to mitigate required rate increases when the Bipole III Transmission Reliability Project (Bipole III) and related infrastructure, including the Riel Converter Station, comes into service later this decade. The Board also set Manitoba Hydro's revenue requirement based on Demand-Side Management (DSM) spending of $24 million for 2012/13 and $35 million for 2013/14, ordering the discrepancy resulting from any underspend to be placed into a deferral account for disposition at the present General Rate Application (GRA).

In Order 49/14, the Board further approved a 2.75% increase in Manitoba Hydro consumers' billed rates effective May 1, 2014 on an interim basis. However, of this increase, the revenues from a 0.75% rate increase were to be placed into the Bipole III deferral account established in Order 43/13. In Order 49/14, the Board further directed Manitoba Hydro to file a two-year GRA for the 2014/15 and 2015/16 fiscal years.

The Current General Rate Application

On January 16, 2015, Manitoba Hydro filed the current GRA for a three-year period, involving the 2014/15, 2015/16 and 2016/17 fiscal years. In the GRA, Manitoba Hydro sought the following approvals:

(a) Approval, on an interim basis, of rate schedules incorporating an across-the-board 3.95% rate increase to all components of the rates for all customer classes effective April 1, 2015, sufficient to generate additional revenues of $57 million in 2015/16;

(b) Approval of a further 3.95% across-the-board rate increase to all components of the rates for all customer classes effective April 1, 2016, sufficient to generate additional revenues of $60 million in 2016/17;

(c) Final approval of Orders 49/14 and 51/14 which approved, on an interim basis, a 2.75% rate increase effective May 1, 2014 applied on an across-the-board basis, and final approval of any other interim rate Orders issued subsequent to the filing of the Application and prior to conclusion of this proceeding;

(d) Final approval of the Light Emitting Diode (LED) rates for the Area and Roadway Lighting class approved on an interim basis in Order 79/14;

(e) Approval to implement Time-of-Use Rates for the General Service Large customer class served at greater than 30 kilovolts ("kV"), effective April 1, 2016, including the change in the definition of billing demand to be the highest measured on-peak demand in the month, 50% of contract demand or 50% of the highest on-peak demand in the previous 12 months;

(f) Confirmation that the Board accepts the rate approval process given proposed modifications to the Terms and Conditions of Option 1 of the Surplus Energy Program (SEP) as outlined in Tab 6 of this Application, that were approved on an interim basis in Order 43/13;

(g) Confirmation that the Board accepts the rate approval process given proposed modifications to the Curtailable Rate Program ("CRP"), as outlined in Tab 6 of this Application, that were approved on an interim basis in Order 43/13;

(h) Final approval of all SEP interim ex parte rate Orders as set forth in Tab 10 of this Application, as well as any additional SEP ex parte Orders

issued subsequent to the filing of this Application and prior to the Board's Order in this matter;

(i) Final approval of CRP ex parte Order 46/14 as well as any additional ex parte Orders in respect of the CRP issued subsequent to the filing of this Application and prior to the Board's Order in this matter;

(j) Final approval of Orders 116/12 and 117/12 that approved, on an interim basis, a 6.5% rate increase to the full cost portion of the General Service and Government rates in the four remote communities served by diesel generation effective September 1, 2012, and final approval of diesel zone interim Orders 17/04, 46/04, 159/04, 176/06, 1/10, 134/10, 1/11 and 48/11, subject to confirmation that MKO has provided the parties to the agreement with the required affidavits from representatives of signatories to the agreement; and,

(k) Approval to rescind the Demand-Side Management deferral account established pursuant to Order 43/13 for the 2012/13 and 2013/14 fiscal years and on a go-forward basis.

The Current General Rate Application – Procedural Matters

The Board considered Manitoba Hydro's GRA and, by letter dated January 27, 2015, advised Manitoba Hydro that it would not set rates for 2016/17 at this time and would limit the GRA process to 2014/15 and 2015/16, as per its directive in Order 43/13. In the letter, the Board further indicated that it did not consider interim rates effective April 1, 2015 to be in the public interest and instead would seek to set final rates in the GRA process.

On January 30, 2015, Manitoba Hydro applied to review and vary the Board's decision, as set out in the January 27 Board letter, submitting that a three-year rate approval

would be a more practical and efficient process, and that a lack of new interim rates on April 1, 2015 would result in lost revenues in the amount of $4 million per month.

In Board Order 17/15, the Board denied Manitoba Hydro's request to review and vary the Board's decision set out in the January 27 Board Letter.

On February 5, 2015, the Board held a Pre-Hearing Conference with prospective interveners at the Board's offices in Winnipeg. Subsequent to the Pre-Hearing Conference, the Board granted Intervener status to the following entities by way of Board Order 18/15:

- The Consumer Coalition, a coalition between The Consumers' Association of Canada (Manitoba) Inc. and Winnipeg Harvest;
- The Green Action Centre;
- The Manitoba Industrial Power Users Group;
- Manitoba Keewatinowi Okimakanak Inc.;
- The Manitoba Métis Federation; and
- The City of Winnipeg.

Two rounds of written Information Requests were directed to Manitoba Hydro, and one round of Information Requests to Interveners. The Board received oral evidence from May 25, 2015 to June 15, 2015, with closing submissions taking place on June 17, 18 and 19, 2015.

3.0 Rate Increases for 2014/15 and 2015/16

Issues

In the current General Rate Application (GRA), Manitoba Hydro requests the 2.75% rate increase, awarded on an interim basis in Orders 49/14 and 51/14 for the 2014/15 fiscal year, to be finalized and an additional 3.95% increase for the 2015/16 year to be approved. The 2.75% rate increase generated $35 million in additional revenue in fiscal 2014/15 and is projected to generate $39 million of additional revenue in 2015/16. The proposed 3.95% rate increase for 2015/16 is projected to generate $57 million of additional revenue in that year.

Combined with the interim 2.75% rate increase granted for 2014/15, Manitoba Hydro is seeking approval to collect an additional $96 million annually from consumers.

The requested rate increases will raise over $1 billion for Manitoba Hydro over the next 20-year period.

Operating Results Update

In April 2014, in support of its Interim Application, Manitoba Hydro filed Integrated Financial Forecast IFF13 with the Board. In that forecast, Manitoba Hydro indicated it would have net income of $116 million for the year ended March 31, 2014. Actual results for that year were $147 million, or $31 million better than forecast, due mainly to the effects of the coldest winter in 100 years in Manitoba.

Manitoba Hydro filed IFF14 in support of its application for 2014/15 & 2015/16 rates, which included the interim rate increase of 2.75% granted May 1, 2014. Manitoba Hydro's forecast net income was to be $55 million for 2014/15 and $12 million for 2015/16. In IFF14, Manitoba Hydro revised its forecast for 2014/15 to $102 million, which is a $48 million improvement, and revised its forecast for 2015/16 to $115 million, which is a $103 million improvement from IFF13.

Overall, Manitoba Hydro's recent financial outlook for 2013/14 to 2015/16 has improved by $182 million as reflected in the following table:

Comparison of Forecast /Actual Net Income IFF14 vs. IFF13 ($Millions)

Fiscal Year	IFF14	IFF13	Change
2013/14 (Actual to Forecast)	$147	$116	$31
2014/15 (Revised Forecast)	$102	$55	$48
2015/16 (Revised Forecast)	$115	$12	$103
Total Net Income	**$364**	**$183**	**$182**

Manitoba Hydro attributed the improvement largely to favourable water flows, lower financing costs and lower depreciation expense, although this was partially offset by lower than expected export prices.

During the hearing, Manitoba Hydro provided an update of its forecast for 2014/15 indicating that the net income forecast of $102 million would be lower than forecast by no more than $10 million. This lower financial result was in part attributed to lower export revenue as well as the renegotiation of the Wuskwatim Power Limited Partnership Agreement, which resulted in an estimated net income reduction to Manitoba Hydro of $16 million in 2014/15.

Forecast Need for Rate Increases

Manitoba Hydro indicates 3.95% annual rate increases must be implemented for the next decade and a half, even in years with average water flows and projected financial results. According to Manitoba Hydro, the long term rate setting perspective is beneficial to customers. Focusing only on the shorter-term financial outlook will defer required rate increases several years into the future, resulting in larger rate increases in future years and rate instability for ratepayers. Manitoba Hydro stated that confirmation of the interim

rate increase of 2.75% and the approval of a 3.95% rate increase for the 2015/16 fiscal year will start Manitoba Hydro on a sustainable path that will prevent higher rate increases in future years.

Manitoba Hydro maintains that the approval of the proposed rate increases is necessary to maintain net income and financial ratios at acceptable levels and to promote longer term rate stability for customers. Absent approval of the proposed 3.95% rate increase, Manitoba Hydro is projecting net income of $57 million in 2015/16. Manitoba Hydro indicated that rate increases in line with inflation of 2% would result in Manitoba Hydro earning $87 million in 2015/16.

Manitoba Hydro attributes the need for rate increases to several factors. One of the factors cited was lower forecast net export revenues. The utility has seen a material decline in export revenue since 2009. Historically, net export revenues have enabled Manitoba Hydro to maintain low electricity rates for Manitobans, with export revenues averaging $365 million a year between 2005 and 2009. Net export revenues have not been as strong as in previous years and are projected to be $150 million in 2014/15 and $181 million in 2015/16. Manitoba Hydro believes that rates need to gradually increase to compensate for this reduction in export revenues.

Another factor cited by Manitoba Hydro for the requested rate increases was the need for additional cash flow to assist in funding major and sustaining capital investments. Manitoba Hydro is entering a period of extensive capital investment to meet growing energy requirements of its export and domestic customers, to replace aging utility assets and address increased capacity constraints on its system.

Manitoba Hydro plans on increasing its base (also referred to as ‘sustaining’) capital spending, which excludes Major New Generation and Transmission, by about $100 million annually from previous levels and forecasts. Base capital expenditures typically represent requirements to meet electricity service replacements and expansions throughout the province. The utility spent $470 million in base capital spending in

2013/14 and plans on increasing its base capital spending to $571 million in 2014/15 and $577 million in 2015/16. IFF14 reflects $12.3 billion in base capital spending over the 20 year forecast.

Manitoba Hydro stated that cash flow is an important consideration for rate-setting purposes and that rates should generate sufficient cash flow to fund its operations, including its sustaining capital expenditures. Manitoba Hydro indicated that it needs rate increases to generate additional cash flow to meet its higher level of sustaining capital spending.

Manitoba Hydro stated that the 3.95% rate increase would not provide sufficient cash flow to fully fund sustaining capital requirements in all years of the forecast. The funding of Manitoba Hydro's forecast sustaining capital from its revenues falls short in six of the next ten years of the forecast. Manitoba Hydro is projecting that it may be required to borrow funds to finance sustaining capital expenditures in these years.

Manitoba Hydro also experienced significant increases in the capital costs of Major Generation and Transmission projects. In the past year, the cost of the Bipole III Transmission Reliability Project (Bipole III) has increased from $3.2 billion to $4.6 billion, a $1.4 billion or 44% increase in the cost estimate previously provided to the Board. Coupled with the current estimated cost of the Keeyask Generating Station of $6.5 billion, the proposed amortization of $397 million in Conawapa Generating Station sunk costs, as well as updated costs for the Great Northern Transmission Line to $675 million, these new major capital projects are contributing to the need for rate increases.

Domestic revenues must increase to cover some of the costs to bring these new major capital projects into service. The 2019/20 additional annual in-service revenue requirement of Bipole III will be $384 million. The additional 2021/22 annual revenue requirement of a fully in-service Keeyask Generating Station will be $462 million after deducting the net export revenues.

To support and fund these new capital expenditures, Manitoba Hydro indicated that electricity rates will have to increase by 42% by 2024.

Manitoba Hydro acknowledged that these investments in new capital spending will place pressure on Manitoba Hydro's financial strength. The current IFF14 forecasts operating losses commencing in 2019 and totaling $980 million over eight years.

The Consumer Coalition (Coalition) submitted that the Board should approve, as final, the 2.75% interim rate increase granted for 2014/15. The Coalition further recommended the Board approve a 2.5% rate increase for 2015/16. The Coalition did not support rate smoothing in principle, suggesting that rate increases should be assessed based on the needs in each year under consideration.

The Coalition did not believe the higher requested rate increase for 2015/16 was supported and that Manitoba Hydro should first demonstrate it has its financial house in order, including demonstrating that its interest rate forecast is accurate.

The Coalition has no confidence in the current financial forecast which it believes embeds a financial cushion. The Coalition also believes that higher rate increases should not be considered until the planning and prioritization of sustaining capital spending is refined. The Coalition expressed concerns with the quality of information used in determining the level of sustaining capital spending. The Coalition also noted Manitoba Hydro's current financial position, which is expected to improve by $180 million for a three-year period, should assist in affording a lower rate increase while Manitoba Hydro addresses its information shortcomings with respect to sustaining capital.

The Manitoba Industrial Power Users Group (MIPUG) agreed that the 2.75% interim rate increase for 2014/15 should be confirmed as final. MIPUG did not support the 3.95% rate increase sought for 2015/16. MIPUG stated that cash flow is not the normal tool for determining appropriate rate levels. MIPUG noted that Manitoba Hydro could take internal actions to improve its cash flow forecast position, such as pacing and

prioritization of spending on Demand-Side Management (DSM) and sustaining capital, as well as recognizing higher staff vacancy rates than forecast. MIPUG indicated that the pacing and prioritization of capital spending merits attention as a way to reduce rate increase requirements over the next ten years.

MIPUG submitted that DSM spending during the period of investment merits review to avoid adding to operating cash flow issues when export revenues are low and other capital spending is in a 'bulge' period, with a large amount of new hydro generation coming into service.

MIPUG also noted that the cash flow forecast could be further improved if interest rates remain lower than forecast, or if any government relief – from current fixed charges on capital spending or water rentals – was provided during the major investment period.

MIPUG recommended the Board grant a 2015/16 rate increase in the range of 2% to 3% and urged the Board to set requirements for the next GRA, including a meaningful assessment of pacing and prioritization of: capital spending, Operations, Maintenance, & Administration (OM&A) spending, DSM, and how such options could reduce future rate increase requirements below 3.95%.

The Manitoba Métis Federation (MMF) did not support Manitoba Hydro's requested rate increase in light of the MMF's opinion that Hydro has failed to provide adequate mitigation opportunities through DSM initiatives or bill assistance, most notably for the MMF's citizens, many of whom are all-electric customers who heat their homes or businesses using electricity. The MMF submits the Board's jurisdiction and mandate is to set just and reasonable rates for Manitoba Hydro that are in the public interest, which includes consideration of the fiscal health of the utility, as well as the impact of rates on customers. According to the MMF, it is not in the public interest to award the rates sought by Manitoba Hydro in the present GRA without providing the utility with the necessary motivation to ensure it provides vulnerable customers with the required tools to alleviate the burden associated with a long term forecast of rate increases. The MMF

did not offer a recommendation on the alternative level of rate increase, deferring to other interveners.

Manitoba Keewatinowi Okimakanak Inc. (MKO) recommended that there be no increase in rates over the amount of 2% for the next two years. MKO submitted a rate increase of 3.95%, or 5% as alternatively presented by Manitoba Hydro, would be severely prejudicial to MKO ratepayers. The percentage of customers in arrears in MKO First Nations communities ranges from 27% to 80% and having these new rates put into effect immediately is going to result in a majority of the MKO communities not being able to pay their bills. According to MKO, Manitoba Hydro has not proposed any solutions to mitigate the impact of the rate increases.

Board Findings

The Board will approve as final the 2.75% rate increase granted on an interim basis in Order 43/13.

The Board will grant a further rate increase of 1.8% effective August 1, 2015 to improve Manitoba Hydro's financial position. The Board considers this increase to be justified in light of decreased export revenue projections and the revenue requirement created by Manitoba Hydro’s newly renegotiated agreement with its First Nations partners in the Wuskwatim Generating Station, the wages and benefit increases by the utility and the impacts of additional planned base capital expenditures. The Board notes that this rate increase broadly aligns with the anticipated inflation rate.

Manitoba Hydro is already ramping up borrowings because it is entering a period of significant investment in its physical installations. The 1.8% rate increase will improve Manitoba Hydro's retained earnings and its financial ratios in the near-term. The Board will expect Manitoba Hydro to manage its operations with this increase in rate revenues.

Bipole III Transmission Reliability Project Deferral Account

The Board notes that Manitoba Hydro is continuing to spend money for the construction of Bipole III, which capital cost estimate has increased from $3.2 billion to $4.6 billion.

In Order 43/13, the Board determined that the project will require additional annual revenue requirements of approximately $300 million when put into service, which yearly amounts will have to be recovered from domestic customers' rates. Based on the updated capital cost estimate, the annual revenue requirement when Bipole III is fully in in-service has now increased to $384 million.

As part of the last GRA, the Board in Order 43/13 required Manitoba Hydro to establish a deferral account into which the revenues from a 1.5% rate increase were to be accumulated to defray a portion of the rate impacts of the project. In Order 49/14, while approving a 2.75% interim rate for 2014/15, the Board directed that revenues from 0.75% of the 2.75% rate increase granted be accumulated in the deferral account.

The Board notes that along with the annual $384 million impact of Bipole III starting in 2020, the annual revenue requirement of the Keeyask Generating Station will be approximately $462 million, net of revenues from export sales, when it is brought fully into service in 2022.

In light of these looming costs, the Board will approve an additional rate increase of 2.15%, the revenues from which are to be directed into the Bipole III deferral account that will be used to meet the rate increase impacts required when Bipole III comes into service. The disposition of the deferral account will be addressed at a future GRA.

When the Board is requested by Manitoba Hydro to review and approve changes to electricity rates, the Board seeks to determine whether the proposed changes in rates are just and reasonable in relation to the public interest. In broad terms, the public interest includes the balancing of the interests of the utility's ratepayers with the financial health of the utility. Included in the many factors that may be considered by the

Board, in reaching a decision as to new rates, are the policy considerations that the Board considers relevant to the matter.

The following table shows the revenue requirements when Manitoba Hydro's major capital projects come into service and the cumulative indicative only rate increases required at that time:

Revenue Requirement Impacts ($ Million)

Year Ending March 31	**2019**	**2020**	**2021**	**2022**
Bipole III Transmission Reliability Project	234	384	382	377
Keeyask Generating Station	28	80	316	462
Manitoba/Minnesota Transmission Project - /Great Northern Transmission Line	1	5	85	115
Conawapa Sunk Costs	35	34	34	33
Additional Annual Revenue Required for New Projects	298	503	817	987
Cumulative Indicative Only Annual Rate Increase Required to Pay New Costs	20%	34%	54%	65%

Sources: Application Appendix 11.15, Exhibit MH-118

The Board has determined that there is a compelling policy interest to phase in the required rate increases over a number of years in advance of the in-service dates of the new major capital projects and avoid rate shock for consumers. If the Board waited until the new capital projects come into service before raising consumer rates, the rate increases would have to be substantially higher. For example, compared to current rates, when the revenue requirement impacts of Bipole III fully materialize in 2020, a rate increase of 25% would be required to pay the additional $384 million of annual Operating Statement costs.

The Board accordingly directs that the annual revenues from a 2.15% rate increase (of the total 3.95% rate increase) should also be designated to flow into the Bipole III deferral account to assist in the payment of future in-service costs.

The Board will consider various options regarding a process to review rates for April 1, 2016. The Board does not expect to award any further rate increases until a Cost fo Service Study (COSS) Application has been filed and the Board has sufficient time to review the application.

4.0 Bill Affordability

Issues

In light of above-inflation rate increases projected by Manitoba Hydro for the next 17 years, the affordability of electricity bills to lower-income ratepayers will become an ever greater concern. Manitoba Hydro is currently offering ratepayers some relief through its Demand-Side Management (DSM) programs, including the Affordable Energy Program (AEP) (both of which are discussed in Chapter 10.0), but it is prudent to recognize that bill affordability will become a more pressing issue in the years to come and that some additional measures may be required.

Manitoba Hydro's current targeted bill affordability programs include emergency bill assistance through the Neighbours Helping Neighbours program administered by the Salvation Army as well as deferred payment arrangements for customers in arrears. Green Action Centre's (GAC) witness noted that Manitoba Hydro's deferred payment arrangements fail 50% of the time, indicating that this is not a suitable response to bill affordability. In GAC's view, Manitoba Hydro has not investigated non-payment of bills resulting from affordability problems.

GAC recommended that the Board direct the establishment of a collaborative process that would address bill affordability for lower income ratepayers. GAC's witness explained several different bill affordability models are used throughout North America, but did not recommend a particular model for Manitoba. Those different models include capping a customer's bill, providing a fixed credit on the bill, a fixed credit percentage on the bill, or a tiered rate discount, all based on household income. Additional models include a uniform rate discount for all customers or an inclining block (inverted) rate. According to GAC's witness, with a bill affordability program, Manitoba Hydro can expect to receive a greater percentage of bills paid in full, overall greater recovery of billed amounts, and improved cost effectiveness of its collections activities.

GAC submitted that the Board has the jurisdiction to require Manitoba Hydro to implement a bill affordability program and cited the case of *Advocacy Centre for Tenants-Ontario v. Ontario Energy Board* (2008), O.J. No.1970 in support of its proposition.

The collaborative process as proposed by GAC would be directed by the Board with stakeholders including Manitoba Hydro. GAC's expectation is that the collaborative process will not result in a consensus among all stakeholders. Where there is disagreement, GAC expects the Board to adjudicate and direct the implementation of a program to address bill affordability. GAC recommended that conservation rates, otherwise known as inverted rates, should be considered in the collaborative process. Conservation rates are proposed to be implemented in 2018/19 by Manitoba Hydro as part of its Power Smart Plan.

The Manitoba Metis Federation (MMF) stated that Manitoba Hydro's current bill assistance programs are inadequate and recommended elimination of late payment charges on accounts in arrears, or, alternatively, reduce the interest rate from 16% to the equivalent interest rate charged by Manitoba Hydro for its Pay-As-You-Save program. Manitoba Keewatinowi Okimakanak Inc. (MKO) recommended that all current arrears be alleviated by a combination of long term repayment terms and write-offs of interest on past due accounts. MMF and MKO supported GAC's collaborative process. Manitoba Keewatinowi Okimakanak MKO asserted that it needs to be involved in the collaborative process because of the unique needs of lower income First Nations customers.

Manitoba Keewatinowi Okimakanak (MKO) recommended that all current arrears be alleviated by a combination of long term repayment terms and write-offs of interest on past due accounts. MMF and MKO supported GAC's collaborative process. MKO asserted that it needs to be involved in the collaborative process because of the unique needs of lower income First Nations customers.

Manitoba Hydro submitted that a bill affordability program falls outside of Manitoba Hydro's legislative mandate as set out in *The Manitoba Hydro Act.* According to Manitoba Hydro, the utility is legally required to recover the cost of supplying power pursuant to section 39(1) of that statute and section 43(3) prohibits the use of Manitoba Hydro's funds for purposes of the Government or any government agency. Manitoba Hydro further submitted that the Board does not have the jurisdiction to order it to implement a bill affordability program as the Board's jurisdiction is limited to setting the prices to be charged for the provision of power but does not extend to the setting of social policy. Manitoba Hydro also indicated that in *Dalhousie Legal Aid Service v. Nova Scotia Power Inc.,* 2006 NSCA 74, the Nova Scotia Court of Appeal found that the Nova Scotia Utility and Review Board had no jurisdiction to order a bill affordability program to be implemented. Manitoba Hydro acknowledged that cases in other jurisdictions are not determinative of this Board's jurisdiction to order such a program in Manitoba.

Board Findings:

The Board recognizes that higher electricity rates will have an impact on lower income ratepayers. This is a particular concern with respect to all-electric customers, many of whom live in areas in which natural gas is not available as an alternative heating source.

The Board sees merit in the approach recommended by GAC's witness to start a collaborative process to determine the best options to address affordability issues. However, it is the Board's view that Manitoba Hydro is in a better position to lead such a process than the Board. Manitoba Hydro has expertise with respect to low-income programs, as evidenced by the recent successes in the AEP discussed in Chapter 10.0.

The Board therefore directs Manitoba Hydro to initiate a collaborative process to develop a bill affordability program harmonized with Manitoba Hydro's other programs supporting low-income ratepayers. Manitoba Hydro shall file, for Board approval, Terms of Reference for this process (including proposed facilitators and proposed stakeholder

participants) by October 31, 2015. The Terms of Reference should explain and include items in scope as well as items specifically out of scope. If Terms of Reference cannot be agreed upon between Manitoba Hydro and participating stakeholders, the Board is prepared to receive submissions from the parties and adjudicate the appropriate scoping. The goal of the process should be to develop a program for implementation within one year from the approval of the Terms of Reference.

The Board is prepared to entertain submissions for participant funding to be charged to Manitoba Hydro in appropriate cases and in accordance with the Board's Rules of Practice and Procedure.

Upon completion of the collaborative process the Board will evaluate the options presented and decide on their implementation.

The Board has been asked to consider establishing a bill assistance program before, notably in Order 116/08, in which the Board required Manitoba Hydro to propose such a program for approval. In Order 116/08, the Board concluded that it has jurisdiction to order the implementation of a bill affordability program. This remains the Board's view. However, the Board notes that at this time, it is not ordering such a program to be established and the collaborative process should not be limited to the consideration of special lower income rates. From a policy perspective, there may well be better solutions that have not been proposed to date. Furthermore, the optimal solution may well involve a portfolio of measures rather than a single measure. However, the idea of lower income rates should not be discarded upfront due to jurisdictional concerns.

The Board interprets section 39(1) of *The Manitoba Hydro Act* to require the aggregate price of power realized by Manitoba Hydro to be such as to achieve full cost recovery, subject to the requirement that such rates must be just and reasonable. This is illustrated by several examples:

- The power from historical generating stations is currently being sold for significantly more than the actual cost to generate, while power from new

generating stations is sold for significantly less than the cost to generate. Rates are set based on Manitoba Hydro's aggregate revenue requirement, not the cost attributable to individual stations.

- While Manitoba Hydro exports some power (primarily firm power) at prices higher than the average cost to generate, it also sells opportunity power for less than the average cost to generate, attributing no fixed costs to such power.

- Certain classes of customers, such as existing Curtailable Rate Program customers, achieve benefits not available to other customer classes or customers in the same class.

The Board does not read the legislative requirement for "postage stamp" rates to prohibit the creation of a lower income customer class, provided that no geographic limitations are imposed on such a class. Similarly, while subsection 43(3) prevents the commingling of government funds with Manitoba Hydro funds, it does not prohibit the creation of a rate class that pays less than the average cost to serve such customers.

The Board notes that while Manitoba Hydro is regulated on a cost of service basis, section 26(4) of *The Crown Corporations Public Review and Accountability Act* specifically authorizes the Board to consider "any compelling policy considerations that the Board considers relevant to the matter." In that respect, the Board's jurisdiction is similarly broad as that of the Ontario Energy Board pursuant to *The Ontario Energy Board Act, 1998*. Subsection 26(3) of *The Crown Corporations Public Review and Accountability Act* further stipulates that *The Public Utilities Board Act* applies with any necessary changes to the Board's rate-setting mandate. As such, rates are not only required to meet the requirements of subsection 39(1) of *The Manitoba Hydro Act* but must also be "just and reasonable." In the Board's view, affordability is a factor to consider when setting just and reasonable rates.

As such, it is the Board's intention to evaluate any future proposals for bill assistance programs from a comprehensive policy perspective rather than through the lens of

jurisdictional constraints, provided that such proposals fall within the legislative framework set by *The Manitoba Hydro Act*, *The Crown Corporations Public Review and Accountability Act*, and *The Public Utilities Board Act*.

5.0 Operation, Maintenance & Administration Expenses

Issues

Growth in Operating Expenses

Operation, Maintenance & Administration (OM&A) expense is one of Manitoba Hydro's highest expense categories constituting its revenue requirement, most of which relates to labour costs.

From 2011/12 to 2015/16, Manitoba Hydro's total annual electric OM&A cost has grown from $773.8 million to $883.3 million. The increase is due to growth in staffing levels driven by the major capital projects as well as accounting policy changes, including the implementation of International Financial Reporting Standards (IFRS).Taking into account the portion of the electric operating costs that are capitalized, OM&A expense has increased from $412.0 million in 2011/12 to a forecast $541.7 million in 2015/16.

The actual and forecast OM&A expenses for fiscal years 2011/12 to 2015/16 are as follows:

Operating, Maintenance and Administrative Costs ($Millions)

	Actual				IFF14-1	
Fiscal Year	2012	2013	2014		2015	2016
Labour and Benefits	$611.4	$658.1	$700.0		$725.0	$751.5
Other Expenses	185.1	183.1	188.0		199.8	198.5
Total OM&A	796.5	841.2	888.0		$924.8	$950.0
OM&A Charged to Centra	(62.7)	(63.7)	(66.8)		(67.8)	(66.7)
Total Electric Costs	**$733.8**	**$777.5**	**$821.8**		**$857.0**	**$883.3**
Capitalized Costs	(321.8)	(314.5)	(340.4)		(371.2)	(341.6)
Total OM&A Expense	**$412.0**	**$463.0**	**$480.7**		**$485.8**	**$541.7**

Manitoba Hydro capitalized $321.8 million (44%) of OM&A cost in 2011/12 and forecasts to capitalize $371 million (42%) in 2015/16 and $341.6 million (41%) in 2015/16. The vast majority of costs capitalized are labour and benefits. Employees involved with capital projects have grown in 2013/14 from 2,204 Equivalent Full Time positions (EFT) with a payroll cost of $234.5 million to a forecast in 2015/16 of 2,568 EFTs with a payroll cost of $287.9 million.

Accounting Changes

Since 2007/08, Manitoba Hydro has made changes to its capitalization practice to move away from “full cost” accounting and provide consistency with other Canadian utilities. Manitoba Hydro capitalizes overhead costs directly attributable to capital initiatives and has identified certain previously capitalized costs that it now plans to expense as period costs. Canadian Generally Accepted Accounting Principles (CGAAP) have converged in some areas to be consistent with IFRS. Manitoba Hydro has adopted these changed accounting policies gradually in its transition to IFRS in 2015/16. Manitoba Hydro made system changes in 2012/13, including changes to its cost allocation methodology and overhead rates to support Manitoba Hydro's transition to IFRS. The change in capitalization practice is consistent with CGAAP and is directionally consistent with IFRS.

In total, Manitoba Hydro indicated at the last General Rate Application (GRA) that $93 million in overhead costs would be expensed. However, in this GRA, Manitoba Hydro proposed that $118 million in overhead costs be expensed when IFRS is implemented in 2015/16.

Manitoba Hydro will adopt interim standard IFRS 14 Regulatory Deferral Accounts upon transition to IFRS. This interim standard allows Manitoba Hydro to continue to recognize rate regulated assets and liabilities. Manitoba Hydro’s forecast assumes that regulatory deferral accounts will continue to be recognized throughout the 20-year forecast period.

The International Accounting Standards Board (IASB) is continuing its comprehensive rate-regulated activities project, which could result in a standard on rate regulation or decision not to develop specific requirements. By issuing IFRS 14, the IASB has indicated it is not anticipating the outcome of the comprehensive project.

The Manitoba Industrial Power Users Group (MIPUG) recommended the Board reject Manitoba Hydro's proposal and maintain, for rate-setting purposes, capitalization policies consistent with those in place prior to IFRS. This change is consistent with the longstanding interpretation of fair cost distribution, balancing costs that should be paid today versus those that are capitalized and paid over the life of the new capital plant. The Board, by clarifying this requirement, will provide Manitoba Hydro options on how to reflect the decision in its IFRS-compliant financial statements.

Staffing Levels

Almost 79% of OM&A costs relate to labour costs, including employee benefits. Wages and salaries have increased by an average of 4% per year, primarily as a result of contract settlements with bargaining units and an increase in total Equivalent Full-Time positions (EFTs). Staffing levels are projected to grow from 5,769 EFTs in 2004 to 6,902 EFTs in 2015/16, an increase of over 1,100 EFTs. Manitoba Hydro attributed the increase in EFTs to growth in its capital program, including new generation and transmission projects such as Bipole III, the Keeyask Generating Station and the Pointe du Bois Generating Station spillway.

Cost Containment Measures

Manitoba Hydro committed to containing the growth of OM&A expenses to one percent, excluding the impact of accounting changes. Manitoba Hydro completed a review of staffing and operational efficiency to meet customer needs in the most cost effective and efficient manner. As part of the process, the utility committed, within the next three years (2014/15 through 2016/17), to reduce its full time staff complement by at least 331 positions through attrition and process efficiencies as follows:

Planned Position Reductions:

	2014/15	2015/16	2016/17	Cumulative
President & CEO	2	2	2	6
General Counsel & Corporate Secretary	1	1	1	3
Human Resources & Corporate Services	33	27	21	81
Corporate Relations	3	2	1	6
Finance & Regulatory	4	3	3	10
Generation Operations	9	12	6	28
Major Capital Projects	1	1	0	2
Transmission	30	18	42	90
Customer Service & Distribution	46	19	13	78
Customer Care & Energy Conservation	16	6	5	27
Annual Commitment	**146**	**91**	**94**	**331**
Forecast Cost Savings:				
Annual Savings ($M)	$ 7.3	$ 12.3	$ 10.0	$ 5.1
Cumulative Annual Savings ($M)	7.3	19.3	29.7	35.8

Manitoba Hydro reported that for 2014/15, it exceeded its targeted position reductions by 80 positions for that year. Manitoba Hydro had forecast 146 operational position reductions in that year and attained 226 position reductions, which represents an additional $8 million in OM&A expense savings.

Further, Manitoba Hydro set a target to limit operating cost increases to 1% per year over the ten-year period, excluding the impacts of accounting changes. To accomplish this 1% target, the utility has identified the need for an additional 600 position reductions by 2022/23.

The Coalition acknowledged Manitoba Hydro's efforts related to cost containment to manage operating costs but is not satisfied with capital cost containment efforts related to capital spending.

First Nation Partnerships

Manitoba Hydro currently incurs ongoing expenditures related to its First Nations partnership arrangement with the Wuskwatim Power Limited Partnership (WPLP). The WPLP Operating Statement indicates allocated revenues of $100 million to $150 million per year out to 2034/35.

Manitoba Hydro amended the contractual arrangement with WPLP and filed finalized documentation during the hearing. Overall, the amendments reduce net income to Manitoba Hydro by $16 million for each of 2014/15 and 2015/16, as well as $15 million on average annually thereafter.

When the Keeyask Generating Station comes into service, contractual arrangements with the Keeyask Hydropower Limited Partnership will also have a revenue requirement impact on Manitoba Hydro. The contractual arrangements have not been finalized.

Board Findings

At the last General Rate Application (GRA), the Board agreed that the accounting changes were appropriate for 2012/13 and 2013/14 and that no further accounting changes be made for rate-setting purposes until the Board had reviewed an IFRS status update. The Board understood that with the adoption of IFRS, additional overhead costs of $36 million per year would be no longer capitalized. The quantum of those costs has increased materially in Manitoba Hydro's Status IFRS Status Update, by $20 million per year.

The Board understands that Manitoba Hydro has made changes in 2012/13 to its integrated cost allocation methodology and overhead rates in its compliance with IFRS. The increases in overhead costs have been primarily attributed to changes in capital activity and overhead allocations. The Board will not accept the higher level of OM&A costs requested in this application but will allow $36 million of additional costs be

expensed for 2015/16 as indicated at the last GRA. The remaining administrative costs will continue to be capitalized as per existing practices.

6.0 Depreciation and Amortization

Issues

Overview

Depreciation Expense is Manitoba Hydro's third-highest expense category and is scheduled to almost double by 2033/34 as a result of both new major generation and transmission assets and planned sustaining capital expenditures. Depreciation Expense was $410 million in 2013/14 and is forecast to be $404.5 million in 2014/15 and $401 million in 2015/16.

Depreciation Expense is forecast to grow to $873 million by 2033/34.

Proposed Changes to the Calculation of Depreciation Expense

Depreciation Expense is recognized on a straight-line basis over the estimated remaining service life of assets, based upon depreciation studies conducted periodically by the utility. Manitoba Hydro engaged Gannett Fleming Inc. to prepare an updated depreciation study of assets in service as of March 31, 2014. The depreciation study and recommended depreciation rates replace the rates that have been in effect since April 1, 2011 based on a depreciation study of assets in service as of 2010 which was presented at Manitoba Hydro's 2012/13 & 2013/14 General Rate Application (GRA).

Gannett Fleming provided updated service lives for several asset classes as well as rates for new asset classes. The study resulted in changes that extended the average service lives of certain plant components, such as substation transformers, whose service lives were extended from 35 years to 50 years based on updated historical experience. The changes in expected service lives resulted in a reduction of depreciation expense of $25 million in 2014/15 and $29 million in 2015/16 compared to the methodology from the 2010 depreciation study.

Gannett Fleming also developed new rates reflecting two changes in the depreciation methodology effective April 1, 2015, namely:

- Switching from the Average Service Life (ASL) methodology of group depreciation to the Equal Life Group (ELG) procedure; and
- Removing the pre-collection of net salvage costs from depreciation. To date, Manitoba Hydro has added 10 percent to the up-front cost of capital assets to recover the eventual cost of decommissioning.

The combined annual financial impacts of the proposed changes to the calculation of depreciation expense during 2014/15 and 2015/16 are as follows:

Revenue Requirement Impacts of Depreciation Study Changes

($ millions)	**Years Subject to this GRA IFF14-1**		**Outlook IFF14-1**	
Fiscal Year ended March 31	**2015**	**2016**	**2024**	**20 Year Total**
Change in service life – Property Plant & Equipment (net of contributions)	(25)	(29)	(42)	(746)
Overhead Ineligible for Capitalization	-	-	(14)	(310)
Change to (ELG) Procedure	-	36	69	1,238
Removal of Asset Retirement Costs (Net Salvage)	-	(60)	(119)	(2,141)
Net Impact	**($25)**	**($53)**	**(106)**	**($1,959)**

Manitoba Hydro recommended that the Board should consider the combined overall impact of the collective depreciation changes for rate-setting purposes under the regulatory principle of fairness, rather than concentrating on any individual changes. According to Manitoba Hydro, the overall impact of the changes is to reduce Depreciation Expense and the associated revenue requirement.

Equal Life Group vs. Average Service Life

To date, Manitoba Hydro has used the ASL methodology of calculating Depreciation Expense. Gannett Fleming testified on behalf of Manitoba Hydro to recommend a switch to the ELG procedure. While the ASL methodology groups assets by type of asset and then depreciates the assets in the group according to their average service lives, ELG groups assets according to their lifespan, not the type of asset. According to Gannett Fleming, the ELG approach more closely tracks the actual depletion of the underlying assets. In Canada, both methods are in use by utilities.

Both the ELG and ASL methodologies are appropriate under International Financial Reporting Standards (IFRS). However, Gannett Fleming indicated that if ASL were to be utilized, the level of componentization into asset groups would have to be more granular than what is currently being presented. Gannett Fleming was of the opinion this additional componentization would significantly reduce the annual difference in Depreciation Expense between ASL and ELG.

Manitoba Hydro estimated that it would cost approximately $2.5 million to further componentize its plant assets to the degree required in order to be IFRS compliant using the ASL procedure. Gannett Fleming further submitted that changing to the ELG procedure would comply with the depreciation requirements of IFRS without the need to further componentize to the level of detail that using an ASL method would require.

Manitoba Hydro also noted that in applying the ASL method to an asset group with a wide dispersion in service lives, it can be expected that assets will retire at ages different than the average life used to depreciate the group resulting in gains and losses

upon retirement. IFRS requires that these gains and losses be recognized immediately to net income. Manitoba Hydro submitted that such gains and losses are expected to be much smaller under ELG since this method calculates depreciation with consideration of the different service lives of the assets in a component group.

Manitoba Hydro acknowledged that the existing regulatory practice, whereby asset retirement gains and losses are recorded in the accumulated depreciation account for the retired asset's respective component group and then factored into future depreciation rate changes for the group, may be continued for rate-setting purposes if ordered by the Board pursuant to rate-regulated accounting.

Manitoba Hydro also indicated that if the ASL methodology was retained for rate-setting purposes, IFRS would require Manitoba Hydro to establish a regulatory deferral account and to maintain two separate sets of asset sub-ledgers to capture the differences between depreciation determined for financial reporting and depreciation determined for rate-setting purposes.

Manitoba Hydro initially indicated to the Board that it wanted to switch to ELG in its 2012/13 & 2013/14 GRA. In Order 43/13 the Board stated:

> *The Board also is concerned that not enough information has been provided to date to assess the true impact on ratepayers of a switch to Equal Life Group. As such, the Board will require Manitoba Hydro to file additional information, including a determination of depreciation rates and schedules based on the Average Service Life methodology, to provide a meaningful comparison between the two approaches. [Order 43/13 pg 18]*
>
> *The Board will require Manitoba Hydro to provide a comparison, for the next General Rate Application, of the impact on the Integrated Financial Forecast of an Average Service Life methodology (without net salvage) and an Equal Life Group methodology (without net salvage), where each of the accounting methodologies are applied to planned major capital additions in the Integrated Financial Forecast. Given the forecast to increase net plant by over $21 billion over a 20 year period, it will be important to understand the*

> *implications on ratepayers of using each approach at the next General Rate Application.*
>
> *The Board further expects Manitoba Hydro to file, as part of its next General Rate Application, additional information to support Manitoba Hydro's view that an Average Service Life methodology compliant with International Financial Reporting Standards requires increased componentization. As part of this information, the Board expects to see evidence as to what level of componentization would be required, and how such level of componentization would increase Manitoba Hydro's costs, if at all. [Order 43/13 pg 18- 19]*
>
> *…*
>
> *IT IS THEREFORE ORDERED THAT:*
>
> *…*
>
> *8. That Manitoba Hydro file updated depreciation rates and schedules based on an International Financial Reporting Standards-compliant Average Service Life methodology with the next General Rate Application.*
>
> *9. That Manitoba Hydro file with the Board, with the next General Rate Application, a chart showing a comparison of the impact on its Integrated Financial Forecast (i.e. 'Budget') of asset depreciation pursuant to the Average Service Life methodology (without net salvage) and the Equal Life Group methodology (without net salvage), applying both methodologies to all planned major capital additions.*

Instead of preparing a depreciation study based on IFRS-compliant ASL, Manitoba Hydro submitted an extrapolation study prepared by Gannett Fleming, based on a sample of plant accounts representing approximately 20% of Manitoba Hydro's total asset base. The analysis was not based on a random statistical sample but based on plant accounts chosen collaboratively with Manitoba Hydro based on select criteria. A random statistically-based sample was not considered because of the time and effort required to evaluate the level of componentization of the selected accounts on this basis.

Based on the results of the study, Gannett Fleming determined a difference in depreciation expense of $700,000 on the plant accounts tested. Extrapolating the results of the analysis indicated that an ASL-based IFRS-compliant depreciation methodology would result in a depreciation expense $3.6 million lower than one based on the ELG procedure.

In cross-examination, it was demonstrated that the extrapolation study was sensitive to changes in assumptions. For example, one of the asset components analyzed was Manitoba Hydro's head office building, which represented less than three percent of Manitoba Hydro's total asset base. Exclusion of this account from the extrapolation analysis increased the difference between ASL and ELG to $4.4 million. Similarly, while the extrapolation study analysis included the Bipole III Transmission Reliability Project, it focused on synchronous condensers, which represent approximately 15% of the cost of the project, but not the metal transmission towers and conductors, which represent approximately 36%. In cross-examination, Gannett Fleming indicated that using the towers and conductors would increase the difference between ASL and ELG.

Both the Consumer Coalition (Coalition) and the Manitoba Industrial Power Users Group (MIPUG) recommended that the Board not approve Manitoba Hydro's proposal to change to the ELG procedure for rate-setting purposes, but retain the ASL methodology without including any net salvage in depreciation rates.

MIPUG submitted that ASL is appropriate for rate setting and is used by the vast majority of regulated North American utilities, particularly Canadian Crown utilities and hydro-based operations.

MIPUG submitted that the use of ASL benefits the intergenerational perspective and that a Crown-owned, hydro-electric utility, such as Manitoba Hydro, should take a consistent and properly matched long term approach to collection of depreciation which matches the use and usefulness of the assets. This is done by using ASL, which charges the same depreciation rate in each year of the asset's life.

MIPUG further submitted that ELG is not a more precise method of depreciation as the claims of ELG precision are linked to a theoretical construct of ELG that is not used in practice, where the theoretical purity of the method is significantly diluted.

Both the Coalition and MIPUG expressed concern related to the extrapolation analysis. An expert witness on behalf of the Coalition and MIPUG testified that the extrapolation study was not reliable and counterintuitive as ELG with a growing asset base will always lead to a higher depreciation expense. MIPUG submitted that the Board should not attribute any evidentiary weight to the extrapolation study.

Both MIPUG and the Coalition argued that the extrapolation study does not comply with the Directive given in Order 43/13 for an IFRS-compliant ASL study. The Coalition recommended the Board find that Manitoba Hydro has not complied with Board Directive 8 from Order 43/13, in which Manitoba Hydro was to file updated depreciation rates and schedules based on IFRS-compliant ASL methodology. The Coalition also recommended that the Board find that its response to Board Directive 9 is inadequate.

The Coalition recommended that the Board not accept ELG for rate-setting purposes on the grounds that Manitoba Hydro failed to comply with Board Directives 8 and 9. The Coalition further recommended that the Board direct Manitoba Hydro to provide a timeline by which it intends to comply with Directives 8 and 9 and, until then, set Manitoba Hydro's revenue requirement based on the traditional ASL methodology.

Removal of Net Salvage

Gannett Fleming advised that IFRS would no longer permit the inclusion of net salvage in the depreciation rate calculations for financial reporting purposes. Depreciation rates currently include a provision for net salvage, representing the cost of disposal of property, plant, and equipment when it is taken out of service. Under IFRS, the future cost to retire and salvage assets will become a cost of the replacement asset.

Manitoba Hydro plans on removing net salvage from depreciation rates when it implements IFRS in conjunction with its proposed change to the ELG methodology.

Manitoba Hydro indicated that it was a policy decision to not request the Board to allow Manitoba Hydro to establish a regulatory deferral account. Manitoba Hydro suggested that this choice was made to reduce the impact of switching to the ELG methodology of depreciation. Manitoba Hydro indicated the impact of removing net salvage from depreciation rates is to lower Depreciation Expense by approximately $60 million in 2015/16.

The Coalition supported MIPUG's recommendation that the Board approve Manitoba Hydro's request for the elimination of ongoing accumulation of net salvage charged through depreciation. MIPUG believes net salvage should be removed from annual calculations as a sound regulatory principle, as the assets are expected to be replaced upon retirement with a new generation of assets that benefits from the pre-existence of the original assets.

Book Accumulated Depreciation Surplus

The change in estimated service lives resulted in a book accumulated depreciation surplus of over $474 million. Book accumulated depreciation surplus is 'over-depreciation' that has resulted from an excess of collected Depreciation Expense on Manitoba Hydro's books. Removing net salvage from the current ASL methodology-based depreciation rates increases the accumulated depreciation surplus to over $1 billion. If depreciation is calculated based on the ELG methodology and no net salvage, the book accumulated depreciation surplus is reduced to approximately $603 million. Manitoba Hydro proposes an annual true-up to refund the balance over the remaining life of each asset account. This approach is consistent with the approach followed in prior depreciation studies.

Board Findings

The Board accepts the calculated book accumulated depreciation surplus based on the 2014 Gannett Fleming study.

The Board also accepts Manitoba Hydro's position that net salvage should be removed from depreciation rates as of April 1, 2015, concurrent with Manitoba Hydro's implementation of IFRS. The Board notes that while the inclusion of net salvage creates a cash flow due to eventual asset removal obligations, any such cash flow is not sheltered in any reserve accounts and forms part of the general revenue requirement of Manitoba Hydro instead. The Board heard evidence that energy-generating assets are rarely decommissioned and removed entirely, and are most frequently replaced. In such instances, IFRS requires removal costs for the existing asset to form part of the overall capital cost of the new asset recovered from future ratepayers. In the Board's view, there are no compelling reasons to set up a deferral account to allow for the continued collection of net salvage.

However, the Board, at this time, is not prepared to determine Manitoba Hydro's revenue requirement for rate-setting purposes based on a switch from the ASL methodology to the ELG procedure.

Under either ASL or ELG, Manitoba Hydro is eventually made whole, since by the time an asset is decommissioned, the entire capital cost has been recovered by Manitoba Hydro from ratepayers. However, there is no doubt that over the next twenty years (the timeframe for Manitoba Hydro's integrated financial forecast), a switch to ELG would increase Depreciation Expense in every single year. Furthermore, Manitoba Hydro was unable to advise the Board at which point ratepayers should expect a "crossover point" at which the increased Depreciation Expense recovered in the early years reduces Depreciation Expense in the later years. As such, the Board must assume that during the entirety of the foreseeable 20 year planning horizon, a switch to ELG would increase the amount of Depreciation Expense consumers are expected to fund through their rates.

For purposes of rate-setting, the Board orders Manitoba Hydro to continue to determine Depreciation Expense based on its existing ASL methodology at this time.

This is not to say that the Board is rejecting outright an eventual adoption of ELG. However, to the extent that the choice is between IFRS-compliant ASL and IFRS-compliant ELG, the Board does not currently have sufficient information upon which to make a decision. As shown in the table above, a change in methodology leads to significant long term consumer rate consequences and is a decision which the Board cannot make on an incomplete record.

While the Board considers the extrapolation study filed by Manitoba Hydro to be illustrative, and the Board accepts that additional componentization would reduce the difference between ASL and ELG, the Board does not consider the extrapolation study reliable enough to base a rate-making decision on it. As such, the Board will order Manitoba Hydro to retain the existing ASL methodology for rate-setting purposes until Directives 8 and 9 from Order 43/13 have been complied with and the Board has been provided with an IFRS-compliant depreciation study based on ASL.

Accepting Gannett Fleming's testimony that additional componentization tends to reduce the difference between ASL and ELG, the Board requests that the IFRS-compliant ASL depreciation study, if and when filed by Manitoba Hydro, be based on the minimum level of additional componentization required by IFRS, but avoid optional additional componentization. The study should also demonstrate whether and when there would be a cross-over point at which time Depreciation Expense as calculated using ELG becomes lower than that calculated using ASL. If Manitoba Hydro is able to file such a study in time for the next GRA, as well as comply with Directive 9 from Order 43/13, the Board intends to make a final disposition with respect to the appropriate long term depreciation methodology for rate-setting purposes at the hearing of that Application.

7.0 Finance Expense

Finance expense, which includes the annual interest payments on Manitoba Hydro's debt, is forecast in Integrated Financial Forecast IFF14 to be $495 million in 2014/15 and $510 million in 2015/16. After Operating and Administrative expenditures, Finance Expense is the second largest annual expenditure by Manitoba Hydro in 2015/16 and is expected to be the largest component of revenue requirement by 2017/18.

At the last General Rate Application (GRA), Finance Expense was forecast to be over $1.6 billion in 2028. Given the termination of the $10.2 billion Conawapa Generating Station and the current historically low interest rates, Finance Expense is now forecast to peak at $1.3 billion in 2023/24, some $300 million lower than what was forecast at the last GRA.

Manitoba Hydro capitalizes all interest on capital projects until the project is placed into service, which means the annual interest payments are added to the cost of the capital project and are not recovered from current year revenues. Once the capital project is brought into service, then the previously capitalized interest payments are included in Finance Expense in the annual operating expenses of Manitoba Hydro.

Of its total annual interest costs, Manitoba Hydro is forecasting to capitalize $146 million (or 23%) in 2014/15 and $207 million (or 29%) in 2015/16. Manitoba Hydro has capitalized over $2.1 billion of interest costs as of 2013/14. Based on IFF14, Manitoba Hydro is forecasting to capitalize an additional $2.2 billion in interest over the next 20 years which will result in $4.4 billion of capitalized interest.

In the near term, Manitoba Hydro plans on new borrowings, including refinancing of existing debt, totalling $1.9 billion in 2014/15, $2.4 billion in 2015/16, and in the order of $3 billion annually between 2016/17 to 2018/19 to fund its capital program. Long term interest rates in IFF14 were estimated based on a Fall 2014 interest rate forecast.

Manitoba Hydro's long term interest rates were projected to be 4.50% in 2014/15 and 5.10% in 20115/16 (inclusive of the 1% Provincial Debt Guarantee Fee Manitoba Hydro pays to the Province of Manitoba in exchange for guaranteeing Manitoba Hydro's debt).

Manitoba Hydro is forecasting long term interest rates to increase from 5.10% in 2015/16 to 5.50% by 2016/17, to reach 6.2% in 2019/20, and to remain at that level for the remainder of the forecast through 2033/34.

However, Manitoba Hydro provided a January 2015 update to its interest rate forecast. The update indicated that long term rates had fallen by 30 basis points in 2014/15 from 4.50% to 4.20%. The long term interest rate for 2015/16 dropped by 110 basis points to 4.0%. The interest rates over the forecast period have all declined from Manitoba Hydro's forecast level with the forecast long term rate falling by 45 basis points to 5.75%. Manitoba Hydro stated that it had taken advantage of the low interest rates with its new borrowings to the benefit of ratepayers.

Manitoba Hydro provided a further update based on the Spring 2015 Economic Outlook and forecasts received in May and June 2015. These forecasts indicated that rates for 2015/16 had fallen from the January 2015 update by an additional 5 basis points in 2015/16 to 3.95% and by 15 basis points for 2016/17 to 4.40%.

Manitoba Hydro indicated that based on the January 2015 update, Finance Expense in 2015/16 would be lower than initially forecast by $13 million. The updated forecast also indicated that the long term interest rate beyond 2017/18 increased to be more in line with the rates included in IFF14.

The Consumer Coalition (Coalition) stated that it had little confidence in Manitoba Hydro's interest rate forecasting and that the utility has consistently overestimated short and long term interest rates. The Coalition cited recent new debt issues negotiated by Manitoba Hydro which were at lower rates than what is forecast in the IFF. The Coalition believes that the Finance Expense for 2015/16 and 2016/17 will be lower than that forecast by Manitoba Hydro and that the utility will benefit from some positive

developments due to lower interest rates over the short term. In this current year, the Coalition submitted there is an ability to lock in substantially lower than forecast interest rates, suggesting a reduction of risk for this very substantial year of borrowing, and a significant rate mitigation opportunity.

The Coalition stated that Manitoba Hydro's interest rate forecast has been a source of substantial uncertainty, with a prevailing trend to overestimate interest rates. The Coalition noted anecdotally that this uncertainty is also prevalent with Manitoba Public Insurance and recommended the Board direct a technical conference involving both Manitoba Hydro and Manitoba Public Insurance to address interest rate volatility and forecasting.

The Manitoba Industrial Power Users Group (MIPUG) also noted the lower interest rates as a positive factor for ratepayers, indicating that favourable changes since last Integrated Financial Forecast (IFF) can have large impacts on Manitoba Hydro's forecasts which remove an immediate need for the 3.95% rate increase.

Board Findings

The Board notes that Manitoba Hydro's long term debt is forecast to grow from $10.8 billion in 2013/14 to peak at over $24.5 billion by 2028/29. This will lead to Finance Expense that will exceed $1.3 billion in 2021/22 once the Keeyask Generating Station is in service. The annual Finance Expense to pay the carrying costs of the debt, along with other revenue requirement items, will ultimately be borne by ratepayers when assets are placed into service.

The Board notes that in the near term, there is a benefit of lower interest rates and borrowing costs that is not currently reflected in Manitoba Hydro's financial forecast. Additionally, and since the close of evidence at the GRA, the Board notes that the Bank of Canada has further reduced interest rates. A lower long term trend in interest rates, if sustained, would be to the benefit of ratepayers due to lower borrowing costs.

The Board also notes that Manitoba Hydro remains vulnerable to the risk of rising future interest rates above those currently forecast. There is great uncertainty related to interest rate movements in Manitoba Hydro's forecast. The Board awaits reviewing the risk report Manitoba Hydro commissioned from KPMG (a business consulting firm), which is expected to examine Manitoba Hydro's interest rates, at the next GRA.

The Board will not require a technical conference on interest rate forecasting at this time, as recommended by the Coalition. The Board notes that Manitoba Hydro has implemented Board-recommended changes to its interest rate forecasting methodology and obtains forecasts from a number of external sources. Furthermore, interest rate risk is expected to be examined in the KPMG report, allowing the Board to conduct a more comprehensive review at the next GRA. As such, the Board is of the view that it is premature to start an interest rate forecasting review outside the regular GRA process.

The Board also takes judicial notice that Manitoba Hydro's credit rating was not affected by Moody's recent downgrade of the provincial credit rating.

8.0 Risks and Financial Targets

Issues

As a proxy for its financial strength, Manitoba Hydro has the stated goal of meeting a set of three financial targets:

- To achieve and maintain a minimum debt to equity ratio of 75:25.
- To achieve and maintain an annual gross interest coverage ratio of greater than 1.20, meeting all interest payment obligations from annual operating revenues without having to borrow additional funds to make interest payments; and
- To achieve and maintain a capital coverage ratio of greater than 1.20, funding all base or sustaining capital expenditures from internally generated funds.

In setting its financial targets, Manitoba Hydro recognizes that targets may not be attained during years of major investments in the generation and transmission system. While credit rating agencies are aware that financial targets will not be met during the period of Manitoba Hydro's major capital expansion program, Manitoba Hydro indicated that rate increases were needed so as to demonstrate progress towards attaining the targets over the long term.

Manitoba Hydro advised the Board that it commissioned a risk review study from KPMG (a business consulting firm), which is expected later this year. As part of KPMG's mandate, the firm will review and consider the appropriateness of Manitoba Hydro's financial targets.

Debt-to-Equity Ratio

The debt to equity ratio measures the relationship of long term and short term debt less short term and sinking fund investments to equity (retained earnings including Accumulated Other Comprehensive Income and unamortized customer contributions).

This ratio is used to assess the overall financial risk to Manitoba Hydro by examining the level of debt in relation to the amount of equity held. Historically, Manitoba Hydro's equity has ranged from a low of 5% in 1990 to a high of 25% in 2009 when the utility met its target level several years ahead of schedule.

Manitoba Hydro's capital structure is forecast to weaken to a debt to equity ratio of 90:10 over the period 2022/23 to 2026/27 due to planned capital spending on major projects. Manitoba Hydro stated that it is important that its financial position improve following the investment period as external stakeholders, such as credit rating agencies and lenders, will closely monitor Manitoba Hydro's progression towards its financial targets. Further, the utility indicated that, in its judgment, the projected deterioration in the debt to equity ratio in IFF14 to 90:10, predicated on the requested 3.95% rate increase, is the minimum acceptable financial operating level. Manitoba Hydro indicated that it would be financially vulnerable to drought risk if the ratio dipped any lower.

As previously mentioned, Manitoba Hydro retained KPMG to conduct a review of its financial targets, which is expected to be completed in the fall of 2015. At that time, Manitoba Hydro will consider the recommendations from KPMG's report as well as further internal financial modelling changes and submit the recommendations to the Manitoba Hydro Electric Board for approval for inclusion in the next Integrated Financial Forecast (IFF15). Manitoba Hydro submitted that until the financial target review is complete and the results of the review have been approved by the Manitoba Hydro Electric Board, the current financial targets remain as the key measure of the utility's financial strength and are the appropriate guide for rate-setting purposes.

Manitoba Hydro noted that even with on-going 3.95% annual rate increases, the debt to equity ratio target of 75:25 will not be reached again until 2033/34.

Based on IFF14, long term debt is forecast to be over $24 billion in 2029 versus $29 billion forecast in IFF11-2 at the previous General Rate Application (GRA). The lower debt level is due to the suspension of construction of the $10.2 billion Conawapa G.S.,

offset by increased capital spending of $1.4 billion on the Bipole III Transmission Reliability Project and approximately $2 billion of increased sustaining capital spending.

Interest Coverage Ratio

The Interest Coverage Ratio is calculated to measure the degree to which Manitoba Hydro can meet its interest payment obligations from the current year's operating revenues. An interest coverage ratio below 1.0 indicates that Manitoba Hydro may have to finance interest payments with new debt rather than pay them out of revenue from operations. In IFF14, the 1.20 target is not achieved throughout the forecast period with the ratio falling below 1.0 from 2019 to 2026, an extended period during which Manitoba Hydro is forecasting $900 million in losses.

Manitoba Hydro is considering changing the determination of the interest coverage ratio to include consideration of depreciation and amortization, a non-cash expense. KPMG has recommended that Manitoba Hydro change its interest coverage ratio to be based on earnings before interest, taxes and depreciation and amortization (EBITDA) rather than earnings before interest (EBIT). This change would be consistent with the way credit rating agencies view the interest coverage ratio.

Manitoba Hydro indicated that in the company's 20-year forecast, the lowest interest coverage ratio calculated based on the existing methodology will be 0.85; however, on an EBITDA basis, the ratio would not fall below 1.35. The Manitoba Industrial Power Users Group (MIPUG) noted that, based on the revised formula, even in the worst year of the forecast, Manitoba Hydro has a substantial ability to meet its interest obligations.

Capital Coverage Ratio

The capital coverage ratio measures the ability of internally generated funds from the current period to finance sustaining capital expenditures (excluding major new generation and transmission capital expenditures).

A capital coverage ratio less than 1.0 indicates that Manitoba Hydro must borrow to fund some of its sustaining or base capital requirements. Manitoba Hydro's target capital coverage ratio is set at 1.20. To the extent the ratio exceeds 1.0, it provides internally generated funds that are used by Manitoba Hydro to fund major capital projects. The use of such funds displaces the requirement for additional borrowings that are the primary source of funding major capital projects. Manitoba Hydro has historically funded its sustaining capital spending from internally generated funds.

In 2013/14, the utility spent $470 million on sustaining capital projects. Manitoba Hydro forecasts increased spending in the order of an additional $100 million annually over the next ten years and specifically $571 million in 2014/15 and $577 million in 2015/16. As a result of the increased level of spending, the utility is forecasting capital coverage ratios below 1.0 in six years of the 10-year forecast, which indicates that the utility will not generate sufficient revenues to fund its sustaining capital expenditures and must borrow in order to renew or replace existing infrastructure.

Risk Factors Identified by Manitoba Hydro

Manitoba Hydro's risk analysis was largely focused on three risk areas:

- Drought Risk, which reflects a five-year drought starting in 2016/17 that reduces net revenues by a total of $1.7 billion or a seven-year drought starting in 2016/17 that reduces net revenues by a total of $2.3 billion. Manitoba Hydro also indicated that a 15-year low-water scenario (e.g. 1929/30 to 1943/44) starting in 2016/17 would reduce net revenues by $4 billion.

- Infrastructure Failure Risk, wherein Manitoba Hydro has flagged an "unspecified" major facility failure outage resulting in a revenue reduction of $2 billion or more. Manitoba Hydro did not provide a specific project scenario that supports this value.

- Loss of Export Market Access, wherein Manitoba Hydro suggested that 30% of total revenues are at "risk". It is unclear whether this risk relates to current contract sales, future contract sales, or all export sales. Manitoba Hydro estimates that a loss of export market access could result in a revenue reduction of $200-300 million per year.

Another risk currently facing Manitoba Hydro is the pending finalization of the utility's Lake Winnipeg Regulation licence by the Clean Environment Commission. Manitoba Hydro indicated that if the Clean Environment Commission was to reduce the upper licence limit for Lake Winnipeg water levels from 715 feet to 714 feet, it could reduce Manitoba Hydro's retained earnings by $172 million by 2022.

Only MIPUG took issue with Manitoba Hydro's evaluation of drought risk, suggesting that Manitoba Hydro's use of 100 years of flow scenarios input to the SPLASH Model already account for the financial impact of historical droughts. MIPUG suggested a reduced level of retained earrings be employed and that the rate increases during the drought would avoid depletion of the retained earnings reserve.

Drought Reserves

Manitoba Hydro indicated that its current retained earnings are $2.7 billion and are forecast to fall to $2 billion by 2024. According to the utility, this level of retained earnings is just sufficient to absorb the $1.7 billion impact of a five-year drought. Historically, Manitoba Hydro has experienced drought situations in approximately 25 of the last 100 years.

The Board previously expressed concern with respect to the level of reserves to meet drought and other risks and stated as follows in Order 43/13:

> *The Board is concerned that, by moving towards a 90:10 debt-to-equity ratio by the end of the decade, there will be an insufficient retained earnings reserve to deal with droughts and other risks such as infrastructure failure or rising interest rates. The Board*

> *sees a need to further examine and quantify the other risks that Manitoba Hydro faces at the next General Rate Application and determine whether these should be subject to separate reserve provisions. The Board will require Manitoba Hydro to provide an analysis of risks on a quantitative and probabilistic basis at the next General Rate Application. [Order 43/13]*

Manitoba Hydro did not provide this analysis at this application, but requested KPMG to provide this analysis in conjunction with the review of Manitoba Hydro's financial targets.

MIPUG submitted that Manitoba Hydro's focus on keeping its equity at $1.7 billion or higher is misplaced, as the level is arbitrary in light of the current review of financial targets being undertaken by KPMG. MIPUG further suggested that the forecast level of retained earnings is also not reasonable in light of the current investment spending and the utility's historical track record of having an equity level of less than 10 percent for extended periods of time. According to MIPUG, the existing retained earnings level exceeds the estimated cost of a five-year drought throughout a period of intense capital spending pressures, providing an exceptional level of financial protection for Manitoba Hydro.

Board Findings

The Board notes that Manitoba Hydro's financial targets are not going to be fully achieved over the next 10 years of the 20-year forecast. The Board reiterates its concern expressed in Order 43/13 of the forecast deterioration in the utility's financial measures and notes that the current outlook contemplates a further deterioration from what was presented to the Board at the last GRA.

The Board recognizes that Manitoba Hydro's near-term drought risks are adequately reflected in the 5-year and 7-year drought net revenue reductions. However, it is questionable whether a retained earnings level of $2.5 billion is sufficient to also cover the loss of major infrastructure or loss of export market access. These additional risk consequences can be concurrent with low water or drought events. However, the

financial impacts of a temporary loss of infrastructure will be reduced when the Bipole III Transmission Reliability Project and Keeyask Generating Station come into service later this decade.

To the Board, it seems likely that the pending U.S. Environmental Protection Agency's Clean Energy Rule and the Clean Environment Commission's Lake Winnipeg Regulation licence constraints will be resolved within the next four to five years. At this time, the Board cannot anticipate whether they will impact Manitoba Hydro's financial position positively or negatively.

The Board reiterates its concern raised in Order 43/13 that the move towards a 90:10 debt-to-equity ratio by the end of the decade may not provide sufficient retained earnings reserves to deal with droughts and other risks faced by the utility. The Board's ruling in this Order should not be taken as a tacit acceptance of a 90:10 scenario. However, in light of KPMG currently examining Manitoba Hydro's risk and being scheduled to provide a comprehensive report later this year, the Board considers it premature to stray from Manitoba Hydro's existing plan. The Board notes that in setting rates, it has balanced consumer rates with improving Manitoba Hydro's financial strength and meeting the utility's internally established financial targets, including the 75:25 debt to equity target. In its Needs for and Alternatives To (NFAT) report, the Board supported a relaxation of Manitoba Hydro's 75:25 debt-to-equity ratio to moderate proposed rate increases.

The Board looks forward to reviewing the KPMG report, which will analyse the adequacy of reserves on a quantitative and qualitative probabilistic risk basis. Among other things, the Board expects this report will examine the Board's NFAT recommendation. The Board will reserve judgment on this very important issue until it has an opportunity to review the KPMG report with a fulsome public review of this issue at the next GRA.

9.0 Capital Expenditures

Issues

Major New Generation and Transmission

Manitoba Hydro is currently in the midst of an unprecedented capital investment campaign. After the Needs For and Alternatives To (NFAT) Review of Manitoba Hydro's Preferred Development Plan in 2014, the Board recommended that spending on the Conawapa Generating Station be discontinued. The Province of Manitoba adopted that recommendation, but allowed technical environmental studies and analyses required to preserve knowledge gained through extensive fieldwork and Aboriginal Traditional Knowledge (ATK) studies to continue. Manitoba Hydro also continues to invest in the Bipole III Reliability Project (Bipole III) as well as the Keeyask Generating Station.

Manitoba Hydro's IFF14 forecasts $25 billion of capital spending over the next 20 years, $12.6 billion of which relates to major new generation and transmission. $3.8 billion of electric assets are projected to be placed into service by 2017 and $20.1 billion between 2015 and 2024. In the medium term, it is this investment in new assets that drives the requirement for rate increases and higher revenue requirements over the next 20 years. The projects have been approved by the Province of Manitoba and received the requisite environmental licences.

By 2021/22, the annual in-service costs for the Major New Generation and Transmission projects will be $1.14 billion, consisting of revenue requirements for the Wuskwatim Generating Station, Bipole III, the Riel Converter Station, the Manitoba-Minnesota Transmission Project, Great Northern Transmission Line, the Keeyask Generating Station, and the write-off of expenditures with respect to the Conawapa Generating Station.

The Impact of Successive Cost Escalations

The impact of the various projects on Manitoba Hydro's revenue requirement is amplified by increases in the projected cost of those projects over successive capital expenditure forecasts. The following table illustrates how the projected capital costs have increased over the past eight years.

Progression of Capital Cost Estimates

	Capital Expenditure Forecast Year (CEF)								
($ millions)	CEF6	CEF7	CEF8	CEF9	CEF10	CEF11-2	CEF12	CEF13	CEF14
Wuskwatim G.S.	1,094	1,275	1,275	1,275	1,275	1,375	1,449	1,449	1,449
Wuskwatim Transmission	257	320	316	316	291	298	323	320	320
Wuskwatim Total Project	**1,351**	**1,595**	**1,591**	**1,591**	**1,566**	**1673**	**1,771**	**1,768**	**1768**
Herblet Lake Transmission	54	95	93	93	75	75	77	76	76
Bipole III Transmission Line	1,880	2,248	2,248	2,248	3,280	3,280	3,280	3,280	4,653
Riel C.S.	103	105	268	268	268	268	268	330	330
Kelsey G.S.	166	184	190	190	302	302	302	302	340
Kettle G.S.	61	61	76	76	166	166	166	166	192
Pointe du Bois Spillway	-	-	-	318	398	398	560	560	575
Pointe du Bois Trans.	-	83	86	86	86	86	86	114	114
Pointe du Bois Rebuild	834	818	818	-	1,538	1,538	1,538	1,538	1,852
Slave Falls G.S.	179	192	198	198	223	230	230	126	126
Conawapa G.S.	4,978	4,978	4,978	6,325	7,771	7,771	10,192	10,492	397
Keeyask G.S.	-	-	3,700	4,592	5,637	5,637	6,220	6,220	6,496
500 KV Dorsey U.S. Border	-	-	205	205	205	205	205	350	350
Total	**9,606**	**10,359**	**14,451**	**16,190**	**21,515**	**21,629**	**24,894**	**25,322**	**17,270**

The significant drop in the Capital Expenditure Forecast CEF-14 "total" amount is due to the removal of Conawapa. In CEF-14, the most significant jump is a $1.4 billion increase to the projected cost of Bipole III. Manitoba Hydro indicated that the increase reflects a change to the approved control budget. This will place significant upward pressure on domestic electricity rates, since there is virtually no export revenue associated with this transmission line to mitigate or offset such cost increases.

The projected cost of the Keeyask Generating Station also increased an additional $300 million but remains within the overall budget presented to the Board at the NFAT.

Since Bipole III was outside of the scope of the Board's NFAT Review into Manitoba Hydro's Preferred Development Plan, the Board has not been in a position to assess the economics of the project or the risk factors with respect to capital cost escalations. However, given the very significant projected cost increase of which the Board was advised in this hearing, the causes of the cost escalation were explored further.

Manitoba Hydro advised that the Bipole III cost increase is primarily attributable to a price increase related to the converter stations. Manitoba Hydro was initially optimistic that it could utilize lower-cost voltage-source conversion (VSC) technology in the Bipole III converter stations. However, while vendors initially indicated that the use of this technology was feasible, they ultimately were not prepared to design and provide VSC technology, resulting in a requirement for line-commutated converter (LCC) technology and synchronous condensers to meet performance requirements.

Manitoba Hydro advised that the three bids for High Voltage Direct Current (HVDC) conversion equipment closed on March 20, 2014. All bids were based on LCC technology. Manitoba Hydro completed its technical review of the proposals by June 20, 2014. The revised control budget was prepared in August of 2014 and approved by Manitoba Hydro's executive committee in August 2014. Manitoba Hydro indicated that it did not advise the Board of cost increases during the NFAT since it took several months to prepare the control budget.

Manitoba Hydro also currently includes a replacement of the Pointe du Bois Powerhouse in its Capital Expenditure Forecast, at a cost of $1.8 billion. Like Bipole III, this project was expressly excluded from the Board's NFAT mandate and review that took place last year. Accordingly, the economics of this project have not been independently reviewed to date.

Manitoba Hydro is also investing in the Manitoba/Minnesota Transmission Line and taking responsibility for the majority of the cost of the Great Northern Transmission Line in the United States. Starting in 2021/22, these projects will create an in-service revenue requirement of $115 million annually for Manitoba Hydro. The two projects will be used to facilitate 1,000 GWh per year of 5x16 (5 weekdays by 16 hours per day) dependable sales and 400 GWh per year of 2x16 (i.e. 16 hours on weekends) dependable sales to Minnesota Power. At this time, there are no other contracted export revenues to offset the in-service cost of these two transmission line projects, nor is there any indication that Manitoba Hydro will receive transmission tariff revenue.

The Consumer Coalition (Coalition) noted that the Board identified during the NFAT Review that the cost of Bipole III may have been understated and expressed disappointment that Manitoba Hydro was still pursuing a 3.95% rate increase despite development on Conawapa ceasing. The Coalition further noted that salary and benefits charged to capital projects are increasing at a rate of 7.6% per year and that Manitoba Hydro should be directed to demonstrate, for the review of 2016/17 rates, that the utility is implementing cost control measures with respect to its capital program. The Coalition also requested the Board to recommend to the Province that the Board receive authority to review and approve Manitoba Hydro's major capital projects.

The Coalition submitted that to the extent Manitoba Hydro is seeking gradual rate increases to avoid rate shock at the time the new major projects come into service, there is a difference between increasing rates to fund adequate reserves and increasing rates to fund projects that are not yet in service. The Coalition stated that it was not convinced that the Board had the authority to require current ratepayers to pay for future projects.

The Manitoba Industrial Power Users Group (MIPUG) questioned Manitoba Hydro's transparency with respect to capital costs, noting that since the NFAT Review last year, the parties have been presented with an additional $2 billion in capital costs. MIPUG submitted that a repeat of the Bipole III experience, with several successive rounds of

significant cost increases, must be avoided. In MIPUG's submission, the parties should move away from an adversarial information-gathering process with respect to capital cost estimates.

MIPUG also suggested that since a final decision as to whether to pursue the construction of Conawapa has not yet been made, and Manitoba Hydro is keeping open the option to revive the project, it would be inappropriate to include $19 million of Conawapa's amortization costs in 2016/17 rates as Manitoba Hydro is currently planning. If Conawapa is permanently stopped, MIPUG suggests extending the amortization of existing costs over 30 years.

MIPUG also expressed disappointment with Manitoba Hydro's current capital spending plan and submitted that there was a need for a stepped approach and adequate prioritization. In MIPUG's view, the capital savings associated with the discontinuance of Conawapa were replaced with other capital spending in only six months.

Sustaining Capital Expenditures

Sustaining capital (also known as "base capital") spending is used to replace and refurbish existing assets, extend the electrical distribution system to new customers, and to meet the load growth of existing customers. In 2013/14, Manitoba Hydro spent $470 million on sustaining capital. In CEF-14, Manitoba Hydro plans on increasing its sustaining capital spending by approximately $100 million annually to $570 million in 2014/15. This represents planned spending of $5.6 billion over the next ten years and $12.4 billion over the 20 year forecast period, which is a $1.8 billion increase in sustaining capital spending forecast in CEF-13. Manitoba Hydro justified this planned increase as being required to address system reliability issues, stating that much of the existing infrastructure was built decades ago and is nearing the end of its life span.

Manitoba Hydro attempts to fund all sustaining capital expenditures from cash flow, without taking on new debt to make such investments. Even with the additional planned spending during the 2014/15 and 2015/16 fiscal years, Manitoba Hydro will continue to

be able to fund such expenditures from cash flow. However, Manitoba Hydro states that in the absence of the proposed rate increases, Manitoba Hydro would be required to fund an increasing portion of its sustaining capital expenditures through debt financing as opposed to cash flow generated from operations. These rate increases reduce the need for borrowing and additional financing costs that must be borne by customers through rates.

Despite the fact that sustaining capital expenditures replace existing assets, any such investments are fully capitalized, which means they are depreciated over the expected life of the new asset. As such, the incremental effect on revenue requirement of the $100 million spending increase during 2015/16 is only approximately $4 million, and sustaining capital is not a significant driver of the 2015/16 rate increase.

Manitoba Hydro established the following sustaining capital expenditure budgets to 2020:

- $132 million per year for seven years for generation projects;
- $125 million per year for six years for transmission projects; and
- At least $206 million per year for six years for distribution projects.

In its prior capital expenditure forecasts (e.g. CEF-08), Manitoba Hydro provided details of individual capital projects over $1 million. Now, Manitoba Hydro provides a top-down budget for each of generation, transmission, and distribution and separately identifies only projects over $50 million. As a result, the number of specific projects identified in the CEF decreased from 98 in CEF-08 to 11 in CEF-14.

Manitoba Hydro's Asset Condition Assessment Process

In Board Order 116/08, the Board directed Manitoba Hydro to prepare an Asset Condition Assessment Report that set out the following:

(a) major assets and categories of assets;

(b) the estimated remaining economic life of each major asset and category of asset;

(c) an indication of the implications for operation, maintenance & administration (OM&A) costs related to required and scheduled maintenance;

(d) a listing of scheduled, planned or anticipated major upgrading/decommissioning of major assets and/or categories of assets;

(e) forecast expenditures for planned renovations and/or replacements with respect to now available energy supply and transmission; and

(f) Dam Safety Condition Assessment and Maintenance requirements.

In Order 150/08, the Board varied this Directive and set a timeframe for Manitoba Hydro to file terms of reference by June 30, 2009. No terms of reference were ever filed, and in Board Order 73/13, the Board directed Manitoba Hydro to file an Asset Condition Assessment Study no later than the filing of the next depreciation study.

Manitoba Hydro submits that the Asset Condition Assessment Study filed during the current hearing meets the Board's directive, and that the utility also prepared an in-house distribution asset study, a transmission asset study by Kinectrics, and an in-house generation asset study. It further indicated that Manitoba Hydro's view on the life expectancy of its distribution assets was primarily based on age for planning and forecasting purposes, but Manitoba Hydro makes the decision to replace or refurbish assets based on the internal staff views of the condition of the specific assets. Manitoba Hydro also advised that in 2010 it purchased an asset investment planning system called Copperleaf to assist it in planning and prioritizing expenditures.

The Coalition was critical of the distribution asset study filed as part of Manitoba Hydro's GRA and stated that Manitoba Hydro provided a 'pitch', not a 'plan'. In the Coalition's view, the Board has been asking for a plan since 2008 and the quality of capital

planning material filed is not appropriate for approving an increase in capital costs. According to the Coalition, both the Kinectrics report and the distribution asset study were available prior to CEF-13. Additional sustaining capital spending could have been included in CEF-13, yet Manitoba Hydro now insists that an additional $100 million annually is needed in CEF-14.

The Coalition suggested that the Board has not been provided with an adequate explanation of the capital spending optimization process, the types of alternatives considered, the reasons for significantly increasing distribution expenditures, and the anticipated performance outcomes. The Coalition provided information requirements mandated in other jurisdictions and suggested that such information might indicate different levels of required spending. The Coalition called the increases in distribution project spending individually desirable but collectively not sustainable. The Coalition also submitted that the spending increase with respect to buildings cannot be said to be linked to reliability and that the utility's asset planning report provides conclusions without sufficient supporting analysis. The Coalition requested that the Board find that it is unable to conclude whether the proposed magnitude of sustaining capital investment in 2014/15 and 2015/16 is prudent and direct Manitoba Hydro to provide a more robust asset health assessment and capital asset management strategy for the next General Rate Application (GRA).

The Coalition's submissions were largely mirrored by MIPUG, which suggested that Manitoba Hydro has not proved that it is adequately pacing and prioritizing its capital spending, and that existing asset conditions are good, with no urgent, short term replacement needs. MIPUG also argued that Manitoba Hydro's sustaining capital plan for generation assets is a placeholder, not an actual plan. In addition, since at the NFAT Manitoba Hydro alleged that it could safely maintain assets based on CEF-13 spending levels and the current spending levels fill some of the gap created by the discontinuance of Conawapa, the Board should view Manitoba Hydro's plan skeptically. MIPUG further

suggested that it might make sense to fund some of the replacement of long-lived assets through borrowing rather than from cash flow.

Board Findings

Manitoba Hydro's medium-term revenue requirements are primarily driven by major new generation and transmission assets, the cost of which will amount to two-thirds of Manitoba Hydro's $3.2 billion revenue requirement by 2021/22. This cost will be borne by Manitoba ratepayers, as available projected net export revenues in 2021/22 are estimated at $553 million, which roughly equates to the in-service requirements for the Pointe du Bois spillway, Demand-Side Management (DSM) expense, and the incremental sustaining capital requirements.

The Board reviewed Manitoba Hydro's Preferred Development Plan but not the Bipole III or Pointe du Bois at the NFAT Review last year due to a provincial directive as to the scope of that proceeding. The Board has no inherent jurisdiction to review and approve the costs and economics of Bipole III. The Board agrees with the Coalition's suggested recommendation to the Province of Manitoba for a change in legislation and that the Board should have approval authority relative to Manitoba Hydro's major capital projects. Between planning to spend $4.6 billion on Bipole III (which, in and of itself, will lead to an annual revenue requirement of $384 million in 2019/20) and $1.8 billion on the Pointe Du Bois powerhouse replacement, Manitoba Hydro is making very large capital investments without independent oversight. The utility is a provincially owned Crown corporation regulated on a cost of service basis, which means that any downside risk of these investments is borne by the ratepayers of Manitoba.

The Board shares the concern expressed by Interveners that updated capital cost information with respect to major new generation and transmission projects is not provided on a timely and transparent basis.

The Board is of the view that Manitoba Hydro knew or ought to have known prior to the conclusion of the NFAT that bidders were opting for the LCC converter technology

which Manitoba Hydro had priced at $2.48 billion in August of 2009 - $0.65 billion higher than Manitoba Hydro's March 2011 estimate for the converter contract(s). As such, there is information to suggest that the Bipole III cost estimate provided during the last GRA hearing was out of date and an updated budget should have been provided during the NFAT Review as opposed to a year later.

With respect to the Keeyask Generating Station, the Board is concerned that Manitoba Hydro's project costs are not updated annually and that contingency reserves and management reserves are not tracked separately in the capital cost justifications. A quarterly reporting process on each of the Keeyask contracts, identifying costs to date and an update of the project cost target for each contract, would allow potential problems to be identified earlier.

While the Board has never been asked to consider the economic viability of the Pointe du Bois powerhouse rebuild, the Board is skeptical of the economic viability of the project and recommends that a thorough cost-benefit analysis be performed and alternatives considered.

The Board also sees a need to monitor both the project costs and the revenues attributable to the Manitoba-Minnesota Transmission Project and the Great Northern Transmission Line.

Overall, the Board sees a need for Manitoba Hydro to file detailed quarterly reports for all Major New Generation and Transmission projects, including the ones currently under development. These reports are to outline the proposed budget (at time of contract), budget changes and reasons for such changes, and the revised projected in-service costs. Where capital costs have increased materially, Manitoba Hydro is to explain how such increases will impact domestic revenue requirements and projected impacts on Manitoba Hydro's financial forecasts and targets. These reports will allow the Board to identify capital cost overruns and the associated impact on revenue requirement in a timely manner.

As part of the quarterly reports, the Board should be provided with all capital cost justifications for Major New Generation and Transmission and other projects greater than $50 million approved by the appropriate Division Vice Presidents, even if such capital cost justifications are subsequently deferred by the Manitoba Hydro Electric Board or Manitoba Hydro's Executive Committee.

The Board accepts that Manitoba Hydro is faced with aging infrastructure and there may be a genuine need to expand sustaining capital expenditures. As such, for the 2014/15 and 2015/16 fiscal years, the Board accepts Manitoba Hydro's increased sustaining capital spending. However, the Board is not satisfied that Manitoba Hydro has adequately evaluated the long term pacing and prioritization requirements. The Board considers that top-down caps or placeholders are insufficient to justify increased spending in the future. As such, the Board's acceptance of the increased sustaining capital spending during this GRA should not be construed as an endorsement of Manitoba Hydro's long term sustaining capital plan.

To bridge what the Board considers to be an information gap, the Board expects Manitoba Hydro to file, by October 31, 2015, updated Terms of Reference and schedules for an Asset Condition Assessment. The schedules should contemplate completion of the Assessment in advance of the next GRA. In the Board's view, the Terms of Reference should, at minimum, include the items set out in Appendix G of this Order.

10.0 Load Forecast and Demand-Side Management

Issues

Load Forecast

Manitoba Hydro prepares an annual Load Forecast of domestic electricity consumption, the most recent of which was prepared in 2014. Manitoba Hydro forecasts growth over the next ten years in residential electric consumption of 1.4% per year and in the General Service (i.e., mass market commercial) sector of 1.7% per year. In prior years, General Service load growth tended to closely track Residential load growth. Manitoba Hydro is forecasting load growth for Top Consumers (the utility's largest customers, for whom consumption is forecast individually for the short term) of 2.8% per year for the next ten years, despite this sector experiencing essentially zero load growth over the past ten years.

By 2023/24, the gross firm energy forecast is 29,626 GWh and the gross total peak forecast is 5,400 MW, compared to the 2013/14 weather-adjusted actual load of 24,677 GWh and 4,587 MW.

These projected growth forecasts are lower than Manitoba Hydro forecasted at the Needs For and Alternatives To (NFAT) Review, where Manitoba Hydro forecasted gross firm energy of 30,491 GWh and a gross total peak of 5,498 MW by 2023/24. The following charts show the progression of load forecasts since 2012:

	Energy (GWh)				
	2012 Base Forecast	2013 Base Forecast	NFAT 2013 Update (with pipeline)	2014 Base Forecast	NFAT 2013- 2014 Difference
2013/14	25734	25239	25239	24677	-562
2014/15	26071	25676	25676	25639	-37
2015/16	26393	26013	26013	26130	117
2016/17	26677	26322	26691	26436	-255
2017/18	27128	26606	27345	27174	-171
2018/19	27616	27003	28111	27662	-449
2019/20	27919	27398	28876	28247	-629
2020/21	28400	27789	29268	28583	-685
2021/22	28859	28197	29675	28937	-738
2022/23	29322	28605	30084	29284	-800
2023/24	29779	29013	30491	29626	-865
10 yr inc	**4045**	**3774**	**5252**	**4949**	

denotes weather adjusted actual

	Winter Capacity (MW)				
	2012 Base Forecast	2013 Base Forecast	NFAT 2013 Update (with pipeline)	2014 Base Forecast	NFAT 2013 - 2014 Difference
2013/14	4609	4601	4601	4587	-14
2014/15	4677	4680	4680	4716	36
2015/16	4738	4742	4742	4803	61
2016/17	4794	4801	4851	4861	10
2017/18	4874	4857	4959	4985	26
2018/19	4959	4930	5082	5068	-14
2019/20	5024	5002	5205	5166	-39
2020/21	5109	5074	5276	5223	-53
2021/22	5192	5147	5350	5284	-66
2022/23	5276	5222	5424	5342	-82
2023/24	5360	5296	5498	5400	-98
10 yr inc	**751**	**695**	**897**	**813**	

Notably, the weather-adjusted actual load in 2013/14 was 562 GWh lower than forecasted in the NFAT Updated forecast, while the forecasted load for 2014/15 is nearly the same in the NFAT Updated forecast and the 2014 Load Forecast.

The NFAT load forecast included expected growth in the Top Consumers sector attributed to increased pipeline load in the oil and gas sector. The reduction in the load forecast from the NFAT to 2014 was primarily attributed to the reduction in the expected pipeline load. The pipeline load initially forecasted by Manitoba Hydro at the NFAT was 1,700 GWh, which was reduced to 1,487 GWh by the end of the NFAT. According to Manitoba Hydro, this was further revised downwards in the 2014 Load Forecast to 655 GWh based on more current information obtained by Manitoba Hydro from the pipeline operators. Manitoba Hydro does not include an assessment of the load factor (as a percentage of the contract demand) in its load forecasting, nor does it forecast demand by customer or sector.

Also in the Top Consumers sector, Manitoba Hydro includes Potential Large Industrial Load (PLIL) of 91 GWh per year starting in Year 4 of the Load Forecast. The inclusion of PLIL recognizes that industrial load is not added gradually in the same way as residential or General Service load, but through infrequent, large increments. PLIL adds about 1,700 GWh to the 20 year forecast for the Top Consumers load.

Manitoba Hydro re-introduced a price elasticity variable into its Load Forecast to account for the fact that some customers have the option to switch from electricity to natural gas for space and water heating. The price elasticity variable reflects the ratio of gas rates to electricity rates. Manitoba Hydro hired an external consultant to review the price elasticity in its load forecast model, although the consultant's findings are not yet available.

Keeyask is expected to enter service in 2019 with full operation in 2020. The reduction in the domestic load forecast, specifically the pipeline load, coupled with the projected energy and capacity savings from Manitoba Hydro's Power Smart Plan, means that

energy from Keeyask is not needed to meet domestic load and existing export commitments until 2030/31. On a capacity basis, without Keeyask, Manitoba Hydro would need other capacity resources such as diversity exchanges in 2021/22 to address a capacity shortfall of approximately 50 to 150 MW. With Keeyask, new capacity resources are needed initially in 2033/34 but not on a persistent basis until 2037/38, while new energy resources are not needed until approximately 2038. This further highlights that there is no requirement for Conawapa or its associated expenses in the foreseeable future.

Conawapa's average annual energy output of 7,000 GWh would have an in-service cost of approximately 13 ¢/kWh. In 2029/30, Manitoba Hydro currently forecasts average unit export revenues of 9 ¢/kWh. In the Board's view, based on the large surplus of dependable generation from Keeyask and the more economical alternatives to supply new capacity, there is no evidence to support construction of Conawapa in the foreseeable future. Based on the current forecasts of export prices, Conawapa as a merchant plant does not seem viable.

Demand-Side Management

Demand-Side Management (DSM) is the reduction of the demand for electricity through targeted measures. While DSM reduces a utility's net income in the short term, it has the potential to defer or eliminate the need for new generation in the long term.

The Power Smart Plan is Manitoba Hydro's plan for DSM energy conservation and load management activities designed to lower the demand for both electricity and natural gas in Manitoba. In Accordance with *The Energy Savings Act*, Manitoba Hydro prepares a Power Smart Plan annually in cooperation with the provincial government. The most current Power Smart Plan for 2015/16 is a single year plan, in contrast with the previous two Power Smart Plans which are three year plans. For its long term internal planning purposes, Manitoba Hydro also prepares a 15 year supplement to the Power Smart Plan. Manitoba Hydro has not updated the supplement since 2014, but it has updated

its forecast of capital expenditures related to DSM. Compared to CEF-13, Manitoba Hydro has forecast increased spending on DSM of $900 million over the next 20 years, with an additional $500 million over the first ten years.

Manitoba Hydro forecasts increased energy savings along with the increased spending in each of 2014/15 and 2015/16, although the overall savings for 2015/16 year compared to those projected a year ago are significantly reduced. Energy savings targets have increased to 1,136 MW and 3,978 GWh (including savings resulting from changes to codes and standards) over 15 years, compared to the targets in the 2013-16 Power Smart Plan of 490 MW and 1,552 GWh. The 3,978 GWh of energy savings represents 12.7% of the base load forecast for 2028/29. In 2015/16, the utility intends to spend $63.4 million to achieve 217 GWh of savings at the customer meter.

Manitoba Hydro's DSM priorities include lower income, Aboriginal, and Northern community customers, as well as customers that were previously excluded from Power Smart programs because they were in arrears. For industrial customers, Manitoba Hydro is focusing on load displacement measures, which are typically onsite generation facilities. In Aboriginal communities that do not have access to natural gas, Manitoba Hydro is promoting community geothermal programs implemented by AKI Energy, a third party organization to which Manitoba Hydro supplies funding. AKI Energy trains First Nation members to install the geothermal systems, and has installed 177 geothermal systems to date in four First Nation communities.

The Consumer Coalition (Coalition) supported DSM as one of only a few tools customers have to mitigate the impacts of increasing rates. The Coalition did not support cutting back on DSM as part of the pacing and prioritization that it recommends Manitoba Hydro undertake with respect to its other capital programs, but it did suggest that Manitoba Hydro consider amortizing the cost of DSM over a longer period than the current ten years to mitigate rate impacts. MIPUG recommends DSM programs be amortized over the life of the benefits realized from each measure, not at an arbitrary ten years.

The Manitoba Industrial Power Users Group (MIPUG) questioned whether it made sense to aggressively invest in DSM at the same time as constructing Keeyask, recognizing that Keeyask's output will primarily be sold as opportunity exports at depressed prices in the near future. MIPUG characterized this as spending money on DSM in order to lose money on export sales.

Natural gas is currently a more efficient and economical fuel choice for space and water heating, with the cost of heating with gas approximately half that of electricity. Manitoba Hydro educates consumers on the benefits of natural gas through its Heating Fuel Choice Initiatives, which are educational and advertising programs. Natural gas is only available in Southern Manitoba, and not to all rural communities, although Manitoba Hydro stated it had a submitted an application to Natural Resources Canada for funding of a gas pipeline extension to The Pas.

The Manitoba Metis Federation (MMF) recommended that DSM efforts be expanded to assist lower income customers in Northern and rural communities that do not have access to natural gas and thus incur higher bills due to use of electricity for heating. Such programs could include incentives for air source heat pumps, appliance replacements, and fuel switching opportunities. Education and incentives should be provided to home builders to encourage construction of homes with natural gas heating.

Manitoba Keewatinowi Okimakanak Inc. (MKO) recommended implementation, over the next two years, of First Nations DSM programs that provide equivalent bill savings to customers as would be available if those customers were to switch to natural gas for space and water heating.

Manitoba Hydro noted that geothermal heating is the only technology that has the potential for energy bill savings comparable with switching from electric to natural gas heating. However, geothermal heating does not lower the overall cost to the customer because the high cost of financing the installation. Manitoba Hydro stated that the payback period on geothermal installations is typically in the order of 25 years.

The Green Action Centre (GAC) and MIPUG recommended that, contrary to the Board's NFAT recommendation, Manitoba Hydro should retain control over DSM instead of creating a new, external entity to deliver DSM programs. According to GAC, removing responsibility for DSM from Manitoba Hydro will have a disruptive effect and there is a risk that Manitoba Hydro's DSM expertise will not adequately be replicated in the external entity.

At the 2012/13 GRA, Manitoba Hydro initially presented its 2011 Power Smart Plan. It then presented a revised 2013-16 Power Smart Plan with reduced forecasts of spending on DSM programs. The Board ordered a DSM deferral account to be established which captured any deficiencies in spending compared to the minimum spending levels in 2012/13 and 2013/14, which the Board set at the levels forecasted in the 2011 Power Smart Plan. In 2012/13 and 2013/14, Manitoba Hydro underspent the targets by a total of $16.3 million. Accordingly, this amount accrued to the DSM deferral account.

Manitoba Hydro applied to have the DSM deferral account rescinded for 2014/15 and future years, citing the increased DSM budgets and savings forecasts in its revised Power Smart Plan and Supplement compared to the 2013-16 Power Smart Plan. MMF supported the continuation of the deferral account, using the 2015/16 spending target in the 2015 Power Smart Plan.

In the 2014-17 15-year Power Smart Plan supplement filed during the NFAT Review, Manitoba Hydro planned to spend $52.3 million in 2014/15. Actual spending levels fell short of this goal by $19 million. Manitoba Hydro attributed this primarily to a temporary delay in the implementation of several programs but expressed optimism about meeting its expanded 2015/16 spending target.

In its NFAT report, the Board recommended the Province of Manitoba mandate incremental annual DSM savings targets in the order of 1.5% of domestic electricity sales. Manitoba Hydro presented a forecast of energy savings that meets or

approaches this target in the years 2016/17 through 2020/21, but then the forecasted savings diminish over time to 0.4% per year. At this time, there is no legislation in place to mandate specific DSM targets, although the Board notes that pursuant to *The Energy Savings Act*, the Province of Manitoba reviews and approves Manitoba Hydro's Power Smart Plans.

Affordable Energy Program

On several past occasions, the Board expressed concerns about the effect of continued rate increases on lower income customers. Manitoba Hydro's Affordable Energy Program (AEP) provides DSM measures to lower income residential customers to help them to offset some of the rate increases through energy efficiency measures. Eligibility is based on the Statistics Canada Low Income Cutoff (LICO) measure, which is based on the number of persons in a household and the size of the community. Until 2014, Manitoba Hydro used 125% of the LICO for each respective community size. In 2014, Manitoba Hydro changed the eligibility criterion across Manitoba to use Winnipeg LICO-125, which extends the program eligibility to more customers in rural areas by setting the income thresholds at higher levels.

Manitoba Hydro has 115,000 lower income customers, excluding customers in apartments, as defined by Winnipeg LICO-125 that are the targets of the AEP. Approximately 11,000 households have participated in the AEP to date. Manitoba Hydro expects 45,500 households to participate by 2028/29. Manitoba Hydro also recently extended eligibility of the AEP to private landlords who commit to having lower income tenants for at least one year.

The energy efficiency measures available under the AEP include water saving and weatherization measures, energy efficient lighting, and improved insulation. These measures are all free to the occupant. If a home has a low-efficiency natural gas furnace, it is eligible to be replaced with a high efficiency furnace at a cost to the occupant of $9.50 per month for five years.

At the NFAT, the Board heard that customers in arrears were not eligible for Power Smart programs, including the AEP, unless they had made and were current with alternative payment arrangements. The Board concluded that the exclusion of customers in arrears from Power Smart programs precluded those that are most in need of these programs from receiving their benefits and that Manitoba Hydro should immediately address this exclusion. Following the NFAT, Manitoba Hydro removed the requirement that customers in arrears must be current in their pay arrangements to access the AEP.

In its NFAT report, the Board was of the view that an independent evaluation of the DSM program performance was important. Manitoba Hydro undertook a third-party evaluation of its AEP by Dunsky Energy Consulting and Summerhill Group. This evaluation concluded that the AEP was “well managed”, was “achieving strong results”, used “best practices”, and that “results [participation rates and savings] are strong”. Shortcomings identified include Manitoba Hydro relying on estimates of energy savings instead of verifying actual energy savings, and that there were not many measures for electrically heated homes. Dunsky and Summerhill recommended making the AEP mandatory if and when emergency bill assistance (the Neighbours Helping Neighbours program) is received as well as adding measures for electrically heated homes.

The Coalition noted Manitoba Hydro has made progress with its AEP since 2013 but would still like to see a faster implementation pace. The Coalition, MMF, and MKO see a gap in measures available to rural electrically-heated homes because, if gas is not available, there are no measures available under the AEP to reduce bills to the same extent.

The MMF recommends that Manitoba Hydro hire an engineering contractor to conduct a physical survey of insulation levels in homes to assess the quality of existing insulation levels. The MMF also recommends that Manitoba Hydro enhance its efforts to increase the pace of the program, consider the cost effectiveness of an appliance replacement program, and implement a cold climate air source heat pump pilot project in the AEP.

Board Findings

Load Forecast

The Board learned that expected domestic demand stemming from the increased pipeline load has been revised downward, further delaying the need for new generation after the completion of Keeyask. Manitoba Hydro forecasts that it will have an even greater surplus of electricity that it can export, due to the decreased domestic demand. The Board previously recommended to the Province of Manitoba that the Conawapa project and the North-South Transmission Upgrade Project be discontinued, and the forecasted reduction in future load further supports this recommendation. With the reduction in the load forecast, Keeyask will primarily be serving the export market until 2030 and new generation after Keeyask would not be needed for domestic demand until approximately 2038. The reduction in the load forecast further highlights that there is no requirement for Conawapa in the foreseeable future, as once Keeyask is built, no additional energy will be required for two decades.

The Board welcomes the external review of the price elasticities re-introduced into the 2014 Load Forecast. Continued growth in the saturation of electric space and water heating appears inconsistent with escalating electricity rates and stable natural gas prices. Appropriate price elasticities in the Load Forecast model should result in more accurate forecasts as consumers respond to the increasing price advantage natural gas is expected to have over electricity for space and water heating.

There is evidence that Manitoba Hydro consistently over-estimates the Top Consumers load growth. The first year of each load forecast for the past five years over-estimated the Top Consumers load in the greater-than-100 kV sub-class. The Potential Large Industrial Load (“PLIL”) does not recognize the last ten years of near-zero load growth in the Top Consumers sector, or that using PLIL in addition to large pipeline load additions overlaps in some years and may be double-counting. The Board sees Manitoba Hydro's PLIL as an inappropriate upward adjustment that does not reflect the

recent Top Consumers load growth history. The Board recommends that Manitoba Hydro take a more rigorous approach to forecasting the Top Consumers load.

Demand-Side Management

The Board reiterates its view from Order 43/13 that Manitoba Hydro should be providing ratepayers with the tools to mitigate their exposure to rising electricity rates through DSM. The Board supports Manitoba Hydro's DSM priorities as these were the same priorities articulated by the Board in its NFAT report. While DSM reduces revenue in the short term, DSM has the potential to push back or eliminate the need for new generation in the long term.

The Board heard that Manitoba Hydro underspent its 2014/15 Demand-Side Management target of $52.3 million by $19 million. Manitoba Hydro explained that a number of projects were delayed or deferred, including $5.5 million that was expected to be spent to upgrade Area and Roadway Lighting to energy efficient light-emitting diodes (LEDs). The Board recognizes that in some instances, delays to DSM initiatives are beyond Manitoba Hydro's control, but that further reinforces the need for the deferral account. Accordingly, the Board denies Manitoba Hydro's application to rescind the DSM deferral account.

The Board wants to be sure that Manitoba Hydro has the necessary funding for any DSM programs that are delayed to a future year. In the case of the $19 million of projects that were not implemented in 2014/15, Manitoba Hydro is to record this amount in, and can draw on the funds in, the DSM deferral account to implement those projects in 2015/16, without affecting the available funds for any projects previously planned for 2015/16. As such, in setting rates for 2014/15, the Board will order the $19 million to be placed in a deferral account, and will direct the accrued amount from 2012/13 and 2013/14 to remain in the account.

In setting rates for 2015/16, the Board sets the DSM spending target at the forecast spending level in the 2015/16 Power Smart Plan of $63.4 million, inclusive of

contributions from the Affordable Energy Fund. The accrued amounts in the DSM deferral account can be used to cover any spending increase above the planned $63.4 million in 2015/16.

At this time, the Board will continue the amortization of DSM capital expenditures over ten years.

Affordable Energy Program

The Board continues to support the AEP, including the increased budget of $9.4 million for 2015/16, compared to the previous budget of $7.3 million. The Board notes, however, that these amounts include spending on natural gas matters, and are not solely devoted to electric DSM.

The Board heard that Manitoba Hydro no longer excludes customers in arrears from participating in the AEP, which the Board applauds. The Board is pleased with the progress made by Manitoba Hydro in reaching out to First Nations communities with AKI Energy community geothermal projects as well as with the AEP.

The Board recommends to the Consumer Coalition, the Green Action Centre, the Manitoba Métis Federation and Manitoba Keewatinowi Okimakanak that these interveners encourage their members to take advantage of potential savings that can be generated by the AEP. The Board is encouraged by Manitoba Hydro's increased efforts to identify customers eligible for the AEP, and believes that these interveners may have valuable additional information to contribute.

11.0 Power Resource Plan

Issues

Manitoba Hydro annually prepares a Power Resource Plan that identifies the domestic load and export commitments as well as the generation and import resources to meet the expected load.

According to the 2014/15 Power Resource Plan, new generation resources are not needed until 2033/34 due to a shortage of winter generation capacity, with persistent capacity shortages starting in 2037/38. A shortfall in dependable energy does not occur until 2038/39. Therefore, the earliest post-Keeyask date that new resources are needed is 2033/34. Manitoba Hydro currently assumes that single cycle combustion turbines will be installed beginning in 2037/38, although that new generation is not the only option. Other options available to address capacity shortfalls could include:

- capacity from a modified Curtailable Rate Program that includes long term commitments from industrial customers, although Manitoba Hydro stated that it is not interested in contracting for additional capacity through the Curtailable Rate Program now when that additional capacity is not needed for 15 years;

- extension of existing diversity exchange agreements with utilities in the United States. Manitoba Hydro currently has 550 MW of diversity exchange agreements with Great River Energy and Northern States Power;

- contracted imports from the United States, especially considering the additional 700 MW of import capacity provided by the Manitoba-Minnesota Transmission Project;

- advancing combined cycle combustion turbines by several years to provide 200-300 MW of capacity as well as a more economical supply of energy than a single cycle combustion turbine; and

- capacity inputs to Manitoba Hydro's grid from self-generation by customers.

Manitoba Hydro undertakes periodic maintenance and repair of its hydraulic generating stations. Hydraulic generation outages over the last five years averaged approximately 2.5% of total generation, or about 100 MW per year. These outages primarily relate to four generating stations that are not on the Lower Nelson River. These maintenance outages may be accounted for in the Power Resource Plan under winter capacity reserves, but do not appear to be included in the dependable energy calculations.

More hydraulic generator drive-train units are approaching replacements in the next 5-15 years. In the longer term, Manitoba Hydro indicated that it plans to replace all 32 Lower Nelson drive-train units within next 14 to 49 years with an average generator size of 98 to 135 MW. This will result in significant capacity outages while generators and turbines are replaced or refurbished.

Typically, Manitoba Hydro expects these outages to last about two years for each unit. This suggests that two units will be out of service every year for 35 years, with a corresponding outage rate of 200 MW per year or 5% of total generation. These outages would be in addition to ongoing outages of generating units on the Winnipeg River, Saskatchewan River, and Upper Nelson River, resulting in total outages of 7.5% or 300 MW per year.

It does not appear that the pending major outages of generation on the Lower Nelson are reflected in either IFF14 as a reduction in export revenue or in CEF-14 as a capital cost.

Board Findings

The Board notes that new post-Keeyask generation is not needed until 2033/34 at the earliest or 2037/38 with the addition of new capacity resources, such as the extension of existing diversity exchange agreements or an expansion of the Curtailable Rate Program.

At the NFAT, the Board heard that a major benefit of the Manitoba-Minnesota Transmission Project was enhanced intertie transmission capacity and the ability to access more capacity and energy resources from the United States. The 2014 Power Resource Plan does not recognize this resource and the 700 MW of additional available import capacity.

The Board notes that Manitoba Hydro's existing hydraulic generation refurbishment and replacement program does not appear to have been integrated into either the 2014 Power Resource Plan or defined in the CEF14 sustaining capital requirements.

12.0 Export Markets

Issues

Manitoba Hydro exports electricity, primarily to the United States, by way of long term fixed price contracts with U.S. utilities and also by way of opportunity sales into the Midcontinent Independent System Operator (MISO) market. The opportunity sales are made during either 'On-Peak' hours or 'Off-Peak' hours. Typically, the volumes of electricity sold on the opportunity market greatly exceed the volumes of electricity sold pursuant to long term fixed-price contracts, as the latter sales are made from 'dependable' resources whereas opportunity sales are made from surplus hydraulic generation in years when water flows are above minimum flows.

Since 2008/09, Manitoba Hydro has been competing with natural gas-fueled electricity generation, such as combined cycle combustion turbine (CCCT) generators, for peak MISO opportunity market share. The on-peak market price has been 3.0 to 4.5 ¢/kWh, while off-peak market prices have averaged about 2.5 ¢/kWh.

Over the past seven years, export prices have not materialized as planned, with prices significantly decreasing around the time of the 2008 recession. This has placed, and continues to place, upward pressure on domestic rates, as any revenue that cannot be obtained from exports must be obtained from domestic ratepayers. However, the overall impact on rates has been somewhat mitigated by many years of higher-than-average water flows, allowing Manitoba Hydro to generate and sell more energy into the export market.

Manitoba Hydro's 2014 export pricing projections do not assume any additional value attributable to carbon dioxide (CO_2) through 2019/20 and, combined with continued low natural gas prices, may signal opportunity market prices remaining below 4 ¢/kWh.

Manitoba Hydro obtains forecasts from five independent forecasters to prepare its own forecast. Manitoba Hydro's export price update in IFF14 shows average prices down

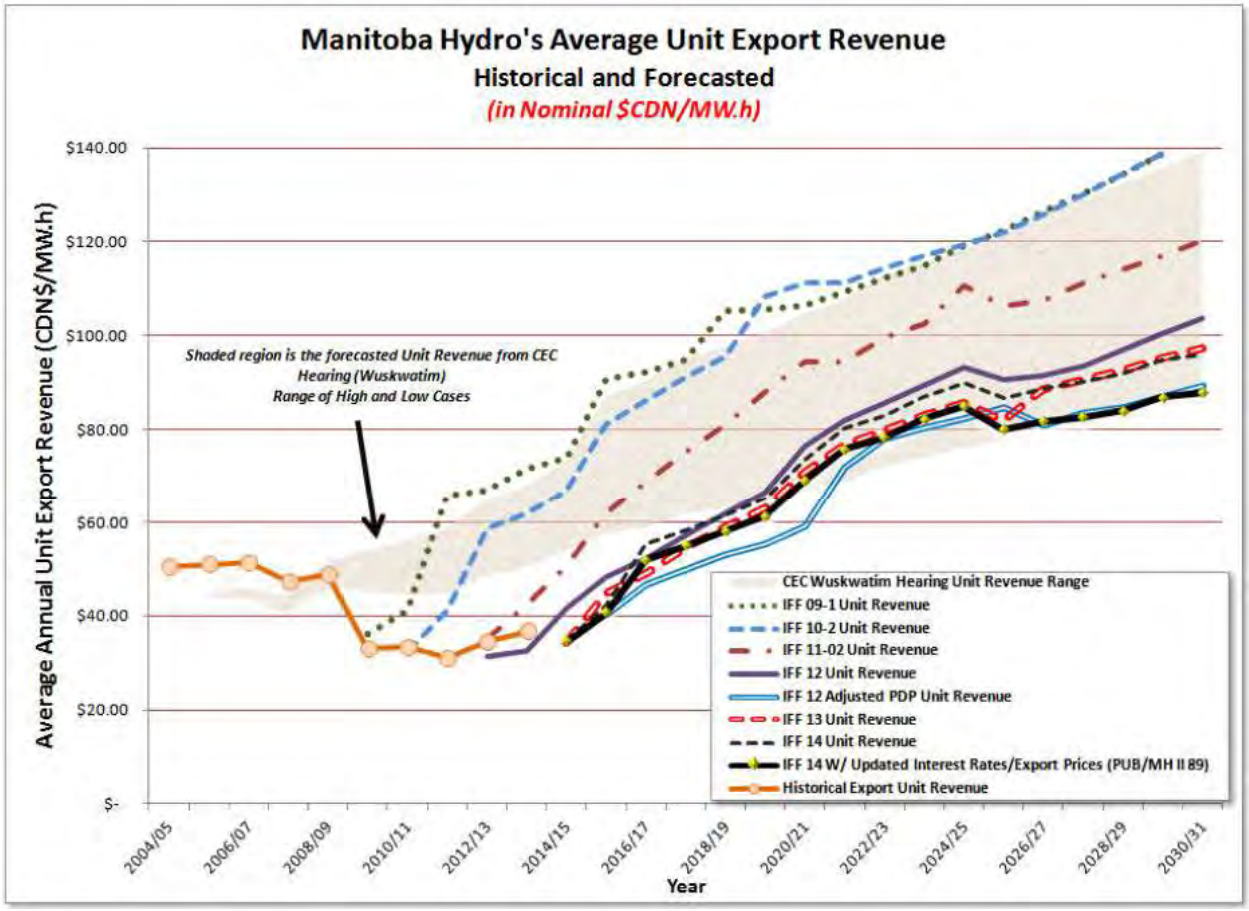
7% over the next 20 years, compared to the prior forecast based on the suite of Manitoba Hydro's independent consultants' price forecasts.

Manitoba Hydro's update to IFF14 suggests net export revenues will decline a further $276 million in the next 10 years and $838 million over the next 20 years, which is an approximate further decline in export revenues of 5%.

Manitoba Hydro is awaiting clarification of the U.S. Environmental Protection Agency's (EPA) Clean Power Rule which is expected in the summer of 2015. This EPA Rule may provide some clarity to the expected reduction in coal generation which may be replaced by natural gas-fired combined-cycle combustion turbines (CCCTs), wind generation, and solar generation. Until the final Rule is released, the future role of Manitoba Hydro exports into the U.S. is unclear as is the value of future export contract opportunities.

The graph below illustrates the history of Manitoba Hydro's average unit export revenues and export forecast projections. Since IFF09-1, when Manitoba Hydro signed most of its term sheets, the average unit revenue forecasts circa 2024/25 have trended downward about 33% from $120/MWh to $80/MWh. Actual average unit revenues since 2008/09 have been below $40/MWh.

Average Unit Export Revenue Forecasts



Interveners also commented on the adverse export price declines in the successive Manitoba Hydro forecasts. The Consumer Coalition (Coalition) noted that since Manitoba Hydro provided IFF10-2, the value of the export revenues declined approximately $3.9 billion and this decline places stress on domestic ratepayers to fund Manitoba Hydro's operating revenue shortfall through rate increases.

The Coalition submitted that Manitoba Hydro's export price forecasts are 'perpetually too high', such that the Board should have little confidence in them when setting rates. The Coalition suggested that the strengthening U.S. economy, coupled with the weakening of the Canadian dollar, could change the export pricing paradigm.

Board Findings

The Board is concerned that successive Manitoba Hydro export price forecasts have been revised downward and consistently overestimate actual results. That trend continues since, according to IFF14, Manitoba Hydro expects a further price decline which will negatively impact the business case for Manitoba Hydro's new investments in generation and transmission.

The Board notes that Manitoba Hydro's latest export price and export revenue forecasts still appear to increase annually due to assumed, but uncertain, increasing natural gas prices.

The Midcontinent Independent System Operator (MISO) market that Manitoba Hydro exports into has changed since 2008 when Manitoba Hydro signed term sheets with Northern States Power and Minnesota Power. The Board anticipates that new contracts for firm export sales may not achieve prices that are as attractive as those agreed to by Northern States Power and Minnesota Power in 2008.

The Board notes that Manitoba Hydro's future exports into the United States are highly dependent on evolving United States Environmental Protection Agency (EPA) rules on carbon dioxide (CO_2) emissions reductions. These future export sales will be competing with new wind, solar, and natural gas-fired combined cycle combustion turbine generation. Manitoba Hydro's hydraulically generated energy is not assured of favourable treatment under the EPA Clean Power Rule as are other United States-based renewable energy resources.

In the Board's view, Manitoba Hydro's export price and export revenue forecast will be affected by the pending EPA Rule, the cost of natural gas-fired generation in MISO, the subsidies provided to other renewable energy generation options, and the access to additional markets through increased peak period intertie transmission capacity.

13.0 Special Rates

Curtailable Rate Program

Manitoba Hydro's Curtailable Rate Program (CRP) allows Manitoba Hydro to curtail a portion of participating industrial customers' peak load in exchange for reduced rates on the same portion of the load when not curtailed. The program currently has three customers, only two of which received any credits in 2013/14. Manitoba Hydro stated that the value of short term capacity in the MISO market has greatly diminished, and because the capacity is contracted on an annual basis, it is not included as a capacity resource in the utility's Power Resource Plan. Manitoba Hydro indicated that, to date, it has not considered entering into multi-year contracts to allow the program to be used as a capacity resource in future planning.

Manitoba Hydro seeks to reduce the amount of Option A and Option R loads available to customers, while eliminating options C and CE entirely and making changes to the terms and conditions imposed on participating customers. According to Manitoba Hydro, this would not affect the current operations of existing customers.

The Manitoba Industrial Power Users Group (MIPUG) was critical of the plan to cap the program and suggested that Manitoba Hydro should take a long term view and consider multi-year contracts, stating that the CRP currently represents 23% of the capacity savings in the Power Smart Plan.

Board Findings

The Board accepts Manitoba Hydro's explanation that, at the present time, the value of the CRP is diminished and notes that new long term capacity resources in Manitoba, once Keeyask is constructed, will not be required until 2033/34. As such, while the Board believes that there may be merit in MIPUG's suggestion that an expanded CRP with long term contracts could provide capacity benefits, it is premature at this time to expand the program. The Board therefore approves the finalization of Manitoba Hydro's proposed changes to the CRP, including the proposed cap.

Surplus Energy Program (SEP)

The Surplus Energy Program (SEP) is a system by which Manitoba Hydro prices electricity generated in excess of its immediate requirements and then sells it based on a pricing mechanism approved by the Board. The pricing of the SEP energy is established to approximate the price offered by Manitoba Hydro to export sales customers on the opportunity market or, in the case where the utility expects to import power, at a price reflective of Manitoba Hydro's cost with a 10% surcharge.

Board Findings

In Order 43/13, the Board approved several changes to the SEP on an interim basis, to be reviewed at the Cost of Service proceeding. With a Cost of Service hearing expected to take place prior to the next General Rate Application (GRA), the Board will keep those changes approved on an interim basis and not finalize them at this time.

The Board approves SEP rates on a weekly basis by way of interim orders that Manitoba Hydro seeks to finalize in this proceeding. In this Order, the Board approves the finalization of all interim SEP Orders since the issuance of Order 43/13.

The Board notes that Manitoba Hydro has undertaken to provide enhanced quarterly SEP reporting upon formal direction of the Board. The Board will therefore direct Manitoba Hydro to set out, in each quarterly report, the National Energy Board pricing and other factors that have influenced prices over the past quarter.

Time of Use (TOU) Rates

In its GRA, Manitoba Hydro applied for the approval of Time of Use (TOU) rates effective April 1, 2016. However, the Board determined that TOU rates would be addressed as part of the upcoming Cost of Service hearing rather than the GRA. As such, the matter was not explored and the Board makes no findings on TOU rates in this Order.

Area and Roadway Lighting Rates

Manitoba Hydro's annual billings for Area and Roadway Lighting are approximately $23 million, approximately half of which is for service to the City of Winnipeg. Area and roadway lighting is not metered – rather, a flat rate is charged for each type of luminaire. The City of Winnipeg was critical of what it perceived to be a lack of data as to the actual luminaires based on which the City of Winnipeg is billed. Manitoba Hydro indicated that its data are improving due to the use of a geographic information system (GIS), and that the utility relies on data provided by the City of Winnipeg at the time Manitoba Hydro acquired Winnipeg Hydro.

Manitoba Hydro indicated that it is currently involved in a seven-year project to replace existing Area and Roadway Lighting with light-emitting diode (LED) luminaires, and seeks final approval of the LED rates. Manitoba Hydro derived the proposed LED rates by determining the annual kilowatt hour savings expected to be achieved by converting from high-pressure sodium (HPS) lighting to LED. Manitoba Hydro then determined the monthly cost savings using the Area and Roadway Lighting energy charge from Manitoba Hydro's 2013 Prospective Cost of Service Study (PCOSS13) updated to reflect the actual and proposed rate increases. The monthly cost savings were then deducted from the proposed April 1, 2015 HPS rates to determine the proposed LED rates.

While the City of Winnipeg did not object to the LED conversion program, which will reduce rates per luminaire, it expressed concern about Manitoba Hydro intending to wait until completion of the program to prepare another Area and Roadway Lighting-specific cost of service study. The City of Winnipeg noted that the most recent study is already over 25 years old and there is no guarantee that the LED conversion program will be completed on schedule. Manitoba Hydro suggested that the LED conversion program should run its course before another Area and Roadway Lighting-specific cost of service study is prepared.

Board Findings

The Board agrees with the City of Winnipeg's submission that there are deficient data on which the City is being billed almost $12 million per year. The Board was provided with insufficient evidence to determine whether the lack of data is due to the state of Winnipeg Hydro's records at the time of sale or the historical state of Manitoba Hydro's own records, but notes that technology now exists to significantly improve data, as evidenced by Manitoba Hydro's GIS system. Nonetheless, no conclusive evidence was presented as to whether there are actual errors in the City of Winnipeg's bills and, unless such errors are proven, the Board has no reason to doubt that Manitoba Hydro's bills are fair and reasonable.

The Board will direct Manitoba Hydro to, by December 31, 2015, file with the Board a five-year plan to complete the City of Winnipeg's luminaire GIS mapping.

The Board shares the City of Winnipeg's concern about the most recent Area and Roadway Lighting-specific cost of service study now being over 25 years old. However, in light of most HPS lighting being replaced over the next six years, the Board cannot justify an Area and Roadway Lighting-specific cost of service study at this time. The Board notes that the overall cost allocated to the Area and Roadway Lighting class will be reviewed at the upcoming Cost of Service hearing, while the City of Winnipeg's bills for the Area and Roadway Lighting class are expected to be reduced as the conversion program proceeds. In the Board's view, an Area and Roadway Lighting-specific cost of service review should take place upon the completion of the LED conversion program. Since the timeframe for the completion of this program is not yet certain, the Board will not schedule such a review at this time. However, the Board expects to be apprised of the LED conversion progress at each GRA hearing.

14.0 Presenter Submissions

The following parties made presentations to the Board in respect of this proceeding. Presentations are not sworn evidence and do not form part of the evidentiary record.

Allan Ciekiewicz

Mr. Allan Ciekiewicz indicated that while the current proceeding does not discuss inverted rates, any future proceeding on inverted rates must address the all-electric customer without an alternative source of heating. He also expressed his concern about the implications on having to supply pipeline projects with electricity during a drought. He submitted that the $1.4 billion already spent on Keeyask would have been better spent on efficient gas turbine generators, that the existing plan is subject to drought risk, and that Manitoba Hydro should focus on domestic needs first.

Mike Velie – International Brotherhood of Electrical Workers

Mr. Mike Velie presented on behalf of the International Brotherhood of Electrical Workers (IBEW), Local 2034, which represents 2,849 employees of Manitoba Hydro. IBEW supports Manitoba Hydro's rate application, stating that otherwise there would be an impact to safe and reliable service. As an example, Mr. Velie provided a freeze on training and a migration of workers to other employers and provinces. According to Mr. Velie, financial constraints led Manitoba Hydro to fall into a deficit position with respect to asset maintenance and 40% of substations are operating above their limitations. He submitted that outside contractors do not have the same level of understanding of the utility's operations, nor the same commitment as Manitoba Hydro employees, and provided an example in which a decision to save on protective equipment injured an employee. Mr. Velie identified the planned reduction in the workforce as a false economy if quality would suffer as a result.

Albertine Spence

Ms. Albertine Spence stated that the communities along the Nelson River are significantly impacted by hydroelectric development, and that these communities have approximately $6.4 million in arrears. She stated that her Manitoba Hydro bill for a trailer has been between $327 and $437 a month when her annual income was less than $32,000. She indicated that she moved to Winnipeg in December 2014 but still receives billings from Tataskweyak Cree Nation, referencing creative accounting and the need for an audit. She also described some of the hardships faced by people in the communities due to electricity bills, and suggested that low-income earners should pay reduced rates.

Dave Mouland

Mr. Dave Mouland with Winnipeg Harvest spoke to the effect of continued rate increases on people living in poverty, stating that the budgets of those living on poverty do not go up by 3.95% every year. Even if utilities are paid through EIA, costs are still indirectly passed on through higher food prices. He also submitted that every major project drives Manitoba Hydro deeper into debt, while little is done to renew existing infrastructure.

Bill Turner (MIPUG) and Dale Bossons (Canexus)

Messrs Bill Turner and Dale Bossons, the chair and co-chair of MIPUG, spoke to the impact of rate increases on industrial consumers. They expressed concern about Manitoba Hydro's proposal to introduce caps on the Curtailable Rate Program (CRP), stating that companies such as Canexus have invested significantly to avail themselves of the program. They also stated that companies in the U.S. can alter their loads to capture the benefits of daily or seasonal energy price fluctuations. According to MIPUG, Manitoba used to be among the lowest-cost jurisdictions, but no longer is at this time. MIPUG also expressed concern regarding industrial DSM being removed from Manitoba Hydro, stating that the utility has the in-depth knowledge and longstanding relationships with industry required for these programs. Lastly, MIPUG expressed surprise that even

with Manitoba Hydro no longer pursuing Conawapa, the utility continues to request 3.95% rate increases, stating that industry could not survive with another decade of such rate increases. Mr. Bosson's added that a 3.95% rate increase represents an additional $2.5 million cost increase to Canexus per year.

Pam Pugh

Ms. Pam Pugh farms west of Portage la Prairie and will have the Bipole III transmission line cross her land. She spoke to security issues with respect to the line, stating farmers do not want to be liable for coming into contact with electric poles, and submitted that the line should be routed underground.

Garland Laliberte and Dennis Woodford – Bipole III Coalition

Messrs Garland Laliberte and Dennis Woodford spoke on behalf of the Bipole III Coalition. They addressed the changing ways in which we use electricity and spoke to the development of microgrids in the U.S. and Europe. They also submitted that once solar grid parity is achieved, it would be reasonable for residential customers to generate with solar power. With respect to the Bipole III transmission line, Mr. Woodford stated that if the Bipole III converters already purchased would be connected to the Bipole I and II transmission lines, there would be sufficient capacity for Keeyask. The Coalition also questioned Manitoba Hydro's case for the reliability need for the Bipole III Transmission Reliability Project, stating that Manitoba Hydro's assumption that a failure of the two existing lines could occur once every 17 years is incorrect, and such a failure would occur only once in 90 years.

Manitoba Hydro

Manitoba Hydro offered to provide, and the Board accepted to hear, a presentation by Manitoba Hydro in response to the presentation made by the Bipole III Coalition. Like the other presentations received by the Board, Manitoba Hydro's presentation was not received as sworn evidence and as such does not form part of the evidentiary record of the proceeding.

Manitoba Hydro indicated that from a global perspective, Manitoba Hydro currently routes a disproportionate amount of power through a single system. Dr. Swatek referred to the 1996 wind storm in which 19 HVDC towers were lost, submitting that risks to the system are not just academic. He suggested that if an F5 tornado were to hit the Dorsey Converter Station, outages could last from several months to three years. Dr. Swatek also spoke to the NERC reliability criteria Manitoba Hydro has to comply with and stated that if Dorsey or the Interlake corridor was lost, Manitoba Hydro would be 1,500 MW short at this time, while in 2020, there would be a deficit of 700 MW compared to a surplus of 1,300 MW with the Bipole III Transmission Reliability Project in service.

Per Stokke

Mr. Per Stokke filed a written presentation but did not make oral submissions. His submission focused on the Pointe du Bois and Wuskwatim spillways. With respect to Wuskwatim, Mr. Stokke alluded to a number of alleged planning errors that caused the initial construction cost estimates to be significantly exceeded. With respect to Pointe du Bois, Mr. Stokke questioned Manitoba Hydro's conclusion that the spillway had to be replaced.

15.0 IT IS ORDERED THAT:

1. The rate increase of 2.75% previously approved as interim on May 1, 2014 **BE AND IS HEREBY APPROVED AS FINAL**.

2. Manitoba Hydro's Application for a 3.95% across-the-board rate increase effective April 1, 2015 **BE AND IS HEREBY DENIED** as filed.

3. A 3.95% overall increase in billed rates for the Basic Charge, the Demand Charge, and the Energy Charge for all rate classes to take effect August 1, 2015, with revenues from a 2.15% portion of the rate increase accruing into a deferral account to be utilized to mitigate the required rate increases when Bipole III enters service and 1.8% accruing to Manitoba Hydro's general revenues, **BE AND IS HEREBY APPROVED**.

4. Manitoba Hydro recalculate and refile, for Board approval, a schedule of rates reflecting a 3.95% increase effective August 1, 2015 to the Basic Charge, Demand Charge, and Energy Charge for all rate classes, together with all supporting schedules including proof of revenue, customer impacts, and revenue requirement.

5. Manitoba Hydro shall lead a collaborative process to develop a bill affordability program harmonized with Manitoba Hydro's other programs supporting low-income ratepayers. Manitoba Hydro shall file proposed Terms of Reference for this collaborative process with the Board (including proposed facilitators and stakeholder participants) by no later than October 31, 2015. If Terns of Reference cannot be agreed upon between Manitoba Hydro and participants, the Board is prepared to receive submissions and adjudicate the issue.

6. Manitoba Hydro shall consider additional measures to increase participation rates in the Affordable Energy Program and to assist all-electric customers, particularly those living in rural Manitoba and aboriginal communities without

access to natural gas heating options, and to provide annual reports on the implementation of the Affordable Energy Program and any additional measures developed by the end of June of each calendar year.

7. Manitoba Hydro shall file terms of reference for an Asset Condition Assessment Report for approval by the Board that, at minimum, include the information set out in Appendix "F" of this Order, by no later than October 31, 2015.

8. The removal of net salvage from 2015/16 depreciation rates in the 2014 Depreciation Study **BE AND IS HEREBY APPROVED**.

9. The incorporation of the use of the Equal Life Group methodology to set depreciation rates in 2015/16 as set out in the 2014 Depreciation Study **BE AND IS HEREBY DENIED**.

10. Manitoba Hydro is to continue to use its existing Average Service Life Methodology for calculating depreciation rates for rate-setting purposes until the Board is satisfied that a change in methodology is warranted.

11. Manitoba Hydro's request to rescind the DSM deferral account **BE AND IS HEREBY DENIED**.

12. Manitoba Hydro is to continue the DSM deferral account to capture shortfalls in Demand-Side Management spending compared to the forecast spending in the Power Smart Plan. The shortfall in Demand-Side Management spending in 2014/15 of $19 million shall accumulate in the DSM deferral account. To the extent Manitoba Hydro's actual spending on Demand-Side Management in 2015/16 falls below the forecasted spending in the 2015 Power Smart Plan of $63.4 million, the shortfall shall accumulate in the DSM deferral account. To the extent Manitoba Hydro's actual spending on Demand-Side Management in 2015/16 exceeds $63.4 million, the excess shall be paid from the balance of the DSM deferral account. The DSM deferral account is to continue with each annual

spending target equal to the forecast spending stated in the most current Power Smart Plan, inclusive of funding from the Affordable Energy Fund.

13. Manitoba Hydro shall file detailed quarterly reports for all Major New Generation and Transmission projects, including the ones currently under development. These reports are to outline the proposed budget (at time of contract), budget changes and reasons for such changes, and the revised projected in-service costs. Where capital costs have increased materially, Manitoba Hydro is to explain how such increases will impact domestic revenue requirements and projected impacts on Manitoba Hydro's financial forecasts and targets.

14. Manitoba Hydro shall file quarterly updates regarding its Operation, Maintenance & Administration (OM&A) expenditures and the actual OM&A expenditures compared to Manitoba Hydro's target.

15. Manitoba Hydro shall identify and provide details of individual capital projects with a value greater than $1 million in future Capital Expenditure Forecasts.

16. The Curtailable Rate Program changes approved on an interim basis by way of Directive 13 of Order 43/13 **BE AND HEREBY ARE APPROVED AS FINAL**.

17. All Curtailable Rate Program Orders from Order 46/14 up to and including all Curtailable Rate Program Orders issued prior to the date of this Order **BE AND HEREBY ARE APPROVED AS FINAL**.

18. All weekly Surplus Energy Program interim ex-parte rate Orders – from Order 47/13 up to and including all Surplus Energy Program Orders issued prior to the date of this Order, **BE AND ARE HEREBY APPROVED AS FINAL**.

19. As part of any future quarterly Surplus Energy Program reports, Manitoba Hydro include an explanation of the National Energy Board (NEB) pricing and other factors that have influenced the pricing during the quarter addressed by the report.

20. By December 31, 2015, Manitoba Hydro shall file with the Board a five-year plan to complete the City of Winnipeg's luminaire geographical information system (GIS) mapping.

Board decisions may be appealed in accordance with the provisions of Section 58 of *The Public Utilities Board Act*, or reviewed in accordance with Section 36 of the Board's Rules of Practice and Procedure. The Board's Rules may be viewed on the Board's website at www.pub.gov.mb.ca.

THE PUBLIC UTILITIES BOARD

Régis Gosselin, B ès Arts, MBA, CPA, CGA
Chairman

"Kurt Simonsen"
Acting Secretary

Certified a true copy of Order No. 73/15 issued by The Public Utilities Board

Acting Secretary

APPENDIX A – APPEARANCES

R. Peters / S. Hombach	Counsel for the Manitoba Public Utilities Board
O. Fernandes / B. Czarnecki	Counsel for the Manitoba Hydro-Electric Board
D. Pambrun	Counsel for the City of Winnipeg
B. Williams	Counsel for the Consumer Coalition
B. Gange	Counsel for the Green Action Centre
A. Hacault	Counsel for the Manitoba Industrial Power Users Group
G. Orle	Counsel for Manitoba Keewatinowi Okimakanak Inc.
T. Masi	Counsel for the Manitoba Métis Federation

APPENDIX B – WITNESSES FOR MANITOBA HYDRO

S. Thompson	President & CEO
D. Rainkie	VP, Finance & Regulatory
L. Kuczek	VP, Customer Care & Energy Conservation
S. Bauerlein	Corporate Controller
D. Cormie	Division Manager, Power Sales & Operations
T. Miles	Division Manager, Power Planning
R. Elder	Division Manager, Bipole III Project
D. Bowen	Manager, Keeyask Project
N. Read	Manager, Generation Maintenance Engineering
D. Swatek	Manager, System Planning (Transmission)
M. Morin	Manager, Distribution Asset Maintenance
L. Carriere	Manager, Financial Planning
M. Schulz	Corporate Treasurer
I. Page	Division Manager, Corporate Planning & Strategic Review
G. Barnlund	Division Manager, Rates & Regulatory Affairs
P. Chard	Division Manager, Business Support Services
L. Morrison	Division Manager, Consumer Marketing and Sales
C. Galbraith	Affordable Energy Supervisor
M. Hooper	Asset Accounting Systems Supervisor
L. Kennedy	External Depreciation Expert, Gannet Fleming

APPENDIX C – INTERVENERS OF RECORD & WITNESSES

City of Winnipeg
Consumer Coalition (P. Lee)
Green Action Centre (R. Colton)
Manitoba Industrial Power Users Group (P. Bowman, P. Lee)
Manitoba Keewatinowi Okimakanak Inc.
Manitoba Métis Federation

APPENDIX D

A. Ciekiewicz	Private Citizen
M. Velie	International Brotherhood of Electrical Workers
A. Spence	Private Citizen
D. Mouland	Winnipeg Harvest
B. Turner & Dale Bossons	Manitoba Industrial Power Users Group
Pam Pugh	Private Citizen
G. Laliberte and D. Woodford	Bipole III Coalition
Manitoba Hydro	
P. Stokke (written presentation only)	Private Citizen

APPENDIX E – UNITS OF MEASUREMENT

Demand/Power represents the size of electricity load over a specific period of time.

expressed in:

- Watts (W)
- Kilo-watts (kW) - 1,000 watts
- Mega-watts (MW) - one million watts
- Giga-watts (GW) - one billion watts

Energy represents the amount of electricity provided to customers to do work or create heat, light, or sound. It is typically expressed as:

- Kilo-watt hours (kWh) - 1,000 watt hours
- Mega-watt hours (mWh) - 1,000 kilo-watt hours
- Giga-watt hours (GWh) - one million kilo-watt hours

Voltage represents the electric potential between two points expressed in**:**

- Volts
- Kilo-volts (kV) – 1,000 volts

Water Flow represents the rate at which water enters or leaves a system, expressed in:

- Cubic Meters per Second (m3/s)

APPENDIX F – LIST OF ABBREVIATIONS

AEP	Affordable Energy Program
ASL	Average Service Life
ATK	Aboriginal Traditional Knowledge
CCCT	Combined-Cycle Combustion Turbine
CEF	Capital Expenditure Forecast
CGAAP	Canadian Generally Accepted Accounting Principles
COSS	Cost of Service Study
CRP	Curtailable Rate Program
DSM	Demand-Side Management
EBIT	Earnings Before Interest and Taxes
EBITDA	Earnings Before Interest, Taxes, Depreciation and Amortization
EFT	Equivalent Full-Time
ELG	Equal Life Group
EPA	Environmental Protection Agency
GAC	Green Action Centre
GIS	Geographical Information System
GRA	General Rate Application
HPS	High-Pressure Sodium
HVDC	High-Voltage Direct Current
IASB	International Accounting Standards Board
IFF	Integrated Financial Forecast
IFRS	International Financial Reporting Standards
IFRA	International Financial Reporting Standards
LCC	Load-Commutated Conversion
LED	Light-Emitting Diode
LICO	Low Income Cut-Off
MIPUG	Manitoba Industrial Power Users Group
MISO	Mid-Continent Independent System Operator
MKO	Manitoba Keewatinowi Okimakanak Inc.
MMF	Manitoba Metis Federation
NFAT	Needs For and Alternatives To
OM&A	Operation, Maintenance & Administration
PCOSS	Prospective Cost of Service Study
PLIL	Potential Large Industrial Load
SEP	Surplus Energy Program
VSC	Voltage Source Conversion
WPLP	Wuskwatim Power Limited Partnership

APPENDIX G - MINIMUM TERMS OF REFERENCE FOR ASSET CONDITION ASSESSMENT

Manitoba Hydro's Asset Condition Assessment Report should include, at minimum, the following:

- For each of Manitoba Hydro's hydraulic generating stations and thermal generating stations, a timeline for the refurbishment and/or replacement up to 2049/50 along with an Asset Health Index. For the hydraulic generating stations, this should include the following components:
  - powerhouse structure and gates.
  - spillway structures and gates
  - main dam
  - secondary dams/dikes/weirs
  - access lands and building facilities.
  - breakers
  - exciters (separately for each unit)
  - generators (separately for each unit)
  - governors (separately for each unit)
  - transformers
  - turbines (separately for each unit)
- Identification of specific components of generating assets that are scheduled for replacement based on chronological age life expectancy as opposed to an Asset Health Index.

- For each of Manitoba Hydro's HVDC and HVAC transmission systems, a timeline for the refurbishment and/or replacement up to 2049/50 along with an Asset Health Index. This should include the following components:
  - Bipole I & II, further broken down into:
    - HVDC breakers
    - HVDC transformers
    - HVDC transmission steel structures.
    - HVDC transmission tower footings.
    - HVDC transmission line cables
    - HVDC converter transformers.
    - HVDC valve groups.
    - HVDC synchronous condensers
    - HVDC shunt reactors.
    - HVDC smoothing reactors
  - Bipole III (to include same listing as above out to 2049/50)
  - HVAC regional transmission lines (to include for each region and as applicable):
    - transmission breakers
    - transmission transformers
    - protector relays

- ♦ AC transmission steel towers
- ♦ AC transmission tower footings
- ♦ AC transmission wood poles
- ♦ AC transmission overhead

- For each of Manitoba Hydro's regional distribution systems, a timeline for the refurbishment and/or replacement up to 2049/50 along with an Asset Health Index. This should include the following components:
  - City of Winnipeg
    - ♦ underground services
    - ♦ overhead services
  - Southern Manitoba.
    - ♦ natural gas available.
    - ♦ natural gas not available.
  - Eastern Manitoba
  - Northern Manitoba

Tab 54

La Capra Associates

NEEDS FOR AND ALTERNATIVES TO (NFAT) REVIEW OF MANITOBA HYDRO'S PROPOSAL FOR THE KEEYASK AND CONAWAPA GENERATING STATIONS

PUBLIC VERSION

Technical Appendix 3A

Alternative Resource Plans

PREPARED FOR

The Manitoba Public Utilities Board

PREPARED BY

La Capra Associates, Inc.
One Washington Mall, 9th Floor
Boston, MA 02108

January 24, 2014

La Capra Associates

PUBLIC VERSION

Technical Appendix 3A: Alternative Resource Plans

Table of Contents

I. Introduction **1**

A. Scope of Report *1*

B. Pending supplemental filing *2*

C. La Capra Associates' approach to evaluating Manitoba Hydro's plan development *2*

II. Overview of Manitoba Hydro's Plan Development **3**

A. Resource needs analysis *3*

B. Resource technology screening *4*

Summary of Resource Technology Screening 6

C. Resource option screening *6*

Additional DSM 7

Hydro 8

Natural gas resources 9

Wind resources 10

Imports 10

Summary of resource option screening 11

D. Alternative plan development *11*

III. Critique of Manitoba Hydro's Resource Needs Analysis **13**

IV. Critique of Manitoba Hydro's Resource Technology Screening **13**

A. Process Critiques *14*

"High Level Screening" 14

Manual screening vs. optimization process 14

Inappropriate unit cost metrics 15

Screening ignores future technology trends 15

B. Technology-specific critique *15*

In-lake wind 16

Solar – PV 16

Solar thermal 17

Geothermal 17

Coal – Conventional and IGCC 17

Nuclear 18

La Capra Associates, Inc.
One Washington Mall, 9th Floor
Boston, Massachusetts 02108

lacapra.com

Biomass (crop residue and wood fuel) 18

V. Critique of Manitoba Hydro's Alternative Development Plans 19

A. Omission of DSM resources, lack of imports 19

B. No evidence of plan optimization 20

C. Single-pass analysis abbreviates process 21

D. Critique of CCGT/SCGT optimization process 21

E. Lack of risk analysis 22

F. Portfolio Analysis vs. Resource Option Evaluation 24

G. Summary of critique alternative development plan process 24

VI. Alternative Plans and Results 25

A. Supplemental resource development plans 25

B. Wind cost assumption analysis 26

VII. Summary and Conclusions 31

A. Resource needs analysis is overly conservative 31

B. Resource technology screening removes too many options on subjective or misplaced criteria 31

C. DSM not considered as a resource option during plan development 31

D. Alternative development plans were manually created instead of optimized, represent limited spectrum of options. 31

E. Wind cost assumptions provide skewed results 32

Table of Figures

Figure 3-1: Results of resource technology screening 6
Figure 3-2: MH's potential development plans 12
Figure 3-3: Wind Cost Assumptions for Sensitivity Analysis 26
Figure 3-4: Impact of Wind Cost Changes on Wind Gas Development Plan NPV 27
Figure 3-5: Impact of Wind Cost Changes on Wind Conawapa Development Plan NPV 28
Figure 3-6: Impact of Wind Cost Changes on Wind Gas minus Preferred Plan CPV 29
Figure 3-7: Impact of Wind Cost Changes on Wind Conawapa minus Preferred Plan CPV 30

Acronyms

Technical Appendix 3A

CCGT	Combined Cycle Gas Turbine
CPV	Cumulative Present Value
DSM	Demand Side Management
EIA	US Energy Information Administration
IGCC	Integrated Gasification Combined Cycle
KP	Knight Piésold
LCA	La Capra Associates
LCOE	Levelized Cost of Energy
MH	Manitoba Hydro
MISO	Midcontinent Independent System Operator
MP	Minnesota Power
NFAT	Needs For and Alternatives To
NPV	Net Present Value
PV	Photovoltaic
SCGT	Simple Cycle Gas Turbine
SOW	Scope Of Work
US	United States
WPS	Wisconsin Public Service

I. Introduction

A. Scope of Report

La Capra Associates (LCA) has prepared this Technical Appendix to address six elements of our Needs For and Alternatives To (NFAT) Scope of Work (LCA SOW) and support other elements of our work that rely on the materials in this report. The specific LCA SOW elements addressed here are:

Power Resource Planning and Economic Evaluation

2. *Assess whether Manitoba Hydro's approach to comparing generation sequences follows sound industry practice; and*
6. *Develop power resource plans and alternatives, including identifying other scenarios that could potentially compete on an economic basis with Manitoba Hydro's Preferred Development Plan; and*
10. *Examine the No New Generation scenario and the potential for extended use of imports to meet Manitoba Hydro's domestic load requirements; and*
13. *Assess the maximum deferral prospects for Keeyask G.S. and/or Conawapa G.S.; and*

Business Case and Risk Assessment

1. *Analyse the financial and economic risks of the Preferred Development Plan and export contracts and export opportunity revenues in relationship to alternative development strategies; and*
5. *Examine and evaluate the treatment of risk in Manitoba Hydro's development of Power Resource Plans and resource scenario models. Incorporate expert opinions on flood and drought risks and optimal strategy.*

The Manitoba Hydro (MH) NFAT process determined the timing of need for new resources, examined potential resource options available, created development plans which would fulfill the resource need, and performed comparative economic and financial analysis on those proposed plans to determine the preferred option.

The specific focus of this Technical Appendix is to review and critique Manitoba Hydro's screening of resource options and creation of the alternative development plans. This report also discusses potential plans that were not initially evaluated by

Manitoba Hydro. Technical Appendix 1: Resource Planning reviews the resource planning criteria and resource needs analysis.

B. Pending supplemental filing

Early in La Capra Associates' review of MH's development plan process we determined that the portfolio of plans developed by MH did not cover the full spectrum of resource planning options. La Capra Associates developed multiple alternative development plans that would provide additional analysis and a wider scope of options for resource planning.

La Capra Associates communicated with Manitoba Hydro regarding these additional alternative plans and MH agreed to perform the modeling and economic analysis on two additional plans. These plans are discussed in Section VI A. Manitoba Hydro has only recently provided the results of this analysis and modeling. La Capra Associates is currently in the process of reviewing the results and will be filing a supplement to this Technical Appendix to provide our analysis of these alternative plans.

C. La Capra Associates' approach to evaluating Manitoba Hydro's plan development

Our approach to evaluating MH's resource option screening and creation of the development plans included the following:

1) LCA reviewed materials relevant to this assessment, including:
   - The information contained in the NFAT submission pertaining to resource needs assessment, resource option screening, and MH's creation of the alternative development plans;
   - MH's responses to Information Requests and information provided to LCA in lieu of responses to IRs; and
   - Publically available information regarding technology cost assumptions.
2) LCA held discussions with MH personnel to discuss needs assessment analysis, generation cost assumptions, and resource plan development.

3) LCA conducted independent analysis on to MH's cost assumptions regarding wind generation and the impact on the economic analysis results of changing these cost assumptions.

The following review and analysis is the product of this approach.

II. Overview of Manitoba Hydro's Plan Development

The NFAT Application under evaluation includes analysis in support of the requested approvals from Manitoba Hydro's resource planning process. The process consists of a series of stages to identify resource need, evaluate potential resources to fulfill the need, develop discrete potential alternative plans, and perform comparative analysis on the alternative plans.

This section of the appendix provides an overview of each of the various stages contributing to the creation of the development plans.

A. Resource needs analysis

The first stage of Manitoba Hydro's process is the resource needs analysis, which compares the forecasted peak and annual energy demand with resource supply available to Manitoba Hydro. The purpose of this process is to determine when additional capacity and energy resources are required.

Manitoba Hydro completes this analysis on an annual basis as part of its Power Resource Plan and has included an updated analysis in Chapter 4 of the NFAT. The analysis concludes that Manitoba Hydro will need new dependable energy resources in 2022/23 and new capacity resources in 2025/26.[1]

MH's resource needs analysis is discussed and critiqued in detail in Technical Appendix 1: Resource Planning.

[1] NFAT Submission, Chapter 4, pp. 46-50.

B. Resource technology screening

Once the need for new resources has been established, MH evaluates generation technologies available to address the need. The NFAT analysis includes a "high-level" evaluation of 16 resource technologies across 15 resource characteristics in order to screen out technologies that are not suitable for further evaluation.[2]

MH screened the following resource technologies:[3]

1. Additional demand-side management (DSM)
2. Hydro with storage
3. Run of River Hydro
4. On-Shore wind
5. In-Lake Wind
6. Solar photovoltaic (PV)
7. Solar Thermal
8. Enhanced Geothermal
9. Simple Cycle Gas Turbine (SCGT)
10. Combined Cycle Gas Turbine (CCGT)
11. Conventional Coal
12. Coal - Integrated Gasification Combined Cycle (IGCC)
13. Nuclear
14. Biomass: Crop Residue
15. Biomass: Wood based fuel
16. Imports

The technologies were screened on the following 15 characteristics, grouped into four categories:[4]

- Technical (Section 7.1.1.1)
  - Maturity of Technology
  - Technical Challenges in Manitoba
  - Ease of Integration into System
  - Intermittency

[2] NFAT Submission, Chapter 7, p. 1.

[3] NFAT Submission, Chapter 7, Table 7.1, p. 3.

[4] *Id.* pp. 4-11.

- Seasonality

- Environmental (Section 7.1.1.2)
  6. Water Quality Impacts
  7. Hazardous Air Pollutants
  8. Greenhouse Gas Emissions (over life cycle)
  9. Land Use Impacts
  10. Wildlife Species of Interest
- Social/Policy (Section 7.1.1.3)
  11. Proximity to Load Center
  12. Regulatory Constraints
  13. Social Acceptability
- Economic (Section 7.1.1.4)
  14. Manitoba Delivered Fuel Costs
  15. Forecast USA Unit Costs ($/MWh)

Each technology was evaluated on each characteristic and given a categorization - red, yellow, or green. Some resource characteristics were scored qualitatively (e.g. land use impacts, regulatory constraints, etc.) and other were characterized quantitatively (e.g. proximity to load, unit costs, etc.).[5] Resources receiving a red rating on any characteristic were screened out.

Of the 16 technologies evaluated, seven passed the initial analysis. The remaining technologies were screened out for various reasons. Figure 3-1 presents the results of the resource technology screening process.

[5] NFAT Submission, Chapter 7, pp. 4-11.

Technology	Result	Reason for failure
Additional DSM	Passed	
Hydro with storage	Passed	
Run of River Hydro	Passed	
On-Shore wind	Passed	
In-Lake Wind	Failed	High unit costs, lack of experience
Solar PV	Failed	High unit cost, intermittency
Solar Thermal	Failed	High unit cost
Enhanced Geothermal	Failed	Low grade resource
Simple Cycle GT	Passed	
Combined Cycle GT	Passed	
Conventional Coal	Failed	Regulatory constraints, public opinion
IGCC	Failed	Low maturity, regulatory constraints
Nuclear	Failed	Difficult to integrate, complex regulations, public opinion
Biomass: Crop Residue	Failed	High collection and transportation costs
Biomass: Wood based fuel	Failed	High collection and transportation costs
Imports	Passed	

Figure 3-1: Results of resource technology screening

Summary of Resource Technology Screening

The resource technology screening process provides a high-level review of the suitability of the various resources for development to meet Manitoba's energy and capacity needs. Based on this review, MH selected seven of fifteen potential technologies for further consideration in the next planning step, the resource option screening process.

The assumptions used by MH in this process are also discussed in Technical Appendix 2: Generation Alternatives.

C. Resource option screening

The seven technologies that passed the initial screening were evaluated further by MH in the "resource option screening" process in order to determine the specific unit configurations that will be incorporated into the alternative development plans. The

purpose of this process is "the selection of specific resource options from each of the resource technologies" that passed the technology screening process.[6]

The following sections review MH's assessment of each resource option.

Additional DSM

MH's further consideration of DSM resources is based on its "continued long-term commitment to pursuing all cost-effective energy efficiency opportunities and to continually monitoring the market for emerging trends and opportunities which may become economically viable."[7]

Manitoba Hydro recently contracted for a DSM potential study which found that there is considerably more DSM potential than MH currently includes in its Power Smart Plan. The study was not available in time for the NFAT analysis, but MH performed a sensitivity analysis incorporating additional DSM.[8] MH is currently conducting alternative development case analysis with DSM estimates derived from this potential study and has indicated its intent to complete those studies (economic and financial analysis) in February and introduce those results in this NFAT proceeding at that time.

This DSM sensitivity case is also discussed in Technical Appendix 1: Resource Planning.

MH concludes the resource option screening of DSM by noting that DSM relies on program participation and does not "carry the same degree of certainty that a generation resource provides."[9]

Unlike the generation options described below, MH did not develop specific parameters for including additional DSM in the alternative development plans. Despite the fact that it passed the technology screening process, no potential plans were developed with DSM. This issue will be discussed further in the alternative development plan critique section below.

[6] NFAT Submission, Chapter 7, p. 20.

[7] *Id.*, pp. 20-21.

[8] *Id.*, pp. 21-22.

[9] *Id.*, p. 23.

Elenchus Research Associates has also reviewed MH's DSM assumptions and potential studies in its report *NFAT Review: A Review of Manitoba Hydro's Demand Side Management Plan*, filed with the PUB.

Hydro

The hydro portion of the resource option screening stage involves the evaluation of total hydro potential and the identification of the projects that are most suitable for development.[10] Overall, MH has identified 8,200 MW of additional hydro potential remaining in the province. Due to various agreements and regulations[11], there are twelve projects representing 4,700 MW available for development. Of these twelve projects, MH's assessment concludes that only two are at a development stage where they could be ready in the 2022/23 time frame.[12]

Keeyask is the most economic project on a levelized cost of energy (LCOE) basis at $60/MWh and has a lead time of seven years. Conawapa is next with an LCOE of $67/MWh and lead time of 13 years.[13] Due to the fact that the other projects have higher estimated levelized costs and longer development timelines, Keeyask and Conawapa were included as resource options for incorporation into the alternative development plans.

Of the ten hydro projects not selected, the Notigi project is furthest into the development process, with a listed lead time of ten years and an LCOE of $88/MWh. This project was not selected because it is small and the lead time would likely be longer than listed because the feasibility studies are of an older vintage – suspended in 2002.[14]

---

[10] NFAT Submission, Chapter 7, pp. 23-28.

[11] These agreements include the Treaty Land Entitlement Framework Agreement and the Canadian Heritage Rivers System, which are discussed in the NFAT Submission in footnote #3 in Chapter 2 and Chapter 7, p. 23.

[12] NFAT Submission, Chapter 7, p. 24.

[13] *Id.*, p. 26. The LCOE figures for Keeyask and Conawapa are net of all sunk costs prior to June 2014, so they are not inclusive of the full capital costs of the project.

[14] NFAT Submission, Chapter 7, pp. 27-28.

Natural gas resources

MH identified gas generation as a suitable resource technology. The resource options screening analysis considered three types of gas units: simple cycle gas turbine (SCGT), combined cycle gas turbine (CCGT), and aeroderivative simple cycle gas turbine. The resource screening concluded with the following evaluation of the specific generator options:[15]

- Heavy duty SCGT: Suitable for large increments of new capacity (>200MW) and infrequent operation (<20% capacity factor). SCGT's have short lead times of 3-5 years. MH evaluated a configuration featuring a 209 MW GE 7FA unit with a heat rate of 9,906 btu/kWh.
- Heavy duty CCGT: Suitable for large increments of new capacity (>200MW) and more frequent operation (>40% capacity factor). Compared to SCGTs, CCGTs have higher upfront capital costs but lower operational costs. Like SCGTs, the CCGT also has a short lead time of 3-5 years. MH evaluated a configuration consisting of a 308 MW GE 7FA unit with a heat rate of 6,652 btu/kWh.
- Aeroderivative CCGT: Most suitable for small capacity increments and infrequent operation, the aeroderivative units have the shortest lead time (3 years) but the highest capital and operational costs. MH evaluated a 47 MW GE LM6000PH with a heat rate of 9,475 btu/kWh.

The NFAT has provided no discussion of any other specific generators considered by MH as part of the resource options screening process. The Knight Piésold Independent Expert Consultant Report ("KP Report") explains that MH contracted for a study by Gryphon International Engineering Services, Inc. to review natural gas generation options and estimate capital and O&M costs.[16]

The configurations discussed above were chosen for inclusion in the alternative development plans.

[15] *Id.*, pp. 28-31.

[16] Knight Piésold Independent Expert Consultant Report, pp. 51-55.

Wind resources

Wind generation passed the initial technology screening process as an approved resource. As part of the resource option screening process, MH evaluated the potential for wind development to fulfill generation need. Southern Manitoba is suitable for several thousand MWs of wind farm development, which can be installed in a modular fashion to match resource need.[17]

In MH's analysis, wind generation is assumed to have zero winter peak capacity due to its intermittent nature and that generators are not reliable at temperatures below -30C, which are the temps that produce the winter peak.[18] Therefore wind projects address energy needs only.

For the purposes of resource planning, MH assumed a wind project configuration of 65 MW with a 40% capacity factor. MH also assumed that the "dependable" portion of the energy generated by a wind project is 85% of the total generation. This total provides enough dependable energy to cover approximately one year of load growth on the MH system. MH assumed that the wind project would be owned and operated by MH, rather than a third party. [19]

Imports

The final resource that passed the resource technology screening is imports. MH notes that imports are an option for either energy or capacity, subject to the limits placed on import energy by the planning criteria.[20] MH several options to take advantage of economical import opportunities, including seasonal diversity agreements in which the winter-peaking MH and summer-peaking United States (US) Midcontinent Independent System Operator (MISO) systems agree to supply capacity to each other during each system's season of surplus.[21]

As with the treatment of DSM as a resource option (discussed above), MH did not specifically develop a configuration of import energy to be used in the development

[17] NFAT Submission, Chapter 7, p. 31.

[18] *Id.*, pp. 31-32. See also NFAT Submission, Appendix 7.4.

[19] *Id.*, pp. 32-33.

[20] NFAT Submission, Chapter 7, p. 34.

[21] *Id.*, pp. 34-35.

plans. Instead, the NFAT submission discusses the qualitative considerations on the use of imports and the limitations codified in the resource planning criteria.[22]

Summary of resource option screening

MH's resource option screening process is a continuation of the resource technology screening whereby more specific resource configurations were established for inclusion as resources in the development plans. At the conclusion of this process, MH had identified two possible hydro options (Keeyask and Conawapa), three possible gas generators (CCGT, SCGT, and aeroderivative SCGT), and a generic wind development option. Specific configurations were not developed for the DSM or import resource options.

D. Alternative plan development

The next stage of the resource planning process is the creation of the development plans. According to MH, "once the initial timing of the need for new resources has been determined, development plans are identified using a number of combinations of new generation options and export opportunities available to [MH]."[23]

Using different configurations and timing of the resource options that passed the initial screening, MH created multiple plans that meet the energy and capacity requirements. In addition to generation resources, the alternate development plans vary depending on the additional transmission capacity assumed in each.[24]

During this stage of the process, 15 plans were developed. Five plans include 750 MW of additional import/export capability with the US, three plans include 250 MW of export and 50 MW of import capability with the US, and seven plans fulfill MH's needs with no new US interconnection. Figure 3-2 below summarizes the development plans created by MH.

[22] This issue is discussed in further detail in Technical Appendix 1: Resource Planning.

[23] LCA/MH I-331.

[24] NFAT Submission, Chapter 8, p. 1.

Plan Number	Development Plan Short Name	Description of Development Plan
1	All Gas	Natural Gas-Fired Generation starting in 2022/23
2	K22/Gas	Keeyask 2022/23, Natural Gas-Fired Generation starting in 2029/30
3	Wind/Gas	Wind Generation starting in 2022/23 supported by Natural Gas-Fired Generation starting in 2025/26
4	K19/Gas24/250MW	Keeyask 2019/20, Natural Gas-Fired Generation starting in 2024/25, 250 MW Export/50 MW Import US Interconnection 2020/21, 250 MW MP Sale
5	K19/Gas25/750MW (WPS Sale & Inv)	Keeyask 2019/20, Natural Gas-Fired Generation starting in 2025/26, 750 MW Import/Export US Interconnection 2020/21, 250 MW MP Sale, Proposed 300 MW WPS Sale
6	K19/Gas31/750MW	Keeyask 2019/20, Imports, Natural Gas-Fired Generation starting in 2031/32, 750 MW Import/Export US Interconnection 2020/21, 250 MW MP Sale
7	SCGT/C26	Simple Cycle Gas Turbine in 2022/23, Conawapa 2026/27, Natural Gas Fired Generation starting in 2038/39
8	CCGT/C26	Combined Cycle Gas Turbine in 2022/23, Conawapa 2026/27, Natural Gas Fired Generation starting in 2039/40
9	Wind/C26	Wind in 2022/23, Conawapa 2026/27, Natural Gas-Fired Generation starting in 2036/37
10	K22/C29	Keeyask 2022/23, Conawapa 2029/30, Natural Gas-Fired Generation starting in 2040/41
11	K19/C31/250MW	Keeyask 2019/20, Natural Gas-Fired Generation starting in 2024/25, Conawapa 2031/32, 250 MW Export/50 MW Import US Interconnection 2020/21, 250 MW MP Sale
12	K19/C31/750MW	Keeyask 2019/20, Imports, Conawapa 2031/32, Natural Gas-Fired Generation starting in 2041/42, 750 MW Import/Export US Interconnection 2020/21, 250 MW MP Sale
13	K19/C25/250MW	Keeyask 2019/20, Conawapa 2025/26, Natural Gas-Fired Generation starting in 2040/41, 250 MW Export/50 MW Import US Interconnection 2020/21, 250 MW MP Sale
14 Preferred Plan	K19/C25/750MW (WPS Sale & Inv)	Keeyask 2019/20, Conawapa 2025/26, Natural Gas-Fired Generation starting in 2041/42, 750 MW Import/Export US Interconnection 2020/21, 250 MW MP Sale, Proposed 300 MW WPS Sale
15	K19/C25/750MW	Keeyask 2019/20, Conawapa 2025/26, Natural Gas-Fired Generation starting in 2041/42, 750 MW Import/Export US Interconnection 2020/21, 250 MW MP Sale

Figure 3-2: MH's potential development plans[25]

[25] NFAT Submission, Chapter 9, Table 9.3, p. 12

These 15 development plans were evaluated based on the economic and financial analytical framework described in the NFAT Submission, Chapters 9-12. These economic and financial analyses are evaluated fully in Technical Appendix 9: Economic Analysis, and Technical Appendix 10: Financial Analysis.

III. Critique of Manitoba Hydro's Resource Needs Analysis

La Capra Associates has reviewed and critiqued MH's resource needs analysis. Our evaluation and conclusions are discussed extensively in Technical Appendix 1: Resource Planning.

Overall, we conclude that MH's resource needs analysis is overly conservative, and that MH's identified timing of energy and capacity need are likely sooner than the actual need will develop. In addition, our assessment concludes that in the near term there are alternative options to address the eventual resource need other than large hydro development that could further delay the large investments necessary for the Preferred Development Plan.

IV. Critique of Manitoba Hydro's Resource Technology Screening

Manitoba Hydro's resource screening process is accomplished in two steps – resource technology screening and resource option screening. The distinction between the two steps is very minimal and for the purposes of this report we will critique the two steps together.

Overall, the screening process has several shortcomings which result in technologies being unnecessarily screened out from further consideration. The following section provides LCA's evaluation of the screening process, and provides specific critiques of MH's treatment of individual technologies.

A. Process Critiques

In general, our primary concern with the technology screening process is that the purpose and process of the screening has been poorly defined by MH and as a result, it has not provided a clear argument for the further consideration of certain technologies and exclusion of other technologies.

"High Level Screening"

As noted in the NFAT report, this initial, "high-level screening of technologies uses a general characterization to determine whether a technology will proceed to the next stage of evaluation."[26] For most of the resource characteristics, the assessment is at least partially subjective and there are no specific thresholds for screening out a technology on that basis. As an example, nuclear technology received a "screened out" rating for several reasons, including due to its "complex & lengthy approval process."[27] There is no discussion of this rating or comparison of the incremental complexity of the nuclear approval process beyond the approval process for hydro or natural gas.

Of the technology characteristics that can be quantified, MH often did not define the thresholds for screening a unit out. For example, in rating technologies on the "proximity to load center" characteristic, the distances from potential new generation were grouped into five categories based on range in kilometers.[28] While various technologies were given yellow or green ratings, MH does not explain which of the five categories corresponds to the various color designations, nor why a resource far from a load center would not be feasible for development since additional cost considerations should be factored in elsewhere in the screening process.

Manual screening vs. optimization process

Manitoba Hydro's process relies on a manual screening of a combination of qualitative and quantitative factors. In many respects the technologies that were screened out were removed not because they are not able to be developed in Manitoba, but because they are not preferable based on the set of base assumptions by which the technologies were evaluated. As discussed below, the assumptions regarding solar PV led to the

[26] NFAT Submission, Chapter 7, p. 11.

[27] *Id.*, Table 7.1, p. 3.

[28] NFAT Submission, Chapter 7, p. 8.

technology being screened out despite industry expectations of large cost declines during the study period. This method, rather than one based on a resource optimization process, can inappropriately remove technologies from potential development. This issue of optimization is address in more detail in the critique of the development plan process below.

Inappropriate unit cost metrics

The primary characteristic that determined which technologies were screened out was unit cost. For this characteristic, MH utilized the US Energy Information Administration estimates of levelized cost, rather than the Manitoba-specific levelized costs it calculated. Regardless of the previous discussion of optimization vs. manual screening, simple reliance on generic US EIA estimates does not incorporate Manitoba-specific characteristics that should be included in the technology screening process.

Screening ignores future technology trends

MH's planning horizon for the NFAT analysis is 78 years and across the development plans, individual scenarios have resources going into service as late as 2047. By performing the resource screening in 2012 and eliminating technologies from consideration through the entire 78 year planning horizon, MH's process ignores future changes in all the characteristics upon which it evaluated the technologies. MH has recognized that wind, solar and combustion turbine technologies are expected to see improvements over time. It is conceivable that by 2047 the evaluation of many technologies would change in regards to public opinion, regulatory status, and particularly cost (discussed in more detail below).

Technical Appendix 2: Generation Alternatives provides additional analysis and discussion of this issue.

B. Technology-specific critique

Our assessment of MH's process criticized the concept of screening out technologies, rather than utilizing an optimization process. Without disregarding this critique, this section of the report reviews the technologies that were eliminated from further consideration by MH's technology screening process and provides a critique of their conclusion.

In-lake wind

The resource technology screening process eliminated in-lake wind as a potential resource primarily due to high resource cost. MH also discusses other potential barriers such as lack of experience, technical challenges, and conflicts with commercial and recreational water uses.[29]

Given the large amount of undeveloped on-shore wind potential, it is reasonable to delay consideration of in-lake wind at this time. However, the technology is promising due to higher performance characteristics and lower development obstacles in certain circumstances. MH should monitor development of marine and in-lake wind projects elsewhere in North America and should study wind conditions for future development in Manitoba.

Solar – PV

Despite acknowledging a good-quality solar resource in southern Manitoba, MH screened out solar PV due to high LCOE costs and intermittency issues.[30]

Technical Appendix 2: Generation Alternatives, provides a review of MH's resource cost and performance assumptions.

Generally, MH has noted that the industry forecasts anticipate solar PV installed cost declines of up 50% by 2020.[31] Yet the technology was screened out from further consideration based on the EIA Annual Energy Outlook 2013 price estimate. The screening based on these estimates eliminated solar PV with an average LCOE estimate of approximately $150/MWh. A 50% decline in costs would make that technology extremely cost competitive with other energy resources.

Based on the long horizon on the NFAT analysis, it would be reasonable for MH to calculate comparative costs between resources farther in the future incorporating cost trends to determine if solar PV may be a cost competitive option.

[29] NFAT Submission, Chapter 7, p. 18.

[30] NFAT Submission, Chapter 7, p. 18.

[31] NFAT Submission, Appendix 7.1, pp. 43-45.

Solar thermal

MH screened out solar thermal due to high LCOE costs. The report also notes concerns with resource intermittency and a mismatch between resource availability and Manitoba's winter system peak. [32] Based on the status of the development of solar thermal technology, there is no compelling reason to consider it more viable than resource underconsideration.

Geothermal

Geothermal was screened out during the resource technology evaluation due because "heat gradients required for these systems remain unproven in Manitoba," as well as other technical and economic challenges.[33]

Based on the status of geothermal technology and the availability of more economic base load resources with fewer technological challenges, there is no compelling reason to pursue geothermal resources at this time.

Coal – Conventional and IGCC

Both coal resources were screened out from further consideration due to the regulatory constraints imposed by the *Climate Change and Emissions Reductions Act*.[34] This legislation requires the phase-out of the use of coal-fired generation.

Based on the regulatory restrictions in place and larger trends in the North American utility industry, it is reasonable for MH to screen out the coal technologies.

[32] NFAT Submission, Chapter 7, p. 18.

[33] NFAT Submission, Chapter 7, p. 19.

[34] *Id.*

Nuclear

MH's resource technology screening process eliminated nuclear as an option due to the high capital investment, difficulty of integrating large units, and regulatory restrictions on storing radioactive waste imposed by *The Manitoba High-Level Radioactive Waste Act*.[35] There are several issues with these justifications for the elimination of nuclear as a potential resource.

MH did not provide analytical support for the exclusion of nuclear due to the high upfront capital investment, particularly given the magnitude of investment being proposed for the hydro units. Regarding integration difficulty, MH provided no analysis supporting any claim that integrating a large nuclear unit is not feasible. In addition, the legislation cited by MH is targeted primarily at preventing the storage of radioactive waste and spent fuel that is generated outside Manitoba. It is not clear from the legislation that nuclear generation would be prohibited.[36]

Despite these issues, it was reasonable for MH to eliminate nuclear as a potential resource option due to high cost uncertainty, high regulatory risk, and environmental concerns.

Biomass (crop residue and wood fuel)

Both biomass technologies evaluated were screened out for the same reason: According to MH's analysis the cost of energy from these resources is "not yet competitive with other forms of generation and are highly dependent upon the uncertain price of transportation fuels."[37] This conclusion is not supported by any analysis of transportation fuel costs or sensitivities.

MH's own analysis shows that there is potential for more than 630 MW of capacity and 4,800 GWh of annual energy from domestic biomass resources. Much of the biomass fuel is located within 100 km of Winnipeg.[38]

---

[35] *Id.*, pp. 19-20.

[36] *The High-Level Radioactive Waste Act*. C.C.S.M. c. R10, July 17, 1987. http://web2.gov.mb.ca/laws/statutes/ccsm/r010e.php

[37] NFAT Submission, Chapter 7, p. 20.

[38] NFAT Submission, Appendix 7.1, Section 4.2.

The cost of energy from both biomass and natural gas generators are highly dependent on fuel costs, yet MH's analysis does not include any evaluation of fuel price sensitivity which would support the exclusion of biomass from further consideration.

Biomass generators are common across North America and MH's technology screening process does not provide a comprehensive justification for screening out this resource.

See Technical Appendix 2: Generation Alternatives, for a full discussion of MH's biomass assessment.

V. Critique of Manitoba Hydro's Alternative Development Plans

As discussed above, MH utilized the resource options that passed the screening process to manually create a variety of potential development plans that fulfill forecasted resource need and, in some cases, take advantage of export opportunities.

This section critiques MH's presentation of its process of creating the alternative development plans for further analysis.

A. Omission of DSM resources, lack of imports

MH's resource screening process identified select resources that were suitable for inclusion in the development plans. While DSM passed all screening tests, MH did not formulate any development plans that include specific levels of DSM programming.

MH has stated that it is committed to pursuing cost-effective DSM opportunities.[39] However, given the analysis that identified DSM as a suitable resource, it would have been appropriate for MH to create development plans that specifically targeted and funded additional DSM programs as a viable resource option.

Similarly, imports were identified as a feasible resource option. Yet only a few plans feature additional import development, and none of the plans are specifically

[39] NFAT Submission, Chapter 7, pp. 20-21.

formulated to take advantage of excess capacity in MISO in lieu of constructing new domestic resources. This issue is addressed further in the following section.

B. No evidence of plan optimization

MH's process for creating and testing the alternative development plans lacks a process of optimization. MH manually develops a variety of plans that follow certain "pathways" that generally represent an informed sample of potential resource options. These plans are then evaluated using the SPLASH model and economic analytical models. It was from this analysis that the Preferred Development Plan was identified.

This process lacks quantitative optimization that is typically used by utilities in resource planning. Internal or third party model software (such as Ventyx Strategist) offer resource planning tools that optimize resource build out given a set of inputs.

This type of optimization can help identify the most beneficial timing of resource addition in a way that MH's process will not. For example, one of MH's development plans calls for the development of Keeyask in 2022, followed by gas capacity beginning in 2029. By manually creating and testing this plan, there is no conclusive evidence that a similar plan with Keeyask in 2021 or 2020 wouldn't be more beneficial or that the timing on the gas capacity couldn't be altered to improve the plan. This example argument applies to all of MH's manually developed plans. MH's modelling process limits their ability to test alternative development plan due to the considerable time requirements to conduct the analysis for a single development plan.

This limitation is an important consideration in the comparison of alternative development plans as MH has done for this NFAT. In the comparison of two development plans, it is not possible to determine whether either plan has been developed with an optimal sequencing of resource additions. The difference in costs between the two plans could be due to the inherent advantages or disadvantages of the resources featured in the two plans or it could, in part, be due to the cost of a resource sequencing that is less optimal in one plan as compared to the other. As a result, the cost differential between two development plans must be viewed with some caution.

C. Single-pass analysis abbreviates process

In lieu of an optimization analysis to develop alternative development plans, other techniques could be employed to test the manually selected plans and enhance them with analysis. However, MH planning process does not incorporate this concept.

MH created the 15 potential development plans and then performed all analysis and sensitivities on these initial plans. From the results of this analysis the Preferred Development Plan was selected after only a single pass through the process. The primary drawback of this strategy is that it does not take advantage of any economic analysis in the plan development process. These initial plans, uninformed by economic analysis, likely do not represent the optimized plan configuration. MH could revise their process to use the initial results as indicative and redevelop the plans based on the lessons learned.

As an example, the two development plans that included wind generation were not the highest performing plans. These plans represent a narrow view of the incorporation of wind into a resource portfolio, rather than a variety of development options. As a result of the poor economic performance, MH is not planning to develop any wind resources. As discussed above, with a strong domestic wind resource, modular development options, and declining resource costs, it is very likely that at least some wind development should be included in an optimized development strategy.

D. Critique of CCGT/SCGT optimization process

When creating development plans with natural gas generators, MH developed a process for determining whether a CCGT or SCGT unit would be included. This process, however, only optimizes between CCGTs and SCGTs under reference assumptions and average water flow years. This exposes MH's planning process to significant risk based on the sensitivity of results to uncertain assumptions. In the context of the MH hydropower system, thermal unit additions serve as sources of capacity and generally provide energy during times of low water. Use of the average water flow year in the process does not appropriately consider the drought hedge value of a thermal resource in the plan development process.

MH followed their specific optimization process to determine the choice of which natural gas generation to add in its All Gas development plan.[40] The optimization attempted to capture the trade-off of whether to invest in the higher cost and more efficient CCGT or utilize the SCGT with its lower capital cost and lower efficiency. MH's process began by developing busbar costs to compare the technologies under reference assumptions. From this MH established a capacity factor threshold required for a new resource below which they would add a SCGT unit and above which they would add a CCGT unit. MH's first pass at modeling through SPLASH would install a generic or average efficiency natural gas generation capacity when its dependable energy and capacity needs analysis established a need for new resources. MH would then review the capacity factor of each of the generic or average natural gas capacity added. MH then would substitute either a CCGT or SCGT as determined by the capacity factor of the generic unit. This new generation sequence of CCGTs and SCGTs then became the All Gas Plan.

MH discussed in its NFAT application that the thermal generation efficiency has its greatest importance during the simulation of low flow or drought water years.[41] It is under these conditions that the thermal units operate at their highest capacity factors. The gas optimization process as discussed above utilizes the average of 99 water flow years to determine the capacity factors of the generic natural gas units to decide on choice of CCGT or SCGT. Even if the use of the average of the 99 years was appropriate, this method gives weight to operational characteristics over economic benefits. Additionally, the averaging method does not allow for placing more importance on a SCGT's ability to help mitigate the risk of drought conditions, a key feature of gas generation resources.

E. Lack of risk analysis

MH's explanation of the process of creating the alternative development includes no evidence of the incorporation of risk analysis into the creation of the plans – only a sensitivity analysis on economic performance of the plans that were developed. Without incorporating risk analysis into the manual plan creation, MH's process is

[40] The methodology is described in SP-018 NFAT Confidential – Optimization of Natural Gas-Fired Generation into the Manitoba Hydro System.pdf.

[41] NFAT Submission, Chapter 5, pp. 33-34

likely resulting in plans susceptible to external factors that will render them sub-optimal.

The following are examples of elements of risk analysis that are missing from the MH plan development process that would likely influence the components and timing of the alternative plans:

- Economic and financial risks: Macroeconomic conditions can strongly influence the performance of resource plans by, for example, impacting interest rates and financing conditions. This is particularly relevant to development plans with high capital expenditures. Additionally, the general condition of the provincial and regional economy can strongly impact demand.
- Export price risk: MH's process created development plans that either target additional exports or not. Export prices have a strong impact on the viability of certain development plans.
- Natural gas price risk: Fuel prices, particularly natural gas, have experienced drastic volatility over the past decade. MH's plan development process does not consider this volatility and the exposure of the plans to this price risk.
- Flood and drought risk: As a hydro dependent system, MH is exceedingly susceptible to water flow conditions. This risk is only evaluated later in the process, well after the plans have been structured.
- Load forecast risk: The Keeyask and Conawapa investments are large, long-term commitments for supply with long lead times to plan and construct. The value of these investments relies in part on future load being as high as forecasts. Other supply options can be added in more modest increments with shorter planning lead times to better match lower load growth.

One way in which these types of risks are often addressed in utility planning is by considering modularity and flexibility in resource options. The flexibility of modular, shorter-lead time resources provide some value in mitigating load forecast risk. For example, by giving priority to modular resource development such as smaller gas units that require shorter lead times, MH's planning can adapt to, for example, gas price volatility or export price erosion. There is no evidence that MH's plan development process includes any consideration for the differences in this flexibility between resources options.

F. Portfolio Analysis vs. Resource Option Evaluation

MH's fifteen alternative development plans are each a portfolio of resource additions combined to meet energy and capacity requirements over 78 years, designed to meet a theme (e.g., all gas, max wind, all hydro). This is typical of a long-term resource planning process which seeks to develop a reasonable scenario of development over time to serve as a basis for specific planning decisions that a utility must make.

Beyond this initial analysis, to evaluate the next specific resource commitment decisions that are to be made typically entails more specific analysis and investigation. In this NFAT, the specific commitment decision posed by MH is for authorization to proceed with the Keeyask Project, the Minnesota Power contract, and the 750 MW transmission line to Minnesota. However, the economic metric used to support that decision is the net present value (NPV) of 78 years of the portfolio performance. The analysis does not evaluate the more specific case of this option as compared to the set of commitments that would need to be made now in the alternative, for example in the All Gas plan.

G. Summary of critique alternative development plan process

MH's process of creating the alternative development plans is not well documented in the NFAT submission or accompanying materials. After identifying suitable resources in the screening process, there is very little detail provided as to how certain resource combinations were created, how the timing of resources was determined, etc.

Overall, despite creating fifteen different plans, MH's range of options represents a relatively narrow view of future development. Additionally the plans do not even fully take advantage of the few resource options that passed MH's screening process, namely DSM and imports. The combination of the manual development process (rather than an optimized process) and the single-pass analysis prevents the planning process from taking advantage of insight that can be gleaned from the economic and financial analysis steps. Finally, MH's plan development process does not incorporate risk analysis during the plan development stage, and therefore exposes the planning to extra risk.

VI. Alternative Plans and Results

La Capra Associates has concluded that MH's review of the alternative development plans has several shortcomings, including an overly narrow range of potential development plans and the use of outdated or inappropriate generation cost assumptions. To address the first issue we have worked with MH to create two additional development plans. This is discussed in Section A below. As noted, Manitoba has only recently completed this analysis and therefore our review of their results will be included in a supplemental report.

To address the second shortcoming, we have prepared analysis evaluating the impact of changing the wind cost assumptions to more current and reasonable estimates. This analysis, discussed in Section B below, provides indicative results that assess the sensitivity of MH's conclusions to the capital cost assumptions.

A. Supplemental resource development plans

Based on our conclusion that MH's plan development process did not produce a full range of potential resource plans, La Capra Associates has worked with MH to develop two additional plans. MH developed the plans and performed a full analysis including SPLASH runs and economic analysis on the results. The plans are summarized below:

- Combined Cycle Plan (CCGT): This development plan builds only CCGT units (i.e., no hydro, no SCGT, etc.). Over the study period, seven CCGTs are built with no new transmission. It has been modeled in SPLASH and the Economic model for all 27 branches of the uncertainty analysis using 2012 vintage data as requested. It has not been evaluated through the financial model. We have also requested analysis using three historical drought conditions, with the Reference-Reference-Reference assumptions being run through MH's financial modeling process.
- No Build / Import Reliance Plan: This plan will test an alternative development strategy to delay new generation build as long as possible. The plan relies on increased DSM (assumed to be 1.5 times the reference DSM), and the promotion of fuel switching to convert existing electric heat to natural gas as well as a reduction in the penetration of electric heating for new dwellings. This plan also assumes the addition of the 750MW transmission interconnection to the US. The

transmission capacity increase would work in concert with a relaxed MH policy constraint on imports, allowing up to 20% of the dependable energy to come from net imports. The timing of the transmission addition would coincide with the need for dependable energy, estimated to be 2029. This plan adds SCGTs and CCGTs over the remainder of the modeled study period in the same sequence as the All Gas Plan.

MH has only recently completed the analysis requested and provided the results. Therefore, La Capra Associates will be filing a supplemental report reviewing the performance of the CCGT and Expanded Imports cases.

B. Wind cost assumption analysis

Given the research showing that MH's onshore wind assumptions were higher than published industry estimates as discussed in Technical Appendix 2: Generation Alternatives, LCA used its version of MH's economic model to rerun the two wind development plans, the Wind Gas and Wind Conawapa, with new onshore wind cost assumptions. This analysis is a sensitivity analysis, using all of MH's assumptions and results from the reference case analysis of the Preferred Development Plan and the Wind Plan, except as noted below.

LCA's wind assumptions for this analysis are included in the table below.

Input	Manitoba Hydro	LCA
Capital Costs	$2400	$1750
Capacity Factor	40%	43%
Lifetime	20 years	25 years
Cost Decline Over Time	None	1%/year through 2032

Figure 3-3: Wind Cost Assumptions for Sensitivity Analysis

LCA implemented its assumptions in the economic model one at a time for each development case. Capital costs were changed first, then an adjustment was made to simulate a higher capacity factor, the project life and then cost decline over time. The charts below show the impact of each variable on the net present value cost of the Wind Gas and Wind Conawapa Development Plans. Changing the onshore wind assumptions does not make either plan less costly than the Preferred Development Plan, but it does bring the NPV cost of the wind plans significantly closer to the

preferred plan on a 78 year NPV metric given the reference case assumptions. The total impact of LCA's assumption on the Wind Gas Development Plan NPV was $1.23 Billion and the total impact on the Wind Conawapa Development Plan NPV was $0.43 Billion.

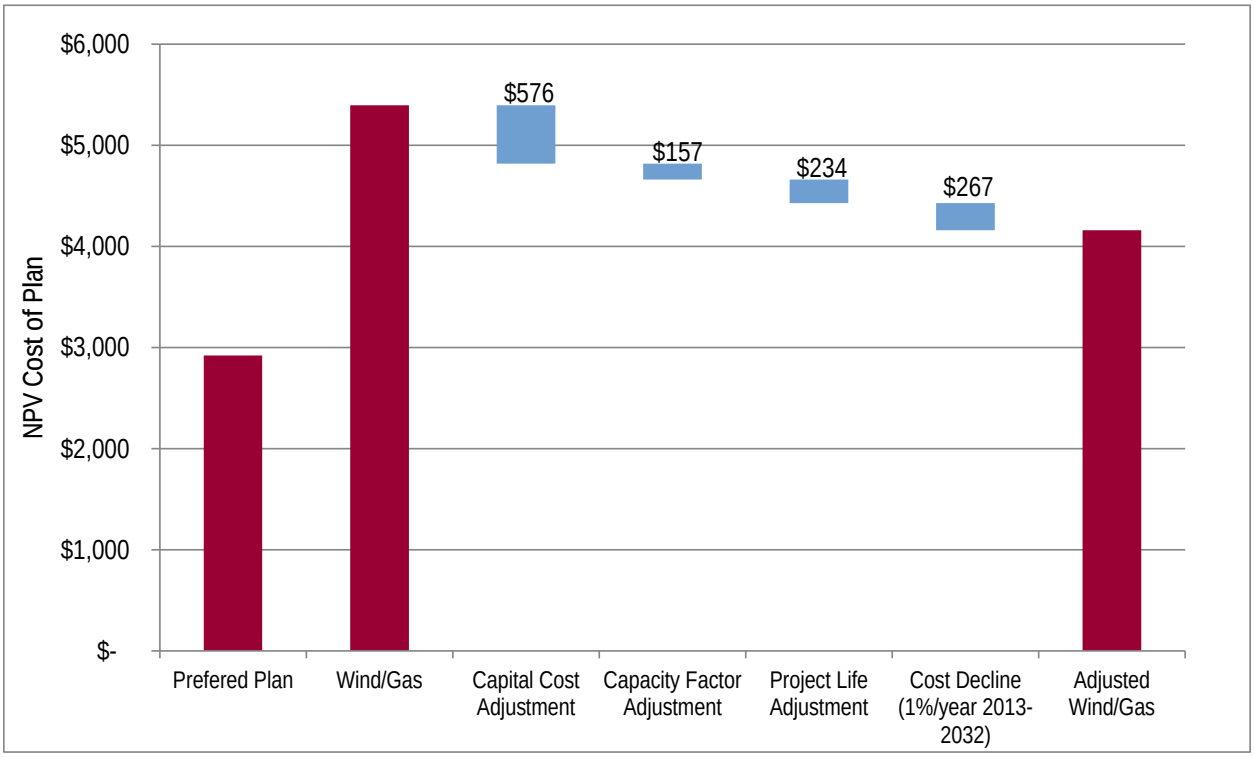


Figure 3-4: Impact of Wind Cost Changes on Wind Gas Development Plan NPV

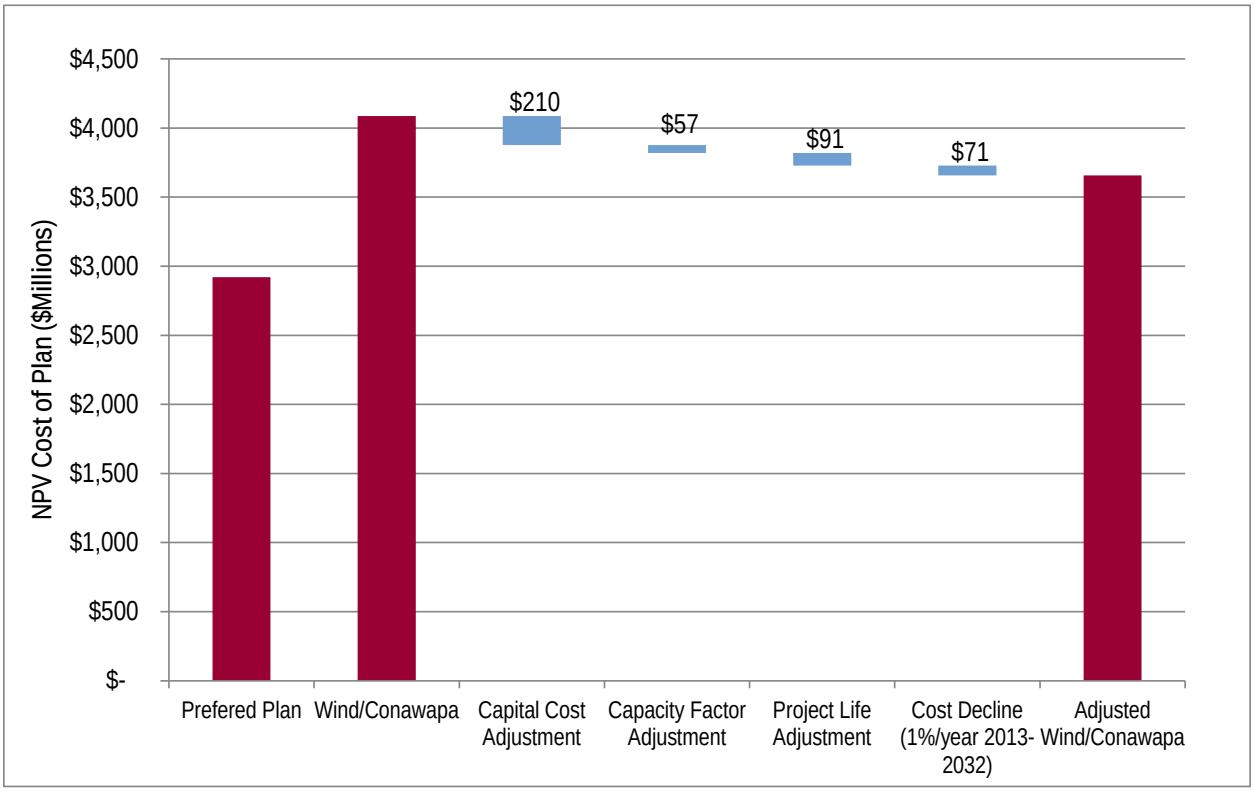


Figure 3-5: Impact of Wind Cost Changes on Wind Conawapa Development Plan NPV

Because of the large upfront capital investment required in the preferred plan, either wind plan has a lower cumulative present value (CPV) than the Preferred Plan for many years into the future. Using MH's assumptions, the crossover point when the Preferred Plan has a lower CPV than the Wind Gas Plan is around 2046 and it is around 2042 for the Wind Conawapa Plan. LCA looked at the impact on this crossover point of using LCA's onshore wind assumptions in the economic analysis. This is shown in the figures below. The crossover point is the point where the CPV line crosses the x-axis. Changing to LCA's wind assumptions moves the crossover point out 11 years to 2057 for the Wind Gas Plan and 10 years to 2052 for the Wind Conawapa Plan.

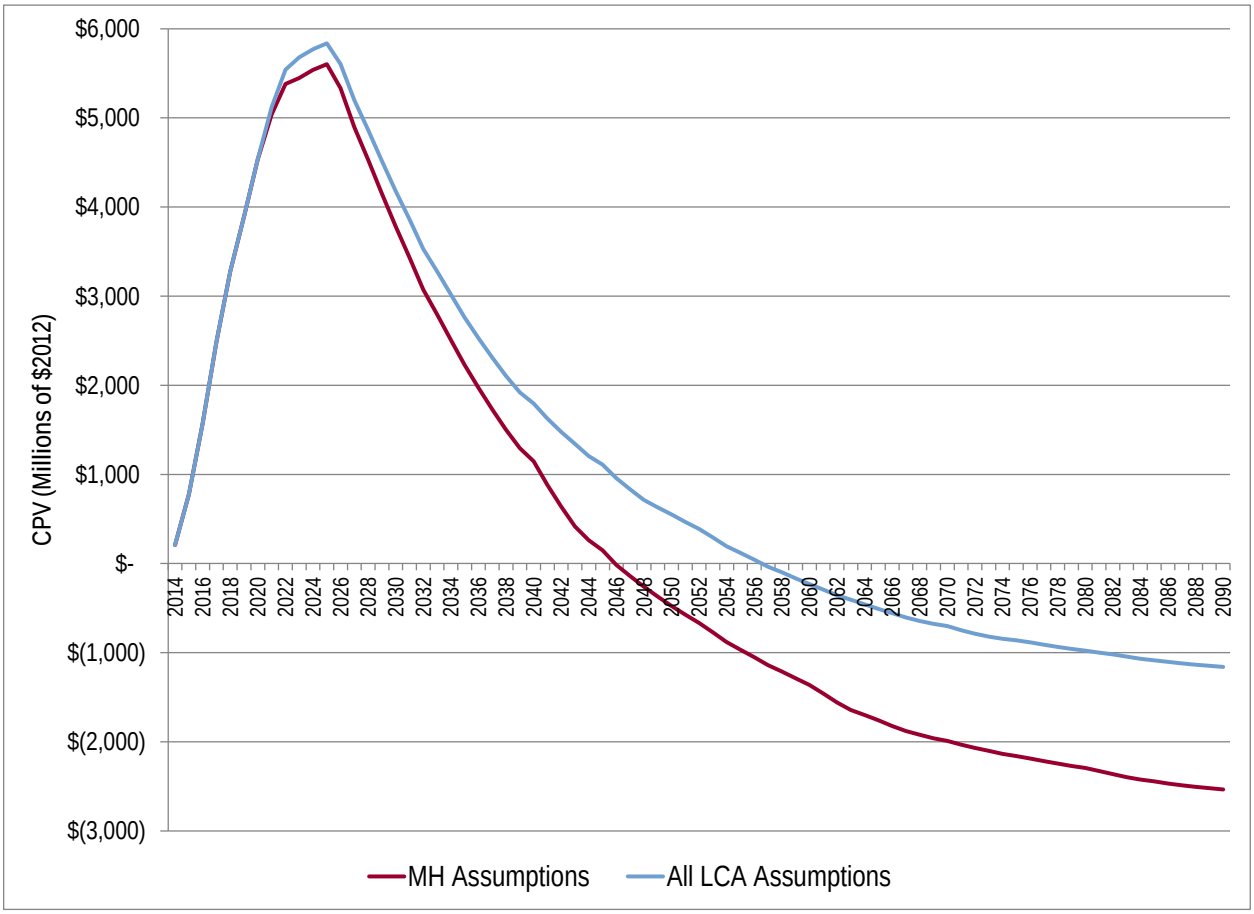


Figure 3-6: Impact of Wind Cost Changes on Wind Gas minus Preferred Plan CPV

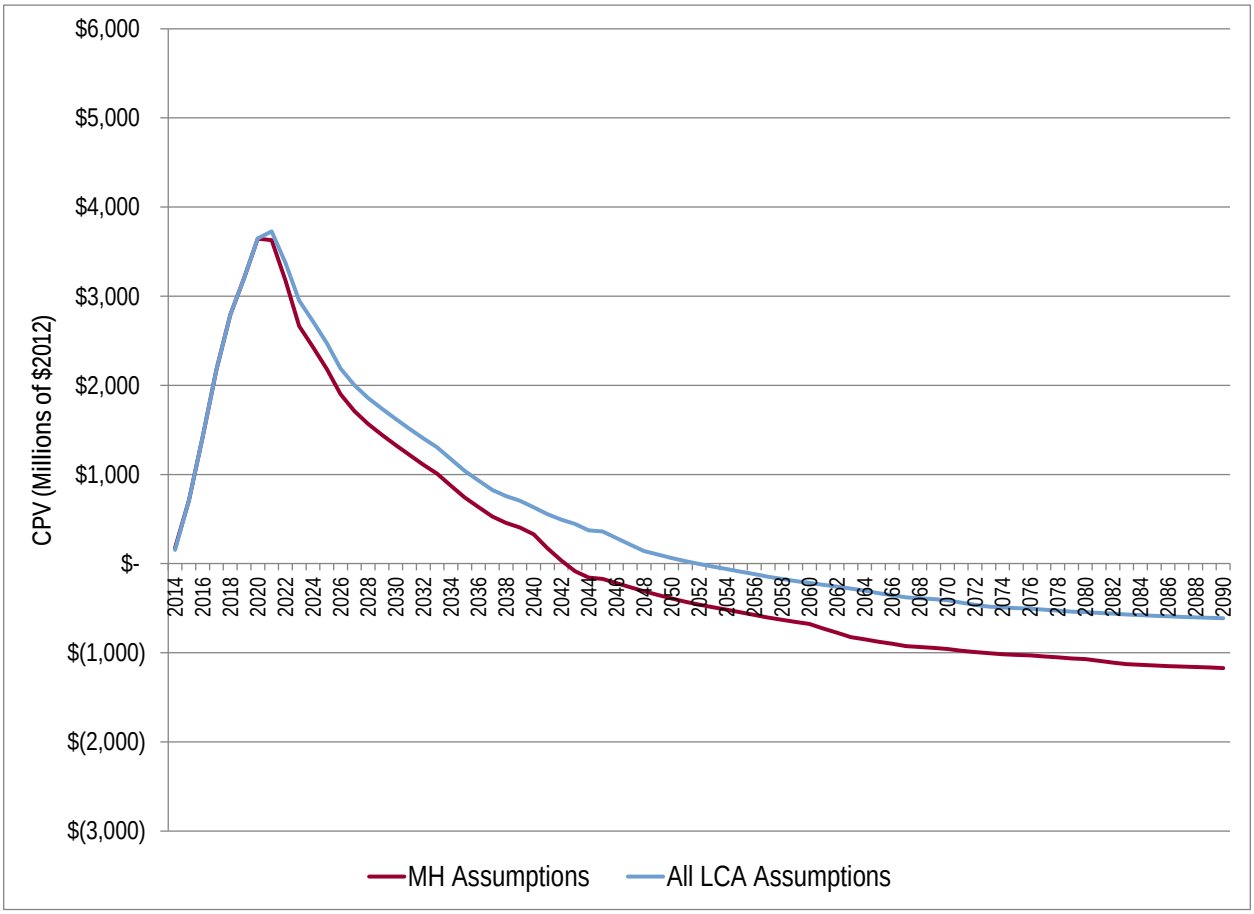


Figure 3-7: Impact of Wind Cost Changes on Wind Conawapa minus Preferred Plan CPV

In addition to the cost assumptions discussed above another issue of MH's treatment of wind is that it places no value on the modularity of wind. In contrast to the Conawapa and Keeyask projects, wind generation is modular and can be built in relatively small quantities and on a relatively short timeline. With wind in its planned portfolio, MH will have the luxury of assessing the project need close to the time of development.

The foregoing analysis indicates the sensitivity of the MH wind cases to the cost and performance assumptions for wind. LCA will be conducting additional analysis on alternative development plans for the supplemental analysis and will be providing additional considerations on the comparison of alternative wind plans to other development plans at that time.

VII. Summary and Conclusions

LCA has reviewed MH's process of creating the alternative development plans. The process begins with the needs analysis and resource option screening, and concludes with the manual development of the potential resource plans. Based on our review and analysis, we offer the following conclusions:

A. Resource needs analysis is overly conservative

MH's process begins with the evaluation of resource need. LCA has evaluated this issue fully in Technical Appendix 1: Resource Planning. Our general conclusion is that MH relied on conservative assumptions and that the actual year of resource need for both energy and capacity will likely be later than MH forecasts. In addition, we identified several ways in which MH could delay the construction of new generation resources to fulfill need.

B. Resource technology screening removes too many options on subjective or misplaced criteria

The resource technology screening process is based on both qualitative and quantitative factors. This manual process is partially based on subjective criteria and does not incorporate any future changes in certain assumptions. An example of this is the screening out of solar PV without considering the significant cost declines expected in the future.

C. DSM not considered as a resource option during plan development

MH included additional DSM as a resource to be included in the development plans because it passed all screening criteria as a feasible and cost effective resource. However, none of the final development plans that were evaluated in the economic and financial analyses included additional DSM.

D. Alternative development plans were manually created instead of optimized, represent limited spectrum of options.

MH considered the forecasted timing of resource need, as well as export opportunities, and manually created the alternative development plans using the resource options that passed the screening process. MH did not perform any optimization analysis during

the plan development process, so there is no analytical foundation for determining whether adjusting timing or parameters would produce a more beneficial result.

The various development plans are developed prior to any economic or financial analysis, and the plan configurations are not revised after this analysis. This single-pass process results in plans structured without the benefit of any analytical results.

Finally, the 15 plans evaluated represent a limited spectrum of possibilities. LCA has worked with MH to develop and model two additional plans. LCA's review of the results of these plans will be submitted in a supplemental filing.

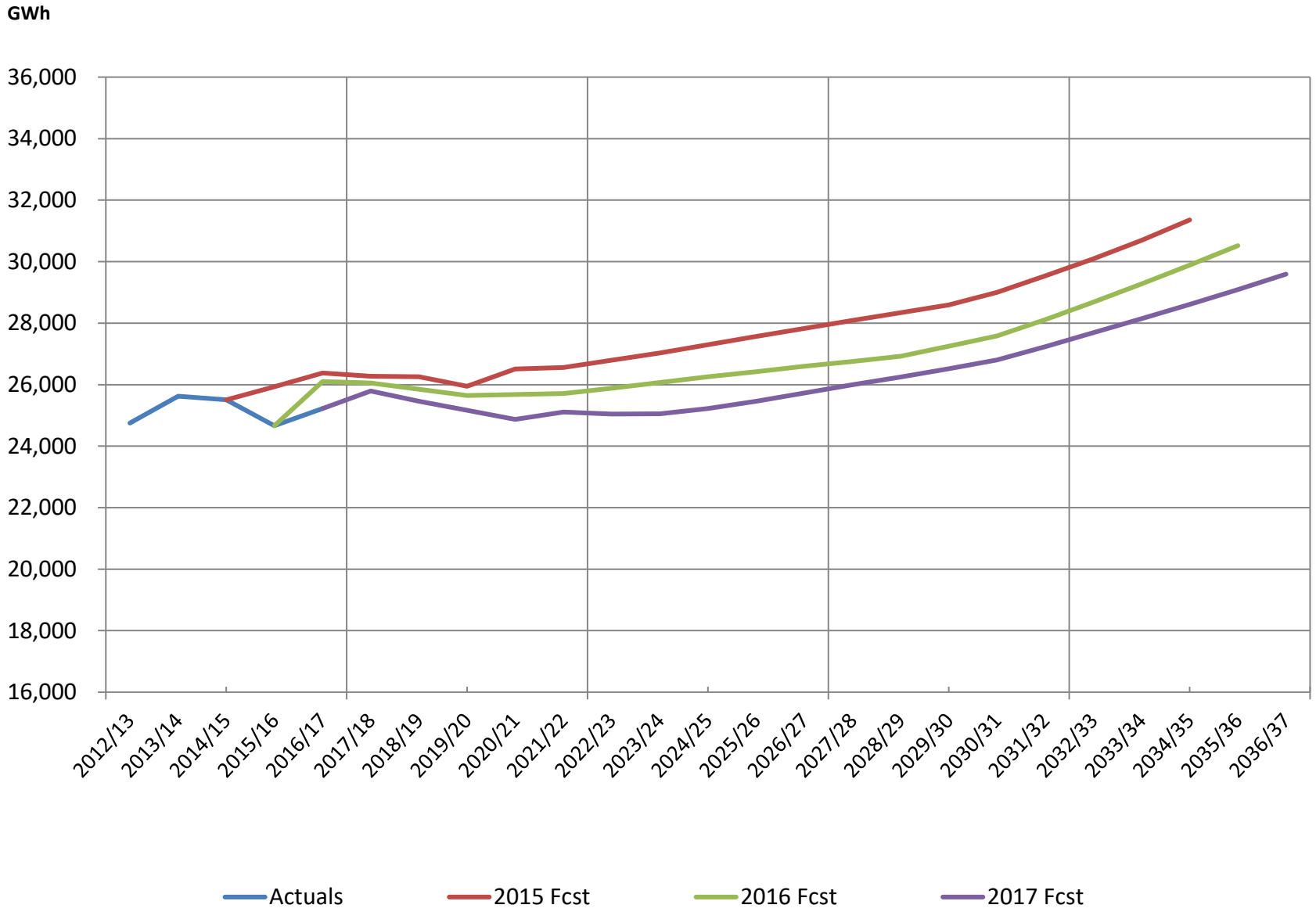
E. Wind cost assumptions provide skewed results

MH prepared its analysis using assumptions for wind generation costs that significantly exceed current industry estimates. LCA has performed analysis using MH's economic model to demonstrate that with more current assumptions, development plans featuring wind capacity are much more competitive than MH has concluded.

MH's process evaluated plans that were heavily dependent on wind. Since those plans did not perform as well as the Preferred Development Plan, wind was essentially excluded as a potential resource. Based on our analysis, an optimized development plan would include some additional wind resources with more realistic assumptions could potentially produce a competitive alternative development plan.

Tab 55

Gross Firm Energy Net of DSM



Tab 56

TSCRIPT.COM™ Digital Transcription Services
"When You Talk - We Listen!"

MANITOBA PUBLIC UTILITIES BOARD

Re: MANITOBA HYDRO

2017/18 and 2018/19

GENERAL RATE APPLICATION

PUBLIC HEARING

Before Board Panel:

Robert Gabor	- Board Chairperson
Marilyn Kapitany	- Vice-Chairperson
Larry Ring, QC	- Board Member
Shawn McCutcheon	- Board Member
Sharon McKay	- Board Member
Hugh Grant	- Board Member

HELD AT:

Public Utilities Board

400, 330 Portage Avenue

Winnipeg, Manitoba

December 11, 2017

Pages 1157 to 1449

APPEARANCES

Bob Peters	)Board Counsel
Dayna Steinfeld	)
Patti Ramage	)Manitoba Hydro
Odette Fernandes (np)	)
Helga Van Iderstine	)
Byron Williams	)Consumers Coalition
Katrine Dilay	)
William Gange	)GAC
Peter Miller (np)	)
Antoine Hacault	)MIPUG
George Orle	)MKO
Senwung Luk (np)	) Assembly of
Corey Shefman (np)	) Manitoba Chiefs
Kevin Williams (np)	) Business Council
Douglas Finkbeiner (np)	) of Manitoba
Daryl Ferguson	) City of Winnipeg

LIST OF APPEARANCES (cont'd)

Christian Monnin	)General Service
	)Small, General
	)Service Medium
	)Customer Classes
William Haight	)Independent Expert
	(Witnesses

TABLE OF CONTENTS

	Page No.
List of Exhibits	1161
List of Undertakings	1162
Discussion	1163
CONTINUED MANITOBA HYDRO PANEL 2 re REVENUE REQUIREMENT	
LIZ CARRIERE, Resumed	
LOIS MORRISON, Resumed	
DAVID CORMIE, Resumed	
SANDY BAUERLEIN, Resumed	
JOEL WORTLEY, Resumed	
SUSAN STEPHEN, Resumed	
CHUCK STEELE, Resumed	
JAMES MCCALLUM, Resumed	
HAL TURNER, Resumed	
GERALD NEUFELD, Resumed	
DAVID SWATEK, Resumed	
Continued Cross-Examination by Mr. Bob Peters	1176
ADDED TO MANITOBA HYDRO PANEL NO. 2:	
TERRY MILES, Sworn	

TABLE OF CONTENTS (Cont'd)

Continued Cross-Examination by Mr. Bob Peters 1208

Cross-Examination by Mr. Byron Williams 1324

ADDED TO MANITOBA HYDRO PANEL NO. 2:

GREG BARNLUND, Sworn

Continued Cross-Examination by Mr. Byron Williams 1343

Re-Examination by Ms. Helga Van Iderstine 1442

Certificate of Transcript

LIST OF EXHIBITS

EXHIBIT NO.	DESCRIPTION	PAGE NO.
CC-32-1	Coalitions Book of Documents	1323

LIST OF UNDERTAKINGS

NO.	DESCRIPTION	PAGE NO.
5	Manitoba Hydro to provide its most current analysis to support the operating and administrative costs in the 2017/'18 year forecast as well as in the 2018/'19 year forecast, including the voluntary departure information	1193

--- Upon commencing at 9:04 a.m.

THE CHAIRPERSON: Good morning, everyone. I hope you had a nice weekend.

Ms. Steinfeld, would you like to sort of give us an overview of the week, and -- and then talk about today?

MS. DAYNA STEINFELD: Certainly, Mr. Chair. For the week we will have Manitoba Hydro's revenue requirement panel up for cross-examination. Board counsel will be concluding its cross-examination of this panel today. If it is agreeable to the Board, Mr. Peters is going to take -- after discussion with Dr. Williams, another hour in the afternoon for a total of approximately four (4) hours on cross-examination and then Dr. Williams will take the remainder of the day.

We're scheduled to sit to 5:30. Dr. Williams will continue his cross-examination tomorrow and into the morning on Wednesday, at which time Mr. Hacault from MIPUG will begin his cross-examination. We do have a shorter day scheduled right now for Wednesday. We're expecting to conclude at 4:30 that day, and then MIPUG will continue its cross-examination through the day on Thursday. Thank you.

THE CHAIRPERSON: Thank you. Ms. Ramage...?

MS. PATTI RAMAGE: Yes, thank you, Mr. Chair. On Friday -- or Thursday I should say you ended last week by raising a process concern related to Manitoba Hydro's revenue requirement panel being cross-examined on independent expert consultant evidence prior to Manitoba Hydro having been -- having filed its written rebuttal on the evidence.

And I want to thank you for recognizing that concern. It's consistent with the concerns Manitoba Hydro raised in its September 18th letter when the possibility of delays first were raised and at that time we indicated the view that natural justice required ICs' work be available and for review and discovery prior to the start of the oral hearing.

Unfortunately, as you indicated, the scheduling problem could not be resolved and we find ourselves in a less than ideal position of being on the stand while the IC reports are coming in while IRs are still being posed and answered and while the rebuttal evidence isn't filed.

And at this point, the best we can say is that it is what it is. And we have to make the best of it and we have to adapt and we have to make

this process work. Having said that, I didn't want to leave the panel with the impression that we don't have concerns. The reality is from the time the decision was made to extend the schedule, this is the inevitable result so the goal is to deal with it the best we can. We're counting on being afforded reasonable accommodation in order to address each of the reports.

From our perspective, that means we likely won't be able to address IEC con -- reports fully or perhaps at all in our direct testimony or under cross-examination, and we may have to ask the revenue requirement panel be recalled. We will work with Board counsel to -- to overcome that and -- and that's Manitoba Hydro's position on it at this point.

But at the end of the day Thursday there was a comment made that our concerns regarding the timing of the MGF report were perhaps overstated and -- because of the fact there's going to be a major capital panel later on and -- and I just want to bring -- to address that specific comment.

Manitoba Hydro's major capital panel will be here to address the management of the projects, their budgets and the concerns raised by MGF. They, and by that I mean, the capital panel are

not the ones to re -- to address revenue requirement issues that may arise from the conclusions of the MGF report; that falls squarely within the bailiwick of this panel, the revenue requirement panel.

Major capital by necessity is being dealt with at the end of January, and that's the rub. The revenue requirement panel will step down on December 19th without addressing what is one (1) of the largest drivers of rates - capital spending. If risks with the major projects are identified, and given Mr. Shepherd's evidence, I think it's a fair assumption. It will be identified. I fully expect the PUB's going to want to hear how those risks could impact the Corporation's financial forecasts.

That's not something that the cap -- the major capital panel can address. And if the PUB wants that perspective, I just want to give the heads-up that we're going to have to plan for it. That the revenue requirement panel is going to have to come back. They're going to have to give direct evidence on -- and they're going to, I assume, be cross-examined.

So I appreciate your bringing that up, and -- and it's something that we'll work with Board counsel to deal with but I didn't want to suggest that

it was not an issue by not addressing it.

The other process issue we would like to bring to the panel's attention is that on Friday we were provided two (2) sets of materials by the Coalition; their index of documents and, secondly, what the Coalition is referring to as Notice of Questions which are, from our perspective, quite clearly Information Requests.

I don't believe that it's Information Requests on the rebuttal evidence. I don't know that this has been provided to the Board, but we want to comment that there is nothing in the schedule or the PUB's process which suggest an Intervenor has the ability to file IRs on rebuttal evidence. The record should stand on completion of Manitoba Hydro's rebuttal evidence. There is no surrebuttal.

And this Board gets the best evidence where witnesses are focused and know the record. Distracting witnesses by sending them off to respond to more IRs the weekend before they're to -- to testify is -- is simply -- it's a distraction, and in our view it's, frankly, because the rebuttal evidence is strong and they need to try a different tact, but that's not how the rules work. These questions could have been asked during the IR process and it's not

reasonable to ignore the process and allow additional IRs to be submitted at any time.

Having said that, we will be making it easier. We're -- we're bringing the issue to the Board's attention in the hope that we can address it going forward. We're able to make it easier, I think on everyone, because the fact is that most of the information the Coalition is looking for is already on the record and we will arrange to have our witnesses point out where that is, and hopefully move on, but these kind of distractions are -- are -- are a problem from Manitoba Hydro's perspective, and -- and we're looking for what were -- we object to the disregard for the process.

We were also provided with an index of documents by the Coalition on Friday. The index directed Manitoba Hydro to nineteen (19) documents which the Coalition indicated they may be referring to during their cross-examination of the panel. We have concerns with the number -- with a number of these documents. For example, five (5) of the documents that are -- were cited in the -- that index, Friday's index, they're referenced in an appendix to the METSCO report. It is accurate to say that the documents are referred to in the METSCO report, but to be clear,

they're not citations in support of a position and they are not documents that were appended to the METSCO report, rather, they're reports or studies provided as examples of utilities with mature asset management report programs. Name of utility; name of study, nothing more.

Now, one (1) of the five (5) we were directed to on Friday is a Toronto Hydro study; that study is twenty-five hundred (2500) pages long. There's no highlighting to so -- show where we're going in that study or why we are being cross-examined on it. And I said it -- and I specifically said it was when we were being directed to. On Sunday night we got a new index of documents. It's not there anymore. Our witnesses' time was wasted. They're trying to keep up and they spent their weekend looking at these materials and it's gone now.

We were also given notice to prepare to be cross-examined on the Tennessee Valley Authority's Form 10K. Why? Because it's referenced in MPA's report. It is not appended, it's referenced. We were told to be referenced -- to be ready to be cross-examined on the Bonneville Power Administration's 2016 annual report. It's not on the record anywhere. It's not a footnote. We were also told to be ready to be

cross-examined on Chapters 7 and 8 of Bonbright, 1988. Those chapters are competitive price as a rate regulation standard and social principles of ratemaking. We asked for copies of the reference materials with passages highlighted to assist in getting ready. We have the book, but we want to make sure we're working from the same version, and we're trying to narrow the focus going forward.

Now Sunday night we were provided excerpts, not from chapter 7 and 8 from chapters 12 and 13; completely different parts of the book. So it would appear, again, our time preparing was wasted. The revised index provided on Sunday evening had instead of nineteen (19) documents listed, it had fifteen (15) documents listed and of the nineteen (19) original, ten (10) are gone entirely and new ones have been added to the fifteen (15) page index.

We've spent eight (8) months preparing for this hearing and have amassed thirty-two thousand (32,000) pages of materials doing so. Witnesses prepare and they prepare based on the record. In legal circles, this tactic is sometimes called it -- or it's similar, at least, to trial by ambush. It's not fair to Manitoba Hydro witnesses, and it's not fair this panel. Because if the information is

important, it should be laid out for the panel in a clear manner. It should run through the process, just like all of Manitoba Hydro's evidence runs through the process.

The purpose of the evidentiary process is to get the best information in front of the Board and this is not, in our view, the -- the means of getting the best information to you. It truly brings the process into disarray and does not promote getting the facts before the panel when these reports are introduced this way. How do we examine the authors? What is their probative value? How are they rel -- relevant? How do we test them?

Now some of the new documents, Mr. Will -- Dr. Williams has introduced in his Sunday night book of documents are his submissions from previous hearings. From Manitoba Hydro's perspective that's not evidence. It's argument. And it's something that our witness -- witnesses should not be asked to deal with. We can deal with that as it arises, but I want to bring this issue to the Board's attention.

In addition to the Bonbright references a list of Board Orders has -- is -- appears in the index. This is something Manitoba Hydro -- this panel

is not the best one to deal with; that's not -- that's something I can deal with Dr. Williams and -- and suggest these questions be deferred to the -- the rate design panel where Mr. Barnlund sits and where they are best dealt with. Those were only introduced last night, so it's not something we could do ahead.

So in the end, and after all of this, I can say Manitoba Hydro will do the best it can to deal with this evidence, however, if witnesses feel they need to clarify the record, it may be -- be again necessary for them to come back.

I can assure you it's not what we want to do, we have enough on our plates but if we want the best evidence in the circumstances, that's what we may have to do if materials are thrown at us at -- this manner. I can -- getting materials while I'm sitting in Eric Coy Arena on a Sunday night where you have to step outside and hold your phone in the air is not the best way to receive evidence.

And -- and we wanted to bring that to the Board's attention, bring it to the Coalition's atten -- our concerns to the Coalition's attention and I assume we will address that when the Coalition begins his cross-examination to understand where we're going with all these materials.

THE CHAIRPERSON: I'm going to call on Ms. Dilay but before I do, on the issue of the Notice of Questions which you sort of categorized as IRs, was it to put you on notice that these questions would be asked or did they actually ask that information be provided to them prior to testimony?

MS. PATTI RAMAGE: I wish I had them copied. They are -- from my -- they are IRS. They're in the same format as Irs. They have a preamble. They've used the IR format, and given us to them --

THE CHAIRPERSON: But is it your understanding, they ex -- they expected something prior to cross-examination in that you would provide the material before cross-examination or is it simply they put you on notice that these are the -- these are the questions they would be putting to you in cross-examination?

MS. PATTI RAMAGE: I think they're materials that -- I -- I don't think the Coalition expected they'd be provided ahead of time because it wouldn't be possible, the time it could potentially take to do them. It would be something akin to an undertaking only because they have already -- these matters have already been addressed. It's not like a question in cross-examination that we can't answer on

the fly. It's because it's already been addressed back in the IR process. It just wasn't asked back that but, as I say, these materials are -- if you go through, you can find the answers.

THE CHAIRPERSON: Okay, Ms. Dilay...?

MS. KATRINE DILAY: Thank you. So in terms of the -- the questions, I can indicate our -- our intention was not to receive the information before the cross-examination, it was I guess a notice of technical questions that the ans -- the answers may not readily be provided during cross-examination.

With regard to the documents that were -- the book of documents that was provided, I believe that Dr. Williams will address that this afternoon either as the issues come up or he might speak to it at the beginning.

THE CHAIRPERSON: Okay, any -- thank you for putting on the record. We were trying to design the process as much as possible so everybody would have a fair opportunity to under -- understand what case they had to meet and we'll certainly take your notice under advisement, Ms. Ramage.

MS. PATTI RAMAGE: Thank you.

THE CHAIRPERSON: I will indicate -- I'm going to talk to counsel at the break and we --

we may have to adjust the procedure at a later date in order to ensure that the -- our goal of having all the evidence on the record is met. Mr. Peters...?

CONTINUED MANITOBA HYDRO PANEL 2 re REVENUE REQUIREMENT

LIZ CARRIERE, Resumed
LOIS MORRISON, Resumed
DAVID CORMIE, Resumed
SANDY BAUERLEIN, Resumed
JOEL WORTLEY, Resumed
SUSAN STEPHEN, Resumed
CHUCK STEELE, Resumed
JAMES MCCALLUM, Resumed
HAL TURNER, Resumed
GERALD NEUFELD, Resumed
DAVID SWATEK, Resumed

CONTINUED CROSS-EXAMINATION BY MR. BOB PETERS

MR. BOB PETERS: Thank you. Good morning, Mr. Chair, Board panel members, Manitoba Hydro witnesses, ladies and gentlemen.

I'd like to ask that volume 1, page 179 be put on the screen just to orientate ourselves this morning.

Ms. Bauerlein, good morning, we see on the screen in front of us from Board counsels' book of documents, which is Exhibit 42-1, page 179. And that's the income statement of the integrated financial forecast that Manitoba Hydro has prepared.

Is that correct?

MS. SANDY BAUERLEIN: Good morning, Mr. Chairman, Madam Vice-Chair and Board members.

Yes, it is the income statement of Manitoba Hydro projected.

MR. BOB PETERS: All right. So we're going to focus for the next short -- short while, on the operating and -- operating and administrative expenses under the test year 2018, and that's $518 million in this forecast?

MS. SANDY BAUERLEIN: That is correct.

MR. BOB PETERS: And then likewise, in the following test year 2019, it shows up as $501 million, correct?

MS. SANDY BAUERLEIN: That is correct.

MR. BOB PETERS: All right, if we could jump well forward to volume 4 of Board counsels' book of documents, and volume 4 is Exhibit 42-4. We're to be in tab 62, and specifically at page 231.

Are you with this, Ms. Bauerlein?

MS. SANDY BAUERLEIN: Yes. Yes.

MR. BOB PETERS: When Manitoba Hydro filed its operating and administrative expense breakdown it was a bit unusual, was it not, in this General Rate Application because Manitoba Hydro was unable to provide the level of detail it had previously provided in -- in other hearings?

MS. SANDY BAUERLEIN: Correct. We had set targets for both the 2017/'18 fiscal year and 2018/'19, but had not undergone a detailed budgeting exercise to break that down into all the individual components.

MR. BOB PETERS: So is the $518 million for the 2018 forecast year, the target?

MS. SANDY BAUERLEIN: That is correct. That is the approved forecast or you may phrase it as a target, yes.

MR. BOB PETERS: Can you explain to the panel why Manitoba Hydro does not have the detail at this point in time?

MS. SANDY BAUERLEIN: So we establish the targets by looking at what we had spent in 2016/'17 and we adjusted it for what we anticipated to be the impacts of the voluntary departure program.

Manitoba Hydro throughout this filing

is continuing to feel the effects of that restructuring. When we -- we -- to put all this together, we made a lot of assumptions in terms of how many people would leave, what the salary of those people would be and even though now we do you have -- we do have a -- a number, a clear number of the eight hundred and twenty-one (821) that are leaving, we continue to be in a process of restructuring throughout many departments where functions are being changes, individuals are being transferred and moved around.

So, the ability to be able to prepare a detailed forecast isn't there. So we manage the total operating and administrative costs at the company level.

MR. BOB PETERS: On the sheet in front of us under Capitalized Labour and Overhead, Ms. Bauerlein, there's the 2016/'17 outlook number of $355.9 million, correct?

MS. SANDY BAUERLEIN: That is correct.

MR. BOB PETERS: Now, I may have put some misinformation through this panel on the record. When I look at that $355.9 million number and compare it to the total employee related expenditures of $854.7 million, it appears that Manitoba Hydro is

actually capitalized -- or had capitalized in 2017 approximately 42 percent of their workforce.

MS. SANDY BAUERLEIN: That's a -- from a point of view of the total costs that are being capitalized.

MR. BOB PETERS: Not necessarily the number of people?

MS. SANDY BAUERLEIN: When I was talking 30 percent, it's the workforce, the number of hours that typically are capitalized.

MR. BOB PETERS: So in addition to the wages, there are overheads capitalized in that $355 million number?

MS. SANDY BAUERLEIN: The three fifty-five (355) is really the capitalization of all the costs that you see in the eight fifty-four (854) number up above. So it's the wages of the employees; the amount of overtime that's related to our capital projects; the amount of benefits that get added to that labour and then charged to the capital projects; as well as other types of costs. For example, motor vehicles, when a crew is working on a capital project they might have some -- some -- a bucket truck, for example, with them. So those costs would also be charged to the capital project through something that

we call an activity rate.

MR. BOB PETERS: Okay. Thank you for that. On page 263 of the same volume 4 of Board counsel book of documents, Exhibit 42-4, Manitoba Hydro provides what is called the headcount and this is the headcount, Ms. Bauerlein, of the employees that have applied for and have been accepted in the voluntary departure program?

MS. SANDY BAUERLEIN: That is correct with the one (1) exception, there were four (4) employees -- additional employees related to our subsidiaries. So because this was an organizational view of our -- our operating and corporate groups, the total year is eight hundred and seventeen (817) but you may have also heard us quote the eight twenty-one (821), which is the total including subsidiaries.

MR. BOB PETERS: And so, for example, which subsidiaries would those four (4) additional people --

MS. SANDY BAUERLEIN: Related to MHI.

MR. BOB PETERS: Manitoba Hydro International?

MS. SANDY BAUERLEIN: Yes.

MR. BOB PETERS: All right. Does this headcount include not only the voluntary departure

program employees, but any other employees whose services may have been terminated by the Corporation?

MS. SANDY BAUERLEIN: No, it does not. It only includes those employees that accepted the voluntary departure program. In some cases it may be management, but it is those that applied for and were accepted under the voluntary departure program.

MR. BOB PETERS: In addition to the eight hundred and seventeen (817) headcount on the Manitoba Hydro electric side, how many additional employees have been terminated?

MS. SANDY BAUERLEIN: I think it was discussed by Mr. Shepherd, there was three (3) executive and I believe approximately forty -- forty-eight (48) or forty-nine (49) but some of that management would be in here and some of it would be through severance.

MR. BOB PETERS: Okay. I was just trying to get a handle for the panel, Ms. Bauerlein, that of the eight hundred and seventeen (817) headcount, as it's called on your -- page 263 of Board counsels' book of documents, Manitoba Hydro estimates that the costs, the salaries associated with those eight hundred and seventeen (817) works out to $91.9, million a year?

MS. SANDY BAUERLEIN: Yes, that is an approximation, yes

MR. BOB PETERS: Now, I'm trying to get in addition to that eight hundred and seventeen (817) it sounds like there could be 53 additional, some of which will be, I suppose, included in the headcount, some of which are not.

MS. SANDY BAUERLEIN: That is correct. Some of them would be included in the headcount and some would not.

MR. BOB PETERS: Are you able to provide the panel with an estimate as to how many over and above the eight hundred and seventeen (817) are employees that will be departing the Company?

(BRIEF PAUSE)

MS. SANDY BAUERLEIN: Sorry, about that. There was approximately ten (10) to fifteen (15) that were severed, the rest would be in that count.

MR. BOB PETERS: And are you able to advise the Board of those ten (10) to fifteen (15) that are severed, they're not included in this headcount or this dollar calculation shown on page

263?

MS. SANDY BAUERLEIN: Correct. This was providing information on the -- the headcount numbers and the savings through the voluntary departure program only.

MR. BOB PETERS: So for the additional ten (10) or fifteen (15), what is the estimated additional savings attributed on an annual basis by not having those salaries and benefits?

MS. SANDY BAUERLEIN: I would have to do a check on that. But I would assume it would be at approximately two hundred thousand (200,000) empl -- I think that would be 150 -- 150,000 in employee plus benefits.

MR. JAMES MCCALLUM: Yeah, I -- I think the -- the order of magnitude here is -- is in the range of $2 million for the additional -- and it's an approximation, ten (10) or fifteen (15) people that were severed as opposed to left the Company through the voluntary departure program. Those were in the main reasonably senior managers and so I think $2 million is probably a good number to work with.

MR. BOB PETERS: And thank you, Mr. McCallum. Were those positions deleted or were just the people terminated?

MS. SANDY BAUERLEIN: Are you talk --

MR. JAMES MCCALLUM: Go ahead, Sandy.

MS. SANDY BAUERLEIN: Are you asking about the voluntary departure program or the ten (10) to fifteen (15) in the management area?

MR. BOB PETERS: I was starting with the -- the management area, Ms. Bauerlein. Were those positions eliminated?

MR. JAMES MCCALLUM: In -- in some cases, yes, for example, the three (3) vice-presidents that left the Corporation, all of those positions were deleted and we consolidated the what we call groups, operating or corporate groups, we consolidated several together in order to permanently eliminate the three (3) vice-president positions. In other cases, we eliminated a department manager position, and combined departments. So, we were able to eliminate a position. In others, we had folks leave the Company and -- and move somebody else into their role.

MR. BOB PETERS: Would you accept, Mr. McCallum, that that if I take the fifteen (15) positions in addition to what's shown on page 263, and those fifteen (15) positions that were severed approximately four (4) of them the positions were removed but eleven (11) of the positions were

refilled?

MR. JAMES MCCALLUM: No, I don't think that's accurate. We would have to go back and look. I mean, these are approximations we're talking to. But in the main, I would say the majority of the positions that were severed, we have carried forward without filling the position. We've combined departments, combined operating groups in order to have one (1) person carry on in the place of two (2).

MR. BOB PETERS: So, Ms. Bauerlein, I'll leave it on the basis that of the -- in addition to the $91.9 million, the best evidence of the Company now is that there's an additional $2 million of annual savings expected from those that were severed from the Company not part of the voluntary departure program?

MS. SANDY BAUERLEIN: Yes, that would be approximation of the additional savings, yes.

MR. BOB PETERS: When would Manitoba Hydro have a more accurate number? Would it have to wait until year end?

MS. SANDY BAUERLEIN: We would wait till the -- for just the management piece or for the total?

MR. BOB PETERS: I was thinking the total.

MS. SANDY BAUERLEIN: We would wait until the end of the voluntary departure program. We're expecting the majority of people to be gone by February 1st of 2018. And at that time, we would have the actual salaries and -- and cost savings. This is, again, is an approximation.

MR. BOB PETERS: When you say the majority will be leaving before -- on or before February 1st of 2018, how long does this voluntary departure program carry on for?

MS. SANDY BAUERLEIN: It does really run till February 1st. There are a couple employees -- - a few employees, two (2) to three (3) that are staying on slightly longer than that timeframe to meet business requirements.

MR. BOB PETERS: So, Ms. Bauerlein, on page 235 of Board counsels' book of documents, volume 4, the forecast information that we were looking at in the response near the last paragraph of the page, the forecast assumed reductions of approximately five hundred (500) EFT's and it was for a partial year.

When we go back to page 231 and we look at that $518 million number, does that now include too few of the employees who are actually going to be

leaving the Company?

MS. SANDY BAUERLEIN: No, it -- it does not. The forecast was put together before we understood what the details of the voluntary departure program was going to be, exactly how many employees would -- would agree to the take-up of the program but, it had a bunch of assumptions in the forecast.

It assumed again, a lower number of people but it assumed many of them leaving sooner, so it assumed that many of those five hundred (500) would be gone earlier in the year.

It made assumptions in terms of salary, what the average of salaries of employees are. And so continually throughout the year, we've been doing analysis to ensure that the $518 million number is still a good number.

Again, many of the employees now are leaving later. The majority of the uptake is -- is in the end of the year, January. So we'll only have three (3) months worth of savings. As well, we've looked at what the -- you know, some of the actual salaries are of some of the employees that are leaving and the terms of the voluntary departure program.

During the forecast we weren't sure what those terms were going to look like. Right now

it's a -- it was -- at this point it's a thirty (30) week. They're getting thirty (30) weeks of -- of paid salary. At the time of the forecast it was forty (40) weeks.

So again, there was just different assumptions based in and we have continually reviewed that number to make sure that -- now that we know some differences that that five hundred and eighteen (518) is still a good number in terms of where we expect our operating and administrative costs to come in for the 2017/'18 fiscal year.

MR. BOB PETERS: If we turn to the 2018/'19 fiscal year, the forecast, Ms. Bauerlein, we see 501 million is the forecast operating and administrative costs, correct?

MS. SANDY BAUERLEIN: That is correct.

MR. BOB PETERS: And in that $501 million number, Manitoba Hydro has assumed is it five hundred (500) voluntary departures under the voluntary departure program?

MS. SANDY BAUERLEIN: Yes. We had assumed the same -- when we did the forecast, we had made the same assumptions in terms of that there would be five hundred (500) people gone and what the average salary would be, at the time we put the forecast

together.

MR. BOB PETERS: And so now you have a degree of confidence that that five hundred (500) number is too low, and there'll be...

MS. SANDY BAUERLEIN: No, again, what we've done is we've done further analysis to verify, you know, is the five hundred and one (501) number, a number that we want to take forward in the test years, and we believe so.

So, while we do have a higher uptake in the VDP, what we have to account for in our costs and what we've done is we've taken a look to say, okay, we now know wage settlement impacts. We know the people that are left. So we know the impacts of those negotiated collective agreements. So, we have an impact on wage settlements.

We also have -- have an impact in terms of -- taking approximately, you know, eight hundred (800) people out of the Company has a significant impact on the work. We're continually, as I mentioned, in trying to put together -- our inability to put together a detailed forecast is because things are changing. People are now needing to perhaps -- we're looking as -- as a manager, you're looking for what work do I need to do, what work can I stop doing,

what work do I do differently, and if I need to continue with that work, how do I do it differently? So I -- we'll need costs for retraining of staff. Some staff need to go into different types of work, so they need retraining for that.

We're also looking for opportunities to try and you -- to take advantage of different IT technologies to assist in enabling the Company to still operate at a -- with the -- such a reduced workforce. Examples that -- things that we're looking at, for example, is something called robotics process automation.

So all of these things that we need to do to be able to facilitate the Corporation in being able to operate and function will require some one (1) time costs that will be incurred in the 2018/'19 fiscal year. So while we've had a higher headcount, we also recognize that there are some costs needed to be able to allow the Company to continue to manage at that level.

So we still believe that 501 million is a -- a good forecast number, and a good target for what our costs need to be for the 2018/'19 fiscal year.

MR. BOB PETERS: Ms. Bauerlein, that

$501 million number only includes approximately $56 million of savings as a result of the voluntary departure program, though?

MS. SANDY BAUERLEIN: In the forecast, yes, but as I said, what we have done is we've taken the savings now, and we've adjusted for -- so we've incorporated the actual savings, which would be greater, but as I said, there's other costs that we anticipate to incur in the 2019 -- '18/'19 fiscal year to allow us to manage.

MR. BOB PETERS: Ms. Bauerlein, are you able to provide the Board with the analysis that you're referring to that will show the updated work by Manitoba Hydro, continues to support the 501 million in the $518 million forecast?

MS. SANDY BAUERLEIN: Yes, we could provide the analysis that shows that the five hundred and eighteen (518) and five hundred and one (501) are -- are still good operating and administrative targets for those years, or forecast for those years, yes.

MR. BOB PETERS: All right. So I'll -- I'll ask that as -- that's something that's not readily at hand, is it?

MS. SANDY BAUERLEIN: Not readily at hand.

MR. BOB PETERS: All right. So then I'll ask through your counsel, Ms. Ramage, if -- if Manitoba Hydro will provide an undertaking to provide its most current analysis to support the operating and administrative costs in the 2017/'18 year forecast as well as in the 2018/'19 year forecast, including the voluntary departure information. Would that be acceptable?

MS. SANDY BAUERLEIN: Yes, we except.

--- UNDERTAKING NO. 5: Manitoba Hydro to provide its most current analysis to support the operating and administrative costs in the 2017/'18 year forecast as well as in the 2018/'19 year forecast, including the voluntary departure information

CONTINUED BY MR. BOB PETERS:

MR. BOB PETERS: Okay. Thank you. The restructuring costs that you mentioned to the panel, Ms. Bauerlein, those aren't shown here, are they? Those would be in other expenses in the --

MS. SANDY BAUERLEIN: The costs that I was referring to are costs that we are going to con -- they're not a -- a direct -- we're not treating them as a direct cost to restructure. The restructuring costs are only the amounts being paid to employees as a result of the voluntary departure program. So the cost that I was referring to in terms of cost that -- for example, a training of staff, that will be charged to operating and administrative costs.

MR. BOB PETERS: Is that shown under the other line on -- on the page 231 that's in front of us?

MS. SANDY BAUERLEIN: It's -- it's not -- some of it might wind up in the other line. Some of it will wind up maybe in -- in other types of costs. So for example, if we hire consultants, for example, to help with some of the implementation of our IT technologies, that would appear in external services.

MR. BOB PETERS: Ms. Bauerlein, in addition to the voluntary departure program, Manitoba Hydro has previously committed to redo -- reduce the workload at the Corporation. Is that correct?

MS. SANDY BAUERLEIN: I'm not sure what you mean by work -- committed to reduce the

workload, yes.

MR. BOB PETERS: Let me rephrase the question. Leaving aside the voluntary departure program, Manitoba Hydro had previously embarked on reductions in the positions at Manitoba Hydro?

MS. SANDY BAUERLEIN: Yes, over the period 2014/'15 to 2016/'17, we reduced approximately for hundred and twenty-nine (429) operational positions.

MR. BOB PETERS: And the Board will see that on page 255 of Board counsels' book of documents, under Tab 65 of Exhibit 42-4. And Ms. Bauerlein, this chart summarizes what you've just told the Board, and that is in terms of what your committed reductions were compared to your actual reductions, Manitoba Hydro has reduced four hundred and twenty-nine (429) positions?

That is correct, four hundred and twenty-nine (429) operational positions were reduced over that three (3) year period.

MR. BOB PETERS: Right. Now, when we say four hundred and twenty-nine (429) operational positions have been reduced, does that mean the position itself was eliminated?

MS. SANDY BAUERLEIN: Yes. The

position was --

MR. BOB PETERS: I mean the --

MS. SANDY BAUERLEIN: -- we call it 'delimited'. The position was delimited. It no longer exists.

MR. BOB PETERS: What happened to the employee that was in the position?

MS. SANDY BAUERLEIN: In some cases, employees retired. In some cases employees had accepted other jobs in the -- in the Company, so they would bid on another job, and then that position would be vacant, and the manager would decide that -- that we were going to either, you know, stop the work, redistribute the work, and then therefore eliminate the position and not automatically fill that position when the employee either retired or moved on to another area.

MR. BOB PETERS: And this is showing the panel the four hundred and twenty-nine (429) positions were delimited bef --

MS. SANDY BAUERLEIN: That is correct.

MR. BOB PETERS: -- before the voluntary departure program?

MS. SANDY BAUERLEIN: That is correct.

MR. BOB PETERS: And the savings that

accrued to the Corporation as a result of that are shown at $43.2 million a year?

MS. SANDY BAUERLEIN: Yes.

MR. BOB PETERS: And on an annual basis --

MS. SANDY BAUERLEIN: That is the cumulative savings --

MR. BOB PETERS: Yes, but on -- on an --

MS. SANDY BAUERLEIN: -- over the three (3) years, yes.

MR. BOB PETERS: -- annual basis, it's -- what is Manitoba Hydro forecasting will be the annual savings as a result of the delimiting of four hundred and twenty-nine (429) positions?

MS. SANDY BAUERLEIN: It would be savings in terms of the incremental of not having those positions anymore. So again, you would be saving your 43.2 million cumulative, and you would save that basically on an ongoing basis, because those costs -- your OM&A would be higher by that much money if those positions still existed.

MR. BOB PETERS: And -- and put inversely, the OM&A expense that you have included in your budget way back on page 231 of Board counsels'

book of documents is $43.2 million lower as a result of the delimiting of those positions?

MS. SANDY BAUERLEIN: It is lower when you compare it over -- so again, we took our -- our outlook -- our -- our '16/'17 numbers. So the '16/'17, the 535 million would already have those savings built into it.

MR. BOB PETERS: In the undertaking that you've agreed to provide, will there be special recognition for these delimited positions in the savings that is accrued to them?

MS. SANDY BAUERLEIN: I was under the understanding I was trying to take you to -- from the five thirty-five (535) to the five eighteen (518). So that would include the impacts of the voluntary departure program and those that were severed. The five thirty-five (535) already embeds those other savings. Those -- those people were gone in the five hundred (500) -- or those positions were gone in the five hundred and thirty-five (535) starting point.

MR. BOB PETERS: All right. I'm still just not clear on the annual savings as a result of the delimiting of the -- of the four hundred and twenty-nine (429) positions. I have the cumulative total, but on an annual basis, what is Manitoba Hydro

expecting to realize as -- as savings by delimiting those four hundred and twenty-nine (429) positions?

MS. SANDY BAUERLEIN: You don't continually -- to see the savings in each year as a lower number because those savings are already built in. So you've -- you've had the 40 -- $43 million included in your 535 million. So your savings are really, Well, if you still had those people, what would have been my incremental cost? So my $518 million would be $43 million more, approximately.

MR. BOB PETERS: Is it correct that Manitoba Hydro has handled the voluntary departure program and this delimiting of positions internally, through its human resources, or has Manitoba Hydro contracted an external consultant on that matter?

MS. SANDY BAUERLEIN: Can you repeat the question?

MR. BOB PETERS: Well, let's start with the voluntary departure program. Is that being handled by Manitoba Hydro's human resource department, or is there an external consultant that's been engaged to deal with that?

MR. JAMES MCCALLUM: Well, I -- I guess there's a -- a few elements, I think, to your question, Mr. Peters, if I'm understanding it. Vis-a-

vis the kind of practicalities of identifying and dealing with eight hundred and seventeen (817) individuals and having them leave the Corporation, that we did in-house with our human resources department.

The job of figuring out how to continue running the Company after they're gone has been also managed in-house throughout the Company. I mean, every manager, director, and vice president has spent an enormous amount of their time over the last year figuring out an operational plan to continue running our business with 15 percent fewer people.

But if the question is, did we engage outside consultants at this stage to help us with that, we have not. Although, as Ms. Bauerlein spoke to, we recognize that there is going to be some effort and some help required to continue adjusting our business to what is a very significant workforce reduction.

We're kind of just at the initial stages of it, given that -- that of the eight hundred (800) people, you know, roughly only three hundred (300) have left to date with -- with more than five hundred (500) still to leave on February the 1st.

MR. BOB PETERS: All right. Thank

you, Mr. McCallum.

I'd like to turn briefly to Tab 70 of Board counsels' fourth book of documents, page 322, and my only point to turn to this is to bring to the panel's attention some questions that had been asked earlier by, I think counsel for MKO related to payments from government or payments to government.

This is a summary page, is it, that reflects what payments Manitoba Hydro makes on an annual basis to various government entities?

MS. SANDY BAUERLEIN: That is correct.

MR. BOB PETERS: And but for the column called municipal GILT, or gifts in lieu of taxes and business taxes, the other payments are made to the Province of Manitoba?

MR. JAMES MCCALLUM: I'd just correct that there -- it's not a gift in lieu of taxes, it's a grant in lieu of taxes, but -- but --

MR. BOB PETERS: 'Tis the season, Mr. McCallum?

MR. JAMES MCCALLUM: Ho ho ho. Yes, the balance goes to the Province.

MR. BOB PETERS: Does this -- does this chart include Manitoba Hydro's expected or anticipated payments to the Province on account of

Keeyask and Bipole III as well?

MS. SANDY BAUERLEIN: I'm not sure what -- what you're asking. In terms of the impact on our -- our provincial guarantee fee, or capital taxes? I'm -- I'm not --

MR. BOB PETERS: Let me try it this way. On -- on page 334 of Board counsels' book of documents, Manitoba Hydro has provided a chart of what payments Manitoba Hydro has made and expects to make to the Province of Manitoba related to the Keeyask project, correct?

MS. SANDY BAUERLEIN: Correct.

MR. BOB PETERS: And these payments are included in the previous schedule that we reviewed on page 322?

MS. SANDY BAUERLEIN: Yes.

MR. BOB PETERS: All right. Thank you. Also, on page 335, Manitoba Hydro has provided the Board with an indication of what payments Manitoba Hydro will -- has made and will be making on a forecast basis to the Province related to the Bipole III project, correct.

MS. SANDY BAUERLEIN: That is correct.

MR. JAMES MCCALLUM: I -- I might just caution, Mr. Peters, that these payments you've

referenced on page 335 and the other relating to Keeyask kind of have a simplifying assumption around how much debt remains attached to each of Bipole and Keeyask.

I think we -- we kind of talked about last week that we don't stream or finance individual projects individually. So the master sheet, and I've lost it -- ult -- ultimately, our debt guarantee fee, our capital tax are really determined by the capitalization and the business, regardless of where it's applied. As well, the water rental fees are -- are determined basis, the -- the generation of the business regardless of which station it -- it's generated at. So I think the -- the master schedule is probably the -- the best one to look to as to the payments to the Province.

MR. BOB PETERS: Do I understand the point of your comment, Mr. McCallum, to be telling the Board that even though Manitoba Hydro has calculated the payments to the Province for the Keeyask project and for the Bipole III project, that's not in practice how Manitoba Hydro does the math?

MR. JAMES MCCALLUM: That -- that's correct. We do it on a consolidated -- meaning at the electric segment level, a consolidated basis, if that

hopefully makes sense. I can try again.

MR. BOB PETERS: All right. Thank you. I'd like to leave OM&A expense, if I could, Mr. Chair, Board members, and turn over some power resource and some export issues. And I believe Mr. Cormie, you will be assisting the panel in this regard.

Could we start, please, on Board counsels' fourth book of documents, Exhibit 42-4 on page 102, 102.

(BRIEF PAUSE)

MR. BOB PETERS: And Mr. Cormie, help me as you can, and I -- I see Mr. Miles isn't far away. And if -- if additional information is required, certainly avail yourself of his assistance.

But what you're showing the Board on page 102 of Board counsels' book of documents is how Manitoba Hydro plans to meet its load each and every year in the forecast?

MR. DAVID CORMIE: Yes, that -- this table shows how we expect to meet the energy demand.

MR. BOB PETERS: And on page 102 of Board counsels' fourth book of documents, you say the

energy demand because you're wanting the Board to know that you also do a similar sheet, and we -- we'll -- we'll come to that, on the capacity side?

MR. DAVID CORMIE: Yes, the capacity is -- is to ensure that we have enough generating capacity to meet the peak demands of our customers plus our reserve obligations.

MR. BOB PETERS: And on this chart, Mr. Cormie, there's also in the heading, if we could just scroll up a little bit, we see the word "dependable resources," correct?

MR. DAVID CORMIE: Yes, that -- that's correct.

MR. BOB PETERS: You showed the panel in your direct evidence the last approximate hundred years of water flows with your -- with your bar chart, correct?

MR. DAVID CORMIE: I did, yes.

MR. BOB PETERS: And do the dependable resources reflect the resources that would be available to Manitoba Hydro if Manitoba Hydro suffered the lowest water levels in its recorded history?

MR. DAVID CORMIE: Yes, this reflects the -- the worst-case historic drought.

MR. BOB PETERS: So everything above

the historic drought will be surplus to what's on this chart?

MR. DAVID CORMIE: Yes. There will be surplus energy available under better than minimum flow conditions, yes.

MR. BOB PETERS: If we briefly look, the -- the top half of the page, or the -- sorry, the top third of the chart is -- is empty, and that reflects that Manitoba Hydro has no new power resources on the horizon?

MR. DAVID CORMIE: That's correct. On that -- on that page, I -- there is a -- a second page that carries on.

MR. BOB PETERS: And -- and if I'm looking at page 103, I -- I think it's likewise, nothing is included on the planning horizon at this point in time. Have -- would that be a correct interpretation?

MR. DAVID CORMIE: I think the purpose of this chart is to show -- whether we need them or not, this is the -- this is the supply and demand balance, assuming no new resources are put in.

MR. BOB PETERS: So let's go back, please, to page 102, and we look under "base power supp -- base supply power resources," in the left-hand

column. The existing and committed Hydro reflects the plants that Manitoba Hydro has online, plus what's going to be coming online, particularly, the -- the Keeyask project, correct?

MR. DAVID CORMIE: That's correct.

MR. BOB PETERS: And under the thermal resources -- well, before we get there, is -- is the -- I'm not sure if this is -- if it's -- is it the mothballing of Pointe du Bois, is that reflected in the supply and demand tables.

MR. DAVID CORMIE: I believe, Mr. Peters that we're assuming that four (4) units at Pointe du Bois are unavailable for service in this table.

MR. BOB PETERS: And does that carry forward into the forecast of export volumes in the integrated financial forecast?

MR. DAVID CORMIE: I think, Mr. Peters, it's better if Mr. Miles speaks to the issue of Pointe du Bois.

MR. BOB PETERS: I'd be pleased. If he wants the microphone from the back, or do you want him at the front row, Ms. Ramage?

MS. PATTI RAMAGE: We have Mr. Miles here. He hasn't been sworn, and we're ready for that,

but if Mr. Simonsen would like to come over and swear him, he can speak from the back row.

MR. BOB PETERS: Okay. Thank you.

TERRY MILES, Sworn

CONTINUED BY MR. BOB PETERS:

MR. BOB PETERS: Good morning, Mr. Miles. I think the panel would appreciate your update, then, on the Pointe du Bois and how it's been treated in the -- in the power resource planning.

MR. TERRY MILES: Okay. Well, good morning, everyone. So Pointe du Bois in this -- in this plan has been treated not going ahead with four (4) unit refurbishments moving forward. We were intending on having four (4) units in Pointe du Bois upgraded, if you will, and carry those on for probably thirty (30), forty (40) years into the future.

We've re-looked at those options, and given the capital costs, given the market value, and given our re-look at capital, we have chosen not to include those costs in our current budgeting and planning right now. So as a result, then, we've removed that work on a go-forward basis.

So under this plan, it assumes that in

the -- I think it's in the 2021 or 2022 timeframe, that then the existing units at Pointe du Bois will receive significant enough failures that we wouldn't refurbish them, and that would be considered as we go over in -- in time, but one (1) unit would remain. There's one (1) unit that is still in good working condition. It's this draft flow unit. That's an 8 megawatt unit that will then continue on for the planning horizon.

As a result of that, what happens then on the dependable side, which is probably what you're looking at, there's about 221 gigawatt hours of generation that would come from those other three (3) units that were -- that were there, and as a result, then, there's a reduction in dependable energy from Pointe du Bois.

MR. BOB PETERS: And thank you, Mr. Miles. So Pointe du Bois has had its capacity dropped from the previous 75 megawatts down to the current thirty-three (33), and you're indicating it's going to go down as low as 8 -- 8 megawatts?

MR. TERRY MILES: That's correct.

MR. BOB PETERS: And while we're on it, the Selkirk Thermal Plant appears limited to 33 megawatts because of transmission constraints? And I

don't know if the panel's heard of those before. Is that a new phenomenon?

MR. TERRY MILES: It -- it's not a new phenomenon. In the -- in the last Power Resource Plan, we'd assume that there would be upgrades for those transmission constraints that would increase the capacity of Selkirk from about 33 megawatts up to 125 megawatts.

Again we're revisiting those expenditures and have taken them out of our -- of our forecast plan going forward. And as a result, then, we've taken, then, the increase from 33 megawatts up to 125 megawatts out of our plan, and that's what's reflected in the tables.

And it's essentially because we don't have those in our plan to do maintenance, we can't include them in our plan, and from a transmission reliability perspective, we're unable to include that additional capacity until such a time as we have those transmission upgrades.

And what happens periodically is a transmission -- we'll do system studies that look at load changes in the system and generation, and depending on where load changes, so you could have a big industrial customer, say, on the Winnipeg River

somewhere, or elsewhere in the Province, and that changes the load dynamic, and it changes how the transmission system works. And when they do their studies, the balance of load in this case only allows 33 megawatts of Selkirk really to be usable under -- there's certain loading conditions that they study.

So that's essentially what caused us to go to the reduced -- the reduced loading, and then revisiting capital caused us to take those expenditures out of our plan. And we'll reconsider them. It doesn't mean it's off the table. It just means currently it's not in the plan and we don't have things in the budget for that.

MR. BOB PETERS: If we could turn to page 98, and Mr. Miles, perhaps you can assist here as well. We're -- we're switching to the capacity resources, and I think we see perhaps more accurately that Brandon Coal, or Unit 5 is scheduled for decommissioning in 2019, is that correct?

MR. TERRY MILES: So Brandon Unit 5 Coal operations, so Brandon Unit 5 is a coal unit. It's a coal-fired thermal unit. And in -- at the end of 2018, we've -- timing essentially with -- with Bipole III coming into service, Brandon Unit 5 as a reliability resource will no longer be required, and

coal operation will be ceased.

The Unit itself, the generation equipment will be -- will be used as a synchronous condenser on a go-forward basis to provide transmission system support in the area. So the Unit will -- will still be used. It's just we won't be using it as a coal unit. It basically acts as a motor to provide stability to the electrical system.

MR. BOB PETERS: But Unit 5 is still needed for emergency operations?

MR. TERRY MILES: Unit 5 will not be operated at all for generation after 2018/'19 until such time as changes to the generation system would be made. It will not have a generation capability beyond that.

MR. BOB PETERS: On the same chart on page 98 of Board counsels' book of documents number four, it appears that wind is now counting towards winter peak capacity. Is that correct?

MR. TERRY MILES: That's correct.

MR. BOB PETERS: And wind is not a dep -- I -- maybe I'll ask it this way. Is wind a dependable resource?

MR. TERRY MILES: Wind, from an energy perspective, is a dependable resource, yes. So in --

over -- over the course of the year, actually, wind -- wind -- we can rely on wind to provide a certain amount of energy over the course of the year.

MR. BOB PETERS: But you just can't dispatch it when you want it?

MR. TERRY MILES: You can't necessary dispatch it when you want it, but that doesn't mean that it can't provide some capacity value at -- when our peak load occurs in the winter. Initial assumptions with wind were that there wouldn't be sufficient generation at the peak load times in -- in the wintertime, and experience has shown that we can allocate a certain amount of capacity resource to wind, because it is there at times. And that's based on our number of years of experience with the wind and observing it in Manitoba under our -- our loading conditions. So that's where that capacity amount has been.

There's always been some in the summertime for the market case. There were always cold weather restrictions attached to the -- to the wind components, and it's in the order of, you know, below minus thirty (30) or minus thirty-five (35). The units, actually -- the -- the wind units that -- they have the turbines aren't guaranteed to operate,

and that's sort of a mechanical aspect of it.

But I think what we see is if they are operating and they are going, the temperature inside the wind turbine in the unit that's there is actually a little warmer than it is outside, so it's able to operate if they are operating. I believe if they weren't operating, and you had to start them up, they wouldn't be able to start up below that minus thirty (30) or minus thirty-five (35). So based on operational experience, we've adjusted that capacity factor in the winter, and allow that -- allow that.

MR. BOB PETERS: In that answer, Mr. Miles, I -- I think I heard you saying if it's too cold, these units might not work unless they're already idling. Is that, in essence, what you're saying?

MR. TERRY MILES: Unless they're actually operating, yeah.

MR. BOB PETERS: And to reflect wind as being a dependable resource, Manitoba Hydro has had to reduce its expectations of what would be available? Would that also be correct?

MR. TERRY MILES: From an energy or capacity perspective?

MR. BOB PETERS: From a capacity

perspective.

MR. TERRY MILES: Sp from the capacity perspective, it's -- it is based on our experience and the operation of the wind turbine.

MR. BOB PETERS: And Manitoba Hydro's relying on historical data or statistical calculations to provide it with the confidence level to include it in its dependable energy?

MR. TERRY MILES: Essentially.

(BRIEF PAUSE)

MR. BOB PETERS: If we could turn back briefly to page 102, and we'll scroll to the bottom two-thirds of this -- this chart.

Would it be correct, Mr. Cormie, in the -- the bottom third, you're telling this Board what Manitoba Hydro's domestic load is going to be expected to -- to consume?

MR. DAVID CORMIE: Yes, that's the -- the base load forecast less the DSM forecast pres -- results in the Manitoba net load.

MR. BOB PETERS: And this was -- as Ms. Morrison had explained to the Board --

MR. DAVID CORMIE: Yes.

MR. BOB PETERS: -- last week? And then Manitoba Hydro also has -- and you can see highlighted -- the net load. The net load number, Mr. Cormie, is -- is the net of the MS. DAYNA STEINFELD: -- demand-side management?

MR. DAVID CORMIE: Correct.

MR. BOB PETERS: And then once we know what Manitoba's load is, Manitoba Hydro also then has to add in what it's committed to provide by way of exports, export contracts that you've had arranged, correct?

MR. DAVID CORMIE: Correct.

MR. BOB PETERS: And under the proposed exports, nothing's on the short-term horizon, it doesn't appear, Mr. Cormie. Is that also correct?

MR. DAVID CORMIE: That's correct.

MR. BOB PETERS: But then less adverse water. And can you briefly explain to the panel why Manitoba Hydro is reducing its total energy demand by an amount related to adverse water?

MR. DAVID CORMIE: Adverse water conditions, Mr. Peters, exist in several of our export contracts that allow us to serve our sale obligations under -- under these extreme conditions by purchasing energy from the company who we're selling energy to.

So in effect, they're self-supplying energy under those conditions.

So it's not energy that Manitoba Hydro has to have on its system. It can rely on the contract provisions to meet its obligation to the customer. So in -- in effect, it reduces the -- our obligation in -- that's served from Manitoba. The obligation still has to be met, but it can be met through a purchase from the export customer.

MR. BOB PETERS: So the -- just to be clear, when Manitoba Hydro -- and this chart depicts the -- the worst historical drought that Manitoba has had. You're indicating that Manitoba Hydro still has to fulfil contractual arrangements, but it doesn't necessarily have to come from Manitoba electrons?

MR. DAVID CORMIE: That's correct. So if you look at the first column, it shows we have contracted for 3,410 gigawatt hours. We still have to provide that electricity in that year, but 370 of those gigawatt hours can be purchased from the export customer. And so it's being purchased off a generator in Minnesota rather than being supplied from a generator in Manitoba, so it doesn't need to show up in our supply and demand balance for Manitoba.

MR. BOB PETERS: And I'm not wanting

to go anywhere near commercially-sensitive information, Mr. Cormie, but does Manitoba Hydro have export contracts that will limit the amount that Manitoba Hydro has to export when it is in a drought, other than through adverse water?

MR. DAVID CORMIE: Yes, there are -- there are contracts where when Manitoba Hydro normally would have an obligation to supply, for example, energy on the weekend under the contract. We have the right not to supply that, and we would have to demonstrate to our customer that we're in that -- in that condition described generally as being in adverse water. And we would -- with the -- we would then be able to exercise our right not to deliver.

MR. BOB PETERS: Mr. Cormie, the last line on this sheet talks system surplus.

Do you see that?

MR. DAVID CORMIE: I see that, yes.

MR. BOB PETERS: Going from my memory, and you can correct me in front of the panel if you choose, that the Keeyask generating station is to add approximately 3,000 gigawatt hours a year of energy.

Do you accept that?

MR. DAVID CORMIE: Yes, I accept that.

MR. BOB PETERS: So when the panel

looks at this last line on page 102, which is in -- on the monitor, for every year in which the surplus exceeds 3,000 gigawatt hours, those would be years in which the energy from Keeyask wouldn't technically be needed to serve Manitoba's domestic load as well as their net export load.

MR. DAVID CORMIE: Not exactly, Mr. Peters, because the Keeyask project was developed in conjunction with the new US interconnection, so the U -- the new US interconnection provides dependable energy as well. And so you have to think of them as a package. You can't just attribute all the surplus to -- to Keeyask. There's a combination of both projects that result in an increase in dependable energy, or an increase in the system surplus that's shown on this table.

MR. BOB PETERS: Well, let's -- let's turn to page 103, the next page, and look at the bottom line, Mr. Cormie. And I suppose much like the checkbook there's some red ink showing up here. And it's in the -- if we can look at the top part of it. I believe it's in 2040? Yes.

If we can now scroll back to the bottom in 2039/2040, we see that the system surplus has turned negative; correct?

MR. DAVID CORMIE: Yes.

MR. BOB PETERS: And so that's telling Manitoba Hydro that if this is a persistent problem, Manitoba Hydro has to find some way to address that persistent shortfall, otherwise, it can't meet its total energy requirements.

MR. DAVID CORMIE: Yes. Under the assumptions associated with the table, yes. But both the Keeyask project and the new interconnection have moved that date of new need out into the 2040. It's not just the Keeyask project that's done that.

MR. BOB PETERS: Oh, I have --

MR. DAVID CORMIE: Absent both projects, it would be much earlier than that.

MR. BOB PETERS: Are you able to indicate how much earlier?

MR. TERRY MILES: It's in the order of 2032/'33.

MR. BOB PETERS: I'm sorry, Mr. Miles?

MR. TERRY MILES: It's in the order of 2032 -- 2032 time frame, that early 2030 time frame. It varies depending on assumptions that are -- that are there.

MR. BOB PETERS: Cut can you explain then, Mr. Cormie, what dependable energy comes from

the intertie by itself?

MR. DAVID CORMIE: The -- yeah, the new interconnection increases our import capability by 700 megawatts. So it essentially doubles it from 700 megawatts to 1,400 megawatts. And we count on a portion of that to add to the dependable energy supply of the system.

And so it's a -- it's -- it's the dependable energy that comes from Keeyask plus the dependable energy that comes from the new interconnection that -- that provides the overall dependable supply.

MR. BOB PETERS: Are the two (2), Keeyask and the intertie, additive in terms of dependable energy?

MR. DAVID CORMIE: Yes, but they're -- but -- but what you couldn't have had one (1) without the other. That's what I'm saying. They're linked. Like, we could -- we wouldn't have built Keeyask without building the interconnection.

MR. BOB PETERS: I remember the NFAT. Mr. Cormie, what you're telling the panel is that because you have now -- Manitoba Hydro now has an additional 700 megawatts of import capability under the new interconnection, Manitoba Hydro can, for

example, import into Manitoba at night and keep water in your reservoirs.

MR. DAVID CORMIE: We would import at night to serve the load demands under these low water conditions. We wouldn't -- we would -- we wouldn't just import to put it in the reservoirs. We'd import it to serve the load.

MR. BOB PETERS: I'm sorry then. So in terms of this -- these charts that we're looking at, this is the -- the worst year on record. So the reason for using the intertie would be to serve the Manitoba load, not just for enhancing storage capability.

MR. DAVID CORMIE: Yes. Serving it on a -- on a dependable basis. We -- we essentially guarantee that we'll be able to call on that 700 megawatts a certain percentage of the time to -- to serve our -- our needs. As opposed to building another generating station we can count on the import capability.

MR. BOB PETERS: All right. If we can go back to page should 98. This deals with the capacity side in the same -- in the same drought scenario; does it, Mr. Cormie?

MR. DAVID CORMIE: This is the -- the

cap capacity table, yes. And it's -- rather than the drought scenario, Mr. Peters, it's -- it's the winter peak demand, and it also includes the planning criteria that we maintain as re -- sufficient reserves as defined by our planning criteria.

MR. BOB PETERS: And you're telling the panel that this is an important chart, because Manitoba Hydro is a winter peaking utility, and we saw little bit of that weather this morning; correct?

MR. DAVID CORMIE: Yes.

MR. BOB PETERS: And if we -- if we look at the generation outages over system peak line item, what does that reflect, Mr. Cormie?

(BRIEF PAUSE)

MR. DAVID CORMIE: Mr. Peters, that is a planned generating -- generation outage that we know today will occur in that year, and -- and we're planning for that.

MR. BOB PETERS: And it's a planned outage for servicing or for...

MR. DAVID CORMIE: I don't know the details of it. It's just that that capacity which we would normally expect to be there is -- is not going

to be there that winter.

MR. BOB PETERS: Looking at the bottom line on page 98, Mr. Cormie, much like we saw with the energy, we can follow out here and see what the system surplus is.

And remind us again, Keeyask is 630 megawatts.

MR. DAVID CORMIE: That's the net addition. Yes, that's correct.

MR. BOB PETERS: So on that bottom line on system surplus, is it every year in which the system surplus exceeds 630 would be indicative of a year in which the capacity of Keeyask wouldn't be required in this dependable example?

MR. DAVID CORMIE: That's correct.

MR. BOB PETERS: If we follow over to page 99 --

MR. TERRY MILES: Mr. Peters, could I also add just a note to that just for the Board?

MR. BOB PETERS: Please.

MR. TERRY MILES: So these tables assume a number of assumptions. So we assume that our system will remain intact. All of our bay system will -- will be there. We talked about an outage, this 15 megawatt outage of a unit. So these tables assume

that we're doing all the maintenance and all those types of things into the future to remain -- keep our whole system intact. So that's the whole, you know, 5,000 plus megawatts of existing system impact between now and the mid-'20s. That's twenty (20) years out into the future.

It also assumes that we achieve the DSM savings and targets out at that time frame that we go in time to as well. So not to think of it at any -- any one (1) component that's there. We can draw the inference and say it's 630 megawatts for Keeyask and -- and do that math. That's a mathematical exercise, but I think we need to understand the base assumptions and what's sort of required and -- and what will be there, if you will, out at that time frame. Just to give a little more context around the assumptions behind the plan.

MR. BOB PETERS: Okay. Well, let's turn to page 99 of Board counsels' fourth book of documents, and look at the bottom line in the year -- I see it in the year 2041/2042.

That's when there is a 56 megawatt shortfall that first appears; correct, Mr. Cormie?

MR. DAVID CORMIE: Yes.

MR. BOB PETERS: And this would be the

beginning of where -- where Manitoba Hydro sees persistent shortfalls in their system planning under dependable conditions?

MR. DAVID CORMIE: With the exception of the -- using the word "dependable." It -- it is the year that -- that we would see persistent deficits under the assumptions that the table is prepared on.

MR. BOB PETERS: And Manitoba Hydro isn't proposing any new generation to meet that deficit; is that right?

MR. DAVID CORMIE: Not at this time. This table is -- is based on the assumption that we wouldn't put in -- we're not putting in -- we're not -- we're not putting -- planning on any resources. This -- the table just says, If we did nothing and our assumptions proved to be true, this is when we would see that shortfall, yes.

MR. BOB PETERS: And so what would Manitoba Hydro's assumption be if Manitoba Hydro had to do something for 2042?

MR. DAVID CORMIE: I don't know. That's a long way away, Mr. Peters. I'm not sure what my -- our children might be deciding to do at that time.

MR. BOB PETERS: So at this point in

time, for planning assumptions, Manitoba Hydro has sufficient time to consider its options and do its integrated resource planning and come up with some ideas?

MR. DAVID CORMIE: Yes, there's -- there's no need to make a decision today to -- when -- based -- based on these assumptions.

MR. BOB PETERS: And so these assumptions that we see include the Keeyask generating station; correct?

MR. DAVID CORMIE: That's correct.

MR. BOB PETERS: So post Keeyask no new resources are needed until, as shown here, 2042?

MR. DAVID CORMIE: Based on the assumptions that this table has made.

MR. BOB PETERS: Are --

MR. DAVID CORMIE: But as -- as Mr. Miles indicated, we assume our DSM program is fully effective. We assume the load forecast here is as expected. Imagine the DSM is less effective or the Manitoba load were to be the high Manitoba load, then resources would be required earlier than that.

MR. BOB PETERS: Thank you. I want to turn, still before the morning recess if I could, to a topic of risks and I'll come back I think, Mr. Cormie,

to you with some additional questions shortly. But one (1) of the reasons Manitoba Hydro is requesting 7.9 percent rate increases is in order to withstand the negative impacts of uncertainties in the forecast.

Would -- would that be correct, Ms. Carriere or Mr. McCallum?

MS. LIZ CARRIERE: That would be correct.

MR. BOB PETERS: If we turn to volume 4, page 134, Exhibit PUB-42-4, Manitoba Hydro has provided the Board with an uncertainty analysis.

Would that be the right way to describe that, Ms. Carriere?

MS. LIZ CARRIERE: I would characterize this table on page 134 as sensitivities to certain variables.

MR. BOB PETERS: All right. Let's go down to -- on the chart to the five (5) year drought line. And it says a five (5) year drought.

Have you located that, ma'am?

MS. LIZ CARRIERE: Yes.

MR. BOB PETERS: And we follow that over and we see that in 2024 Manitoba Hydro is telling the Board that if it had a five (5) year drought Manitoba Hydro's retained earnings would be $1.388

billion less than what is presently forecasted in Manitoba Hydro's integrated financial forecast 16.

MS. LIZ CARRIERE: Yes, if no rate action is taken.

MR. BOB PETERS: Well, let me -- let me understand that. Is it no rate action is taken or Manitoba Hydro is on the rate trajectory that's proposed in integrated financial forecast 16 updated with interim?

MS. LIZ CARRIERE: Yes, this sensitivity to determine the retained earnings impact holds the -- the rate trajectory 7.9 percent constant. What I meant was, is that there is no compensatory rate action taken to recover the $1.4 billion.

MR. BOB PETERS: All right. You're telling the panel that if the five (5) year drought hit and Manitoba Hydro's rate increases were as proposed by Manitoba Hydro, the retained earnings would be down $1.388 billion dollars from what's filed?

MS. LIZ CARRIERE: That's correct.

MR. BOB PETERS: All right. We'll come back to the rate action question. If we turn to page 135 and stay with the -- well, we'll turn there, 135.

Is the Board to understand that drought is the most significant risk that Manitoba Hydro faces?

MR. JAMES MCCALLUM: I wouldn't necessarily characterize it that way. Certainly, the -- as you look to a five (5) year impact, or a ten (10) year impact we don't see a greater diminution in financial condition from other variables as we see with drought. But looking over the longer term my point of view would actually be that debt and interest rate volatility are our greatest risk to the long-term health of the company and long-term rate stability.

MR. BOB PETERS: Okay. We'll -- we'll come back to that thought, Mr. McCallum, in a few minutes.

But from a financial perspective under these sensitivities, Manitoba Hydro is showing that the five (5) year drought or the seven (7) year drought is the one (1) that has the greatest impact on the retained earnings?

MR. JAMES MCCALLUM: That is true. I'm just trying to make clear that that is over a discrete period of time. The benefit, I guess, of a drought is that presumably at some point it will end and the damage will stop. The issue with interest

rates is that depending on where you are on a -- more of a cyclical basis you could end up chasing rates higher and higher for years to come.

MR. BOB PETERS: If we turn to page 135, which is on the monitors in front of us, would it be correct that Manitoba Hydro is showing the Board that if a five (5) year drought hits starting in 2019/'20, or alternatively, if it started in '22/'23, the financial impact on retained earnings is approximately the same $1.4 billion, Ms. Carriere?

MS. LIZ CARRIERE: Approximately, yes, that's correct.

MR. BOB PETERS: And then if we look at the seven (7) year drought, and again different starting dates, that has an impact of somewhere between 1.8 and $2 billion on the retained earnings?

MS. LIZ CARRIERE: Yes, that's correct.

MR. BOB PETERS: Now, I'll do it with one (1). I didn't want to do it with many, but on page 136 of Board counsels' book of documents, Manitoba Hydro has provided the integrated financial forecast runs that suppose a five (5) year drought occurs starting in 2019/'20; correct?

MS. LIZ CARRIERE: That's correct.

MR. BOB PETERS: Now, is it also correct that if we look at those -- that statement most of the years during the drought Manitoba Hydro still manages a positive net income?

MS. LIZ CARRIERE: Assuming the rate trajectory of 7.9 percent, that's correct. We only see financial losses in 2020 and 2021.

MR. BOB PETERS: So when Manitoba Hydro says that the impact of the drought is in the neighbourhood of $1.4 billion, what it's telling the Board is that it's not that the retained earnings are going to be depleted from where they currently are. It's just that they're not going to grow as much as Manitoba Hydro had forecast they would grow under the rate trajectory that Manitoba Hydro proposes?

MS. LIZ CARRIERE: No, I would say they're depleted because you're dropping down from -- if we go back to page -- I forget the page now -- 134. You can see the base -- the base case MH16 update with interim by the end of the drought is $5 1/2 billion. Or, sorry, $4.9 billion, nearly $5 billion. And under a drought case that would be $1.4 billion lower.

(BRIEF PAUSE)

MR. BOB PETERS: I understand your clarification, Ms. Carriere. You're telling the Board that compared to what Manitoba Hydro was forecasting, a drought would reduce the retained earnings from what was forecast by Manitoba Hydro?

MS. LIZ CARRIERE: That's correct.

MR. BOB PETERS: Now, if we look to the bottom part of the page that you brought us to at page 134, and we go down to the -- the line that talks about a five (5) year drought starting in -- it's '19/'20, that row depicts what is actually happening -- happening to the retained earnings account of Manitoba Hydro during the drought; correct?

MS. LIZ CARRIERE: Correct. That's the -- for that sensitivity your absolute level of retain -- or retained earnings will be $3.6 billion.

MR. BOB PETERS: But it starts off at 2.9. There is a -- you notice -- you brought to our attention the -- the one (1) year decline. And then it climbs slowly up to $3.58 billion; correct?

MS. LIZ CARRIERE: Yes, I -- I see your point, Mr. Peters, that you are going to $3.6 billion. But at the same time we are seeing net debt growing as well to compensate for that -- for the loss re -- retained earnings.

(BRIEF PAUSE)

MR. BOB PETERS: If we turn to page 149, we see a similar scenario runs. But this time, Ms. Carriere, instead of Manitoba Hydro's assumed rate trajectory of seven-point-nine-zero (7.90), Manitoba Hydro has assumed three-point-nine-five (3.95); correct?

MS. LIZ CARRIERE: That's correct.

MR. BOB PETERS: And at the bottom part of the table, we can also see the incremental decrease in retained earnings is roughly the same at $1.4 billion, as it was with the other rate plan on page 134?

MS. LIZ CARRIERE: Yes, that's correct.

MR. BOB PETERS: However, it appears when Manitoba Hydro ran the scenarios that -- and I'm looking at, I believe, page 150. Well, let's go 1 -- 152.

In these years under the rate trajectory of three-nine-five (395) Manitoba Hydro's net income turns negative for most of those five (5) ears?

MS. LIZ CARRIERE: That's correct.

MR. BOB PETERS: And that's a function of having less rate increase revenue to buffer against that drought; correct?

MS. LIZ CARRIERE: That would be correct.

MR. BOB PETERS: Now, back to page 134, I just want to maybe conclude on this with you this morning. In the far right-hand column, it reads:

"Incremental annual electric rate increase/decrease required.

Do you see the column, Ms. Carriere?

MS. LIZ CARRIERE: That's -- yes. 1.29 percent.

MR. BOB PETERS: And you had previously told the panel that the retained earnings would go down, and I'm gonna go to that to 2024 column, $1.4 billion, $1.388 billion. And you said if no, I believe, additional rate relief was provided.

MS. LIZ CARRIERE: That's right.

MR. BOB PETERS: So if we go over to the right-hand side we see that the incremental annual electric rate increase required is 1.29 percent?

MS. LIZ CARRIERE: Yes, that would be an even annual amount over and above the rates projected from 2019/'20 to '27/'28. So there's about

-- there's nine (1) -- eight (8) or nine (9) years of 1.29 percent required to get you to about the same level of retained earnings as the base case under two (2) -- 2027/'28.

MR. BOB PETERS: Is that a -- so just in my language, in addition to the seven-nine-zero (790) rate increases and then the four-five-two (452) then the 2 percent numbers that are in Manitoba Hydro's IFF16 updated with in -- interim, you're telling the panel Manitoba Hydro would need an additional 1.29 percent annual rate increase to keep it on the same financial track?

MS. LIZ CARRIERE: That's right.

MR. BOB PETERS: And this 1.29 percent of additional rate increase would be in each and every year for those eight (8) years that you mentioned?

MS. LIZ CARRIERE: Yes, that's right.

MR. BOB PETERS: Before I leave this table...

(BRIEF PAUSE)

MR. BOB PETERS: Ms. Carriere, on this chart you've shown a number of sensitivities and their impacts on retained earnings, and they should be

understood similarly to how you've explained the details of the five (5) year drought; correct?

MS. LIZ CARRIERE: That's correct.

MR. BOB PETERS: Now, if we go to that far right-hand column, and I'll make this up, we see a five (5) year drought starting in '19/'20. You're telling the Board that to hold Manitoba Hydro whole accor -- according to its current IFF16 updated plus interim plan, you'd need an extra 1.29 percent on top of the rate increases already in that plan?

MS. LIZ CARRIERE: That's correct.

MR. BOB PETERS: Now, if I layer on top of that hypothetical situation the high export price line item that's just above it, and that assumes just for argument's sake that Mr. Cormie goes and finds some attractive export contracts, or the export market improves in the MISO region, and Manitoba Hydro's export revenues are high, we see that there's a negative one-point-two-six (1.26) rate impact with that item.

Are you with me?

(BRIEF PAUSE)

MS. LIZ CARRIERE: I see that, but I'd

caution that the two (2) cases are not additive. You -- under a drought with high export prices, you would have actually a higher cost of drought.

MR. BOB PETERS: And maybe it's because I picked -- are you saying that none of these are additive on this chart, or just the two (2) that I happened to highlight?

MS. LIZ CARRIERE: I -- yeah, I -- I couldn't say that these are -- any of these cases are additive.

MR. BOB PETERS: What you can say is that if Manitoba Hydro uses its IF -- its integrated financial forecast 16 updated with interim with a 7.9 percent rate increases, and there is also high export price, Manitoba Hydro rates would be 1.26 percent too high on each of those eight (8) years to achieve the exact number that Manitoba Hydro was striving for?

(BRIEF PAUSE)

MS. LIZ CARRIERE: If you look at the -- the low export price case in isolation, your -- your rates could be on average 1.26 percent lower conceptually.

MR. BOB PETERS: You meant the high

export price?

MS. LIZ CARRIERE: Yes, sorry. The high export --

MR. BOB PETERS: Yes, and that was my point, is that you're just telling the panel that instead of a 7.90 percent rate increase under high export, if the rate increase was 1.26 percent lower than that Manitoba Hydro would still be on target.

MS. LIZ CARRIERE: That's correct.

MR. BOB PETERS: All right. Last point I want to cover is there's a $1 billion in capital overruns on this chart.

Do you see that, Ms. Carriere?

MS. LIZ CARRIERE: Yes, I see that.

MR. BOB PETERS: And I -- I think there was a -- an exchange between your president and the Board Chair about the P50, P90 costs related to Keeyask.

Were you aware of that?

MS. LIZ CARRIERE: Yes.

MR. BOB PETERS: So let's -- let's -- right now Manitoba Hydro is saying that the P50, the probability of 50 percent cost being correct on Keeyask would lead them to believe that $8.7 billion will be the completed cost of Keeyask.

MS. LIZ CARRIERE: That's correct.

MR. BOB PETERS: And if Hydro wanted more confidence in what number would absolutely provide greater certainty, not absolute certainty, but greater certainty and wanted to go to a 90 percent probability of what that number would look like, the number between the Chairman and your president was in the -- was either 9.6 or $9.9 billion.

Do you remember that?

(BRIEF PAUSE)

MR. JAMES MCCALLUM: Yeah, let me just jump in. We had a few numbers bouncing around, as we always seem to. But the $9.6 billion number reflects a -- when we -- when we approved the -- when the Board of Directors of Manitoba Hydro approved the new control budget for Keeyask, in that process we looked to the P90 estimate, which was $9.6 billion. The $9.9 billion figure reflected a scenario we ran which also included a further delay in Keeyask to being a thirty-two (32) month delay from -- from its original in-service date, or an additional eleven (11) months from what's in the IFF16 here.

MR. BOB PETERS: All right. Thank you

for that, Mr. McCallum. So let's -- let's stick with Manitoba Hydro's P90 number, and that number remains 9.6 billion today, Mr. McCallum?

MR. JAMES MCCALLUM: That's correct. Yes.

MR. BOB PETERS: All right. And it's approximately $1 billion more than the 8.7 P50 number that is on the record here?

MR. JAMES MCCALLUM: Yes.

MR. BOB PETERS: All right. So let's follow, Ms. Carriere, that $1 billion in capital overruns across.

And is Manitoba Hydro telling the Board that in addition to its 7.90 percent rate increase, it would need an additional 0.43 percent of a rate increase to hit the financial targets of IFF16 updated with interim?

MS. LIZ CARRIERE: That's correct. Spreading them evenly over that eight (8) -- eight (8) or nine (9) year period.

MR. BOB PETERS: Thank you. And Mr. McCallum brought up the scenario that perhaps led to some of the discussion as between the Chairman and your president. And back in Board counsels' volume 1 of its book of documents on page 437 and 438, let's

turn to page 439, please. Sorry. And thank you.

Mr. McCallum, this was the integrated financial forecast that you were referencing when the -- the $9.9 billion number surfaced. Would that be correct?

MR. JAMES MCCALLUM: You know, subject to check, I believe this scenar -- scenario reflects a $9.9 billion in-service cost and an in-service date of -- I guess would be roughly September of 2022 reflecting what we referred to as a thirty-two (32) month delay.

MR. BOB PETERS: And this came -- the Boston Consulting Group had first raised the sceptre (sic) that there could be a thirty-two (32) month delay.

Do you recall that, Mr. McCallum?

MR. JAMES MCCALLUM: Yes, I do.

MR. BOB PETERS: And layered on top of the thirty-two (32) month delay is the approximate billion dollars more in capital costs; correct?

MR. JAMES MCCALLUM: Recognizing that part of the reason for an increase in capital costs will actually be a -- a function of the delay in that we continue to capitalize interest to the project for another eleven (11) month period. So the -- the

underlying, you know, what you might call the hard costs of the project, you know, could -- could not -- you know, you could -- for example, might not change at all. However, simply by delaying the in-service you're going to capitalize more interest and thus drive the final project cost higher, but --

MR. BOB PETERS: And the capital costs assumed on this IFF, subject to your check, Mr. McCallum, is the $9.9 billion; correct?

MR. JAMES MCCALLUM: Inclusive of capitalized interest, yes.

MR. BOB PETERS: And we see that the percent increase on the rates across the row is the trajectory that Manitoba Hydro has put into its integrated financial forecast 16 updated with interim, 7.9 for six (6) years, followed by 4.5, followed by 2 percent and 2 percent?

MR. JAMES MCCALLUM: I see that.

MR. BOB PETERS: And is it also correct, then, that if -- if the Keeyask project was a billion dollars over its current price estimate that Manitoba Hydro would achieve a 24 percent equity in the 2027 year, the last year on the on the chart?

MR. JAMES MCCALLUM: That's what this scenario shows, yes.

MR. BOB PETERS: And that recognizes that this works with 9.9 billion as opposed to 9.6 billion; correct?

MR. JAMES MCCALLUM: And also works with a different in-service date than the sensitivity analysis we just reviewed.

MR. BOB PETERS: Eleven (11) months later?

MR. JAMES MCCALLUM: Correct.

MR. BOB PETERS: All right. Thank you. Mr. Chairman, I appreciate the indulgence of the panel. This would be an appropriate time for the morning recess if it suits the panel.

THE CHAIRPERSON: Thank you. We'll take fifteen (15) minutes. Thank you.

--- Upon recessing at 10:51 a.m.

--- Upon resuming at 11:09 a.m.

THE CHAIRPERSON: Mr. Peters...?

CONTINUED BY MR. BOB PETERS:

MR. BOB PETERS: Thank you, Mr. Chair. This morning --

MS. PATTI RAMAGE: Oh, Bob, sorry, if

I could just introduce -- I neglected to introduce Ms. Val Iderstine this morning when I dove in. Ms. Van Iderstine is also Manitoba Hydro counsel in this, and she will be dealing with anything to do with capital. So, as Mr. Peters bumps to capital we'll have our capital group move in and I will move out and Ms. Van Iderstine will move in just to let the Board -- let the panel know what's going on.

I also thought I should because, Mr. Chair, you asked at the beginning of the hearing for witnesses to state how long -- their experience at Manitoba Hydro. We sort of jumped Mr. Miles into the hearing without any of the panel members who weren't in the NFAT --

THE CHAIRPERSON: Mr. Miles has grey hair so I --

MS. PATTI RAMAGE: Well, he -- I can advise he's been with Manitoba Hydro twenty-five (25) years and eh is the Director of Power Planning so you are --

THE CHAIRPERSON: Thank you.

MS. PATTI RAMAGE: -- talking to a knowledgeable source.

THE CHAIRPERSON: Thank you.

MR. TERRY MILES: And I just add the

grey hair for effect actually, it's just -- it's not real.

THE CHAIRPERSON: Yeah, I add the baldness for effect too. Hasn't had much of an effect. Okay, Mr. Peters...?

CONTINUED BY MR. BOB PETERS:

MR. BOB PETERS: Thank you, Mr. Chair. This morning, Ms. Bauerlein, I had understood that approximately eight hundred and seventeen (817) Manitoba Hydro electric side employees will be departing the Company based on the voluntary departure program, correct?

MS. SANDY BAUERLEIN: That is correct.

MR. BOB PETERS: I understand from the materials filed that Manitoba Hydro has restructuring costs approximately 50 or $53 million in its budget to deal with the costs related to those employees' departures?

MS. SANDY BAUERLEIN: That is correct.

MR. BOB PETERS: Can you tell the panel whether the $53 million in restructuring costs includes any pension related costs?

MS. SANDY BAUERLEIN: No, it does not include any pension related costs. It is simply the

severance amounts and it's about 50 million for the -- the payouts to the employees for thirty (30) weeks of severance pay.

MR. BOB PETERS: Of the eight hundred and seventeen (817) employees leaving the Corporation, is it Manitoba Hydro's understanding that a percentage of those will draw their pension earlier than has been actuarially planned?

MS. SANDY BAUERLEIN: Yes, that is -- that there are -- will be some employees who are drawing their pension earlier than the actuarial assumptions would have indicated.

MR. BOB PETERS: Can you indicate to the Panel, what's the impact of that on Manitoba Hydro's financial position?

MS. SANDY BAUERLEIN: We are still working with our actuarial on some assumptions with respect to what our pension impact is in terms of the what we have now recorded as a liability, and what the potential impact to that liability is.

MR. BOB PETERS: How much of a liability are you forecasting?

(BRIEF PAUSE)

MS. SANDY BAUERLEIN: I can't recall the number off the top my head and I could check that.

MR. BOB PETERS: If you -- okay, I'd like you undertake to check the liability being forecast by Manitoba Hydro --

MS. SANDY BAUERLEIN: Or the pension liability.

MR. BOB PETERS: -- on account of pensions as a result of the eight hundred and seventeen (817) people that are --

MS. SANDY BAUERLEIN: We would be able to provide the Board what the current liability is. Again, we are working with our actuarial as part of this assessment. We have a December 31st assessment. We're actually in the process of -- of RFPing for our actuarial and what that impact will be on the liability for the March 31st, 2018 year end.

MR. BOB PETERS: In that answer, Ms. Bauerlein, are you telling the Panel that you don't know what, if any, impact there will be as a result of the voluntary departure program on the pension liability?

MS. SANDY BAUERLEIN: We are still assessing what that impact is what the actuarial's assistance.

MR. BOB PETERS: You haven't forecast an amount or estimated an amount?

MS. SANDY BAUERLEIN: No, we haven't at this time.

MR. BOB PETERS: And how -- Ms. Bauerlein, the pension liability that you spoke of, does not then reflect the -- additional liability that may come from the voluntary departure program?

MS. SANDY BAUERLEIN: It does not reflect the impact on the overall liability either in the -- the liability to Manitoba Hydro as a result of the eight hundred (800) and some odd people leaving the Company.

For example, some employees may decide to take out their commuted value out of the pension whereas some employees may decide they want to draw down their pension. So there's a lot of factors and analysis that goes in to assessing what the impact on our liability account will be.

MR. BOB PETERS: So the earliest that this Board would see that liability would be in the year-end financial statements on March 31 of 2018?

MS. SANDY BAUERLEIN: That is correct.

BOARD MEMBER GRANT: Could I ask about -- I'm assuming -- sorry. To be eligible for the

voluntary program, did you have to be eligible for the pension plan? Did you have to meet -- have the current eligibility requirements?

MS. SANDY BAUERLEIN: No, there were some employees who chose just to leave the Company so they would not be eligible to retire. The majority of the employees that chose were eligible to retire but there were some who were not who just, for whatever reasons, felt that they didn't want to continue their employment with Manitoba Hydro.

BOARD MEMBER GRANT: And these would be in the defined benefit retirement programs?

MS. SANDY BAUERLEIN: Yes, we have a refined benefit pension plan.

BOARD MEMBER GRANT: So -- so -- but there could be quite a number that would be leaving well before the actuarial forecast would have them leaving?

MS. SANDY BAUERLEIN: There are some that are leaving before -- when the actuary would have assumed.

BOARD MEMBER GRANT: Okay. And -- and if it did cause a significant increase in the pension liability, at what point would that come back into your -- the current expenses or expenditures? Would

you --

MS. SANDY BAUERLEIN: So we adjust the liability for a number of factors, including impact on the discount rate, et cetera. That will be reflected in the year-end financial statement with potentially some adjustment to our pension expense, which is in our O&A cost adjusting for the change in the liability.

BOARD MEMBER GRANT: Okay, thank you.

MR. BOB PETERS: Mr. Chair, last week, Board counsel also sent some questions to Ms. Ramage in an effort to, I thought, expedite the demand-side management to -- and not having to have Ms. Morrison come back. Apparently some of the questions that were asked weren't going to be for only Ms. Morrison and so while this Panel is here, Mr. Miles on page 79 of Board counsels' volume 4 of book of documents is a -- is a response to an Information Request.

And marginal costs number that flows out of the bottom, you'll see one (1) number left on this page, is 77.73 cents; correct?

MR. TERRY MILES: I see that, yes.

MR. BOB PETERS: And that was dollars per kilowatt per year?

MR. TERRY MILES: Dollars per megawatt hour.

MR. BOB PETERS: Yes. And is it correct that Manitoba Hydro wanted to update this information?

MR. TERRY MILES: That's correct, yes.

MR. BOB PETERS: Is that something you can advise the Panel as to when that would be updated?

MR. TERRY MILES: Well, I'll say we are very, very close to having it updated and will submit it under an undertaking when it is completed.

MR. BOB PETERS: I'm mindful that the undertaking that to Ms. Bauerlein was offering with respect to pension liability is not required because that would be something in the last annual report, in any event.

MS. SANDY BAUERLEIN: Correct. One (1) thing I should clarify, especially for Dr. Grant, is that as the majority of people are leaving February 1st, many of them will still -- or some of them are opting to take that thirty (30) weeks as leave. So, therefore, they may not be collecting pension until sometime in 2018/'19.

So we actually expect the bigger hit to be on our liability for the '18/'19 fiscal year rather

than the '17/'18 fiscal year.

MR. TERRY MILES: Mr. Peters, just for clarification. It's Terry Miles. The -- our plan would be to update this IR as part of the filing and it's PUB 2-57. So we would file an updated Information Request for that IR. Is that acceptable?

MR. BOB PETERS: Yes, that would be find and you say that that will be relatively shortly?

MR. TERRY MILES: I -- I anticipate that, yes. If there's any change from that we'll -- we'll advise the Board.

MR. BOB PETERS: All right, so there's no undertaking needed on that in terms of the transcript. We'll just await for Manitoba Hydro to revise that information.

Mow, Ms. -- Ms. Bauerlein, when it came to the DSM deferral account there happens to be sitting approximately $43.6 million in that account currently; is that your understanding?

MS. SANDY BAUERLEIN: Actually the current balance is 48.8. The 43.6 was based on some assumptions as where we thought the 2016/'17 year was going to be -- or to come in at in the MFR and it was subsequently updated in IR Coalition-MH-1-139A.

MR. BOB PETERS: And so can you

explain to the Panel what Manitoba Hydro is proposing to happen with this deferral account balance?

MS. SANDY BAUERLEIN: Right now we're not really sure what will happen to this deferral account balance until Efficiency Manitoba is fully established and it delivers on whatever its plan will be. It is uncertain as to what the impacts will be on our load and, therefore, what actions might be necessary to clear the balances in these accounts at this time.

MR. BOB PETERS: In that answer, Ms. Bauerlein, are you suggesting that Manitoba Hydro is -- - is envisioning having to transfer this over to Efficiency Manitoba, this 80 -- this $48.8 million?

MS. SANDY BAUERLEIN: Efficiency Manitoba would be unable to actually transfer the amount over as they are not a regulated -- or I don't envision they're going to be a regulated organization. So these balances will stay -- there's actually a regulatory deferral asset and a regulatory deferral liability equal to the same amount.

Those balances will stay until we sort of understand the full impacts of Energy Efficiency Manitoba and how it will integrate -- the financial part will integrate with Manitoba Hydro.

MR. BOB PETERS: Has this DSM deferral account, Ms. Bauerlein, impacted Manitoba Hydro's net income?

MS. SANDY BAUERLEIN: No, it has not. What impacts net income is the actual DSM expenditures which we expense. We then -- because those costs are deemed to be amortized over a ten (10) year period for ratesetting purposes, we remove those costs in our net movement and add back in the amortization of the DSM expenditures. So, that's what hits net income.

The difference -- the DSM deferral records what is actually spent versus what was projected to spend, and we -- we take that amount and we create a regulatory deferral asset and a regulatory deferral liability.

MR. BOB PETERS: Does Manitoba Hydro intend then to continue to amortize this deferral account balance through the net movement and regulatory accounts?

MS. SANDY BAUERLEIN: We are not amortizing at all the DSM deferral balance. What we are amortizing is the actual DSM expenditures. Sorry if I was unclear on that.

(BRIEF PAUSE)

MR. BOB PETERS: Manitoba Hydro is amortizing the accumulation of all of the DSM expenditures that it makes over a ten (10) year period, correct?

MS. SANDY BAUERLEIN: Correct. The actual demand-side management expenditures are amortized over a ten (10) year period. They're brought in to -- to as an expense into our -- our statement of income over a ten (10) year period.

MR. BOB PETERS: And is it Manitoba Hydro's intentions to continue that -- to amortize those cumulative expenses?

MS. SANDY BAUERLEIN: Yes, it is.

MR. BOB PETERS: Mr. Cormie, let's turn to some more export revenue issues if we could. In volume 4 on page 168 we have a busy looking graph and what Manitoba Hydro is attempting to show the Board on page 168, Mr. Cormie, is what has happened to net export revenue forecast compared to Manitoba Hydro's 2015 forecast, correct?

MS. LIZ CARRIERE: I'll try and help you out, Mr. Peters. Yes, that's what it's attempting to do.

MR. BOB PETERS: All right. And there are three (3) variables at play in this -- in this

graph and one (1) of them is the US exchange rate; correct?

MS. LIZ CARRIERE: That's correct. There's -- the green line represents the change from the previous forecast due to the exchange mainly.

MR. BOB PETERS: And the inverse relationship as the Canadian dollar weakens, we -- we see that Manitoba Hydro gains export revenue because of that factor?

MS. LIZ CARRIERE: That's correct.

MR. BOB PETERS: And compared to last time, it's fluctuating somewhere between 25 and $50 million a year additional revenue based on the exchange rate?

MS. LIZ CARRIERE: Yes. I should just point out for the Board, though, that those impacts are offset by a reciprocal relationship between -- we have coupon payments or interest payments that are also in US dollars, and they essentially -- and other -- other payments in US dollars, such as imports that offset that US exchange rate.

So overall, the impact on net income is relatively minor.

MR. BOB PETERS: I wasn't going to the net income line, but you've just reminded the Board

that Manitoba Hydro uses its -- the revenues that it receives in US funds to pay its US denominated debt under its exposure management program?

MS. LIZ CARRIERE: That's right.

MR. BOB PETERS: All right. Let's turn to the volume variable shown on this chart, and Manitoba Hydro is showing the Board that the volume of exports is falling on the redline at least until 2021; correct?

MS. LIZ CARRIERE: That's correct.

MR. BOB PETERS: Is that as a result of Keeyask being delayed?

MS. LIZ CARRIERE: Yes, that's correct.

MR. BOB PETERS: And when Keeyask is in service, then the volumes pick up again?

MS. LIZ CARRIERE: Yes.

MR. BOB PETERS: The price variable shown on this chart is telling the Board that as a result of Manitoba Hydro's export price forecast, export revenue is expected to be down somewhere showing 100 to 100 and -- to $200 million a year?

MS. LIZ CARRIERE: That's right. I should just make one (1) clarification about the volume. In the early years, it's declining because

we're drawing down reservoirs be -- from the -- from the above-average level of water flows down to average.

The other thing that's impacting volume that you can see in the longer term is because we have lower load. We have a little bit more in surplus sales as well available for exporting.

MR. BOB PETERS: The result of those three (3) variables shows the Board shaded in the grey what the variation is from the last time the load fore -- the export forecast was before them?

MS. LIZ CARRIERE: Yes, that's -- represents the total change from MH15.

MR. BOB PETERS: And -- and I recall in the materials -- tell me if I'm correct, that the -- the sum total of that shaded grey area is approximately an $800 million reduction over that forecast period?

MS. LIZ CARRIERE: That's correct.

MR. BOB PETERS: We see on page 169 of Board counsels' book of documents the average forecast unit revenues compared to what Manitoba Hydro actually received, and I just want to make sure that the panel is understanding what Manitoba Hydro is showing here, that the solid black line depicts where Manitoba

Hydro's average unit revenues are from its exports?

MS. LIZ CARRIERE: That's correct.

MR. BOB PETERS: And the average unit revenues include the firm fixed price contracts as well as the opportunity sales that Manitoba Hydro makes into the market?

MS. LIZ CARRIERE: That's correct.

MR. BOB PETERS: And would it be correct that to the extent that the water flows have been above average and were -- and Manitoba Hydro was making more opportunity sales, those opportunity sales are at lower prices than what Manitoba Hydro would be getting under fixed price contracts?

MS. LIZ CARRIERE: Yes, generally.

MR. BOB PETERS: And so generally, the average unit price is being suppressed or brought down by the heavy weighting of the opportunity sales that are going on?

MS. LIZ CARRIERE: That's correct.

MR. BOB PETERS: And the Board sees in this that -- and I think Mr. Cormie had maybe a cleaned-up version in his materials, but this started back in IFF, Integrated Financial Forecast 08 with -- I believe that's a red dotted line, and that was Manitoba Hydro's then expected trajectory for the

export revenue prices that it would receive on average?

MS. LIZ CARRIERE: Yes, that's right.

MR. BOB PETERS: And progressively, we can march through -- and we won't -- the different dotted lines, but it brings us up to the -- I'll call it the purple dashed line, where Manitoba Hydro is showing the Board that going forward, the forecast is not as -- as lucrative as it was previously?

MS. LIZ CARRIERE: Yes, that's right.

MR. BOB PETERS: And that's the 7.9 percent number shown on the right of the chart that ties to the -- the one that's in Manitoba Hydro's Integrated Financial Forecast 16?

MS. LIZ CARRIERE: That's correct.

MR. BOB PETERS: Can you explain to the panel what the -- the Integrated Financial Forecast 16 low and the Integrated Financial Forecast 16 update are to reflect?

MS. LIZ CARRIERE: So the IFF16 reference forecast was based on -- it was an adjustment to the original 2016 forecast made in January. The low was this -- the low forecast at approximately the same time.

And then the IFF16 update, that was the

MH16 update that was submitted in -- I believe it was July, which actually represents a 2017 forecast of -- of average unit revenues. All told, between the IFF16 and IFF16 update, we saw approximately a 20 percent reduction in prices on average.

MR. BOB PETERS: And on page 168, I -- I'd like to just go back and make sure that the panel has the latest information in light of what you're providing us, Ms. Carriere, that I believe I suggested to you and you agree that that grey shaded area represented an approximate $800 million negative development in terms of the export forecast going forward?

MS. LIZ CARRIERE: That's correct.

MR. BOB PETERS: If you -- we take that -- that $800 million. You've reminded me that Manitoba Hydro provided an update to its materials in the Integrated Financial Forecast 16 update. Do you recall?

MS. LIZ CARRIERE: Yes, that's right.

MR. BOB PETERS: And there was additional negative reduc -- a negative adjustment to the export forecast through that update?

MS. LIZ CARRIERE: Yes.

MR. BOB PETERS: And that was an

additional $310 million over the ten (10) years?

MS. LIZ CARRIERE: Subject to check, yes.

MR. BOB PETERS: Thank you. And when we look at the price line on page 168 of Board counsels' book of documents, we see that it is -- it has decreased relative to the previous forecast that Manitoba Hydro shared with the Board last yea -- or two (2) years ago, correct?

MS. LIZ CARRIERE: Can you repeat that please?

MR. BOB PETERS: Yes, and it might even be for Mr. Cormie. The price forecast that we see depicted on page 168, which is on the monitors, has declined relative to what the Board had presented last time to -- to it from Manitoba Hydro?

MS. LIZ CARRIERE: Relative to MH15, we're -- the -- we're seeing a reduction, yes, attributable to prices.

MR. BOB PETERS: And again, Mr. Chair and panel members, I'm -- I'm mindful that I'm not looking for anything that is considered by the Corporation to be confidential.

But Manitoba Hydro has made two (2) changes to their forecast assumptions that -- that is

contained in their Integrated Financial Forecast 16. Is that correct?

MS. LIZ CARRIERE: Yes, that's correct.

MR. BOB PETERS: And one (1) of them had to do with capacity value, and one (1) had to do with a -- a premium for being dependable?

MS. LIZ CARRIERE: That's correct.

MR. BOB PETERS: Can you explain to the panel why Manitoba Hydro had -- has made those -- those assumption changes?

MS. LIZ CARRIERE: Well, I'll start with the premium. That had been included in previous forecasts, and it was based on analysis that Manitoba Hydro had done looking at the -- the export prices that were achieved in -- in contracted sales relative to the market forecast at that time. And that premium was included in previous forecasts to -- to recognize the additional value we were getting in contracted sales relative to the market forecast.

We haven't signed any sales in recent -- recent years, and so we can no longer substantiate putting that premium into our forecast. We can't anticipate what we're going to achieve relative to the market forecast.

MR. BOB PETERS: And on that note, Ms. Carriere, before the morning recess, Mr. Cormie and Mr. Miles were explaining to the Board the adjustments that were made on their planning assumptions and the Power Resource Plan.

And we drew to the Board's attention the surplus energy that was at the -- at the very bottom of the chart. Do you recall that?

MS. LIZ CARRIERE: Yes.

MR. BOB PETERS: And what is at the bottom -- I suppose we can go back to page 102 briefly, if we could, in the fourth volume of Board counsels' book of documents.

The bottom of the chart will depict the system surplus. And this is system surplus that is dependable energy. Would that be correct?

MS. LIZ CARRIERE: That's correct.

MR. BOB PETERS: And so in previous forecasts, Manitoba Hydro would be ascribing some premium to this energy in its financial -- in its forecast, in it's Integrated Financial Forecast?

MS. LIZ CARRIERE: That's right. These are -- these would be sales -- potential sales that we could make from dependable energy, and previously, we would have assumed a premium on that --

on sale of that energy.

MR. BOB PETERS: And you're telling the Board that Manitoba Hydro can no longer assume that it's going to achieve a premium on this energy?

MS. LIZ CARRIERE: That's right. There's not enough certainty.

(BRIEF PAUSE)

MR. BOB PETERS: Are you able to tell the Board generally when the last time Manitoba Hydro was able to achieve a premium on this dependable surplus energy?

(BRIEF PAUSE)

MR. DAVID CORMIE: Mr. Peters, I -- I don't think we can -- we can tell you -- I can give you that answer without referring to a specific contract, but what I can tell you is that since we signed the last contracts in the United States utilities are able to purchase renewable energy equivalent to that -- what Manitoba Hydro would provide, and it's being subsidized.

And so they have -- they -- they no

longer have -- they no longer see that Manitoba Hydro has an advantage with regard to emission reductions or cost that they would previously be able to acquire for Manitoba Hydro. We have -- we now have competitors because of the subsidy who can provide the same product at a lesser -- at a lesser price. And so we've lost -- we've lost that market niche that we -- that we previously had.

When -- or utilities are purchasing subsidized wind now at a discount, and that provides them a long-term hedge for the length of the wind farm at -- at a fixed price. And so, you know, Manitoba Hydro's ability to provide fixed-price power for ten (10) or fifteen (15) or twenty (20) years is no longer an advantage. And those -- with those two (2) factors we've -- we no longer can ask for a premium for a product because they have alternatives.

MR. BOB PETERS: Does that answer -- and thank you, Mr. Cormie, relate to only subsidized renewables that are available in the United States?

(BRIEF PAUSE)

MR. DAVID CORMIE: The Canadian market is not -- is not subsidized. However, the Canadian

market does not have renewable targets that utilities are trying to achieve. Therefore, the Canadian market is not prepared to pay a premium as well.

MR. BOB PETERS: Can you explain to the panel what has happened, Mr. Cormie, with respect to the capacity value that Manitoba Hydro would -- would want to obtain for it -- from -- for its energy and its capacity? What's changed since 2015?

MR. DAVID CORMIE: And -- and what has changed is that Manitoba Hydro has taken out the capacity revenue from the forecast that we had previously assumed that we would be able to include in our revenue forecast. That is -- has been a -- has been a policy decision based on the fact that we do not have signed term sheets in place for that -- those capacity sales. And although we are having discussions, we are not in a position to say with confidence that that capacity revenue will show up.

And we've judged that the risk to customers and -- is -- is higher to count on that revenue in the forecast as opposed to putting the revenue in the forecast at some future time in -- at -- at some -- at -- at a future time when those term sheets are signed and we can start counting on it. Then I think that's the reason we've taken it out.

MR. BOB PETERS: So on page 98 of Board counsels' book of documents, you and Mr. Miles reviewed with the Board the -- the capacity side. The bottom line in terms of system surplus of capacity, we'll see at the very bottom of the page the -- this is dependable supply surplus, Mr. Cormie?

MR. DAVID CORMIE: Yes. And there's two (2) issues with this table, Mr. Peters, is generally we're limited by our summer capacity surplus, not our winter capacity surplus. So if we're looking at the capacity revenues it's -- would be better to look at the summer table.

MR. BOB PETERS: So then --

MR. DAVID CORMIE: If you have that exhibit handy.

MR. BOB PETERS: Let's turn to page 100 and 101. Let me -- let me just understand then -- and I thank you for -- for guiding me there, Mr. Cormie. What you're telling the Board is that a lot of Manitoba Hydro's capacity is needed in the winter, so your greatest surplus is in the summer.

MR. DAVID CORMIE: That's true. But what -- what is more important is that US utilities, they're peak demand's in the summer, so that's where the market is. So having an extra --

MR. BOB PETERS: Inverse to Manitoba Hydro because they need it presumably for things like air conditioning load?

MR. DAVID CORMIE: Having extra capacity in the winter doesn't help them. It's our ability to supply capacity in the summer that -- so it -- this is why this table is more -- is more appropriate.

MR. BOB PETERS: And we see on the bottom line, in terms of system surplus, that Manitoba Hydro does have considerable summer capacity surplus; correct?

MR. DAVID CORMIE: Yes.

MR. BOB PETERS: In previous export price forecasts Manitoba Hydro was making an assumption that this surplus capacity would have an adjustment to it and to increase the -- the forecast because the capacity had, Manitoba Hydro assumed, some value?

MR. DAVID CORMIE: Up to our ability to support it with firm transmission in this -- into the market. So, you know, this table shows 1,700 megawatts or 1,694 megawatts. I'm not sure what year that is on the bottom line. We would need to have 1,694 megawatts of firm transmission be able to sell

that capacity.

MR. BOB PETERS: All right. And you were going to explain to the panel what has happened since 2015 to lead Manitoba Hydro to conclude that that capacity adder wouldn't be available.

MR. DAVID CORMIE: Well, I -- I think the decision to remove the capacity revenue is a policy decision, and maybe Mr. McCallum could speak to that.

MR. JAMES MCCALLUM: Sure. I'll -- I'll maybe add a couple of points here. In this forecast we've elected to take out capacity values for contracts we don't have. So past forecasts would have assumed we are able to find a counterparty and agree to a dependable contract at an assumed price where we would receive this -- this capacity value.

For this forecast we've taken that out. The point of view being that while Mr. Cormie continues to work very hard with his team trying to find additional counterparties, this is not easy and can't be counted on. And back to some comments we made last week around the importance of what we put into a financial forecast or financial model, we can't kind of continue a pattern of assuming too many good things happen.

I think I would also just point out, and Mr. Cormie can speak better than I to the market dynamics, but really the -- our practical ability to enter into new capacity sales or new, dependable contract sales that would yield additional revenue in the next five (5), six (6), seven (7) years is pretty low.

Again, Mr. Cormie can speak more to this, but when a customer, as I understand it anyway, enters into a contract with us they are often doing it in lieu of -- of building their own capacity. And so if you -- if you're -- if you're running a major utility and you find yourself in need of -- of, you know, secure, firm, dependable power on anything, you know, shorter than five (5), six (6), seven (7) years in the future, you've probably done something wrong in your planning.

And so really we're talking about our ability to add contracts that generate revenue more towards the very tail end of this ten (10) year horizon we're focused on here. Makes really very limited difference in the next five (5) or six (6) years due to the practical inability to sell the power.

MR. DAVID CORMIE: Mr. Peters, I just

wanted to add to Mr. McCallum's comment. We're -- we're still faced with the uncertainty of the Keeyask in-service date. And so in the short term, you know, around '21/'22 and '22/'23, we would be reluctant to sell out the surplus that's shown on this table in those years. And -- and as Mr. McCallum suggested, the big jump in surplus capacity doesn't end until the NSP sales expire in 2025.

And -- and so, you know, the -- that's -- that's the large block of capacity that we are expecting to be able to take to market, but that -- that won't have an effect on the revenue projections until 2025. So it's a long way away outside -- essentially outside of the -- of the -- of where we're looking at the rate case today.

And then one (1) final point I wanted to make, and was reminded by my back row, that it's the lesser of the winter capacity or the summer capacity that determines the surplus and because the capacity market is an annual market and -- and we have to have it both winter and summer. So it's the summer demand, but it -- but that demand has to be supplied in the winter. So it's the minimum of the -- of the -- of those two (2) numbers shown on those two (2) tables that you took me through.

MR. BOB PETERS: Is that requirement, Mr. Cormie, for the capacity to be an annual market, is that a new MISO requirement?

MR. DAVID CORMIE: No, it's not. It's -- it's always been an -- an annual capacity market.

MR. BOB PETERS: And does Manitoba Hydro deal with that on its diversity exchange arrangements only on a seasonal basis?

MR. DAVID CORMIE: Well, we -- we can enter into the seasonal diversity contracts, but it's still an annual -- it's still an annual construct.

MR. BOB PETERS: Do you un -- do you know, Mr. Cormie, if the MISO market is changing the annual requirement for the capacity market?

MR. DAVID CORMIE: Yes, we've been active for several years trying to have the MISO capacity market become a seasonal market. As of today we haven't made progress there and it looks like that's less of a priority to the -- to the MISO market. And -- and it's going -- for our planning purposes it's going to remain as an annual for the near term.

MR. BOB PETERS: If we could turn to page 182 of Board counsels' fourth book of documents, Exhibit 42-4. There's a list, Mr. Cormie, of

contracts, and I think most of them have your fingerprints on them. You raised the topic before, but let me -- let me add to it. Absent from this list is the 308 megawatt sale to Wisconsin Public Service; correct?

MR. DAVID CORMIE: Yes.

MR. BOB PETERS: Can you explain why that is no longer on Manitoba Hydro's list?

MR. DAVID CORMIE: One (1) of the conditions precedent in that agreement with Wisconsin Public Service was Manitoba Hydro had the right to terminate the contract if we chose not to proceed with Conawapa. We've chosen not to proceed with Conawapa. Therefore, the contract is -- has -- has no effect anymore and we've removed it from our plans.

MR. BOB PETERS: Was that condition precedent that you talk about, that legal concept, was that for Manitoba Hydro's benefit, or was it for Wisconsin Public Service's benefit?

MR. DAVID CORMIE: That was for our benefit.

MR. BOB PETERS: So Manitoba Hydro had the choice whether to remove that contract from its list or not?

MR. DAVID CORMIE: We did, but

Wisconsin Public Service also had similar protection where they would require regulatory approval for the contract. And that's become a moot point because we are -- we've told Wisconsin Public Service we're not building the project and therefore the contract is of no consequence anymore.

MR. BOB PETERS: Okay. Could Manitoba Hydro have served that contract without Conawapa?

MR. DAVID CORMIE: No. That contract was tied to a commitment to build Conawapa.

MR. BOB PETERS: Okay. I'll -- I'll rephrase my question.

Could Manitoba Hydro have served that Wisconsin Public Service contract from the energy that's available on its system excluding what Conawapa would provide?

MR. DAVID CORMIE: For that to happen, Mr. Peters, Manitoba Hydro would have to renegotiate the contract. And I believe we would probably have the resources from Keeyask in order to do that. But more importantly is whether Wisconsin Public Service would be interested in -- in that it's not -- it's more of their willingness to renegotiate given the passage of time.

MR. BOB PETERS: And does Manitoba

Hydro have the transmission rights that would be necessary to serve that arrangement under the new Great Northern transmission line in the Manitoba Minnesota transmission plan project?

(BRIEF PAUSE)

MR. DAVID CORMIE: I'm reminded, Mr. Peters, that we're going into the details of contracts that we prefer not to talk about.

MR. BOB PETERS: All right. I -- I have your point. The last point on that contract is you -- you're telling this panel that as a result of actions by Manitoba Hydro there's no longer the negotiated arrangement in place and that if anything further was to be done it would require a new negotiation and a new contract?

MR. DAVID CORMIE: I -- I think what I can say, Mr. Peters, is we've removed that contract from our list of obligations and we're not planning to serve it. But to go into more of the details is -- it's -- it's getting into that grey area.

MR. BOB PETERS: All right. Let's stay away from that if we can, Mr. Cormie. But on that same list on page 182, is Manitoba Hydro still

able to serve all of these contracts, even with the delay in Keeyask that Manitoba Hydro has planned, the twenty-one (21) month delay?

MR. DAVID CORMIE: Yes, Manitoba Hydro has sufficient resources to meet all our obligations.

MR. BOB PETERS: Does that take into account that answer, Mr. Cormie, that if any of these arrangements required specific environmental attributes Manitoba Hydro would still have those available from its existing resources?

MR. DAVID CORMIE: Yes, Mr. Peters. As I said, we can meet all our obligations under our contracts.

MR. BOB PETERS: If Keeyask is delayed thirty-two (32) months can Manitoba Hydro still serve all of these contracts listed on page 182 that's on the monitor?

(BRIEF PAUSE)

MR. DAVID CORMIE: Subject to check, Mr. Peters, I believe we do. We also have the ability to acquire resources in the short term if that became necessary. We -- we can enter the market, and if it was necessary, acquire resources if -- if there were a

delay of thirty-two (32) months for an additional delay.

MR. BOB PETERS: One (1) of the larger contracts that begins in 2020, Mr. Cormie, is the Minnesota Power 250 megawatts sale?

MR. DAVID CORMIE: Yes.

MR. BOB PETERS: And would the Board be correct in understanding that the Manitoba Minnesota transmission line project may be delayed?

MR. DAVID CORMIE: Is there a question, Mr. Peters?

MR. BOB PETERS: Will the -- well, let me just under -- let me ask it this way. There was reports that Manitoba Hydro would have to embark on a different process to get approvals, regulatory approvals, for the Manitoba Minnesota transmission line project.

Is that correct?

MR. DAVID CORMIE: We've been advised by the National Energy Board that we require a certificate process for the approval of the Minnesota Manitoba transmission project. I've been advised by our transmission business unit that in spite of that certificate process that we will still achieve the targeted June 1st, 2020, in-service date. And there

is sufficient flexibility in the schedule to achieve the contracted in-service date.

MR. BOB PETERS: All right. Thank you for that, sir.

(BRIEF PAUSE)

MR. BOB PETERS: Mr. Chair, the last topic I had questions on is a matter that I know is also going to be canvassed by my friends opposite. So I'm proposing that if it suits the panel, we could take the lunch recess, the lunch break, and I will discuss with them who will be asking questions about the business operations capital of the Corporation. And it may be that the we can streamline it through those discussions. So if that suits the panel that's what we would do.

THE CHAIRPERSON: Ms. Ramage...?

MS. PATTI RAMAGE: I have no comment on that. I wanted to jump in and just -- Ms. Bauerlein had a clarification she wanted to make of one (1) of her answers. And so before we moved on to the topic --

THE CHAIRPERSON: Okay.

MS. PATTI RAMAGE: -- or moved to the

lunch break.

THE CHAIRPERSON: Certainly. Ms. Bauerlein?

MS. SANDY BAUERLEIN: Thank you. I just wanted to clarify, when we were discussing the operating administrative targets, while the target did assume a reduction of five hundred (500), it was five hundred (500) operational people. The eight hundred and twenty-one (821) that have left the company, a portion of those people will also work on our capital construction.

So many of our employees one (1) day may be working on a maintenance project and they timecard to that, so they would be in our operating administrative costs. And the next day they would be working on a capital construction project, so would -- those costs, that time that they're spending, their salary associated with when they're spending time on capital is not part of the O and A costs. So that eight hundred and twenty-one (821) is not all operational. It -- a portion of it is -- is the construction as well.

THE CHAIRPERSON: Mr. Peters, any follow-up from that?

MR. BOB PETERS: No. I thank Ms.

Bauerlein for the clarification.

THE CHAIRPERSON: Thank you. We will adjourn for one hour. Thank you.

--- Upon recessing at 12:01 p.m.

--- Upon resuming at 1:02 p.m.

THE CHAIRPERSON: Thank you, Mr. Peters...?

CONTINUED BY MR. BOB PETERS:

MR. BOB PETERS: Thank you. Good afternoon, Mr. Chair, Board members, Manitoba Hydro's updated witness panel and certainly to Ms. Van Iderstine.

Welcome. I would like to start the afternoon with just putting the context out by looking at the page 525 of Board counsels' fourth book of documents, which is on the screen in front of us. It is part of Exhibit PUB-42-4. I'll be referring to that volume in my questioning.

And, Mr. Wortley, it would be correct to say that Manitoba Hydro's in the midst of its largest capital expansion in the history of the Corporation?

MR. JOEL WORTLEY: Yeah, I think that would be fair to say.

MR. BOB PETERS: And would it also be correct if I could ask that one (1) of the Information Requests that My Friend Ms. Dilay had asked Coalition Manitoba Hydro first round 148.

Mr. Wortley, as I understand what's on the screen in front of us happens to be the system average interruption frequency index chart of Manitoba Hydro versus all other Canadian electric utilities.

Is that your understanding, sir?

MR. JOEL WORTLEY: Yes versus the CEA group of utilities.

MR. BOB PETERS: And when you say CEA that's the Canadian Electrical Association, which is the umbrella group that represents the electric utilities in Canada?

MR. JOEL WORTLEY: That's correct.

MR. BOB PETERS: And is it your understanding that the Canadian Electrical Association gathers data from the Canadian electric utilities and then provides it to the utilities?

MR. JOEL WORTLEY: That is my understanding.

MR. BOB PETERS: And Manitoba Hydro

would have contributed to that data collection?

MR. JOEL WORTLEY: I believe so, yes.

MR. BOB PETERS: All right. And I'll try to stay away from the acronyms. I'm not sure how well I'll do. But what's in front of the panel is the depiction of the four (4) different quartiles in which the Canadian utilities find themselves in terms of their -- the frequency of interruption of their systems; is that correct?

MR. JOEL WORTLEY: Yes, it is.

MR. BOB PETERS: And just to orient ourselves to this chart, the blue at the bottom is the first quartile, meaning the best quartile; is that your understanding?

MR. JOEL WORTLEY: That is my understanding.

MR. BOB PETERS: And then we see the second is in red, third in green and the fourth in orange; correct?

MR. JOEL WORTLEY: Correct.

MR. BOB PETERS: And there's a black line that's plotted against these other -- this collection of quartiles and that black line represents Manitoba Hydro's actual experience as to where it falls relative to the four (4) quartiles that the

Canadian Electrical Association has provided?

Do you agree?

MR. JOEL WORTLEY: Yes, I would.

MR. BOB PETERS: And would it be correct, Mr. Wortley, to suggest that Manitoba Hydro finds itself in the first quartile of Canadian electrical utilities with respect to the frequency of interruptions?

MR. JOEL WORTLEY: Yes, with some variation.

MR. BOB PETERS: And when I say "frequency of interruptions," in the left side access that's calibrated in minutes per year, is it?

I stand corrected. Sorry, this is the frequency of interruption. So, this is the absolute number of interruptions that Manitoba Hydro's customers on average would experience in the respective years?

MR. JOEL WORTLEY: Yes, I believe that's on a per customer basis.

MR. BOB PETERS: Thank you. So what -- what the -- what it's telling the Panel is that, on average, Manitoba Hydro's customers are interrupted approximately once a year.

Would I be reading that correct, sir?

(BRIEF PAUSE)

MR. JOEL WORTLEY: Yes, that is correct.

MR. BOB PETERS: Thank you, Mr. Wortley, and if we turn to the next page of this Information Request, we have a new acronym and a new chart, but this is the system average interruption duration index, as I understand it, correct?

MR. JOEL WORTLEY: That's right.

MR. BOB PETERS: And it also comes from the Canadian Electrical Association from their surveys of all Canadian electric utilities including Manitoba Hydro's, sir?

MR. JOEL WORTLEY: I couldn't comment on exactly what the Canadian Electrical Association membership is, but that's the right idea.

MR. BOB PETERS: All right. And on this chart it's also divided into quartiles, sir, correct?

MR. JOEL WORTLEY: Correct.

MR. BOB PETERS: And Manitoba Hydro is plotted as the -- the black line, mostly in the first quartile?

MR. JOEL WORTLEY: With some

variation, yes.

MR. BOB PETERS: And this is the system average index interruption duration index. So this one on the left-hand margin -- the left-hand axis, is that calibrated in -- in minutes?

MR. JOEL WORTLEY: Yes, it is.

MR. BOB PETERS: And would I be correct, Mr. Wortley, in looking at this chart to say that Manitoba Hydro's average duration of interruption is somewhere around the -- can I say, one hundred (100) minutes per year?

MR. JOEL WORTLEY: That's right. The five-year average is a hundred and thirty-four (134) minutes.

MR. BOB PETERS: And so with the variations that you've noted, Mr. Wortley, Manitoba Hydro ranks generally in the first quartile on both the duration index and the frequency index?

MR. JOEL WORTLEY: Correct.

MR. BOB PETERS: And would it also be correct that Manitoba Hydro is investing billions of dollars to further improve the reliability of Manitoba Hydro's system?

(BRIEF PAUSE)

MR. JOEL WORTLEY: The business operations capital that Manitoba Hydro reinvests in its systems every year is currently targeted really at maintaining its existing service level, not improving it as a -- as suggested?

MR. BOB PETERS: Well, let me re-ask the question. One (1) of the reasons Manitoba Hydro is investing in Bipole III is to improve the reliability of Manitoba Hydro's system?

(BRIEF PAUSE)

MR. JOEL WORTLEY: Yes, so my comment referred to the business operations capital. The Bipole III project falls under our major new generation and transmission investment segment and is a little different in that what we're seeing on the chart here with system average interruption, frequency and duration is a distribution or a customer centric metric.

Bipole III will re -- improve the bulk electric reliability of the system. And so it won't have a direct impact on SAIDI or SAIFI but it will make the grid system as a whole more reliable.

MR. BOB PETERS: And if the grid

system as a whole is more reliable, that may be reflected in the -- you called it the SAIDI and the SAIFI, which are these interruption duration and frequency indexes that we refer to.

MR. JOEL WORTLEY: It -- it -- it's possible. It's -- it's a different level of interruption that we're talking about. SAIDI and SAIFI are in -- are affected by numerous small events. For the bulk electric system to have a interruption, for instance, a -- have a Bipole I, II failure due to a weather event and have -- the impacts would be much, much larger. So, you'd have a very large number of customers impacted whereas mostly when we're talking with SAIDI and SAIFI, they're relatively small events.

MR. BOB PETERS: But if the -- but if the Bipole III system was interrupted or -- sorry, let me rephrase the question.

If the Bipole system was interrupted, would that be reflected on these charts that you and I have just reviewed?

MR. JOEL WORTLEY: It could. Depends on the magnitude of the disruption. So for instance, when Bipole I and II went down some years ago, everything was done within Manitoba Hydro's power to not have the customer impacted and, for the most part,

the customer wasn't.

And so, it really depends on how serious the event is. If it's large enough, certainly, there will be brownouts, blackouts, customers will be impacted but we'll do everything that we can to mitigate that impact.

MR. BOB PETERS: If we turn to page 591 of Board counsels' fourth book of documents. Again, Exhibit 42-4, there appears to be some information provided on page 591.

Would it be correct, Mr. Wortley, that this chart would suggest to Manitoba Hydro that its customers are satisfied with the existing performance of Manitoba Hydro system?

MR. JOEL WORTLEY: Yeah, I think that's a fair interpretation.

MR. BOB PETERS: So not only does the Canadian Electrical Association guidelines put Manitoba Hydro near the top, but it's Manitoba Hydro's own customers also appear to echo that with their satisfaction of the reliability of Manitoba Hydro?

Would you agree?

MR. JOEL WORTLEY: I would agree.

MR. BOB PETERS: If we go to page 592 there's some information here with Manitoba Hydro's

customers and their satisfaction with Manitoba Hydro's rate increase plan; is that correct?

(BRIEF PAUSE)

MR. JOEL WORTLEY: Sorry, I don't see here where it says that the customers were asked about the rate increase plan.

MR. BOB PETERS: Okay. Do you understand it to be your customer satisfaction with the price of electricity that they -- they have in Manitoba?

MR. JOEL WORTLEY: That seems appropriate, yes.

MR. BOB PETERS: All right. Let's turn the page then to page 594 and as I understand what Manitoba Hydro has provided here is the result of a 2013 survey that was done on Manitoba Hydro's customers, Mr. Wortley.

Are you familiar with that?

MR. JOEL WORTLEY: I see it here, yes.

MR. BOB PETERS: And in this particular survey the question asked of the customers is: Do you think an increase of 4 percent in your electricity bill each year for the next five (5) to

ten (10) years to invest in these improvements is a good idea you'd support; something you don't like, but think is necessary; a bad idea that you oppose; and then if support is opposed, would that be strongly or somewhat?

MS. HELGA VAN IDERSTINE: Mr. Peters -- Peters, I'm just interrupting at the moment because I'm not sure this is the right panel to the directing that kind of question to. And Mr. Wortley can correct me if I'm wrong, but this wouldn't be the sort of information that he would have been privy to, and been part of preparing.

So, I'm not sure he's the right person to be asking this of.

MR. BOB PETERS: Well, I'll -- I'll try and if Mr. Wortley is unable to provide us that information then we'll -- we'll move it along then, Ms. Van Iderstine.

CONTINUED BY MR. BOB PETERS:

MR. BOB PETERS: But Mr. Wortley, in looking at this survey, it appears that 68 percent of Manitoba Hydro customers that were surveyed are opposed to the annual 4 percent rate increases to invest in improvements in the Hydro system.

Is that your understanding, sir?

MR. JOEL WORTLEY: That's what I see here, yes.

MR. BOB PETERS: And you were aware of that, were you, before this rate case started?

MR. JOEL WORTLEY: I was not personally aware, no.

MR. BOB PETERS: So these results, if you take it subject to check, came out of a 2013/'14 customer survey.

Do you know if Manitoba Hydro has a more current survey than this one, sir?

MS VAN IDERSTINE: Sorry, I'm feeling at a bit of a disadvantage in terms of whether we take that subject to check because I'm not -- this is definitely not the panel to be asking that question of and so -- as we progress I'm -- if there's a more --

MR. BOB PETERS: How about if we take it, Ms. Van Iderstine, that unless Manitoba Hydro tells the panel otherwise, we'll take that this 2013/'14 survey is the most current.

Would you be satisfied with that, ma'am?

MS. VAN IDERSTINE: Yes, I think that we would --

MR. BOB PETERS: Okay, thank you for that.

MS. VAN IDERSTINE: And if there's something more recent than we will produce it, presumably in response to this same question that was asked here as the under -- the IR reference.

MR. BOB PETERS: Thank you, ma'am, that'll be fine.

CONTINUED BY MR. BOB PETERS:

MR. BOB PETERS: So, Mr. Wortley, the rate increase proposal in this survey was 4 percent, according to the materials. Do you agree?

MR. JOEL WORTLEY: I do.

MR. BOB PETERS: And if the survey asked about an 8t percent increase in electricity bills, would you -- would Manitoba Hydro expect more than 68 percent of its customers would be opposed?

MR. JOEL WORTLEY: I can't comment on that.

MR. BOB PETERS: Mr. Wortley, has Manitoba Hydro factored customer opposition to rate increases into the business operations capital budgeting process?

MR. JOEL WORTLEY: The business

operations capital planning process involves striking the right balance between cost performance and risk for the customer. No one wants to pay more than they have to. I'm a customer too. I don't want to pay more than I have to but I also want my lights to be on and I want my furnace to run when -- when it's cold out.

And so when we plan the business operations capital, it's with an eye towards keeping the system running safely and reliably for customers. And as much as we'd rather not have to pay when we -- for things that are necessary, if they are necessary and they're going to impact the reliability of the system, then we plan them and proceed with those investments.

So it's very much with an eye towards what's going to be the best for the customer and striking that balance between cost performance and risk that drive our planning processes.

MR. BOB PETERS: All right, Mr. Wortley, are you telling the Panel that the business operations capital planning has resulted in the rate impacts being reduced from what they otherwise would have been because of the biz operations capital's view of customer acceptance?

MR. JOEL WORTLEY: Sorry, I'm not sure I understand your question.

MR. BOB PETERS: Fair enough. I'll rephrase it. Do I take from your last answer to the Panel that the budget and the planning for the business operations group is not impacted by customer comments?

MR. JOEL WORTLEY: The -- the objective of the planning is to do what's best for the customer. There is not a process today to gather comments directly from the customer for consideration in that planning.

MR. BOB PETERS: It's what Manitoba Hydro then will determine, using its judgment, what would be best for the customers; correct?

MR. JOEL WORTLEY: That's correct.

MR. BOB PETERS: All right, on page 568 of Board counsels' fourth volume we have -- excuse me.

We have a comparison, Mr. Wortley, of Manitoba Hydro's capital expenditure 15 versus its capital expenditure 16, correct?

MR. JOEL WORTLEY: That's correct.

MR. BOB PETERS: And would this Panel be correct in -- in interpreting this information that

Manitoba Hydro actually increased the budgets for its transmissioning and its marketing customer service in CEF 16 relative to the capital expenditure forecast from 15?

MR. JOEL WORTLEY: Yes. As part of Manitoba Hydro's annual budgeting process for the business operations capital is a look at the three (3) portfolios to see you where we're sitting relative to what we feel our issues on our generation transmission and dissipation systems.

So in this case with -- with an objective of doing what's going to be best for the customer, some portfolio budgets were increased a little bit, others were decreased a little bit, and overall $240 million were taken out of the budget over ten (10) years. So, in fact, costs were reduced in this year-over-year analysis.

MR. BOB PETERS: Just a point of clarification, when you mentioned distribution, that's the -- the old name for marketing and customer service?

MR. JOEL WORTLEY: That's correct. The -- t he group is called marketing and customer service, the system is the distribution system.

MR. BOB PETERS: All right and you say

that -- we see in the bottom right hand that there's $240 million of lower spending on a ten (10) year total and that's what you drew the Board's attention to, sir?

MR. JOEL WORTLEY: That's correct.

MR. BOB PETERS: Can you confirm to the Board that at least $140 million of that is related to something Mr. Miles told them before lunch today and that was that there was a decision made to stop the major rebuilding of Pointe du Bois due to low export prices?

MR. JOEL WORTLEY: Subject to check on the number, I would confirm that that led to some savings, yes.

MR. BOB PETERS: If we could go back to that Consumers Coalition Information Request and the -- and the graphs, Coalition Manitoba Hydro first round 148.

Mr. Wortley, we're looking at the duration index, correct, on -- on the screen?

MR. JOEL WORTLEY: That's correct.

MR. BOB PETERS: Has Manitoba Hydro considered providing rate relief for ratepayers by targeting a second quartile reliability performance, rather than a first quartile reliability performance?

MR. JOEL WORTLEY: No, not in that -- within our systems as they exist today we are not able to make a direct prediction of what reliability performance will result from a given level of investment; that's something we're working on.

But it is also important to understand that reliability isn't the only -- the only thing at stake when it comes to investing in -- in the various systems. I think clearly on the distribution system the assets are throughout the province and public safety is a significant concern. Things like streetlight bases rusting out, potentially falling into traffic. Employee safety is another concern if we've got wood poles that are rotting and -- and employees need to be able to climb them safely so they need to be renewed on a -- before they become unsafe.

And so it's a significant challenge and a complicated assessment to be able to predict what say -- what investments would not occur which would push us to acute -- second quartile performance while keeping other risks in check; that -- that requires a very complex analysis to get it right.

MR. BOB PETERS: And Manitoba Hydro's not in a position to do that at this point in time?

MR. JOEL WORTLEY: We are not in a

position to that at this point in time. We are currently rolling out the tools and the processes that will enable that. It's coming.

MR. BOB PETERS: And not to steal some thunder from Mr. -- or Dr. Williams, but it's coming in -- in approximately -- is it a three (3) to five (5) year timeline.

MR. JOEL WORTLEY: Yeah, that -- we were very conscious that -- that these are difficult challenges, and that it's often easy to think from the front looking in that it's going to be easy and to underestimate how long it's going to take.

There are tools and processes that need to be rolled out. There are data sets that need to be gathered. And then with the new processes, time has to be given for them to mature, as in, people have to get good at them. And so you want to make sure that you can trust the output.

And so on that basis, making sure that we're confident in the timeframe, the current idea is three (3) to five (5) years to get to that point of maturity.

MR. BOB PETERS: Does that maturity take it past the five (5) years, and maybe more in the five (5) to seven (7) year range?

MR. JOEL WORTLEY: We don't expect so at this point, no.

MR. BOB PETERS: On page 566 of Board counsels' fourth book of documents is another a Information Request from Manitoba Hydro. And that at the top of the page, it's highlighted that:

> "No projects or programs identified for execution in the test years were deferred expressly to offset the impacts of major projects."

I read that correctly, Mr. Wortley?

MR. JOEL WORTLEY: You did.

MR. BOB PETERS: Does that suggest to this Board that no projects or programs were deferred as a result of Keeyask and Bipole III in the Manitoba/ Minnesota transmission line?

MR. JOEL WORTLEY: The statement refers to our budgeting process that does not have a total cap as the culmination or the accumulation of business operations capital and major new generation and transmission capital; such that if the major new generation and transmission spending went up, the business operations capital wouldn't automatically go down.

MR. BOB PETERS: And so on page 568 of

the book of documents, which is the budget that we -- or sorry, the comparison of the capital expenditure forecast from 15 to the capital expenditure forecast of 16, the fact that there was $240 million less in spending over a ten (10) year horizon is not tied to offset the impacts of any major projects such as Keeyask and Bipole III, sir?

MR. JOEL WORTLEY: Not directly, no. The reduction in capital spending is part of our broader initiative as a company to constrain spending, but also more granularly I look at each of our distribution, transmission and generation systems to see what spending was absolutely required in the test years and what could be reduced.

So it's a -- it's another look at the risks on the systems, the need to balance cost and performance, and doing -- making the best choices we can about where the money needs to go.

MR. BOB PETERS: If we look to the far right-hand side, the ten (10) year total under 2018 to 2027 on page 268, Mr. Wortley, that $140 million, I think you've agreed, subject to check, that that's mostly tied up with the Pointe du Bois project; correct?

MR. HAL TURNER: I'll figure this

out. Two (2) projects actually --

MR. BOB PETERS: Mr. Turner, tell us which two (2).

MR. HAL TURNER: So there was a -- a project to install some new units in Pointe du Bois and also some -- a project to address some -- the structure of the facility itself to do some improvements to the facility. So both projects were suspended.

MR. BOB PETERS: Both projects relating to one (1) generating station?

MR. HAL TURNER: Correct.

MR. BOB PETERS: Okay. Thank you, sir. And at the bottom of the page, Mr. Wortley, we go down to that same column and we see the $240 million number in brackets that you've referenced as being the savings over ten (10) years comparing the budgeted in '15 to the budget in '16, correct?

MR. JOEL WORTLEY: Correct.

MR. BOB PETERS: And we've already talked with Mr. Turner about 140 million. The remaining hundred million dollars, a lot of that seems to be tied up in this change in unallocated target adjustment.

Have I got that correct, it's $104

million adjustment on that line item?

MR. JOEL WORTLEY: Correct.

MR. BOB PETERS: Can you explain to the Panel what is in "unallocated target adjustment?"

MR. JOEL WORTLEY: These are adjustments that are put into the plan to smooth the cash flow from year to year and are bit of a -- bit of an artifact as we transition from past practices to future practices.

In past practices the targets were made up of particular projects forecasted to occur in particular years, and often they totalled more than we wanted to spend in a given year. And so an adjustment was put in to bring that back to the targeted level.

So this is something we are phasing out as we go forward, but it's still shown here as a vestige of past practice.

MR. BOB PETERS: Would be analogous to having a contingency fund, Mr. Wortley?

MR. JOEL WORTLEY: No, it would be more analogous to -- reflective of an uncertainty as to where the money is going to go in that particular year and -- but wanting to ensure that the constraint, the budget, is at the -- at a desirable level and so it's suggested down to apply appropriate rationing in

the budgeting process.

MR. BOB PETERS: And in other years this unallocated target adjustment would have been adjusted upwards; correct?

MR. JOEL WORTLEY: That's right. Those are years where the forecast spending does not total the target amount, largely because it's far enough out in the future that it's -- the visibility of potential spends in that timeframe is -- is not as clear as in the near term.

MR. BOB PETERS: So there was money in the budget, but there weren't enough projects to use up all the money?

MR. JOEL WORTLEY: That as -- from the current point in time and the -- the CEF, capital expenditures forecast, is a snapshot in time. It tells you what can be seen from a particular moment. From that particular moment, there was not enough visibility of projects in those years to -- to encompass the entire target.

MR. BOB PETERS: Thank you, sir, on page 260 -- 252 of Board counsels' fourth book of documents, Manitoba Hydro -- make it 652, please, thank you.

There is a chart provided by Manitoba

Hydro as to which proportion of the business operations capital categories cannot be deferred in the second test year that's before this Board, correct?

MR. JOEL WORTLEY: Correct.

MR. BOB PETERS: And if -- can I read this a different way, Mr. Wortley, that Manitoba Hydro is telling the Board that 100 percent of customer connections cannot be deferred in 2019.

MR. JOEL WORTLEY: That -- that's correct. This -- this -- these numbers were prepared to try to respond to the question of how much control does Manitoba Hydro have over spending in a given year.

And with customer connects the -- we are mandated to serve. So if a customer arrives and wants to be connected, we don't have the ability to put them off for a year.

MR. BOB PETERS: All right. Now, if I go down to the bottom of this chart under the business operation support, there is a line item called Generation, Building and Grounds.

And conversely to what you just answered to the Panel, Mr. Wortley, it appears Manitoba Hydro has the ability to defer 100 percent of

those expenditures passed the test year.

MR. JOEL WORTLEY: That is what the chart shows, and it reflects that these projects are not in the supply chain. They're not critical to the generation of electricity and so if -- if there was enough impetus they could be deferred, but deferring them means taking on whatever risks those projects were going to meda --- mitigate or taking on whatever additional inefficiencies or costs that come with not performing those projects. So it's a balance.

MR. BOB PETERS: What is the rationale for the claim that 98 percent of system load capacity projects cannot be deferred?

MR. JOEL WORTLEY: These again are -- are projects that are required to meet regional load growth or capacity issues that need -- are needed to keep the system reliable.

MR. BOB PETERS: Maybe seems so long ago to me but I had understood from Ms. Morrison's evidence that Manitoba Hydro's load growth is, essentially, flat for the next six (6) years.

MR. JOEL WORTLEY: On average over the province, that's true but regionally, it's not. There are areas of further or growing commercial development and residential development that are leading to

capacity issues. There are several of them.

MR. BOB PETERS: If a project, Mr. Wortley, has already been started by Manitoba Hydro, Manitoba Hydro is not in a position to defer it; is that also correct?

MR. JOEL WORTLEY: It is certainly not our preference to defer work that's already begun. It's inefficient, costly and so we would take the view that that would be unwise to defer such work.

MR. BOB PETERS: Manitoba Hydro wouldn't have conducted a cost-benefit analysis to do that, but it's based on the advice of your people that that should not be deferred at this point in time?

MR. JOEL WORTLEY: The -- I mean, it varies from project to project. I don't think I can give you a blanket answer there.

MR. BOB PETERS: Okay. Does Manitoba Hydro prepare cost benefit analyses to determine whether or not a project can be paused?

MR. JOEL WORTLEY: If there were some question as to the overall justification for the project, if something changed much as it did with the Pointe du Bois project, yes, there would be a cost-benefit analysis performed to see if we should carry on.

MR. BOB PETERS: Looking at that same chart under System Efficiency, under the sustainment category, Manitoba Hydro is telling this Board that 81 percent of the projects cannot be deferred a year or longer under system efficiency.

Can you explain why that's the case?

MR. JOEL WORTLEY: In this view -- sorry, give me a moment.

(BRIEF PAUSE)

MR. JOEL WORTLEY: So system efficiency in this view is -- totals $14 million of spending in the given year and the 81 percent would be referring to a number of those projects being in flight, and therefore, not good candidates for deferral; and a smaller number being not yet started and therefore deferred, if necessary, with the associated loss in efficiency that would be gained by performing those projects.

MR. BOB PETERS: And was that -- was that done with the ben -- with a cost-benefit analysis?

MR. JOEL WORTLEY: The system efficiency projects are justified by cost benefit

analyses. They're directly paying back and achieving a saving somewhere else.

MR. BOB PETERS: But the decision to defer them, Mr. Wortley, --

MR. JOEL WORTLEY: Oh please don't --

MR. BOB PETERS: -- more accurately the decision that you're not able to defer 81 percent of them is based not on a cost-benefit analysis?

MR. JOEL WORTLEY: So there would be a cost-benefit analysis to justify the project to begin with. If the project is already in flight and some money has been invested to defer it at that point and forego this -- the system efficiency that was to be achieved by the project, which was justified by the project spend to begin with, it's -- unless something has changed fundamentally in the -- in the business case for the project, it would only make sense to carry on.

MR. BOB PETERS: Mr. Wortley, before we leave that chart that's shown on the screen at page 652 of the book of documents, volume 4, has Manitoba Hydro calculated the dollar value of the projects that could be deferred?

MR. JOEL WORTLEY: That's where these numbers came from, yes.

MR. BOB PETERS: And so let me ask it directly then: By turning what -- what is the value of the business operation capital projects that could be deferred past 2019 based on this chart?

(BRIEF PAUSE)

MR. JOEL WORTLEY: Subject to check, I believe it's $160 million.

MR. BOB PETERS: Now in fairness, you might not have been enjoying all of Mr. McCallum's time on the microphone, but he indicated to the Panel that ostensibly $100 million of savings on the capital side doesn't move the needle - I think that was his words - and I'll find a transcript reference if he needs to, but I think we can show that to the Panel if we turn to page 134 of volume 4.

This is a chart that we looked at before the morning recess and there is a line item in the top half of the page where it says "capital down $100 million a year."

Do you see that, Mr. Wortley?

MR. JOEL WORTLEY: I do.

MR. BOB PETERS: And if you're comfortable answering; if not, Ms. Carriere's got her

hand poised and ready to -- to jump in.

This is a sensitivity impact that Manitoba Hydro calculated to show this Board what would happen if the capital spending came down $1 million per year.

Is that your understanding?

MR. JOEL WORTLEY: It is.

MR. BOB PETERS: If I said a million dollars I meant to say $100 million. But again, it's a different neighbourhood than I'm used to.

Mr. Wortley, would the Board be correct in interpreting that line item of capital down $100 million a year as indicating that if that happened, then the requested rate increases that Manitoba Hydro presently has before this Board could be reduced by 0.34 percent a year?

MR. JOEL WORTLEY: That is how I would read this chart.

MR. BOB PETERS: All right. Well, that's consistent with what Mr. Wortley had said in terms of --

MR. JOEL WORTLEY: I should point out that the --

MR. BOB PETERS: -- I'm sorry, McCallum said --

MR. JOEL WORTLEY: -- the deferral that we talked about a moment ago from the business operations capital might push the costs out a year, maybe a little bit longer, depending on the project and how much risk is willing to be taken in deferring those, but it certainly couldn't be adjusted by $100 million a year, every year. That would leave a far too large a -- the -- the corresponding balance of risk would be unacceptable, and so the -- the -- these two (2) are not directly comparable in terms of scenarios.

MR. BOB PETERS: The risk you refer to, Mr. Wortley, is that there may be more interruptions, or there -- the interruptions that happen could be longer in duration. That's what you're referring to?

MR. JOEL WORTLEY: That's one (1) potential impact. The -- these are risks to the safe and reliable operation of the system. So it -- it could be customer impacts in terms of reliability. It could be safety to the public, safety to our own staff. These -- these all come into play.

MR. BOB PETERS: Well, we've got your -- we've got your comments on that, Mr. Wortley, but let's follow that hundred million dollars of reduced

annual capital expenditures. And just so that we understand what happens to the -- to the financial forecast of the Company, we saw -- we saw on page 525 of Board counsels' book of documents, Volume IV, the total capital costs. And in 2018, it looks like $3.058 billion, and in 2019, it's $2.7 billion, correct, Mr. Wortley?

MR. JOEL WORTLEY: Correct.

MR. BOB PETERS: And of that amount, the business operations capital in the 2018 year is 526 million, and it's 517 million in the second test year, 2019. Have I got that right?

MR. JOEL WORTLEY: Yes.

MR. BOB PETERS: Manitoba Hydro was asked through an information request to explain the impact of, say, a million -- no, say $100 million reduction in spending. And I think if we go to page 671 of Board counsels' fourth book of documents, we can -- we can look at that.

(BRIEF PAUSE)

MR. BOB PETERS: Ms. Carriere, we may need some assistance in explaining this from you, ma'am, but the understanding is that the Integrated

Financial Forecast was run to assume $100 million of lower annual capital spending starting in 2019, ma'am?

MS. LIZ CARRIERE: That's correct.

MR. BOB PETERS: And on page 671, which we're looking at, that has a corresponding result of a increase in the net income to Manitoba Hydro in 2026 of $60 million?

MS. LIZ CARRIERE: That's correct.

MR. BOB PETERS: And it -- it grows from 2019, where it's 2 million, all the way through to 2026, correct?

MS. LIZ CARRIERE: Yes, that's right.

MR. BOB PETERS: Is there a quick explanation as to why that wouldn't be a linear number, because it's more exponential than that.

MS. LIZ CARRIERE: You -- it's because each year, you're spending $100 million, and there's assumptions around when that would go to service. Since we're -- the scenario we're trying to simulate a reduction in -- in revenue -- or a reduction in capital expenditures that -- for business operations capital, those projects tend to have a shorter in-service -- or shorter duration. So we're putting some of that into service.

So, you know, you're only seeing in --

in 2019, 100 million, basically half of that going into service. In the second year, you've got the full hundred million plus another half of the hundred million going into service. So only that portion of your -- your finance expense and depreciation are being -- impacting the income statement.

So that's -- as you're putting more in-service, you're -- you're -- or taking more out of service, technically, because this is a down scenario, then you're seeing the -- the -- on a cumulative effect, more and more being pulled out of the -- out of the -- the in-service and the -- and the associated carrying -- carrying costs. As Mr. Wortley suggested, this assumes a permanent reduction of roughly a billion dollars over the ten (10) year period.

MR. BOB PETERS: And if we turn, Ms. Carriere, to page 672, the next page, in the 2027 year -- excuse me -- what we see is that the equity ratio percentage improves. If we scroll up -- a bit further down, please -- and the at the bottom of the page, there we see the equity ratio improves by 2 percent by 2027, and 7 percent by 2034?

MS. LIZ CARRIERE: Yes, I see that.

MR. BOB PETERS: On page 675 of Board counsels' fourth book of documents, we have the

corresponding cash flow statement, Ms. Carriere. And I take it this cash flow statement assumes that there is $100 million less expended under the property, plant, and equipment line, net of contributions?

MS. LIZ CARRIERE: That's correct.

MR. BOB PETERS: It shows up as a positive number because this is generally a very large negative number, correct, that is, the property, plant, and equipment investment?

MS. LIZ CARRIERE: Yes. Property, plant, and equipment on the cash flow statement is shown as a cash outflow. That's why it's negative. So here, we're reducing the cash outflow, so it's showing as a positive number here.

MR. BOB PETERS: And the result in the bottom right-hand corner is that Manitoba Hydro has $545 million of more cash by the end of 2026? That's after eight (8) years of reduced capital spending?

MS. LIZ CARRIERE: Yes. The cash balance at that point in time would be $545 million higher.

MR. BOB PETERS: Higher than what was showed in your other IFF16 update plus interim?

MS. LIZ CARRIERE: That's correct.

MR. BOB PETERS: And I don't want to

dwell on this, but when I look at the financing activity, middle portion of the -- the chart, it appears that Manitoba Hydro assumes borrowing $200 million less in 2019, and then also borrowing 200 million less in 2020, correct?

MS. LIZ CARRIERE: That's correct. You're deferring the need for issuing long-term debt.

MR. BOB PETERS: So that would mean Manitoba Hydro has borrowed $400 million less over the eight (8) years?

MS. LIZ CARRIERE: That's correct.

MR. BOB PETERS: Now, let's follow that through even a bit further to understand the impact of the assumed hundred million dollars of annual reduction in capital spending on Manitoba Hydro's new modified cash flow to cash expense analysis.

And we did that way back in Volume II of Board counsels' book of documents, on page 358. And we'll have to put on the screen for, Ms. Carriere, if we could. That'd be Volume II, page 358.

And just so we're oriented on this page, Ms. Carriere, the heading, figure 2.6., this is Manitoba Hydro's IFF16 integrated financial forecast 16 updated with interim, but it -- instead of using

the rates that Manitoba Hydro is proposing, it reverts back to a 3.95 percent rate increase?

MS. LIZ CARRIERE: That's correct.

MR. BOB PETERS: So then if we look, Ms. Carriere, at the bottom, and we see in the year 2019, that Manitoba Hydro, under this analysis, shows a cash flow deficiency of $99 million, correct?

MS. LIZ CARRIERE: Yes, that's correct.

MR. BOB PETERS: Has -- does it follow, then, that reducing the -- the capital expenditures by a hundred million dollars would make that cash flow positive to the extent of a million dollars?

MS. LIZ CARRIERE: Well, if you're looking at this purely mathematically, yes, it would. But what you're not seeing here is, as Mr. Wortley was alluding to, was any changes to the cash receipts from customers for, you know, any lost revenue, either domestic or export revenue. You're also not seeing the cost of maintaining the system that would eventually go up.

MR. BOB PETERS: And Mr. Wortley -- and -- and Ms. Carriere, Manitoba Hydro has not yet been able to analyze what the loss of revenue would be

if there was a reduction in the business operations capital to the extent of a hundred million dollars a year?

MS. LIZ CARRIERE: That's correct.

MR. BOB PETERS: And likewise, Ms. Carrier, if there is an increase in the cost of maintenance for initially deferring a project and then picking it up some years down the road, at this point in time, Manitoba Hydro isn't able to quantify what that additional cost would necessarily be?

MS. LIZ CARRIERE: That's correct.

MR. BOB PETERS: And is it the Board to understand that at the end of this three (3) to five (5) years, Mr. Wortley, that we talked about, Manitoba Hydro would expect to be in a position to quantify those types of decisions?

MR. JOEL WORTLEY: The objective of the -- the planning processes that we're -- we're deploying right now are to have a longer outlook on the planning horizon, and a more confident outlook on the planning horizon, such that we wouldn't expect to stop/start a project. That would be highly irregular.

We do expect to be able to have more confidence in -- in how much money we need to support the system, and to have confident plans that we can

run through from beginning to end without disruption.

MR. BOB PETERS: And that state would be expected by Manitoba Hydro in approximately three (3) to five (5) years from today?

MR. JOEL WORTLEY: That's our current outlook, yes.

MR. BOB PETERS: Mr. Chair, at this time, I'd like to thank Manitoba Hydro's revenue requirement panel witnesses for their responses to my questions. I'll have no further questions at this time, and -- and honouring my agreement with counsel opposite, I would suggest the Board call on counsel for the Consumers Coalition for any questions they may have of these witnesses. Thank you.

THE CHAIRPERSON: Thank you. Dr. Williams...?

DR. BYRON WILLIAMS: Yes. Thank you, and good afternoon, members of the panel. I'll note that Ms. Desorcy from the Consumer -- Consumers Association of Canada, Manitoba branch, is in the back row, just to the left of Cheryl, with articling student-at-law, Robert Walichnowski. Cheryl, we'll give you the spelling at the coffee break.

Just before we start, we do have an exhibit, being Coalition 32-1 to distribute. I -- I

note from this morning, My Learned Friend Ms. Ramage expressed some concerns with our efforts to notify them, being Manitoba Hydro, of intended documents. So certainly, we're happy to deal with -- if there is an objection, to deal with them as they arise. But I just will indicate to the Board, we certainly undertook our efforts on Friday and the weekend with the best of intentions, trying to give Manitoba Hydro a heads-up as early as possible in terms of potential documents.

We did make one (1) error in that we sent them the wrong chapters reference for -- for Bonbright. We -- we believe we clarified that on Sunday and provided the actual references to them. So there was certainly no ill intent. I know My Friend also observes that some of the materials that we alerted Hydro that we might file weren't presented in the sustaining capital material today, and I would simply note, that's because they're not related to sustaining capital. We will have a -- a couple of matters tomorrow related to export revenues that we tried to give notice to Manitoba Hydro of on Friday.

I think the con -- current third concern of Manitoba Hydro is capsulated in Tabs 1 through 6 of this book of documents. These are

documents that were referenced expressly in the METSCO evidence, both in the main text and in the appendix. And you can see where they're referenced on the record. So certainly, our clients believe they're quite properly on the record. They would have expected that Manitoba Hydro, in the course of reviewing METSCO's evidence for rebuttal, would have at least add -- begun to address their minds to these material.

But for Board members who were here during the last General Rate Application, I'll simply say that you've heard from Manitoba Hydro this afternoon of where they want to be in three (3) to five (5) years, whether that's in predictive modelling or in terms of dialogue with consumers. These documents which are referenced on the record in METSCO's evidence are illustrative of where best practice is. And for our clients, and also for the Board members who were here a couple years ago, it's very hard to visualize, in our respectful submission, what do we mean by "predictive modelling"? What do we mean by "alternative scenario analysis"?

So these are excerpts from the record. We're not asking Manitoba Hydro to become an expert in EPCOR's scenario planning, but we want to use them as

illustrative of -- of what good practice scenario planning looks like, referencing documents that are already on the record.

So we're, again, happy to hear any objections at the appropriate point in time, but I -- I hope with that, those comments -- that may allay the concerns of Manitoba Hydro, and any -- if -- if there were any of the Board.

THE CHAIRPERSON: That's fine, Mr. Williams. We'll -- Dr. Williams, we will -- we'll deal with objections if and when they arise.

--- EXHIBIT NO. CC-32-1: Coalitions Book of Documents.

CROSS-EXAMINATION BY DR. BYRON WILLIAMS:

DR. BYRON WILLIAMS: Thank you, and good afternoon, members of the Hydro panel. Ms. Carriere, I feel I'm going to neglect you this afternoon, largely, but you know, pop -- pop up whenever you feel like it. I suspect most of my questions will go to Mr. Wortley, but if there are more appropriate -- whether to Mr. Steele, Turner, or Neufeld, again, I leave it to your panel's discretion in terms of how you handle the question.

Mr. Wortley, I've got a tough one for you right off the bat. You'll agree that Manitoba Hydro enjoys a monopoly in the retail sale of power in Manitoba, sir?

MR. JOEL WORTLEY: Yes, I would.

DR. BYRON WILLIAMS: And you may have to speak up. I can -- I can barely hear you, which may be my hearing, sir.

And the real -- the -- the upshot of that is that to the extent that residential customers are unhappy with either the price or quality of Hydro service, there is no other retail provider of -- of Hydro electricity in Manitoba, agreed?

MR. JOEL WORTLEY: I would agree.

DR. BYRON WILLIAMS: In that context, residential customers cannot vote with their pocketbooks, correct?

MR. JOEL WORTLEY: Correct.

DR. BYRON WILLIAMS: They -- and given that mon -- monopoly, you'll agree, Mr. Wortley, that Manitoba Hydro has a duty to steward its resources with prudence and care, agreed?

MR. JOEL WORTLEY: Yes. I believe I've said several times that Manitoba Hydro needs to do its best to get the right balance of cost

performance and risk for the customer.

DR. BYRON WILLIAMS: And that right balance. Always has to be considered in light of the recognition that there are not unlimited resources, agreed, sir?

MR. JOEL WORTLEY: That -- that I -- yes, that's -- that's the definition of balance between cost, performance and risk. If -- if one (1) of them was unlimited, there wouldn't need to be balance.

DR. BYRON WILLIAMS: And recognizing scarce resources, Hydro as you've agreed, has a duty to be mindful of both trade-offs and risks, agreed, sir?

MR. JOEL WORTLEY: I would agree.

DR. BYRON WILLIAMS: And not all investments in Manitoba Hydro's electrical infrastructure are created equal, sir?

MR. JOEL WORTLEY: No. That's why we have systems for evaluating them.

DR. BYRON WILLIAMS: And there may be some which are given a higher pri -- priority, whether for reasons of economics or real -- reliability, correct?

MR. JOEL WORTLEY: Correct.

DR. BYRON WILLIAMS: And there may be some investments, sir, which are just not necessary, agreed?

(BRIEF PAUSE)

MR. JOEL WORTLEY: There are investments that are considered and never -- and never executed. So, yes, I would agree that sometimes, what appears to be initially an investment of -- of merit, after further investigation, turns out not to be.

DR. BYRON WILLIAMS: And turning to asset management and -- perhaps we'll see if you agree with this suggested definition, sir.

I'll suggest to you that asset management today involves maximizing the value of the existing access base, serving customers by providing stable and reliable services, and making economically and operationally optimal decisions regarding whether, how and when to intervene in the asset base?

MR. JOEL WORTLEY: I'm not familiar with that particular definition.

DR. BYRON WILLIAMS: Any discomfort with that definition, sir?

MR. JOEL WORTLEY: Not at face value,

no.

DR. BYRON WILLIAMS: And as you discussed with My Learned Friend, Mr. Peters, even at a time of substantial investment by Manitoba Hydro in new generation and transmission assets, over the next decade, there are billions of dollars projected to be spent in terms of sustaining capital exp -- expenditures, agreed?

MR. JOEL WORTLEY: I would agree.

DR. BYRON WILLIAMS: Kristen, if you can turn to Appendix 5.1, being the UMS report for Manitoba Hydro's General Rate Application filing. And Kristin, if I call you Diana from time to time, you'll -- what's that -- you'll forgive me, and also see it as a compliment, because you're matching Diana's tremendous per -- performance.

(BRIEF PAUSE)

DR. BYRON WILLIAMS: Mr. Wortley, you're familiar with the UMS report?

MR. JOEL WORTLEY: I am.

DR. BYRON WILLIAMS: And perhaps we can turn to page 6. In essence, I'll suggest to you that UMS Group assessed Manitoba Hydro's asset

management practices against ISO -- ISO 55,000, and its general understanding of best practice asset management. Would that be fair, sir?

MR. JOEL WORTLEY: That would be fair.

DR. BYRON WILLIAMS: And what you see before you, sir, being page 6 of Appendix 5.1, is an AM maturity scale running on the left-hand side from innocence through awareness, development, competence, and towards excellence. Do you see that, sir?

MR. JOEL WORTLEY: I do.

DR. BYRON WILLIAMS: And in essence, Mani -- UMS defines competence as maturity level 3, correct?

MR. JOEL WORTLEY: Correct.

DR. BYRON WILLIAMS: Excellence is maturity level 4, agreed?

MR. JOEL WORTLEY: Agreed.

DR. BYRON WILLIAMS: And development is maturity level 2, sir, agreed?

MR. JOEL WORTLEY: Agreed.

DR. BYRON WILLIAMS: And this report was provided to Manitoba Hydro in December 2016, on or about, sir, subject to check?

MR. JOEL WORTLEY: That's correct.

DR. BYRON WILLIAMS: And overall, as a

collective, UMS ranked Manitoba Hydro as a one point five (1.5), sir; agreed?

MR. JOEL WORTLEY: Agreed.

DR. BYRON WILLIAMS: That's somewhere between the awareness and developmental scale, agreed?

MR. JOEL WORTLEY: Agreed.

DR. BYRON WILLIAMS: Far below the numb -- maturity level 3 ranking for competence, agreed?

MR. JOEL WORTLEY: Agreed.

DR. BYRON WILLIAMS: And in terms of the individual business units, sir, generations scored one point seven (1.7), correct?

MR. JOEL WORTLEY: Correct.

DR. BYRON WILLIAMS: Transmission, one point six (1.6), agreed?

MR. JOEL WORTLEY: Agreed.

DR. BYRON WILLIAMS: And customer service and distribution, one point three (1.3), sir?

MR. JOEL WORTLEY: Yes.

DR. BYRON WILLIAMS: We can go there if you need it, sir. Well, let's -- let's go back a page, to page 5 at the top, please, Kristin. You'll see a statement by UMS at the very top of this page, that in previous utility management transformations, I

-- they suggest that utilities have seen significant improvements in productivity and overall cost savings. Do you see that, sir?

MR. JOEL WORTLEY: I do.

DR. BYRON WILLIAMS: And just to be fair, UMS has not promised those type of savings to Manitoba Hydro?

MR. JOEL WORTLEY: No. They're just quoting their past experience and their past experience with different companies from which the starting point is not particularly known. And so it is worth noting that your starting point obviously reflects or influences what savings you may be able to achieve.

So Manitoba Hydro, already being at one point five (1.5), and therefore ahead of other companies, as noted in the US -- UMS report, who may be at zero, may not have as much potential to save as others, but we won't know until we work our way in and start to make those assessments.

DR. BYRON WILLIAMS: Are you aware whether or not UMS did studies for Toronto Hydro, sir?

MR. JOEL WORTLEY: I couldn't tell you off the top of my head, no.

DR. BYRON WILLIAMS: So you're not

aware of the score that Toronto Hard -- Hydro received in terms of its studies, sir?

MR. JOEL WORTLEY: I am not.

DR. BYRON WILLIAMS: Okay. Now, at -- I -- I wonder if we can turn to -- quickly to page 7, in the middle of the page, and then we'll go to page 8. Go down the Key Gaps.

Just on this page, Mr. Wortley, you'll agree that UMS is discussing some of what they articulated in December of 2016 as the Key Gaps in terms of the -- between Manitoba Hydro and best practice, agreed?

MR. JOEL WORTLEY: That's right.

DR. BYRON WILLIAMS: And we'll come back to this page, but we'll go to page 8. Right there is fine, thank you. And focusing your attention on the second full paragraph, sir, UMS informed Manitoba Hydro that there was no one (1) group or function responsible at that point in time for optimizing total asset life cycle costs, agreed?

Do you see that reference, sir?

MR. JOEL WORTLEY: I do.

DR. BYRON WILLIAMS: And UMS also informed Manitoba Hydro that, from its observations, most asset management efforts were focused on capital

spending, with minimal attention given to optimizing O&M, which is a key part of the asset life cycle, agreed?

MR. JOEL WORTLEY: That's what it says, yes.

DR. BYRON WILLIAMS: And by O&M, sir, you understand that to mean operations and maintenance?

MR. JOEL WORTLEY: I do.

DR. BYRON WILLIAMS: You'll see as well a concern being expressed by UMS in terms of the lack of form -- in the next paragraph, the lack of formal data management and government processes and metrics, agreed?

MR. JOEL WORTLEY: No. I'm sorry, you used the word "concern," and I think it's important to understand that the UMS report was commissioned to look for opportunities for improvement. So this was not an audit. This is not a -- a critique. It was a review of processes in comparison to best practice to see where there was opportunity to improve.

DR. BYRON WILLIAMS: Fair enough. So, sir, they observed a lack of formal data management, and government processes and matrices, agreed?

MR. JOEL WORTLEY: That's right.

DR. BYRON WILLIAMS: And going to the top -- the bottom of page 7 and rolling onto page 8, so if we can keep both screens, that's -- you also see an observation, sir from UMS in December of 2016 that there are no corporate risk standards, tolerance levels, or risk assessment requirements to guide the business units, leading to a situation in which risk is being avoided rather than managed. Do you see that reference, sir?

MR. JOEL WORTLEY: I do.

(BRIEF PAUSE)

DR. BYRON WILLIAMS: Just scrolling more fully on to page 7, there's just one (1) more of these observations. Just one (1) second. Right there is fine, Kristin.

Under Key Gaps, the second paragraph, the second line, sir, you'll see as line -- sorry, the third line, the -- the second sentence, you'll see as well the observation by UMS that asset management has developed independently in each business unit, and that the asset management functions are split within the business units, suggesting that it has led to a lack of standardization of processes and hindered the

sharing of best practices. You see that observation, sir?

MR. JOEL WORTLEY: I do.

DR. BYRON WILLIAMS: Kristin, if you can move to page 34 of -- of this document. And, sir, we won't go through these at this point in time, but you'll agree with me that in terms of closing the competence gap, UMS has made twenty-eight (28) recommendations to Manitoba Hydro? You can scroll through if Mr. Wortley's checking my math.

MR. JOEL WORTLEY: Yeah. That's correct.

DR. BYRON WILLIAMS: And I understand that, as it stands today, Manitoba Hydro has not developed a -- an official response to these recommendations because that will arise in Phase 3 of its overall rollout of its asset management strategy.

Is that correct, sir?

MR. JOEL WORTLEY: I would describe in that UMS has -- was hired to do a gap assessment, which they've done, and they've identified a number of areas where there are -- there is room for improvement. But they've also laid out a four (4) step process for closing those gaps. And that involves, first of all, creating the right

environment, designing the change, implementing the change, and then working on moving towards excellence.

And so there needs to be a plan built to follow that path. And so we are currently working at creating the right environment, and as that evolves out of our corporate restructuring and our voluntary departure program, we'll be in a place -- we'll be well situated to map out the -- the rest of the journey and -- and execute.

And so I don't see a future where we write a rebuttal to Man -- or to UMS's gap assessment. I do see a future where we embrace it and develop a plan to close the gaps where it's beneficial.

It's important understand, amongst other things, that everything comes at a cost, and standardization is a great example. Standardization is worthwhile, if you need to be able to compare the output on a common basis or a common denominator, if there's value of that in your decision-making. If there's not, standardization comes at a cost because you've got a police and promote consistent practice across your organization.

So we want to be very careful to make sure that as we institute the process improvements and as we close gaps that each one of them brings a

benefit, commensurate or -- or in proportion, to the cost. 'Cause these are not going to be inexpensive. These are -- are significant endeavours that require broad deployment across a large organization. That means a lot of change management. That means a lot of working with -- with people who are busy trying keep the lights on, and so we're taking them away from their business; we want to make sure that it's worthwhile.

So we will move forward, but will do it in a very deliberate way, making sure that every step is worthwhile.

DR. BYRON WILLIAMS: Mr. Wortley, I have no doubt your -- your response will be deliberate. I'll just note, I'm on a clock, so I let you finish that answer, and I'm always prepared to, but I'll -- I'll try and keep my -- my questions more directive.

MS. HELGA VAN IDERSTINE: Thank you, Mr. Wil -- Dr. Williams. I appreciate letting him respond fully.

CONTINUED BY DR. BYRON WILLIAMS:

DR. BYRON WILLIAMS: The -- Mr. Wortley, you -- you talked about the future. I'd like

to talk a bit about the past. And I'll direct your attention to Tab 7, page 127, of the Coalition's book of documents, being 32-1.

And, Mr. Wortley, this being an excerpt from Board Order 116/08.

You see that, sir?

MR. JOEL WORTLEY: I do.

DR. BYRON WILLIAMS: Okay. And -- and, Mr. Wortley, as we turn to -- to page -- excuse me just one (1) second.

I'll -- I'll direct your attention to page 128 of the document.

And you see that commentary here from the Manitoba Public Utilities Board, in terms of sustaining capital expenditures, being the first two (2) paragraphs. And you'll see the Public Utilities Board agreeing with Intervenors on the need for a pera -- periodic asset condition assessment study.

You see that, sir?

MR. JOEL WORTLEY: I do.

DR. BYRON WILLIAMS: And this is the Public Util -- this -- this is the Public Utilities Board, back in 2008, seeking asset condition assessment information.

Agreed?

MS. HELGA VAN IDERSTINE: All right. I think Mr. -- again, Dr. Williams...

(BRIEF PAUSE)

MS. HELGA VAN IDERSTINE: I -- I wanted to alert Dr. Williams to the fact that, in case he was a -- wasn't aware, that Mr. Barnlund will be coming to speak to -- on another panel, and he might be, again, the right person to talk about with the Board orders.

DR. BYRON WILLIAMS: With respect, this -- this goes to the credibility of -- of Manitoba Hydro in undertaking and responding to Board orders specifically relating to sustaining capital management. So these are the proper questions for this panel.

MS. HELGA VAN IDERSTINE: So, Mr. Chair, I just do want to raise the fact that Mr. Barnlund is the person responsible within Manitoba Hydro for responding and dealing with the Board orders. And I think that that -- he'd be the appropriate person to respond to questions relating to them.

THE CHAIRPERSON: I'm going to look -

- let the ques -- you know, Mr. Barnlund had some -- we've got all sorts of different issues arising from Board orders. I think that we'll let this go ahead.

But if the witness needs time to read this, certainly the witness can take whatever time's required to read the -- the Board order if he's not familiar with it.

CONTINUED BY DR. BYRON WILLIAMS:

DR. BYRON WILLIAMS: Mr. Wortley, you're -- you've been a long time employee of Manitoba Hydro?

MR. JOEL WORTLEY: Fifteen (15) years.

DR. BYRON WILLIAMS: You're familiar with the dialogue before the Public Utilities Board over that last fifteen (15) years?

MR. JOEL WORTLEY: Not directly. This is my first direct participation in a -- in a rate hearing.

DR. BYRON WILLIAMS: Do you need a couple minutes to review this material, Sir?

MR. JOEL WORTLEY: That really depends what kind of questions you asked me about it.

DR. BYRON WILLIAMS: Well, let's -- let's just leave that open to you, sir.

You see here, sir, the Board, in 2008, is seeking periodic asset condit -- asset condition assessment studies.

Do you see that, sir. You've not reviewed this book of documents, Sir?

(BRIEF PAUSE)

MS. HELGA VAN IDERSTINE: Sor -- sorry, Mr. Chair. I do want to raise the point that these are the documents that we were provided last evening. So to the extent that Mr. -- Dr. Williams is raising the issue of whether or not they've reviewed them, you know, again I -- it's come back to saying -- they -- we had them focus on the areas of their expertise. Mr. Barnlund is the appropriate person to be focusing on that, and he just received these, so.

DR. BYRON WILLIAMS: Sir, the -- these were to the Board -- these were also the subject of a Public Utilities Board Information Request, being 1-89(a) to (c), in which Manitoba Hydro provided this. So this is not anything new to Manitoba Hydro.

THE CHAIRPERSON: Well, if the witness requires time, I -- you know, I -- I don't know, Dr. Williams, If we need to go through each tab,

so the witness has time to review it, if the witness hasn't it. I still think that this is the appropriate -- if -- if the issue relates to this panel, the fact that Mr. Barnlund is the person responsible for orders, I -- I still think it should be going through this panel. But the witness needs an opportunity to review the material in order comment if the witness doesn't have it.

So if counsel wants to take ten (10) minutes and advise and discuss what issues are going to arise or he's going to address, so that the witness has -- or witnesses on this panel have an opportunity to review the material, you know, that's fine.

What I don't want, is I don't want to have every question, you know, falling into this -- into this area because it -- it's going to be delaying matters considerably.

DR. BYRON WILLIAMS: Just for efficiency reasons, and thank you for the Board's guidance, I would suggest then that we sit down for -- sit -- sit down for a few minutes and we can go through this with Manitoba Hydro.

THE CHAIRPERSON: Okay. We'll -- how long would you need?

DR. BYRON WILLIAMS: Well, personally,

I wouldn't have expected this would've taken very long, so --

THE CHAIRPERSON: Well --

DR. BYRON WILLIAMS: -- I'm going to suggest fifteen (15) to twenty (20) minutes.

THE CHAIRPERSON: Okay. We'll give twenty (20) minutes -- we'll adjourn for twenty (20) minutes and counsel can meet; 2:40, thank you.

--- Upon recessing at 2:20 p.m.

--- Upon resuming at 2:41 p.m.

THE CHAIRPERSON: Mr. Barnlund, how nice of you to join us.

MS. HELGA VAN IDERSTINE: Mr. Barnlund needs to be sworn in before he can give any evidence on this panel. So if we could have Mr. Simonsen take care of that for us.

THE CHAIRPERSON: Was he not sworn in earlier? Okay.

GREG BARNLUND, Sworn

THE CHAIRPERSON: Dr. Williams...?

CONTINUED CROSS-EXAMINATION BY DR. BYRON WILLIAMS:

DR. BYRON WILLIAMS: Yes, and good afternoon and welcome, Mr. Barnlund.

I'm going to be directing some questions to you. I may have a couple follow-up questions on this with Mr. Wortley as well, but, Mr. Barnlund, perhaps we can start with tab 7 of the Coalition's book of documents, page 129 -- 128, excuse me, towards the top of page 128. Thank you.

Mr. Barnlund, you'll agree this is an excerpt from Order 116/08?

MR. GREG BARNLUND: Yes, sir, it is.

DR. BYRON WILLIAMS: And, sir, you're a long time employee of regulatory affairs?

MR. GREG BARNLUND: Yes.

DR. BYRON WILLIAMS: And as part of your duties in regulatory affairs, you're responsible for follow-up to Board Orders?

MR. GREG BARNLUND: I am, sir.

DR. BYRON WILLIAMS: And for communicating those with -- with -- with the requisite departments; agreed?

MR. GREG BARNLUND: That's correct, yeah.

DR. BYRON WILLIAMS: And, sir, here you'll see and -- and no doubt will recall the Board

entering into a discussion related to capital expenditures that are not related to major generation and transmission projects.

Do you see that in the first paragraph, sir?

MR. GREG BARNLUND: Yes, sir, I do.

DR. BYRON WILLIAMS: And nowadays we call that sustaining capital?

MR. GREG BARNLUND: Correct.

DR. BYRON WILLIAMS: And the -- the Board, you'll agree, sir, is directing Manitoba Hydro to provide a asset condition assessment study.

Would that be fair?

MR. GREG BARNLUND: Yes, sir.

DR. BYRON WILLIAMS: And, sir, a -- so this is back in 2008 and, Mr. Barnlund, perhaps if we can go to the next page, being page 129 of Coalition 32-1. Towards the bottom you'll see that the Board is discussing Mr. Harper's evidence in terms of asset condition assessments.

Do you see that, sir?

MR. GREG BARNLUND: Yes, that's the Board -- literally that discussing Mr. Harper's evidence. Yes.

DR. BYRON WILLIAMS: And you'll

recall, sir, that Mr. Harper were -- was an evid -- a witness for the Coalition in that hearing?

MR. GREG BARNLUND: Yes.

DR. BYRON WILLIAMS: Okay and if we go to the top of the next page, being page 130. The point I really wish to draw you to, Mr. Barnlund, is -- is if we focus on Mr. Harper's evidence as characterized by the Board, he's talking about in the first full paragraph, the issue of prioritizing assets by way of asset condition assessment; agreed?

MR. GREG BARNLUND: Yes, that's correct.

DR. BYRON WILLIAMS: And so, Mr. Barnlund, I'm going to suggest to you that back in 2008 the dialogue before the Public Utilities Board was about two (2) things; one was getting a data assessment in terms of Manitoba Hydro's -- as it related to gen -- generation, distribution and transmission; and secondly, how it prioritized expenditures.

Would that be fair, sir?

MR. GREG BARNLUND: I think it's fair to say that -- that the Board was requesting that we provide a condition report. I'm not so sure -- sure that we went so far as to say, a report on the

prioritization of expenditures.

DR. BYRON WILLIAMS: And that's fair enough, sir, and I'm not -- I'm not asking you to agree that there was a request for report on the prioritization of expenditures, but you'll agree that there was a dialogue in terms of Manitoba Hydro's priortization of those expenditures; agreed?

MR. GREG BARNLUND: That was a matter that was discussed at that hearing, yes.

DR. BYRON WILLIAMS: Turning to tab 8 and -- and let's be careful --

MR. JOEL WORTLEY: Just before we leave that one, if I could, for just a quick second. I do note in the following paragraph that Mr. Harper further recommends that Manitoba Hydro undertake regular asset condition assessments every two (2) to three (3) years.

And I just wanted to note that within best practices and asset management, the frequency of your condition assessment should be tied to the decisions you need to make around the asset. And that the idea of a blanket frequency like this would not be an efficient way to proceed.

DR. BYRON WILLIAMS: Mr. Wortley, thank you for that. You're not suggesting that it

would be efficient to -- to not supply an assessment for many years, though, are you?

MR. JOEL WORTLEY: I'm suggesting that the data acquisition needs to be programmed, as required, to manage the assets.

DR. BYRON WILLIAMS: Mr. -- Mr. Barnlund, and I guess Mr. Wortley, you've read the material now?

MR. JOEL WORTLEY: I've skimmed it.

DR. BYRON WILLIAMS: Okay, we'll come back to that.

Mr. Barnlund, if we can turn to tab 8 of the Coalition's book of documents, and specifically page 134.

Sir -- sir, just to be clear, this is not an excerpt from a Board Order, this is an excerpt from a closing argument, being the closing arguments of a certain Mr. Williams; agreed?

MR. GREG BARNLUND: I understand that, yes.

DR. BYRON WILLIAMS: And sir, if I direct your attention back to lines 10 through 12 of this submission, that's fine. Right there, Kristin. Lines 9 through 13, excuse me.

You'll see there is a suggestion that

each functional area of Manitoba Hydro is separately addressing the prioritization process; would that be fair?

MR. GREG BARNLUND: I see that written there, yes.

DR. BYRON WILLIAMS: If we can turn to tab 9 and -- and specifically page 139.

Mr. Barnlund, this is now 2012 -- January of 2012; agreed?

MR. GREG BARNLUND: Yes.

DR. BYRON WILLIAMS: And here we are back to the Public Utilities Board speaking in Order 5-12?

MR. GREG BARNLUND: Yes.

DR. BYRON WILLIAMS: And you see the Board in 2012 expressing a concern that an asset condition study has been delayed.

Do you see that reference, sir?

MR. GREG BARNLUND: I do. And -- and, you know, it might be useful if I could also turn our attention to an Information Request that we had answered with respect to the chronology on this.

DR. BYRON WILLIAMS: And this is PUB-1-89, sir?

MR. GREG BARNLUND: First round 89 (a)

to (c), that's correct.

And maybe I could just -- if it, you know, would assist the Board in understanding that there was a -- I think there was a number of developments that occurred since the issuance of the initial directive to Manitoba Hydro in terms of an asset condition study that -- that had a rule in terms of the timing of how these things have come to pass.

And there was a fair bit of correspondence and communication back and forth between Manitoba Hydro and the Public Utilities Board through this timeframe. One (1) of the limiting factors that Manitoba Hydro encountered was the need to be do -- doing a new depreciation study that was going to be reflective of the introduction of international financial reporting standards.

And that was a -- a complication, if you would, in terms of us being able to do some of the -- the study work that was being requested because a lot of it would flow along with the depreciation study itself.

DR. BYRON WILLIAMS: Mr. Barnlund, thank you for that. You're not suggesting, sir, that other utilities were not able to conduct asset condition assessments at the same time that they

undertook depreciation studies, are you, sir?

MR. GREG BARNLUND: Well, I would suggest you, Mr. -- or Dr. Williams, that many other utilities adopted US GAAP through that period of time, and likely didn't have the complications that Manitoba Hydro faced.

If you recall the discussions we've had with regards to IFRS, there was a number of delays and a number of changes in the schedule of IR -- IFRS's adoption -- or finalization and adoption that tended to complicate things, where other utilities that would be reporting under US GAAP would not face that same set of complications as did Manitoba Hydro.

DR. BYRON WILLIAMS: Mr. Barnlund, I wonder if you can go with me to tab 12 being an excerpt from -- of the Coalition book of documents being an excerpt from Order PUB 49/14, and specifically page 163 in the middle of that page.

MR. GREG BARNLUND: Yes, sir.

DR. BYRON WILLIAMS: Again, sir, you'll see a reference to directive 7 of Order 43/13 requiring Manitoba Hydro to file an asset condition assessment no later than the filing of the next depreciation study; that will help continue the conversation, sir?

MR. GREG BARNLUND: Yes, I see that.

DR. BYRON WILLIAMS: Sir, move with me, if you would, to tab 13, specifically page 170(a).

MR. GREG BARNLUND: Yes, sir.

DR. BYRON WILLIAMS: And go down to the per -- just up the page a bit, that's perfect, Kristin.

Here you see the Board in Order 73/15 on the fourth line articulating a concern that Hydro has not -- that it's -- excuse me, that it's not satisfied that Manitoba Hydro has adequately evaluated the long-term pacing and prioritization requirements, sir? Agreed?

MR. GREG BARNLUND: I see it written there, yes.

DR. BYRON WILLIAMS: And at the last three (3) lines of that same paragraph, you'll see the Board suggesting that it --

> "It's acceptance of the increased sustaining capital spending during this GRA -- GRA should not be construed as an endorsement of Hydro's long-term sustaining capital plan."

Agreed?

MR. GREG BARNLUND: Yes, that -- that's their finding, and -- and I think that it's important to reflect on where Manitoba Hydro found itself in 2015 with regards to migrating to -- to the work that Mr. Wortley has been testifying to in terms of how we're going to be transitioning to our new asset management and investment strategies and -- and -- and -- and program.

So we were -- were -- we were sort of with one (1) foot in either camp here but -- at the time at this Order was written.

DR. BYRON WILLIAMS: With --

MR. JOEL WORTLEY: I think I could add that by no means has Manitoba Hydro been idle during this time and that asset management is often described as a journey and so it has to happen across many fronts in parallel, but also in sequence.

And so when I think about the history of Manitoba Hydro and the history of asset management at Hydro -- at Manitoba Hydro there have been many -- many steps made, many practices improved and to bring up page 11 of the UMS report appendix 5.1 from the General Rate Application, there's a convenient little graphic here that I -- I think will help understand a little bit.

Areas that Manitoba Hydro has made improvements in and areas where improvements are still to come. And so it's a little bit complicated. I -- I apologize for that. But if you think about the latter I showed in direct evidence where the customer drives from the top, influences what the objectives of the company need to be, and so on down to a particular asset decisions, the customer sits at the top left side of this diagram. It influences company strategy. That company's strategy drives the business objectives which turn into an asset management policy and strategy you can see in the centre -- top centre. That drives down into asset management objectives and targets and into the development of asset management plans, the bottom row middle.

Those plans affect what spendings can occur in Opex, or operating and maintenance and Capex, capital expenditures. Capital expenditures are optimized and then you can see on the far right side coming back, asset health indices are an input to this process.

So you can see which of the boxes are -- are our darker coloured and are rated by UMS as being close to competent and which areas still require -- or still have larger gaps to be closed.

And so significant progress has been made here, and UMS does note that we compare favourably to North American industry as a whole.

So while we have not always been able to produce the reports that have been asked of us, we have not been idle in advancing our asset management journey.

DR. BYRON WILLIAMS: Mr. Wortley, UMS gave you a score of 1.5 in aggregate, with confidence being at level -- at Level 3; agreed?

MR. JOEL WORTLEY: That's correct.

DR. BYRON WILLIAMS: Mr. Barnlund, going to tab 15 of the Coalition book of documents being Order 59/16, and specifically at page 181.

Sir, this is 2016 now?

MR. GREG BARNLUND: Yes, sir.

DR. BYRON WILLIAMS: And you see as -- going to the very last reference on page 181, you see the Public Utilities Board, again, requiring Hydro to file the complete asset condition assessment at the next General Rate Application?

MR. GREG BARNLUND: Yes, sir.

DR. BYRON WILLIAMS: Mr. Barnlund, it's always a pleasure, you're more than welcome to hang out for the rest of the day, subject to the

guidance of your legal counsel, in terms of the regulatory history, those are the questions that I intend to ask today. So I'll leave it to your -- leave it to you -- to you to decide whether you wish to be excused or not.

Thank you, Mr. Barnlund.

MR. GREG BARNLUND: Thank you.

DR. BYRON WILLIAMS: We're going make a just a quick dive into the Boston Consulting PowerPoints, and specifically MFR-72, appendix 1. Boston Consulting Group, page 176.

Mr. Wortley, have you seen this slide before?

MR. JOEL WORTLEY: I have.

DR. BYRON WILLIAMS: Okay. And you see the characterization of the Boston Consulting Group as Manitoba Hydro having strong current reliability; agreed? You see that at the top, sir? The headline?

MR. JOEL WORTLEY: Yes.

DR. BYRON WILLIAMS: And sir, when we -- when we look at asset management -- management planning, clearly, reliability and safety are -- are very important considerations; agreed?

MR. JOEL WORTLEY: They are.

DR. BYRON WILLIAMS: Cost-effectiveness is -- is also an important considerations, sir?

MR. JOEL WORTLEY: I would agree.

DR. BYRON WILLIAMS: And ultimately, the impact on ratepayers, both in terms of reliability as well as in terms of costs, are -- is an equally important consideration, sir?

MR. JOEL WORTLEY: They're both important.

DR. BYRON WILLIAMS: Thank you. Now I'm going to ask to pull up Manitoba Hydro's response to Coalition 2-68, attachment 1.

MR. JOEL WORTLEY: Sir, were we done with BCG benchmarking there or were we going to explore that --

DR. BYRON WILLIAMS: I was moving on, sir.

MR. JOEL WORTLEY: Before we move on, can we just take a quick stop at -- MFR-72, page 340.

I just want to comment that on this slide we see that albeit that BCG found that Manitoba Hydro's reliability to be currently good, aging assets are looming as an issue.

And if we go to the next slide, the

benchmarks indicate spend has been similar or less than peers.

And to the next one again, the system renewal capacity -- system renewal capital insufficient to replace aging assets. And so I just want to point out that with respect to benchmarking, these are interesting findings, but they're not sufficient with which to make any real decisions. You can't go increase the capital program simply because BCG found that potentially the dollars were less than someone else was spending. You got to go back to the reasons for the investments and make sure that each one is of value.

So, similarly, albeit we find BCG's findings on the other aspects to be of interest, I do note that they're not particularly useful for driving direct action.

DR. BYRON WILLIAMS: And one (1) of those reasons, sir, would be that BCG in terms of its retainer was at Manitoba Hydro for basically three (3) months; agreed?

MR. JOEL WORTLEY: I couldn't comment on it.

DR. BYRON WILLIAMS: Okay. Let's go to Coalition 2-68, attachment 1. And let's go to page

1 just for a second, please, Kristin.
Mr. Wortley, this is -- and whether this is to you or Mr. Turner. This is a report from the engineering services division generations op -- operations covering a period between May and -- and January -- May 2015 and January 29.
Would that be fair?
MR. JOEL WORTLEY: Yes, it would.
DR. BYRON WILLIAMS: And, Mr. Wortley, you'll recall from the UMS report of December 2016 a suggestion that most asset management efforts were focused on capital spending with minimal attention given to optimizing operations and maintenance.
Do you recall that, sir?
MR. JOEL WORTLEY: I do.
DR. BYRON WILLIAMS: And if we turn to page 3 of this page -- go to page 2 just for one second, Kristin.
This is a review of and an effort to develop a strategic maintenance plan for the general operations asset. Mr. Wortley, is that right?
MR. JOEL WORTLEY: I think that's fair.
DR. BYRON WILLIAMS: And going to page 3 and focusing your attention on -- on the second

bullet, one (1) of the challenges identified was that the current condition monitoring of the equipment was not adequate.

Do you see that reference, sir?

MR. JOEL WORTLEY: I do.

DR. BYRON WILLIAMS: And were you head of generation at this time, sir?

MR. JOEL WORTLEY: I was.

DR. BYRON WILLIAMS: And also going to the third bullet:

> "Information on the current condition of much equipment was also not adequate at that point in time."

Would that be fair, sir?

MR. JOEL WORTLEY: It would.

DR. BYRON WILLIAMS: Now, I'd like to go to Manitoba Hydro in -- in conducting this analysis did a survey of staff such as station manager, site supervisors and planners; agreed, sir?

MR. JOEL WORTLEY: Yes.

DR. BYRON WILLIAMS: And perhaps we can go to page 40.

And, Mr. Wortley, this was a survey in June of 2015. Has there been a survey subsequent to this, sir -- of this type of survey with -- with

regard to generation?

MR. JOEL WORTLEY: No, there is not.

DR. BYRON WILLIAMS: So, in essence, these are the -- the good folks in generation, the station manager, site supervisors and planners sharing with -- with Manitoba Hydro some of the major themes that they identified in terms of maintenance programs.

Would that be fair, sir?

MR. JOEL WORTLEY: Yes, this is ongoing and continuous improvement endeavour on behalf of those -- those staffers to look for opportunities for improvement and included in that was canvassing the -- the -- the station staff themselves to get a perspective from the shop floor.

DR. BYRON WILLIAMS: And certainly from the stops -- taught -- shop floor, frequent comment number 1 was the lack of quality maintenance procedures.

Do you see that, sir?

MR. JOEL WORTLEY: I do.

DR. BYRON WILLIAMS: And we'll go through some of those other themes, but you'll agree with me, those were the top five (5) frequent comments made by the front line staff?

MR. JOEL WORTLEY: Yes, I would.

DR. BYRON WILLIAMS: And if we can go down to theme 1, for a moment, Kristin, on this same page, being page 40.

And Mr. Wortley, you see in the first paragraph under Section 7.1, line 3, theme 1 being:

> "Unfortunately, the work management measure rep -- measures reports do not have desired effect of looking for improvements with the suggestion in some iss -- areas there's workarounds created to make the numbers look good but not to improve the process."

Do you see that, sir?

MR. JOEL WORTLEY: I do. This is -- one (1) of the reasons that these processes have been improved with our new enterprise asset management system, which is now enrolled out to all the generating stations --

MR. HAL TURNER: Correct.

MR. JOEL WORTLEY: -- and is -- is plugging many of these gaps.

DR. BYRON WILLIAMS: And there was, sir, at the time, a concern that administrative duties appear to be greatly increasing, and tool site -- time

for site maintenance staff is decreasing?

MR. JOEL WORTLEY: Yes, this is a real concern. Particularly as the industry gets more regulated with respect to safety and environment, there are more and more processes being added on site -- supervisory staff that takes them away from tool time.

DR. BYRON WILLIAMS: Sir, going to theme 3, in terms of the RCM Program and Philosophy, and directing your attention to just above (a) you'll see a common understand -- a suggestion that the common understanding of the current program seems to be lacking. Do you see that, sir?

(BRIEF PAUSE)

MR. JOEL WORTLEY: Yes, I do.

DR. BYRON WILLIAMS: And some specific areas of concerns, including no one is reviewing the results from the current maintenance updating failure modes and ensuring current task and intervals are appropriate, with the suggestion that the current program has not been reviewed since implementation greater than ten (10) years?

MR. JOEL WORTLEY: That's correct.

DR. BYRON WILLIAMS: Sir, we're not going to go through all of these, but let's go to theme 4 for a moment.

(BRIEF PAUSE)

DR. BYRON WILLIAMS: And sir, in particular with theme 4, I want to direct your attention to the last sentence, being a concern with the lack of predictive programs that was to be of -- implemented to move towards more condition-based maintenance. Do you see that reference, sir?

MR. JOEL WORTLEY: I do.

DR. BYRON WILLIAMS: And sir, when was EAM implemented?

MR. JOEL WORTLEY: The EAM implementation is ongoing. It wrapped up in the generating stations this year, I believe.

MR. HAL TURNER: Correct. The last generating station was put in in November.

MR. JOEL WORTLEY: And is --

MR. HAL TURNER: November, yes.

MR. JOEL WORTLEY: -- currently being rolled out in -- in other parts of the Company.

DR. BYRON WILLIAMS: Okay. Thank you.

We'll move to theme 5 for a moment, page 42. And focusing on the first three (3) lines, sir, there's a suggestion that there's a lack of proper documented and controlled maintenance procedures, and currently, the quality we have ranges from poor to excellent, but no one is -- was reviewing the procedures for adequacy, consistency or continuous improvement.

Do you see that theme, sir?

MR. JOEL WORTLEY: I do.

DR. BYRON WILLIAMS: Theme 6, sir, suggests that there's been too many forced extensions -- going to the second line, sir, too many forced extensions in the past few you -- years, suggesting a planning issue?

(BRIEF PAUSE)

MR. HAL TURNER: That's correct.

DR. BYRON WILLIAMS: Theme 8, being page 44 of 111, go to page -- yeah. My -- I misspoke, page 43.

Going to the second line and down, there is a suggestion in June of 2015, that some basic condition monitoring tasks, as well as oil analysis, were put into the maintenance program, but the higher

technologies, such as vibration or air gap monitoring, have had limited progress, even though they are key components for measuring and monitoring machine health. Do you see that reference, sir?

MR. HAL TURNER: I do. I think these themes are reflective of the -- a previous -- a -- a system that we had in place, which is -- and so the implementation of EAM is going to address a lot of these things.

We've got other tools that we're putting in. So when we -- when we look at condition monitoring, in the past, it's been very manual, and so we're -- we're putting in a tool called Meridium to help automate these kind of things to make it more -- less onerous, and so that we can get this kind of information processed easier, and we can use it to improve our maintenance practices.

DR. BYRON WILLIAMS: Thank you, sir. And to you, Mr. Wortley, you'll agree that a coordinated, optimized, and dev -- deliverable maintenance program is essential to ensure efficient use of operating funds, agreed?

MR. JOEL WORTLEY: I would certainly agree that maintenance is a critical part to managing assets for which maintenance can make a difference in

their performance or -- or life expectancy, yes.

DR. BYRON WILLIAMS: And it's also critical to improve operations and maintenance performance, agreed?

MR. JOEL WORTLEY: Sorry, maybe you could state the whole -- restate the whole question, please?

DR. BYRON WILLIAMS: Sir, I'll suggest to you that a coordinated, optimized, and deliverable maintenance program is essential to improve operations and maintenance performance, agreed?

MR. JOEL WORTLEY: Yes, I would agree with that.

DR. BYRON WILLIAMS: And sir --

MR. HAL TURNER: Actually, I'd just like to point out, I -- I agree it will help improve our operation and maintenance performance. But if you look back at the BCG benchmarking, you'll see that the generation, wholesales, operations, and administrative performance is actually quite good compared to our peers.

DR. BYRON WILLIAMS: And sir, as of January 16, 2016, and focusing on generation, would it be fair to describe the existing maintenance program activities as inconsistent, isolated, and not having

improved for a number of years?

MR. JOEL WORTLEY: Sorry, where are you quoting from, sir?

DR. BYRON WILLIAMS: Your strategic maintenance plan, Coalition 1-81, sir.

MR. JOEL WORTLEY: Can we bring that up?

DR. BYRON WILLIAMS: Yeah, we certainly can. It's page 13 of 86, Coalition-MH 1-181, first paragraph.

(BRIEF PAUSE)

MR. JOEL WORTLEY: And sorry, what was your question?

DR. BYRON WILLIAMS: As of January 2016, you described the existing maintenance pro -- program activities as inconsistent, isolated, and having not improved for a number of years. Would that be fair?

MR. HAL TURNER: I think that refers to the fact that the maintenance plans were created for each station, because the stations -- that's how we manage our assets at the station level, or that's how we managed our assets at the station level.

And this is speaking to the fact that we want to take more of a asset class approach to it, so that -- I think that's the context of those comments.

DR. BYRON WILLIAMS: Thank you for that. And if we can go to page 65 of 86 of this document, being Coalition 1-81, you'll see Mr. Turner -- Mor -- Mr. Wortley, a suggestion that a consultant review of the current maintenance plan must proceed to create standardized maintenance task templates by system or equipment type. Do you see that reference?

MR. HAL TURNER: I do.

DR. BYRON WILLIAMS: And has this been completed, sir?

MR. HAL TURNER: We did hire a consultant. Just one moment.

(BRIEF PAUSE)

MR. HAL TURNER: I we did hire a consultant to -- Hatch was the name of the consultant -- to look at our generators. Unfortunately, we found that the product that they delivered did not meet our expectations, and the price was significantly higher than originally quoted. So we are currently taking a

look at our cranes and our spillway. So this is as part of -- to support the Keeyask project. And so we are going to do this internally.

As part of our restructuring, we've been able to dedicate some staff to asset management initiatives, and we're going to do this internally, at least for these two (2) assets.

DR. BYRON WILLIAMS: And this task, sir, in terms of this report was described as a huge step towards consistency for the equipment maintenance? Do you see that, sir?

MR. HAL TURNER: Yes. We want to be more consistent than we have, but keep in mind that our plants have been in service since the early 1900, or as late as 2012, so it won't be exactly the same everywhere. There will be some similarities, and -- and sharing of best practice, but it will not be 100 percent consistent across every station.

DR. BYRON WILLIAMS: Now, am I correct in suggesting to you that as part of Hatch's original scope of work, the task of completing this template was to be completed by the 29th of December, 2017?

MR. HAL TURNER: One moment.

(BRIEF PAUSE)

MR. HAL TURNER: I'm sorry, can you repeat that date again? Did you say December 2017?

DR. BYRON WILLIAMS: Yeah.

MR. HAL TURNER: I -- I think it was December 2016, and then it ext -- ended -- ended up getting extended until about March of 2017.

DR. BYRON WILLIAMS: Okay. And that task ultimately wasn't completed and has now been assigned to internal staff? Is that right?

(BRIEF PAUSE)

MR. HAL TURNER: So the consultant was looking at generators, as I mentioned, and they started with the generators at the Grand Rapids Generating Station, and the cost of their exercise significantly exceeded or was trending to significantly exceed what they had originally told us the entire study would cost. So we stopped the generator study, and we are doing an internal review, but not of generators, of powerhouse cranes and spillways.

DR. BYRON WILLIAMS: Thanks. I'll be leaving in the generation maintenance issue, and I just want to have -- deal with some common -- what I

hope are common definitions with Manitoba -- Manitoba Hydro.

And again, Mr. Wortley or -- or otherwise, but in terms of run to failure, is that essentially when assets are run to reach physical end-of-life conditions, with no proactive asset replacement management strategies conducted?

Would that be fair?

MR. JOEL WORTLEY: Yeah. Run to failure is -- is used in the context where the consequence of an asset failing in service is tolerable, and so it is -- it is allowed to deteriorate to a point where it no longer meets its function, whatever that happens to be, before being replaced.

DR. BYRON WILLIAMS: And would you agree that economic end of life, as used in asset management, is the threshold when the asset ceases to be the lowest cost alternative to performing a particular function at a particular expected competence -- competency bundle of quality, safety and reliability?

(BRIEF PAUSE)

MR. JOEL WORTLEY: Sorry, could you repeat, please?

DR. BYRON WILLIAMS: Mr. Wortley, I'll do my best. As used in asset management, economic end of life is the threshold when the asset ceases to be the lowest cost alternative to performing -- performing a particular function at a particular expected competency?

MR. JOEL WORTLEY: I think that's reasonable.

DR. BYRON WILLIAMS: Theoretically, that's when you would want to replace an asset, because it costs you more to keep it than to replace it, agreed?

MR. JOEL WORTLEY: Theoretically, yes. In -- in practical application, it becomes a flag where -- where you should go make a deeper dive. So if the indication is that you're approaching economic end of life, that's the right time to go have a closer look at the asset, evaluate its particular -- you have to understand that economic end of life comes as a function of degradation and degradation or an asset health indices is an assessment of the average health of the asset.

So it doesn't tell you particularly how

that asset's going to fail, if it's just going to continue to degrade in terms of not to be able to turn as fast, or if it's going blow up, or what -- what actually is going to happen to this asset. So before you can make a decision, as to whether to intervene or not, you need to take a closer look at what are the failure modes tied to this particular asset, what is happening that its condition score has gone down to the point that it appears to be at economic end-of-life, do I really need to intervene now, what -- what risks do I carry by leaving it in service?

So, economic end-of-life is helpful in terms of knowing where to look, but it's not definitive in knowing how to act. Or how to react.

DR. BYRON WILLIAMS: And, sir, would it be fair to say that definitions of economic end-of-life change over time as utilities use new processes or equipment, which makes replacement or maintenance more cost-effective? Or the calculation, rather than the definition, sir.

MR. JOEL WORTLEY: The inputs certainly change.

DR. BYRON WILLIAMS: Fair enough. And that's why, sir, asset management, as you aim to practice it, is a comprehend -- comprehensive feedback

loop of theory and practice. Agreed?

MR. JOEL WORTLEY: Yeah. One of the great challenges we have with asset management is definition, so I'm -- I'm glad that we're -- we're clearing some of that up. It is very difficult or challenging in that we all tend to use the same words and mean slightly different things. It's important -- and this sounds almost ridiculous but it's true -- there's a marked difference between asset management and managing assets.

Managing assets is about making particular decisions about an asset, in terms of how to operate it, and how to maintain it, when to intervene.

Asset management is the coordinated activities of an organization to realize value from its assets. So it's that -- that ladder that I showed again in direct leading from the customer, in terms of an objective, right down to day-to-day asset decisions at the bottom of the scale, and making sure that these things are all in alignment.

DR. BYRON WILLIAMS: Okay. Thank you. Sir, hopefully this will be a quicker question.

System Average Interruption Duration, or SAIDI, measures the average outage duration

experienced by customers. Agreed?

MR. JOEL WORTLEY: Agreed.

DR. BYRON WILLIAMS: And System Average Interruption Frequency, or SAIFI, measures the average number of interruptions that customers have experienced. Agreed?

MR. JOEL WORTLEY: Yes.

DR. BYRON WILLIAMS: And for transmission and distribution, those are key long-term performance metrics. Agreed?

MR. GERALD NEUFELD: I would say that for transmission that would not be the case. And -- and the reason for --

DR. BYRON WILLIAMS: Simply for distribution, sir?

MR. GERALD NEUFELD: I'm sorry?

DR. BYRON WILLIAMS: Okay, go ahead.

MR. GERALD NEUFELD: And -- and the reason that the TSAIFI and TSAIDI are not the prominent metrics, is that -- that doesn't mean that there is an outage. What -- what a TSAIFI outage means is that there's a node which has lost one of its supplies. But it could have alternate supplies, so the power is still flowing.

DR. BYRON WILLIAMS: So -- thank you.

So, in essence, Hydro's agreeing that it is for tra -- for distribution? You're nodding your head, Sir?

MR. JOEL WORTLEY: Yes. Yes.

DR. BYRON WILLIAMS: Mr. Wortley, without asking you to elaborate on the corporate value framework, I'll ask you to agree that it was not used to determine which project should be executed within capital expenditure forecast 2016. Agreed?

MR. JOEL WORTLEY: That is correct. The corporate value framework is currently being piloted.

DR. BYRON WILLIAMS: And it would be fair to say that the capital and operating budgets in the current filing were not developed with -- using the new asset management methodologies?

MR. JOEL WORTLEY: Yes. As I described in -- again, in my direct evidence, that the investments in the test years are programmed by our operating and subject matter experts, based on risk assessments, in view of keeping the system operating in a safe and reliable manner in the short-term. And the longer-term forecasts are anchored in historic spending trends shaped around the best information we've got as to where things are going in the future.

MR. HAL TURNER: I need a course on

how to use this mic. I'm sorry.

I would like to add -- so the -- the CEF16 is a snapshot in time of the capital -- the Corporation's capital plan. And, as my colleague Mr. Wortley pointed out, generation wholesale is piloting the use of the corporate value framework. And we did use the corporate value framework to identify scope and set the timing of projects that do actually appear in the test years; they're just not necessarily documented in CEF16.

DR. BYRON WILLIAMS: So, just so I am clear, not transmission, not distribution?

MR. GERALD NEUFELD: Transmission did -- is not yet a position to be using the corporate value framework as a prioritization tool. However, we have a dif -- a -- a different tool, a prioritization tool, that we -- we established back in the early 2000s, which has been enhanced on a few occasions. And that's -- that's the -- the tool we use to prioritize for transmission projects.

MR. CHUCK STEELE: You know, I can comment on distribution. Generally our -- our asset replacement strategies are based around replacing assets that no longer meet our customers' requirements.

DR. BYRON WILLIAMS: Mr. Wortley, in -- and you adverted to this in my -- your conversation with my Learner Friend Mr. Peters.

In the terms -- in terms of determining the optimum design of its portfolio, Manitoba Hydro does not forecast or project SAIDI or SAIFI values. Agreed?

MR. JOEL WORTLEY: Agreed.

DR. BYRON WILLIAMS: And, it would be fair to say, more general -- generally, that Hydro does not forecast reliability improvements associated with the catural -- capital and operating expenditures related to specific projects or programs. Agreed?

MR. GERALD NEUFELD: I -- I would say that that's not true for transmission. We -- we have deve -- developed some tools that use a probability of failure in the analysis, and that's one of the inputs for the prioritization.

DR. BYRON WILLIAMS: You're referring to the System Reliability Risk Model, sir?

MR. GERALD NEUFELD: Yes.

MR. CHUCK STEELE: You know, if -- if I may, I'd like to put some context around SAIDI and SAIFI, and how it's utilized at Manitoba Hydro.

Certainly, my understanding is that our

counterparts at CEA have either advanced metering infrastructure or advanced remote monitoring, whereas Manitoba Hydro does not. So our SAIDI and SAIFI calculations are done on a relatively coarse methodol -- methodology compared to our counterparts.

So our expectation is that if we go down the path of adding more sophistication to be able to record SAIDI and SAIFI with more -- more accuracy, our -- our consultants tell us that the -- our reliability of figures will actually become worse once we have a more accurate accounting for them.

So when we're -- when we're comparing SAIDI and SAIFI, I think it's important to recognize, against our peers, that our method of calculating it is a more coarse method than what our peers would have.

DR. BYRON WILLIAMS: I don't want to follow this too far, sir, but just so I understand it, are you indicating that if the method of calculation improves, the results will be worsened?

MR. CHUCK STEELE: Well, to give an example, our -- our SAIDI calculation starts when a customer phones our contact centre and tells us that they're out of power, in -- in many circumstances. So that's when the clock starts ticking. In another

utility they might know the instant that customer does not have power.

Yeah, also, from a frequency perspective, we don't capture short duration outages. We don't have that sophistication. So if someone has a, you know, a three (3) second outage in their home that, through our system, we're able to reconnect, but we might not be aware that they were out for that -- for that duration you.

DR. BYRON WILLIAMS: Thank you. Thank you. Mr. Wortley, in the current opti -- optimization process, it would be fair to say that capital investment scenario analysis is not part of it?

And -- and if you need more precision, sir, I'm suggesting to you that Manitoba Hydro, for the test years, did not explicitly evaluate alternative investments sary -- scenarios for the test years to determine the relefe -- relative performance outcomes for different levels of investment. Agreed?

MR. JOEL WORTLEY: Yeah, that -- that's -- that is -- I would agree with that. One (1) of the capabilities of the corporate -- or Capital Portfolio Management Program that we are currently deploying, is to allow scenario analysis.

DR. BYRON WILLIAMS: Mr. Chair, I'm

not sure if the Board wishes or desires a -- a quick break this afternoon. If so, I'm going to move into a related area, but --

THE CHAIRPERSON: Well, we can -- we can either take it now or in a half an hour. How long is in the next area you're going into?

DR. BYRON WILLIAMS: I'm gonna say it will take forty-five (45) minutes to an hour.

THE CHAIRPERSON: Then let's take a -- we'll take a fifteen (15) minute break now.

--- Upon recessing at 3:29 p.m.

--- Upon resuming at 3:48 p.m.

THE CHAIRPERSON: Dr. Williams...?

CONTINUED BY DR. BYRON WILLIAMS:

DR. BYRON WILLIAMS: Kristin, if you can turn to Coalition 32-1, page 5.

Mr. Wortley, you'll recall just before the break a bit of a discussion about capital scenario analysis. Do you remember that, sir?

MR. JOEL WORTLEY: I do.

DR. BYRON WILLIAMS: And the indication was that that is something that Manitoba

Hydro aspires to as it moves forward in the next three (3) to five (5) years in terms of its capital asset management portfolio?

MR. JOEL WORTLEY: That's correct. We're laying the groundwork as we speak.

DR. BYRON WILLIAMS: And you're aware as well, sir, that other utilities currently use capital analysis -- excuse me, capital scenario analysis to consider impacts on projected performance metrics of different capital investments scenarios; agreed?

MR. JOEL WORTLEY: Yep.

DR. BYRON WILLIAMS: And you're aware as well that other utilities use capital scenario analysis to consider within a specific portfolio optimized investments aimed at achieving certain performance metrics; agreed?

MR. JOEL WORTLEY: That sounds reasonable.

DR. BYRON WILLIAMS: That your understanding, sir?

MR. JOEL WORTLEY: Yep.

DR. BYRON WILLIAMS: And, sir, recognizing that -- in the course of this hearing you've had the opportunity to review the evidence of

METSCO written on behalf of the Consumers Coalition?

You've reviewed that, sir?

MR. JOEL WORTLEY: I have.

DR. BYRON WILLIAMS: And recognizing that what is before us is not the METSCO report filed for the purposes of this hearing, but you're aware -- and you assisted as well, sir, in developing the Corporation's rebuttal to METSCO's evidence?

MR. JOEL WORTLEY: I did, yes.

DR. BYRON WILLIAMS: And you're aware, sir, that in the course of the METSCO evidence in the course of this hearing they cited a number of good practice examples of -- of different utilities in terms of capital asset management.

You're nodding your head?

MR. JOEL WORTLEY: Yep.

DR. BYRON WILLIAMS: And certainly, sir, you were made aware by your -- that some of those good practice examples might be referred to in the cross-examination of the Coalition; agreed?

As set out in this book of documents?

MR. JOEL WORTLEY: yes.

DR. BYRON WILLIAMS: And so, sir, have you reviewed at tabs 1 through 6 of the Coalition book of documents; you or your team?

MR. JOEL WORTLEY: I've -- would say I've reviewed them far enough to have a general understanding.

DR. BYRON WILLIAMS: Okay. And, sir, recognize as we go through these questions that to a significant degree we're trying to use these for illustrative purposes and not to delve deep into your personal knowledge of EPCOR or other utilities.

Do you understand that, sir?

MR. JOEL WORTLEY: Yes, it would be a short dive.

DR. BYRON WILLIAMS: And so, sir, let's -- let's walk our way through this and -- and just speaking of a short dive, in terms EPCOR, E-P-C-O-R, which I do not believe is an acronym but it's a brand, that, in essence, is Edmonton's power and water utilities, sir?

MR. JOEL WORTLEY: If -- if you say so.

DR. BYRON WILLIAMS: Okay, if you don't know that's fine. Sir, I want to draw you specifically -- before we get into the -- this document specifically, when we look at outage events, would it be fair to say that while some are within the control of the Corporation, there are others that

cannot be mitigated, or can only be partially mitigated.

Would that be fair, sir?

MR. CHUCK STEELE: Yes, I would say that's fair.

DR. BYRON WILLIAMS: Weather events would be one (1) of those where it's difficult to fully mitigate?

MR. CHUCK STEELE: Yeah, cert -- certainly there can be hardened designs of portions of the distribution network that would be better suited to withstand certain weather events but, yeah, generally speaking, a lot of those events are out of our control.

DR. BYRON WILLIAMS: And so when we look at causes of outages potential items such as scheduled outages may be elements that may be more controllable by the Utility; agreed?

MR. CHUCK STEELE: Yes, agreed.

DR. BYRON WILLIAMS: And defective equipment, at least to a certain degree, is a reflection of the -- the choices that a utility makes in terms of its investment decisions; would that be fir?

MR. CHUCK STEELE: Yep. Yes, it would

be fair.

DR. BYRON WILLIAMS: So in terms of outage causes, at least, those two (2) would be examples of ones that are more controllable; agreed?

MR. CHUCK STEELE: Yes and I would argue that I could add to that list: vegetation management. I think equal to defective equipment a large percentage of our outages are due to tree contacts for argument.

DR. BYRON WILLIAMS: Okay. So the big three (3) in terms of controllable would be vegetative management, defective equipment and scheduled outages, from the Corporation's perspective?

MR. CHUCK STEELE: I think that would be a fair summary.

DR. BYRON WILLIAMS: And I wonder if we can turn to tab 1, page 10 of Coalition 32-1. And scroll down the page a bit more. Thank you.

At a high level, and primarily for illustrative purposes, what the METSCO analysis in this document is attempting to do is to examine the consequences of different spending and investment decisions on key performance metrics.

Would that be fair?

MR. CHUCK STEELE: Yes.

DR. BYRON WILLIAMS: And in essence, if we focus on the third paragraph before us, one (1) of the options, one could examine in a scenario, is expenditure level designed to keep metrics at -- at the current level that they -- they are.

Would that be fair?

MR. CHUCK STEELE: Can -- can you maybe point to that a little bit closer.

DR. BYRON WILLIAMS: I'm directing your attention to the last sentence on the third paragraph suggesting mid-point scenarios contemplate maintaining SAIDI and SAIFI at recent levels.

MR. CHUCK STEELE: To the extent they're utilizing SAIDI and SAIFI as their performance benchmarks or metrics, sure, I agree.

DR. BYRON WILLIAMS: Okay.

MR. CHUCK STEELE: That that's what that paragraph says.

DR. BYRON WILLIAMS: And additionally, one could look, directing your attention to the fifth line of this same paragraph, at scenarios targeting improvement in either SAIDI or SAIFI in terms of investment decisions. Agreed?

MR. CHUCK STEELE: Agreed. Can I add some commentary about --

DR. BYRON WILLIAMS: You can, indeed, sir.

MR. CHUCK STEELE: Our -- Manitoba Hydro's investment drivers from a distribution perspective, we don't quantitatively target SAIDI or SAIFI whether it's to maintain or improve.

Our -- our investment drivers are very clearly to -- to meet our customer connection requirements; to ensure that the system is capable of supplying existing; and a reasonable amount of future customer connections. Then finally, we look at our system renewal spend based on condition assessments.

So -- so we don't target system renewal investments on changes or -- or maintaining SAIDI or SAIFI numbers, we -- we base our placements on system assessments -- or condition assessments of those assets.

DR. BYRON WILLIAMS: That's how you do it currently, sir, but --

MR. CHUCK STEELE: That is correct.

DR. BYRON WILLIAMS: -- you're not -- yes, you are not suggesting --

MR. CHUCK STEELE: Our -- our goal certain -- certainly, our goal is to increase our understanding of our system and to have better

analytics going for.

DR. BYRON WILLIAMS: And taking that goal further, sir, it is to be able to make investment dec -- decisions based on an informed understanding of what the potential outcomes may be in a variety of key metrics, including SAIDI and SAIFI; agreed?

MR. CHUCK STEELE: I would agree with that, with the -- maybe added caveat that in all these instances the -- the ends have to justify the means and that if we're going -- as we walk this path as we come down and get closer to being able to -- to build the models to make the predictive analyses, we want to make sure that the effort involved in making the prediction pays off in the decision that is affected by the prediction.

And so if we -- if we see that an unreasonable amount of investment in time and -- and data collection and analysis is going to be required to which they'll be very little impact to the decision, then we're -- we're not going to do it. It's got to make sense and it's got to pay back which is a -- a fundamental tenet of asset management. All of your activities have to carry value.

So if and when we get to a point where predicting outcomes on this scale is of value in the

decision-making, yes, we will do it.

DR. BYRON WILLIAMS: And just to finish what this analysis examines, we've already talked about looking at maintaining the SAI -- the performance metrics that are -- at -- at recent levels; agreed?

MR. CHUCK STEELE: With respect to EPCOR?

DR. BYRON WILLIAMS: Yeah.

MR. CHUCK STEELE: Yes.

DR. BYRON WILLIAMS: We've also talked about improving performance metrics; agreed?

MR. CHUCK STEELE: Again with respect of EPCOR, yes.

DR. BYRON WILLIAMS: Yes. And let's premise all this discussion on this is what can be done in terms of forward-looking practice.

Is that fine with you, sir?

MR. CHUCK STEELE: That's fine.

DR. BYRON WILLIAMS: And as Mr. Peters -- My Learned Friend Mr. Peters discussed with Mr. Wortley earlier, you could also target your investment scenarios, as EPCOR did here, in terms of considering lowering your performance metrics by 10 percent; agreed?

MR. CHUCK STEELE: You know I -- I did skim through the report. I did not look through it very closely. But my understanding was METSCO looked at EPCOR in terms of trends and whether you could have them improving or decreasing reliability metrics but -- but it wasn't specific as to targeting, you know, quantitative numbers so I'm not sure if that's what you're -- you're asking but...

But certainly my impression it was more of a trend that they -- they could target improving reliability or de -- decreasing reliability.

DR. BYRON WILLIAMS: And as you'll see on the third last line of the paragraph before you, sir, even investigating scenarios aiming at a managed 10 percent degradation of both metrics.

Do you see that, sir?

MR. CHUCK STEELE: Yep. Yes.

DR. BYRON WILLIAMS: And turning to page 11 of this document, recognizing this is EPCOR practice, sir, I'll suggest to you that on pages 11 and 12 are eight (8) different scenarios considered by EPCOR.

Will you agree with that, sir?

MR. CHUCK STEELE: Yes, I count -- I count eight (8).

DR. BYRON WILLIAMS: And again, sir, using run to failure as the base case, they examine the outcomes of investment decisions aimed at improving performance, keeping performance stable or having a 10 percent degradation in performance; agreed?

MR. CHUCK STEELE: Agreed.

DR. BYRON WILLIAMS: And if we turn to, sir, page 13 of this document focusing, you'll agree with me, sir, that the -- what this type of material would enable a decision-maker to consider are the outcomes of a family of investment decisions as they affect reliability metrics; agreed?

MR. CHUCK STEELE: You know, agreed. I guess I would add the caveat that I don't know that METSCO wrote this report on EPCOR'S -- EPCOR'S behalf but I don't know to the level that EPCOR accepted the recommendations or the -- the findings of this report.

DR. BYRON WILLIAMS: And sir, I'm not asking you to comment on the recommendations --

MR. CHUCK STEELE: But certainly, the -- the -- METSCO does present some curves that purport to do exactly what you say.

DR. BYRON WILLIAMS: And going to the next page, sir, being page 14, you see a contemplation

of the impacts of different investment scenarios on duration interruptions being figure E-6.

Do you see that, sir?

MR. CHUCK STEELE: Yes.

DR. BYRON WILLIAMS: And going to the next page, being 15, you see similarly scenarios contemplating the consequences of different investment paths on frequency interruptions also known as safety; agreed, sir?

MR. CHUCK STEELE: Agreed.

DR. BYRON WILLIAMS: Now, Mr. Steele, if we can go to page 21 of the tab 1. And if -- you'll see there, sir, the eight (8) scenarios presented by METSCO in this document, sir?

MR. CHUCK STEELE: Yes.

DR. BYRON WILLIAMS: And if we scroll down to the figure, right there is perfect. Thank you.

And what is presented here, sir, is in terms of specific -- and again for illustrative purposes in -- in -- in terms of specific investment choices, the relative cost of different investment choices in achieving systemwide reduction of key performance metrics.

Do you see that, sir?

MR. CHUCK STEELE: Yes, I see it.

DR. BYRON WILLIAMS: And this one on this page, being page 21, cues up in essence an optimal investment order for improving system SAIDI; agreed?

You'll see at that the top -- you see that sir? You're nodding your head.

MR. CHUCK STEELE: You know, I -- I see it. I'm not sure if I understand that it's -- it's prioritized by -- in terms of value. Is that what you're suggesting or...?

DR. BYRON WILLIAMS: Yes, and I'll direct your attention to the paragraph immediately above that, sir.

I'll suggest to you it's a cost-benefit analysis of each of the various investment options when looking to impact reliability performance, sir.

Do you see that?

MR. CHUCK STEELE: Yes. It's just not clear to me whether it's a -- the impact on total performance by each -- each of the vertical scale, or if it's -- or if it's done in the order of -- of value --

DR. BYRON WILLIAMS: Of value. And sir, in essence, what you're seeing from that

paragraph above the figure is that --

MR. CHUCK STEELE: Okay, optimal investment. Sorry when I read it on my piece of paper the type is too small, but if I look on the screen it's -- it's legible.

DR. BYRON WILLIAMS: It's an optimization exercise, sir?

MR. CHUCK STEELE: That's fine.

DR. BYRON WILLIAMS: Okay, so I think I hear you --

MR. CHUCK STEELE: Yes, I agree. I agree, yes.

DR. BYRON WILLIAMS: Okay. And if we go to the next page, being page 22, we see as well for system frequency an optimiz -- optimal investment cue as well.

Agreed, sir?

MR. CHUCK STEELE: Yes.

DR. BYRON WILLIAMS: And recognizing Mr. Wortley's advice about wanting to be cognizant of the cost-benefit of these exercises, this -- this is that what some utilities in Canada, New Zealand, United Kingdom are doing in -- in -- in evaluating different scenarios and in optimizing their portfolios, as measured against projections of future

performance. Agreed?

MR. CHUCK STEELE: You know, I suppose that's the case to the extent that those utilities would target SAIDI and SAIFI as having that value for the customers -- for their customers.

MR. JOEL WORTLEY: That -- that is the missing link here, right, is that they are targeting SAIDI and SAIFI but there's no measure of value in terms of what that really represents to the customer, and therefore, it's not enough information to make actual decisions on whether it's worth making the improvements.

Manitoba Hydro's corporate value framework includes customer impacts and by having it built in to the system for valuing our investments sets the stage such that when we are ready to do SAIDI and SAIFI projections we can actually tie that back to a customer value and make some real decisions with it.

(BRIEF PAUSE)

DR. BYRON WILLIAMS: This same type of exercise, sir, with an input of customer value as well as reliability figures could be done for any good practice corporation; agreed?

MR. JOEL WORTLEY: With enough time and money you can do anything, yes. There's definitely obviously a range of maturities to which we know that the Europeans and Australians are ahead of North Americans, and we know that certain North American industries -- or sorry, companies are further ahead than others.

Manitoba Hydro's progressing and actively pursuing asset management improvements. This is one that we will consider as we go forward.

DR. BYRON WILLIAMS: And certainly, sir, as it relates to the Board, based upon the conversation with Mr. Barnlund, you'll note that this is a conversation that has been going back at least a decade, agreed?

MR. JOEL WORTLEY: Agreed.

DR. BYRON WILLIAMS: If we can turn to Coalition Exhibit --

MR. HAL TURNER: Actually, I just wanted to add one (1) thing. I -- I think it's important to note -- I think the -- the Board should take note that METSCO, your -- your Intervenor expert witness commanded Manitoba Hydro on how we try and take customer impact into the CVF. We're not just basing it on a statistic.

As -- as Mr. Wortley pointed out, it's hard to know what point 1 and SAIDI or SAIFI is worth, but we take it a step further, and we try to understand how that's going to impact our customers so we can make the right investment decision.

DR. BYRON WILLIAMS: This -- Mr. Turner, just so I'm clear -- actually, to Mr. Wortley, just so I'm clear, in terms of the CEF, the Capital Expenditure Forecast for 2016, for the portfolio, this type of analysis was not conducted, although we -- we're -- we're aware of the -- the -- the trial with -- - with --

MR. HAL TURNER: I'm sorry, doc -- Dr. Williams, I thought we were talking about future state. I thought these exhibits were to talk about where we could go.

DR. BYRON WILLIAMS: Mr. Turner, just in terms of your response, you were talking about what we're doing. So simply, I was trying to take it back to what was put into the Capital Expenditure Forecast.

And I do apologize --

MR. HAL TURNER: Right, no. Fair enough. You're right. We're -- we're -- where we want to take it is that we are -- we built into the corporate value framework the ability to quantify the

impact of the customer, and that's where we're headed.

DR. BYRON WILLIAMS: Okay. Mr. Wortley, this type of ability for the overall portfolio of generation distribution and transmission is currently not available to Manitoba Hydro? You're not able to do this right now?

MR. JOEL WORTLEY: It's not part of our regular practices, no.

(BRIEF PAUSE)

DR. BYRON WILLIAMS: If we can turn to Coalition Exhibit 32-1, Tab 5, and specifically the Toronto Hydro distribution system plan. You can pick page 75 for right now.

(BRIEF PAUSE)

DR. BYRON WILLIAMS: And Mr. Steele, I'll -- I'll come back to you in just a second, or to Mr. Wortley. I'm -- I'm agnostic on -- on who answers the questions.

But Mr. Wortley, you're aware -- or sorry, you indicated in your conversation with My Learned Friend Mr. Peters earlier today that to your knowledge, in terms of the CEF16, that Manitoba Hydro

had not undertaken stakeholder research specifically investigating preferences for a trade off between rate increase and reliability performance? Is that your recollection of that conversation?

MR. JOEL WORTLEY: Yes, that is correct.

(BRIEF PAUSE)

DR. BYRON WILLIAMS: And would it be fair to say that currently, Manitoba Hydro does not regularly calculate life cycle cost for asset management purposes?

(BRIEF PAUSE)

MR. HAL TURNER: We may not calculate them explicitly, but we do take them into consideration in our investment decisions. So for example, if we were buying a new turbine runner, we would communicate to the vendor what the efficiency of the runner was worth to us in monetary terms, and so they could use that to optimize their design. So if it made sense for them to do some more testing to fine-tune the efficiency of the turbine runner, they

could understand what that's worth to us and help us make the right investment decision.

So correct that we do not explicitly calculate the life cycle costs for the asset, but we do consider life cyc -- cycle cost implications in our investment decisions.

DR. BYRON WILLIAMS: And -- and let me --

MR. CHUCK STEELE: Sorry, if I could just add to that?

DR. BYRON WILLIAMS: Go ahead, Mr. Steele.

MR. CHUCK STEELE: I -- I believe when we order transformers, for example, or when we go out for tender for transformers and -- and other electrical equipment that might have losses inherent to them, we -- we do a calculation based on the value of those losses over the life cycle of -- of the asset.

DR. BYRON WILLIAMS: Thank you for those that clarifications. Would it be fair to say that the portfolio is not opti -- optimized based on life cycle cost?

MR. HAL TURNER: That's fair, but the -- when we will be optimizing, as we have been in

generation wholesale, it's not just based on economics. It also considers the safety of the public, of our staff, the environment. So it's not just an economic decision when we optimize. We try and look at all those factors.

MR. CHUCK STEELE: I -- I don't know that it's fair to conclude, as you suggest, because we -- at the end of the day, we may have an optimized portfolio based on all of the factors and the -- and the balances that Mr. Wortley often talks about that may, by default, be the best portfolio, from a life cycle cost as well.

DR. BYRON WILLIAMS: And Mr. --

MR. HAL TURNER: Sorry, I just wanted to add one (1) other point. I apologize.

When we're optimizing, we're optimizing at the portfolio level, so we're looking at all of our investments. So I'm talking from a generation perspective --

DR. BYRON WILLIAMS: And -- and you're talking -- you're not talking about the entire portfolio, just --

MR. HAL TURNER: I'm -- I'm just talking -- so, for example, in -- in generation wholesale, when we optimize. So we're looking at all

of our investment needs. So we may choose a solution that doesn't offer the lowest life cycle cost for a particular asset because it may free up, for example, some capital that we could invest in a different asset and bring overall greater value to Manitoba Hydro.

So we don't deal with it on a investment by investment decision. We're -- part of the benefit of -- of the new capital portfolio management process and the corporate value framework is we're making our decisions at the portfolio level. And so we maximize value at the portfolio level, not necessarily at each individual investment.

DR. BYRON WILLIAMS: And again, just to go back to currently, the --

MR. HAL TURNER: Currently that's what we're doing in generation and wholesale.

DR. BYRON WILLIAMS: Right, currently for CEF16.

MR. HAL TURNER: As -- as documented in CEF16, no, test years in CEF16, yes.

DR. BYRON WILLIAMS: For generation and --

MR. HAL TURNER: For generation and wholesale, correct.

DR. BYRON WILLIAMS: So again, Mr.

Steele, this is distribution. If you're not -- are -- are you generally -- you've taken a quick look at the Toronto Hydro distribution materials, sir?

MR. CHUCK STEELE: Yes, I did skim through it.

DR. BYRON WILLIAMS: Okay. You've not memorized it yet?

MR. CHUCK STEELE: No, I -- I have not memorized it, sorry.

DR. BYRON WILLIAMS: And I apologize. Apparently the document as a whole was 2,500, and I --

MR. CHUCK STEELE: Yeah, when -- when I skimmed through it, I skimmed through the 2,500 pages, but I -- I noticed in your book of documents, it's the significantly less, so.

DR. BYRON WILLIAMS: And there was no in -- intent, sir. I -- I do apologize for that inconvenience.

If we can turn to page 78 of -- of this document, and -- and focus on figure 4. Mr. Steele, the narrative here by Toronto Hydro is -- as presented in figure 4, is that they've got a -- what they consider to be the economically optic -- optimal capital investment approach involving a big bang in 2015 of 2.56 billion, and then smaller amounts out to

2019, considerably smaller amounts. Do you see that, sir?

MR. CHUCK STEELE: Yes, I do.

DR. BYRON WILLIAMS: And again, if you you -- you -- If you need a reference, it's again on this page, but you see Toronto Hydro is, in essence, saying given the large step increases in rates, they wanted to look at a couple of different options. Is that your understanding of this -- this paper as well, sir?

MR. CHUCK STEELE: Yes, that is my understanding.

DR. BYRON WILLIAMS: And if we turn to page 81, you'll see a description by Toronto Hydro of an accelerated execution step -- strategy, consisting of investments of $840 million thereabouts in -- in five (5) consecutive years, being 2015 through 2019.

Would that be fair, sir?

MR. CHUCK STEELE: Yes.

DR. BYRON WILLIAMS: So that's one (1) of the options Toronto Hydro considered, and then if we go to page 82, sir, you'll see a consideration of the paced Ontario Hydro consideration, which is of investments, I'll suggest to you, from 2015 through 2019 in the range of half a billion dollars annually?

MR. CHUCK STEELE: Yes, absolutely.

DR. BYRON WILLIAMS: And then with an understanding that -- that this -- the magnitude of investments would have to be paced out -- out between 2020 and 2037? Is that fair, sir?

MR. CHUCK STEELE: Yes.

DR. BYRON WILLIAMS: And if you're not able -- able to comment on that -- this, sir, that's fine, but ultimately, what Toronto Hydro recommended was the paced strategy. Is that your understanding? And if you're not able to comment, that's fine.

MR. CHUCK STEELE: You know, I -- I can't comment. I'm not sure what they recommended.

DR. BYRON WILLIAMS: That's not a problem. If we go to page 83, though, sir, you'll see a comparison again, Toronto Hydro, although not as complex as -- as EPCOR, is projecting a comparison between -- in terms of the impacts upon duration, interruptions, and frequency interruptions between its recommended plan and run-to-fail.

Do you see that, sir?

MR. CHUCK STEELE: Yes, I -- I -- can -- can I assume -- it -- it's hard to tell the scale, but the -- or it's hard to tell the colours on this document, but I'm assuming the run-to-fail results in

worsening reliability.

DR. BYRON WILLIAMS: As compared -- yeah --

MR. CHUCK STEELE: As -- as compared to --

DR. BYRON WILLIAMS: I'll -- I'll suggest to you --

MR. CHUCK STEELE: -- as compared to their proposed plan?

DR. BYRON WILLIAMS: I'll ask you to accept that subject to check, sir.

MR. CHUCK STEELE: Okay.

DR. BYRON WILLIAMS: And again, sir, as comparison to EPCOR, this is a scenario analysis projecting future impacts on duration interruptions and frequency interruptions, albeit considerably less sophisticated?

MR. CHUCK STEELE: No, I -- I agree. I see the similarities, and I note that both are targeting reliability metrics and improvements to reliability.

DR. BYRON WILLIAMS: And --

MR. JOEL WORTLEY: It is interesting to note that, you know, the -- there's quite a bit of discussion about cost, and quite a bit of discussion

around performance, but not a lot of discussion around risk, and that certainly, if -- if the risks are acceptable in the paced solution, why would you ever go to the accelerated solution? It just makes sense --

DR. BYRON WILLIAMS: Okay --

MR. JOEL WORTLEY: -- provided the risks are acceptable.

DR. BYRON WILLIAMS: Thank you. I wonder if we can turn to page 84, and focus on the -- this section on customer needs and preferences.

And Mr. Steele. I don't know if you've had a chance to look specifically at lines 9 through 15, but I'll suggest to you that there you see the customer consultation process undertaken by Toronto Hydro with regard to its capital investment plan?

MR. CHUCK STEELE: Yes, I see.

DR. BYRON WILLIAMS: And you'll see, sir, focusing on line 11, that it included focus groups, agreed?

MR. CHUCK STEELE: Yes.

DR. BYRON WILLIAMS: An online workbook accessible to all customers, agreed?

MR. CHUCK STEELE: Yes, that's what it says.

DR. BYRON WILLIAMS: Facilitor --

facili -- it says that it includes -- included facilitator-led workshops with commercial and industrial users as well?

MR. CHUCK STEELE: Yes.

DR. BYRON WILLIAMS: And finally, a statistical telephone survey, agreed?

MR. CHUCK STEELE: Agreed.

DR. BYRON WILLIAMS: And then it also suggests that there was a final report on the process and findings of this consultation made available?

MR. CHUCK STEELE: Yes. I -- you know, if I can -- I just, you know, add -- to make sure I understand it correctly, my understanding is that Toronto Hydro specifically had -- had engagement with their ratepayers regarding their preferred plan to -- to look at investments directed towards improved reliability.

Certainly, from Manitoba Hydro's perspective, our investments, or the distribution space are driven by condition assessments, so I don't know that we would -- we would necessarily do the same thing, but -- but my understanding may not be correctly. Like I said, I only skimmed through the document.

DR. BYRON WILLIAMS: And let's just go

to that. Mr. Wortley, as -- as we look at the vision for sustaining capital and capital investments more broadly, are these type of consumer engagement undertaken by Toronto Hydro among the types that Manitoba Hydro might contemplate?

MR. JOEL WORTLEY: So an element of -- of Manitoba Hydro's new corporate plan is having a very -- customer focus. It's one (1) of the four (4) pillars of the Company and one to which we need to do considerable development in terms of engaging our customers and making sure that customers -- we understand what -- what customers expect in terms of value, and we deliver it. And so that -- that strategy has not been fleshed out yet, but I could see that something like this could be part of it.

MR. GERALD NEUFELD: I would like to comment on the -- on the SAIFI and SAIDI, and -- and while I believe that SAIDI and SAIFI are -- are good lagging measures, and upgraded -- system upgrade plans could be developed around SAIDI and SAIFI, they have the greatest relevance where there's a denser population areas, and the service feeds -- you have serve -- multiple service feeds int -- into that area.

We -- we have a system on the east side of Lake Winnipeg that -- where we responded on -- on

Coalition -- Coalition IR-157. And here's --here's our location which includes Poplar River, Berens River, Bloodvein River, Little Grand Rapids, Pauingassi, Sagkeeng, Manigotagan, Black River, and a -- a large cottage area. And they have a single feed in -- into there.

And if we lose that single feed, if we lose the transformer, we've got widespread outages for a long time. There is no communication into that area. And I would submit to you that the -- the study of SAIDI and SAIFI in an application like that probably has little relevance to what the -- what the final solution should -- will -- will look like under a -- under a -- a solution that balances cost and -- and reliability.

DR. BYRON WILLIAMS: Thank you, Mr. Neufeld, for sharing that. You're in no way suggesting, though, that there is not value in looking at the consequences for investment decisions on different performance metrics?

MR. GERALD NEUFELD: I absolutely am not saying that, but all I'm saying is that the SAIDI and SAIFI in using these outage statistics have their application, and there -- as Mr. Wortley had suggested earlier, there's a lot of parameters that we take into

account, whether it be raw liability -- safety -- safety measures could fall, and the reliability could be safe -- safety for the public, safety for Hydro workers, environmental aspects, and there's a wide spectrum of -- of factors that are key factors which we take into account as we prioritize our projects.

DR. BYRON WILLIAMS: I wonder if we can turn very quickly to Coalition Tab 2 of this book of not -- doc -- documents, and specifically page 27. I apologize, Kristin, 28's fine.

Mr. Steele, this is a -- a look at pole replacement and substation refurbishment, distribution unit cost benchmarking as undertaken by Hydro One, agreed?

MR. CHUCK STEELE: Yes.

DR. BYRON WILLIAMS: And currently, Manitoba Hydro has not undertaken bench makings -- benchmarking studies to compare its capital spending or asset units cost to other utilities, agreed?

(BRIEF PAUSE)

MR. CHUCK STEELE: Not that I'm aware of for distribution,

DR. BYRON WILLIAMS: Okay. Turning to

page 31 of this document. And really the last paragraph, and -- and if Hydro cannot answer this, this is fine.

But you can see Hydro One indicating that it had made efforts to include more Canadian utilities, but had been only successful in -- in garnering Hydro Quebec, BC Hydro, and three (3) Ontario local utilities.

You see that -- that reference?

MR. CHUCK STEELE: Yes, yes, I do.

DR. BYRON WILLIAMS: To your knowledge was Manitoba Hydro appointed -- approached in terms of this benchmarking study?

MR. CHUCK STEELE: You know, not to my knowledge. But certainly I was -- I was not personally approached, and neither was my colleague behind me who would've been the person to be approached.

DR. BYRON WILLIAMS: Okay. And we won't go through this, but I'll suggest to you, Mr. Steele, that if we look to pages 32 through 50 of this document, one would get an indication of some of the analysis undertaken in terms of the benchmark -- benchmarking costing exercise.

Fair enough?

MR. CHUCK STEELE: Yeah, fair enough. You -- you know, when I -- when I did skim through this document, that I did notice of some of the recommended actions on page 29 were consistent with some of Manitoba Hydro's current practices. For example, our Integrated Pole Maintenance Program and are -- are detailed overhead feeder inspection programs too, so.

DR. BYRON WILLIAMS: Thank you. Mr. Chair, just -- I'm not sure what that timeframe is for today.

THE CHAIRPERSON: 5:30.

DR. BYRON WILLIAMS: 5:30, okay.

MR. JOEL WORTLEY: Maybe I can just add that relative to -- to the benchmarking in general, that benchmarking has its utility -- has its utility as a -- as an indicator of where to look, let's say. And as Mr. Shepherd pointed out, I believe it was on Monday, it -- it's not terribly useful in terms of making particular decisions, but it can be very helpful in guiding you as to where to go next.

And so I would suggest that -- that studies like this certainly are of value, but need to be done at the -- the right time and place such that the information is fruitful in terms of the next step

in your decision-making. And so it is a useful tool when applied correctly. That's -- I just want to caution a little bit.

MR. CHUCK STEELE: Yeah, I -- I can also add, although we may not have participated in this study comparing capital costs, that I believe METSCO's report did reference that are pole replacement costs were -- were favourable to other utilities, but...

CONTINUED BY DR. BYRON WILLIAMS:

DR. BYRON WILLIAMS: Thank you for that.

Let's move away from -- from these examples of benchmarking. And -- and, Mr. Wortley, would it be fair to say that, in terms of corporate value management, the Corporation envisions a three (3) phase plan? And I can give you the phases, if that would assist user.

MR. JOEL WORTLEY: It -- it would help me if --

DR. BYRON WILLIAMS: Okay.

MR. JOEL WORTLEY: -- if you had a reference or -- I'm not sure what you're -- where's you're going.

DR. BYRON WILLIAMS: I'm -- I'm referring to -- it's certainly set -- I don't think we need to go there. I think you'll -- you'll -- you'll know what once I say it. But Section 5.11 of Tab 5 of the GRA.

But in essence, Phase 1 being assessment of current asset management practices, which is now complete. Agreed?

MR. JOEL WORTLEY: Yes.

DR. BYRON WILLIAMS: Phase 2 being the development of asset management policies and strategies. Agreed?

MR. JOEL WORTLEY: Agreed.

DR. BYRON WILLIAMS: And Phase 3, being the development of a detailed roadmap for the implementation of corp -- of a corporate asset management framework. Agreed?

MR. JOEL WORTLEY: That's right. And in terms of the -- this three (3) phase process you've indicated to My Friend Mr. Peters, that you anticipate the -- that the implementation plan will take a somewhere in -- in between three (3) to five (5) years. Agreed?

MR. JOEL WORTLEY: Well, it's a little bit more nuance Of that. So the -- as I try to

described a little bit earlier, there -- there's different scales of asset management. And so the -- the corporate asset management initiative and the three (3) phases as you've described, until we roadmap that out I don't really know how long that's gonna take, and I don't really know how far we're going to go, in that -- will -- will the appropriate time to stop be at a Level 3 maturity, or do we want to put the Level 4, beyond? I'm not sure. And we won't be able to make that decision till we see what it's going to cost to get there, and what value or what benefit we think we're going to -- going to achieve by getting there.

The three (3) to five (5) year timeframe apply specifically to our capital portfolio management and the ability to achieve our objectives of optimizing/executing portfolios and forecasting investment requirements on a -- on a needs basis into the future. And so, one (1) is part of the other. Capital investment, asset investment planning is a subset of asset management.

But asset management totality is a much larger endeavour, involving, as I mentioned earlier, the alignment of an organization's activities to particular goals that requires a culture shift and a -

- and a realignment of the entire organization to be fully effective. And that -- I'm not sure how long that's going to take.

DR. BYRON WILLIAMS: So, just so I understand, the three (3) to five (5) year timeframe applies to the subset, being the portfolio management. Agreed?

MR. JOEL WORTLEY: Correct.

DR. BYRON WILLIAMS: Okay. And -- and in terms of Phase 2 -- and again, you don't need to turn there, but referencing Coalition 2-67 -- at the time of Second Round IRs Phase 2 had not commenced. Agreed?

MR. JOEL WORTLEY: Correct.

DR. BYRON WILLIAMS: And that was due to competing organizational prior -- priorities in the Voluntary Departure Program. Agreed?

MR. JOEL WORTLEY: Yes, the Corporation -- the Corporation's restructuring and absorbing of the voluntary departures is our competing priorities. As well as, there's only so many improvement initiatives that can be undertaken at a time. And so the corporate -- the Capital Portfolio Management Program is -- is being executed, the enterprise asset management is being rolled out.

There -- there comes a point of saturation in to how much change can be absorbed by an organization.

DR. BYRON WILLIAMS: And, sir, in terms of commencing Phase 2, what is your most -- what is your current expectation?

MR. JOEL WORTLEY: My current expectation would be that we need to do some training, need to do some awareness -- some broad awareness around the organization, such that our leaders and our staff and our decision-makers understand the difference between managing assets and asset management, so that they're able to -- to meaningfully participate in discussions of -- of how to move the company forward. And I expect that that will occur beginning in the new year as we come out of the voluntary departure, which will be February 1. And we'll move forward as quickly as we can from there.

DR. BYRON WILLIAMS: Just so I understand, sir, are you suggesting that Phase 2 will commence in the new year?

MR. JOEL WORTLEY: Yes.

DR. BYRON WILLIAMS: And an output from Phase 2, sir, will be the development of corporate asset management strategies and policies. Those are anticipated to be completed in Phase 2,

agreed?

MR. JOEL WORTLEY: Correct.

DR. BYRON WILLIAMS: And it's expected that these documents will help provide consistent asset management strategies, standards, and clearly establish asset management roles and responsibilities. Agreed?

MR. JOEL WORTLEY: They will help, yes.

DR. BYRON WILLIAMS: And when -- given the start in 2018, when do -- does one expect Phase 2 to be completed.

MR. JOEL WORTLEY: The schedule for Phase 2 has not been fleshed out or adopted yet, so we will have to do the plan and determine the schedule as -- available to resource it.

DR. BYRON WILLIAMS: Ballpark, sir. A year? Three (3) years?

MR. JOEL WORTLEY: Oh, it's -- no, it's -- this is a shorter-term step, subject to -- to what else -- what else comes up to compete with it, it should certainly be complete within a year.

DR. BYRON WILLIAMS: I want to turn to a bit of a different subject matter. Probably, most of these questions will go to you, Mr. Steele. But,

Mr. Wortley, or the rest of the team, feel free to -- to chip in.

Would it be fair to say that on an individual asset basis, in general one can make better decisions, if you have information beyond the age of the asset?

MR. CHUCK STEELE: That -- that's probably fair to say. I would -- I would add the caveat that it probably depends on the asset, the level of information you would -- you would benefit from.

I think for a lot of distribution assets, it's -- it's more expensive to collect the information than it is to action on the asset when it fails, for example.

DR. BYRON WILLIAMS: It would also be fair to say that, given Manitoba's climate and unique operating characteristics, the life-cycle of its assets may differ from similar assets in other regions. Agreed?

MR. CHUCK STEELE: I -- I agree. I think every utility has its own unique set of circumstances, for sure.

DR. BYRON WILLIAMS: And certainly having high-quality data of your own may reduce the

reliance on industry life-cycle dat -- data, which may not necessarily be reflective of the Hydro experience. Agreed?

MR. CHUCK STEELE: Agree.

DR. BYRON WILLIAMS: And you'll recall, we just had a extensive discussion about predictive analytics -- analytics?

MR. CHUCK STEELE: Regarding other utilities' --

DR. BYRON WILLIAMS: Performance, yes.

MR. CHUCK STEELE: -- approach to reliability performance, yes --

DR. BYRON WILLIAMS: You recall that conversation?

MR. CHUCK STEELE: -- I recall.

DR. BYRON WILLIAMS: And certainly Manitoba Hydro's aware that the need to use replacement data to help build predictive models and evolve the Corporation's asset management capabilities is -- it's important. Agreed?

MR. CHUCK STEELE: Yes. And maybe as a point of clarification, generally speaking, in the -- - in the test years and in the short-term, assets are replaced based on condition assessments, actual -- actual field measurements of either visual or

mechanical assessments. But certainly you're correct in predicting future expenditures, the more data to -- to -- the more accurate those expenditures can be predicted.

DR. BYRON WILLIAMS: And that's particularly the case in terms of service terminal failure data, which is particularly important to the -- to help predictive models. Agreed?

MR. CHUCK STEELE: Sorry, the -- the phrase used: terminal failure data?

DR. BYRON WILLIAMS: I probably mispoke terribly. I meant to say 'service terminal failure data'.

MR. CHUCK STEELE: Service terminal failure date.

DR. BYRON WILLIAMS: Yeah.

MR. CHUCK STEELE: Like, you're -- you're suggesting the -- when -- when the ass -- predict -- predicting when the asset will actually fail and trying to, where it's -- where it's economic to do so, replace that asset just prior to failure? Like that, that -- that would be beneficial, yes.

DR. BYRON WILLIAMS: At a high level, Mr. Wortley, I'll send this to you, it would be fair to say that the operating groups within Manitoba Hydro

are at different levels of maturity, in terms of applying asset health indices data?

MR. JOEL WORTLEY: Yeah, that would -- that would be fair.

DR. BYRON WILLIAMS: And generally speaking, as compared to generation, transmission and distribution are developing their maturity? I knew Mr. Neufeld was going to jump for this one.

MR. GERALD NEUFELD: Thank you. Yes, we are developing the maturity. We have asset health curves. We've been working closely with Kinectrics.

But I'd like to take the -- the topic back to what some of the key drivers are for facilities where -- in the -- in the year process, or will shortly be embarking on, to improve -- to improve the reliability of supply in -- in southern parts of Manitoba. And I used -- I used the term 'a reliability of supply' rather loosely.

Because what I really mean is, we want to make sure that the -- the transmission feeds into the areas where we've got large residential loads, such as in the Steinbach area, or such as in the Morden/Winkler area where there's been a lot of -- a lot of -- of growth in the last number of years, that we're able to meet the --the loads.

This doesn't have to do with asset health indices. This has to do, simply -- very simply with having the of the -- the wires in place and the power transformers in place to be able to -- to meet the load demand. And it's that simple.

And so, asset health indices do have a substantial amount of value. And the value comes in to -- into play when all other factors are equal. And I'm in the suggest to you that the error that we're in on the transmission side, where we're trying to prove -- improve the reliability of supply to various parts of the province today, we probably wouldn't be using asset health indicators as a -- as the -- as the driver for -- for the recommended upgrades.

And there's another topic on here. And I'm -- I'm going to cut -- I'm going to keep this fairly short. But there are -- of this -- there's other -- other equipment that we're in the process of -- of replacing. It has to do with the Bipole III project, which is being installed.

And the net impact to the -- to the overall system in southern Manitoba with having Bipole III in play, is the there's a phenomenon called the 'short-circuit', or the amount of power that flows when -- when there's a connection say to -- from a

tree to the ground on the -- on the distribution system or, for that matter, on the transmission system, and the -- the impact of putting in a large facility, a substantial facility like Bipole III, is that we find ourselves with circuit breakers. And these are very large circuit breakers, for 230,000 volts and a hundred and -- 115,000 volts. And these -- the circuit ratings are being exceeded.

And it just simply wouldn't -- it would be a -- it -- we just simply couldn't operate Bipole III without having first replaced those breakers, and -- and there's quite a few of them.

So there's a couple of areas where asset health indicators are not the driver for -- for making improvement decisions. And these are fairly costly decisions.

DR. BYRON WILLIAMS: Mr. Neufeld, and certainly not wanting to invite a long answer, but just in terms of the question I posed, as compared to generation, and in terms of asset health indices and how they're integrated, there's some maturing to do on the transmissions. Agreed?

MR. GERALD NEUFELD: Agreed.

MR. CHUCK STEELE: If I can comment on --

DR. BYRON WILLIAMS: Mr. Steele, I was going to just ask for that.

MR. CHUCK STEELE: Yeah. Sorry.

DR. BYRON WILLIAMS: So go ahead.

MR. CHUCK STEELE: Thank you for the opportunity.

Yeah, you know, I agree, maturity somewhat relative between the three (3) operating groups. But certainly distribution being comprised of, you know, literally millions of low-cost assets, often it's probably more expensive to -- to do detailed health assessments, as opposed to allowing those assets to run to failure.

And then on the other end of the spectrum, as I pointed out in the Navigant report, with respect to their recommendations to Ontario Hydro, or Hydro One I guess it was, we -- we are leading industry with respect to some of our integrated pool maintenance programs.

DR. BYRON WILLIAMS: Okay. And Mr. Steele, in terms of distribution, your department has been blessed with two (2) recent studies from Kinectrics, one being the Manitoba Hydro 2016 Asset Condition Assessment, which is dated May 26, 2017. Agreed?

MR. CHUCK STEELE: Yes.

DR. BYRON WILLIAMS: The other being the Manitoba Hydro Acid Degradation Curve Development, which is dated July 20th, 2017. Agreed, sir?

MR. CHUCK STEELE: Yes.

DR. BYRON WILLIAMS: And if we could go to MFR, Minimum Filing Requirement, 92, and specifically the Kinectrics Manitoba Hydro 2016 Asset Condition Assessment. And page 30 -- just go to the cover page for a minute, so page 1. This is the 2014 one. We're actually looking for the one dated May 26th, 2017.

Mr. Chair, I wonder if we can just stand down for a second, just to make sure we can find this document.

THE CHAIRPERSON: Do you want to break, Mr. Williams, for --

DR. BYRON WILLIAMS: Well, just -- I know this is riveting material so I would -- I'd suggest maybe a brief five (5) minute break --

THE CHAIRPERSON: Yes, certainly.

DR. BYRON WILLIAMS: -- just to make sure we're cued up.

THE CHAIRPERSON: Okay.

--- Upon recessing at 4:45 p.m.
--- Upon resuming at 4:57 p.m.

THE CHAIRPERSON: Dr. Williams...?

CONTINUED BY DR. BYRON WILLIAMS:

DR. BYRON WILLIAMS: Yes, and thank you. And, Mr. Steele, just in terms of Kinectrics work on asset condition assessment, the term "data availability indicator" or DAI measures the amount of condition parameter data that an asset has as it's measured against the condition parameters included in the health index formula.

Would that be fair, sir?

MR. CHUCK STEELE: Yes.

DR. BYRON WILLIAMS: So an asset with all condition parameter data represented will, by definition, have a DAI value of 100 percent. Agreed?

MR. CHUCK STEELE: Agreed.

DR. BYRON WILLIAMS: If we can turn to table 1, page 34, I believe of this document. No, let's go to page 14. My apologies. Here we go. And actually, can we make sure that we have the DAI in -- that's perfect.

Mr. Steele, just in terms of some of

the distribution assets studied by Kinectrics, table 1 provides a health index results summary; agreed?

MR. CHUCK STEELE: Agreed.

DR. BYRON WILLIAMS: And on the left-hand side we see certain asset categories ranging from station breakers at the top to OH switches at the bottom; agreed?

MR. CHUCK STEELE: Agreed.

DR. BYRON WILLIAMS: And the last two (2) right-hand columns, the second last one captures the age availability; agreed?

MR. CHUCK STEELE: Agreed.

DR. BYRON WILLIAMS: And in essence, that represents the -- for that particular asset the percentage of asset items for which Manitoba Hydro has the information related to their age; correct?

MR. CHUCK STEELE: Correct.

DR. BYRON WILLIAMS: And if we look to the average DAI or data availability indicator that's on the extreme right-hand column, sir?

MR. CHUCK STEELE: Yes.

DR. BYRON WILLIAMS: And we see there in terms of those parameters a high in the range of 88 percent, which is about -- about seven (7) or eight (8) lines down. Do you see that, sir?

MR. CHUCK STEELE: Yes.

DR. BYRON WILLIAMS: And then we see that the availability of data for a number of these assets is at -- in terms of the parameters used by Kinectrics is -- is zero. Agreed?

MR. CHUCK STEELE: Agreed.

DR. BYRON WILLIAMS: And subject to check, sir, would you agree that for -- for fifteen (15) of these twenty-three (23) assets it is less than the average DAI is 50 -- is less than 50 percent?

MR. CHUCK STEELE: Subject to check. I -- I won't count them, but, you know, I question some of the relevance for those assets where it's identified as zero percent. I -- I believe that a lot of those are -- if not all of them referred to assets that are run-to-failure.

DR. BYRON WILLIAMS: And so my understanding of Hydro's position in terms of the parameters is that for some of these assets, it's acceptable to have them less than 50 percent, for others it is not.

Would that be fair, sir.

MR. CHUCK STEELE: That's fair.

DR. BYRON WILLIAMS: If we could pull up the other Kinectrics study, which is found as

attachment 1, the Coalition MH-1-160, and go to the executive summary, please, which I believe is at page 5. So that's Coalition MH 1-160, attachment one.

And I'm looking for Roman Numeral V. So I guess we need to go back a few pages.

THE CHAIRPERSON: Dr. Williams, there's no test on the formulas, is there?

DR. BYRON WILLIAMS: If there were, I would fail.

CONTINUED BY DR. BYRON WILLIAMS:

DR. BYRON WILLIAMS: But, Mr. Steele, this was -- this is relatively hot off the presses. This was received from Kinectrics by Manitoba Hydro in the summer; agreed?

MR. CHUCK STEELE: Agreed.

DR. BYRON WILLIAMS: And I just want to draw your attention on the executive summary to the -- the fifth paragraph in which Kinectrics suggests that Manitoba Hydro's assets tend to stay in service longer than in other jurisdictions.

Do you see that reference, sir?

MR. CHUCK STEELE: Yes.

DR. BYRON WILLIAMS: That was the finding of Kinectrics?

MR. CHUCK STEELE: Yes.

DR. BYRON WILLIAMS: Agreed? And the suggestion by Kinectrics, in this paragraph, is that since the removal based curves are rather conservative due to replacement of assets for reasons other than condition, the expectation is that the condition based curves will demonstrate even longer service lives.

Agreed?

MR. CHUCK STEELE: Agreed.

DR. BYRON WILLIAMS: And elsewhere in this document Kinectrics suggests that these longer asset lives may be a factor both of the weather -- the cold weather in Manitoba, as well as Manitoba Hydro's practices; fair enough?

MR. CHUCK STEELE: If I recall the document correctly, I believe you're -- you're correct there.

DR. BYRON WILLIAMS: Some short snappers to finish off the day and, Mr. Neufeld, I've neglected you so I -- I do have a couple questions about the transmission and -- and Copperleaf.

And, sir, I -- I want to direct your attention to Coalition Information Request first round 181. The attachment which is a lengthy document and specifically to page 80 of that attachment.

Mr. Neufeld, I'll give you a second to orientate yourself, but this is the asset investment. This is a document prepared by the transmission business unit in March 2015; would that be fair? Do you want to go back to page 1 to orientate yourself, sir?

Let's go to page 1, please. Oh, this is the -- excuse me, this is the generation slide. A bit further on in this document, sir, is the transmission side. You'll agree to that?

MR. GERALD NEUFELD: Let's -- let's -- let's find it.

DR. BYRON WILLIAMS: Okay. Boy, that generation slide says a lot, lots of pictures. Right. Let's go to page 76.

Sir, you'll accept that this is the -- the asset investment planning software implementation roadmap prepared by the Transportation Business Unit on or about March of 2015?

MR. GERALD NEUFELD: Right, that's the Transmission Business Unit.

DR. BYRON WILLIAMS: Okay.

MR. GERALD NEUFELD: We transport electrons.

DR. BYRON WILLIAMS: Okay. That's

your team, sir?

MR. GERALD NEUFELD: That's correct.

DR. BYRON WILLIAMS: I'm not that good with engineering humour, but I'm taking that -- that was funny, sir? Lawyer -- I'm sure engineers are way more funny than lawyers, let me just say that.

And I wanted, sir, to -- to direct you to -- to page. Just one second, please.

(BRIEF PAUSE)

DR. BYRON WILLIAMS: We're going to have to scroll through this. It's only a couple of pages, but I'm looking, sir, for the reference when -- when transmission is discussing the suitability of Copperleaf for -- for it. So keep scrolling through please, Kristin, and I apologize for this, Mr. Chair and members of the panel. Keep going please. Keep going, please. Keep going, please. It's probably going to be about page 85. Keep going. Okay, thank you. And my apologies for the delay. No, excuse me. Go back to page 85 for a second.

(BRIEF PAUSE)

DR. BYRON WILLIAMS: Oh, my apologies. I had it right in front of me. It's page 79 at the top. And my apologies. And just scroll up to page 78 for just a second. Now that I've succeeded in confusing everyone -- no, please keep -- yeah, right there at the bottom, the last paragraph on page 78.

Mr. Neufeld, you'll see a discussion starting at the bottom of page 78 where there's an indication that generation operations is currently using Copperleaf C55 as an -- as an AIP tool.

You'll see that, sir?

MR. GERALD NEUFELD: I do, sir.

DR. BYRON WILLIAMS: At the top of page 79, sir, you'll see the good folks at transmission -- I don't want to get into any jealousy between generation and transmission, but saying that this is a -- a more complex question for transmission, number 1, because it's more statistical in nature and reasons number 2 and 3 are set out there as well.

Do you see that, sir?

MR. GERALD NEUFELD: I do see that.

DR. BYRON WILLIAMS: And later on in this document, and at page 85 from Manitoba Hydro, there is a suggestion in the second paragraph -- the first full paragraph on this page, the second sentence

that to your knowledge, no AIP software tool has yet implemented a robust capability for modelling this type of risk.

So, Mr. Neufeld, you're nodding your head, so that -- you see that suggestion there in front of you, sir?

MR. GERALD NEUFELD: I do.

DR. BYRON WILLIAMS: So, sir, just -- this is some housekeeping, but this is the state of affairs as it was in 2015. In terms of the transmission's needs, has it been satisfied now that Copperleaf 55, has the robust capability being sought?

MR. GERALD NEUFELD: I'd just like to check with my colleague.

(BRIEF PAUSE)

MR. GERALD NEUFELD: So we have made some progress, and what we've done is we've worked with Copperleaf to -- to ensure that it would accept our system reliabi -- reliability risk model that's -- you made a reference to that earlier. And that was the gap that we had at the time of the -- that this was written and we've now closed that gap, and it will work.

DR. BYRON WILLIAMS: Okay. And Copperleaf 55 was implemented for transmission on or about August of 2017, subject to check?

MR. GERALD NEUFELD: That is correct.

DR. BYRON WILLIAMS: Mr. Chair and members of the panel, that was a lot of scrolling around for -- for those housekeeping questions, but I did want to ask Mr. Neufeld a couple questions before I'm finished with this -- this panel.

I am -- in terms of this panel, from my perspective, I know there's a wedding coming up for one (1) of them soon. I'm prepared to release them. I don't know if My Friend Mr. Hacault has any questions he anticipates for them or not.

MR. ANTOINE HACAULT: I don't think I do. I think Mr. Cormie and the members of the previous panel would be able to answer them. They're more of a general nature. So I don't have any questions that I would put to them today.

If -- I'm aware also that there's a -- I don't know which member, but one (1) of the members has got a -- a wedding restriction, so we were -- we certainly are understanding of that, and would have tried to ask any questions.

MR. CHUCK STEELE: Just -- just for

the purpose of putting it on the record, my -- my son is getting married this weekend.

THE CHAIRPERSON: Well, our -- our congratulations, Mr. Steele, I'll just ask if the panel has any questions.

I've got a -- a question, and I -- I don't know who goes to, and I think it may go to Mr. McCallum. And it's more of an educational request for myself, and I suspect for some of the newer members of this panel. And I -- I would suggest we don't do it now, that we'll do it first thing tomorrow morning. But if you could draw our attention, if there are materials already filed, if not, if we could have a -- sort of a ten (10) minute primer.

Here's what I'm interested in -- and we heard comments made from the panel in terms of their respective areas that in terms of establishing priorities, they have different ways of doing it. They look at different factors, and things of that nature.

And I'm interested in the business operations capital budget. And what the decision-making process is when they come to, I assume, Mr. McCallum or whatever, and you go through your departments and figure out how much money you would

like. And of course, there isn't enough money, and how you determine the allocation of the budget on the different areas, what factors you take into account now, and following the process you are undertaking right now on a system-wide basis, where you would like to be after you complete going through all of your -- all of your phases, because I -- I anticipate it will be to -- it'll be a different place.

But I'm trying to figure out, you know, you've got the multibillion dollar company. You've got all of these demands for transmission, generation, and distribution. Certainly, I suspect that there isn't enough money in the budget to meet everybody's requests. How do you -- how you make the decision or -- or decisions in terms of how -- who gets what money?

So if there is materials filed already. If you could draw it to -- to us. If not, if you could, you know, spend ten (10) minutes tomorrow and sort of explain the different processes.

Mr. McCallum's got a -- a frown. I -- I don't know if this -- if thi -- if this is too complicated, or --

MR. JAMES MCCALLUM: No, it -- it was -- it was -- no, definitely not a frown. It was just

trying to think of anywhere in -- in the 32,000 pages --

THE CHAIRPERSON: Yeah.

MR. JAMES MCCALLUM: -- of which, I've only reviewed 31,000. If we -- if we have the material. But we -- we can certainly speak to that.

THE CHAIRPERSON: Yeah, and it -- it -- if it's not, you know, first thing tomorrow, at some point, though. But I -- I would speak on behalf of myself. I'd like to understand the -- the decision-making process. Okay?

Thank you. We'll adjourn and -- and -- sorry, there's -- sorry. Ms. Van Iderstine? Yeah.

MS. HELGA VAN IDERSTINE: I'm a novice on these things. The -- I do have one (1) question on re-exam, if you don't mind, and I have a comment --

THE CHAIRPERSON: Certainly.

MS. HELGA VAN IDERSTINE: -- I'd like to --

THE CHAIRPERSON: Yeah.

MS. HELGA VAN IDERSTINE: -- address the -- to the panel.

RE-EXAMINATION BY MS. HELGA VAN IDERSTINE:

MS. HELGA VAN IDERSTINE: So if I

might -- and I know you've turned it off, Kristen. I'm sorry about that.

I would want to draw your attention -- or Mr. Wortley's attention back to the UMS report, which is filed as Manitoba Hydro -- in Manitoba Hydro's application, which was Manitoba Hydro Exhibit 5, I believe, Appendix 5.1. There we have it. Page 6.

And Mr. Wortley, you'll recall that my friend, Mr. -- Dr. Williams took you to this prior to the -- or very early on in his cross-examination of you, and he asked questions about the maturity level of Manitoba Hydro and -- and how it had been established.

If you could take a look at that executive summary again and comment to us -- let us -- the panel know a little bit more about where Manitoba Hydro fits in the overall -- in the landscape, I guess I'd say, of asset management and public utilities in North America and worldwide.

MR. JAMES MCCALLUM: Sure. I -- I'd be happy to. Maybe we can advance to page 11. That's a bit of a -- a visual. At the bottom of the page, we see here the same maturity scales going from zero on the left to four (4) on the right. And we see a

variety of companies around Canada and -- and internationally.

And we see primarily the ones on the -- on the right-hand edge of -- of the scale are overseas and we -- not shown here but in the text above you'll read that it says that:

> "While the scores may seem low compared to a competent standard of three (3) it is important to realize that many North American utilities would rate a zero (0) unaware of major asset management system requirements or a one (1) aware, but not yet developing. Overall Manitoba Hydro compares favourably against North American utilities in terms of its asset management maturity level; largely as a result of recent progress made, for inst --for example, in capital investment optimization, C-55, the corporate value framework, asset health indices, reliability centered maintenance and failure curves."

And so, overall, we've made quite a bit

of progress in -- in -- across many fronts and we've been at this for many years. Acknowledge fully that there are still gaps to go to -- to best practice but we embrace those gaps. We -- we're much happier knowing about them and being able to address them and close them than -- than not.

And as we reviewed this afternoon, we've got many different initiatives underway to get that going, including the strategic maintenance plan and generation that was talked about, the Kinectrics, our corporate asset management initiative. And so as much as, you know, we'd -- we'd like -- like to be in a better place we are where we are and we see a lot of value in -- in progressing from there.

THE CHAIRPERSON: Thank you.

MS. VAN IDERSTINE: Thank you. And I had one (1) comment I'd like to address the panel for consideration.

My Friend the Coalition of -- produced their book of documents as -- as did the, of course, the Board panel -- or the Board counsel, and I know that represents a lot of work to put those things together because I've had to do it myself. The difficulty is is that they put these documents in now as what they're calling exhibits.

You'll recall we had a concern about the number and the comp -- complexity of the ones that were presented and the index listed on Friday. This is a much smaller one that came to the Board today and -- but even still, not all of the referenced items were even put to the panel to comment.

And so you've now got a bunch of documents that been put in, essentially, as an exhibit. The panel has not had an opportunity to -- to comment on them and, in my submission, they are -- should not properly be before the panel. Even the ones that the panel have -- this panel had an opportunity to comment on, you'll recall in particular with the EPCOR report that they didn't accept that that report reflected anything that they had any knowledge about.

So, I'm -- I'm asking your direction and I would submit that specifically with respect to documents that weren't even brought to the -- to the panel's attention, that they be excluded from the book as an exhibit, and that with respect to those that they didn't accept the -- the content of that those ought not to be accepted by the panel.

You need, as you go forward, the best evidence you can, and this panel and the Manitoba

Hydro wants to provide that to you. And I know that the other Intervenors and the public participation is extremely important. And when they put it forward and ask questions, it's important that the answers that you are provided and the information you're provided is information that can be assessed and tested properly. Just as they've tested -- test the amount of Hydro panels.

So, going back to my concerns about the book of authorities or the book of documents, I would ask that those ones that they didn't reference be removed from the exhibit book and to the extent that they did not accept any of the -- the reports, that those also be removed and not be referenced.

THE CHAIRPERSON: Dr. Williams...?

DR. BYRON WILLIAMS: If I might, with respect in terms of this book of documents, the six -- the first six (6) tabs are expressly on the record already. They're referenced both directly in the METSCO evidence with a specific link provided to them, as well as referenced in the appendix -- appendix. And they are put there as illustrations of best practice. So with respect, they're already on the record.

In terms of the excerpts seven (7)

through fifteen (15), those are -- are from either Board Orders or Board transcripts and are quite properly before the Board. So, in our client's position, the submissions of our -- our friend are without merit.

And I would note regardless of, you know, there were some unpalatable truths perhaps in these documents from the perspective of Hydro's witnesses, but those were put forward, tabs 1 through 6 in the METSCO material. We could go through and -- and -- with them ad nauseam. One makes judgments in the midst -- midst of cross-examination in terms of the Board's tolerance level for conversations about sustaining capital.

In our view, given that they're already expressly referenced on the record, there's not an issue.

THE CHAIRPERSON: Ms. Van Iderstine, we'll take notice of your -- of your concerns and we'll put forward the position of the Panel at a later date.

MS. VAN IDERSTINE: Thank you.

THE CHAIRPERSON: Thank you. Nine o'clock tomorrow morning. Thank you

(PANEL RETIRES)

--- Upon adjourning at 5:23 p.m

Certified Correct,

_____

Cheryl Lavigne, Ms.

Tab 57

2018
ELECTRIC LOAD FORECAST

MARKET FORECAST & LOAD RESEARCH

NOVEMBER 2018



Manitoba Hydro

*Manitoba Hydro is a licensee of the Trademark and Official Mark. This material is the exclusive property of Manitoba Hydro and all rights for use thereof, without the express consent of Manitoba Hydro is prohibited. Available in accessible formats upon request.

IMPORTANT:

THIS MATERIAL IS THE EXCLUSIVE PROPERTY OF MANITOBA HYDRO AND ALL RIGHTS ARE RESERVED. ANY RELEASE, REPRODUCTION OR OTHER USE THEREOF WITHOUT THE EXPRESS WRITTEN CONSENT OF MANITOBA HYDRO IS STRICTLY PROHIBITED

EXECUTIVE SUMMARY

Overview

The Gross Firm Energy in Manitoba is forecast to grow from a weather adjusted value of 25,870 GWh in 2017/18 to 28,627 GWh in 2027/28. This represents an average growth of 276 GWh or 1.0% per year for 10 years. By 2037/38, Gross Firm Energy is forecast to be 32,363 GWh, representing a growth rate of 325 GWh or 1.1% per year.

Gross Total Peak is forecast to grow at a similar pace, from an adjusted value of 4,751 MW in 2017/18 to 5,320 MW in 2027/28, growing 57 MW or 1.1% a year for the next 10 years. By 2037/38, Gross Total Peak is forecast to be 6,035 MW, representing a growth rate of 64 MW or 1.2% per year.

Growth is expected in all sectors with the Residential Basic, General Service Mass Market and General Service Top Consumers sectors forecast to grow annually by 1.2%, 1.5% and 0.2% respectively, over the next 20 years. During the last 10 years, Gross Firm Energy has grown 198 GWh or 0.8% per year. This 10 year period encompasses the 2009 global economic downturn that slowed growth and also reflects the influence of Manitoba Hydro's Demand Side Management activities.

The primary driver of energy growth in Manitoba is the population and the secondary driver is the economy. The population of Manitoba has grown from 1,191,000 people in 2007/08 to 1,342,000 people in 2017/18, averaging 1.2% growth per year. Manitoba's population is forecast to grow to 1,650,000 by 2037/38, averaging 1.1% per year. Real Manitoba Gross Domestic Product (GDP) is expected to grow 1.8% in 2018/19 and average 1.7% annually for the next 20 years. Canada and US Real GDP is forecast to grow 2.1% and 2.6% respectively in 2018/19 and average 1.9% and 2.1% annually for the next 20 years.

Three main components represent the majority of Manitoba's electricity use:

i. **Residential Basic** is forecast to grow at an average of 1.2% per year over the next 20 years. Customer growth, mimicking population growth, is growing 1.1% per year. Average use per customer is increasing, adding 0.15% per year. This is primarily due to the increased use of electric space heating, electric water heating and miscellaneous end uses in dwellings.

ii. **General Service Mass Market** is forecast to grow at an average of 1.5% per year, which is higher than the historic growth of 1.1% per year over the past 10 years. The growth is primarily due to the economic growth in Manitoba.

iii. **General Service Top Consumers** is forecast to grow at an average of 0.2% per year, which is higher than the 0.1% decline per year experienced during the past 10 years. It is less than the 3.1% growth per year during the prior 10 years. The 20 year historical growth of the Top Consumers has been 1.5% per year.

Table 1 – Gross Energy and Peak

Gross Firm Energy and Gross Total Peak History and Forecast 2007/08 - 2037/38					
	Gross Firm Energy		Gross Total Peak		Load Factor
Fiscal Year	(GWh)	Growth (%)	(MW)	Growth (%)	(%)
2007/08	24,122		4,304		64.0%
2008/09	24,417	1.2%	4,509	4.8%	61.8%
2009/10	23,412	-4.1%	4,393	-2.6%	60.8%
2010/11	23,892	2.1%	4,286	-2.4%	63.6%
2011/12	23,605	-1.2%	4,367	1.9%	61.7%
2012/13	24,750	4.9%	4,559	4.4%	62.0%
2013/14	25,625	3.5%	4,743	4.0%	61.7%
2014/15	25,505	-0.5%	4,713	-0.6%	61.8%
2015/16	24,665	-3.3%	4,479	-5.0%	62.9%
2016/17	25,227	2.3%	4,822	7.7%	59.7%
2017/18	25,742	2.0%	4,755	-1.4%	61.8%
2017/18 Wadj	25,870	0.5%	4,751	-0.1%	62.2%
10 Year Avg Gr.	198	0.8%	43	0.9%	
2018/19	25,935	0.3%	4,815	1.4%	61.5%
2019/20	26,237	1.2%	4,863	1.0%	61.6%
2020/21	26,528	1.1%	4,918	1.1%	61.6%
2021/22	26,759	0.9%	4,965	0.9%	61.5%
2022/23	27,018	1.0%	5,015	1.0%	61.5%
2023/24	27,357	1.3%	5,079	1.3%	61.5%
2024/25	27,691	1.2%	5,143	1.3%	61.5%
2025/26	28,001	1.1%	5,202	1.1%	61.5%
2026/27	28,329	1.2%	5,264	1.2%	61.4%
2027/28	28,627	1.1%	5,320	1.1%	61.4%
10 Year Avg Gr.	276	1.0%	57	1.1%	
2028/29	28,951	1.1%	5,381	1.2%	61.4%
2029/30	29,287	1.2%	5,445	1.2%	61.4%
2030/31	29,630	1.2%	5,511	1.2%	61.4%
2031/32	29,991	1.2%	5,580	1.3%	61.4%
2032/33	30,367	1.3%	5,652	1.3%	61.3%
2033/34	30,733	1.2%	5,722	1.2%	61.3%
2034/35	31,106	1.2%	5,794	1.3%	61.3%
2035/36	31,492	1.2%	5,869	1.3%	61.3%
2036/37	31,904	1.3%	5,948	1.4%	61.2%
2037/38	32,363	1.4%	6,035	1.5%	61.2%
20 Year Avg Gr.	325	1.1%	64	1.2%	

Change between the 2017 and 2018 Forecast

The Gross Firm Energy Forecast starts 144 GWh (0.6%) lower in 2018/19 and by 2036/37 is 445 GWh (1.4%) higher than the 2017 Forecast. This is an increase of just over 1 year of load growth by 2036/37. (1 year of load growth = approximately 325 GWh).

The Gross Total Peak is 137 MW higher in 2036/37 than presented under the 2017 Forecast primarily attributable to an increase in the energy forecast but a reduced energy forecast in the Top Consumers sector which results in a lower load factor and higher peak impact. This is an increase of just over 2 years of load growth. (1 year of load growth = approximately 64 MW).

Table 2 – Change in Energy and Peak

Gross Firm Energy and Gross Total Peak Change from Previous Forecast 2018/19 - 2037/38						
	Gross Firm Energy			Gross Total Peak		
Fiscal Year	2018 Forecast (GWh)	2017 Forecast (GWh)	Change (GWh)	2018 Forecast (MW)	2017 Forecast (MW)	Change (MW)
2017/18 Act	25,742			4,755		
Weather Adj.	128			-4		
2017/18 Wadj	25,870	26,065	(195)	4,751	4,767	(16)
2018/19	25,935	26,080	(144)	4,815	4,789	26
2019/20	26,237	26,369	(132)	4,863	4,845	18
2020/21	26,528	26,483	45	4,918	4,868	51
2021/22	26,759	26,459	299	4,965	4,870	95
2022/23	27,018	26,453	565	5,015	4,871	143
2023/24	27,357	26,453	903	5,079	4,875	204
2024/25	27,691	26,519	1,171	5,143	4,890	253
2025/26	28,001	26,639	1,362	5,202	4,913	289
2026/27	28,329	26,892	1,437	5,264	4,958	306
2027/28	28,627	27,241	1,386	5,320	5,022	298
10 Year	276	118		57	26	
Avg Gr.	1.0%	0.4%		1.1%	0.5%	
2028/29	28,951	27,650	1,301	5,381	5,098	284
2029/30	29,287	28,084	1,202	5,445	5,179	267
2030/31	29,630	28,529	1,101	5,511	5,262	249
2031/32	29,991	28,995	997	5,580	5,349	232
2032/33	30,367	29,469	898	5,652	5,438	215
2033/34	30,733	29,942	791	5,722	5,526	196
2034/35	31,106	30,427	679	5,794	5,617	177
2035/36	31,492	30,929	563	5,869	5,711	157
2036/37	31,904	31,459	445	5,948	5,811	137
19 Year	318	284	34	63	55	8
Avg Gr.	1.1%	1.0%	0.1%	1.2%	1.0%	0.1%

The decrease in 2018/19 of 144 GWh is mainly attributable to changes in the Top Consumers short term operating plans.

By 2036/37, the 2018 Forecast is 445 GWh higher than previously assumed in the 2017 Forecast. The difference is attributable to the following:

Residential Basic (+210 GWh)

- Primarily higher due to an decrease in the forecast of electric price

General Service Mass Market (+371 GWh)

- Primarily higher due to an increase in the average use forecast

General Service Top Consumer (-178 GWh)

- Primarily lower due to adjustments in customer short term plans and updates to the longer term growth forecast (PLIL)

Other sales and losses (+42 GWh)

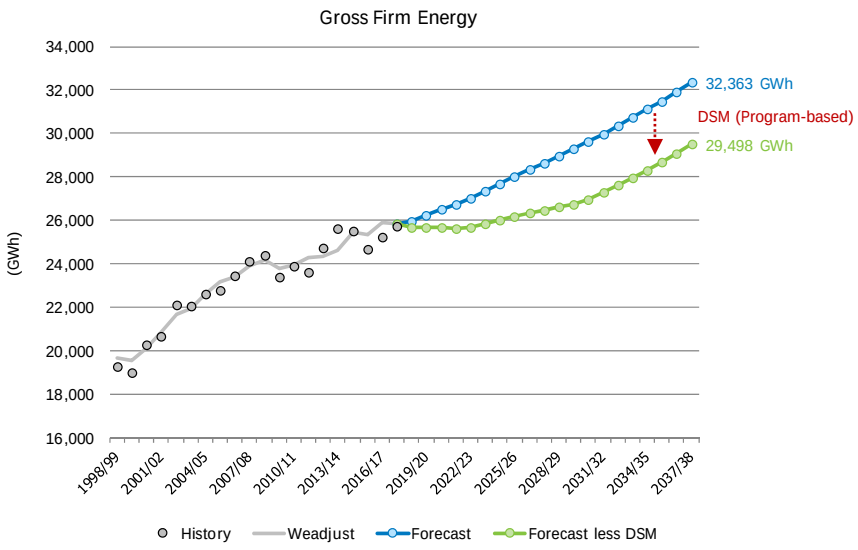
- Increases in other sales and losses

Program-based Demand Side Management (DSM)

Through its Demand Side Management (DSM) initiative, Manitoba Hydro develops and implements cost-effective energy conservation and alternative energy programs. These programs provide Manitoba customers with environmentally friendly initiatives that aim to reduce customer's energy consumption. The 2018 electric load forecast reflects future DSM savings associated with existing Provincial building codes and improved equipment efficiency standards and regulations (Codes and Standards). This is the only effect of DSM initiatives that is specifically accounted for within the forecast. DSM savings arising from future program-based offerings incremental to the above mentioned Codes and Standards are not reflected in this forecast. They are accounted for separately in Manitoba Hydro's DSM Plan and Power Resource Plan.

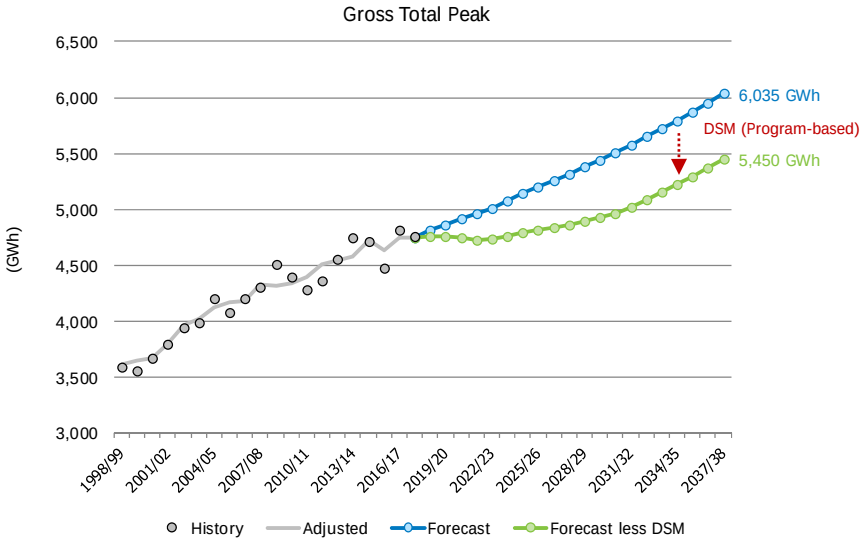
Although not explicitly included in this forecast, the program-based DSM has a significant impact on the projected future load growth expected in Manitoba. Program-based DSM reduces the Gross Firm Energy in 2037/38 from 32,363 GWh to 29,498 GWh, lowering the average growth of 325 GWh or 1.1% per year to an average growth of 181 GWh or 0.7% per year.

Figure 1 – Gross Firm Energy



Program-based DSM reduces the Gross Total Peak in 2037/38 from 6,035 MW to 5,450 29,498 GWh, lowering the average growth of 64 MW or 1.2% per year to an average growth of 35 GWh or 0.7% per year.

Figure 2 – Gross Total Peak



The following table outlines the impacts of incorporating program-based Demand Side Management activity:

Table 3 – Impacts of Demand Side Management

Gross Firm Energy and Gross Total Peak Impacts of Demand Side Management 2018/19 - 2037/38						
	Gross Firm Energy (GWh)			Gross Total Peak (MW)		
Fiscal Year	Forecast	DSM (Program Based)	Forecast less DSM	Forecast	DSM (Program Based)	Forecast less DSM
2017/18 Wadj	25,870		25,870	4,751		4,751
2018/19	25,935	(285)	25,651	4,815	(53)	4,762
2019/20	26,237	(541)	25,696	4,863	(99)	4,763
2020/21	26,528	(861)	25,667	4,918	(169)	4,749
2021/22	26,759	(1,158)	25,601	4,965	(238)	4,727
2022/23	27,018	(1,341)	25,677	5,015	(283)	4,732
2023/24	27,357	(1,509)	25,847	5,079	(319)	4,760
2024/25	27,691	(1,666)	26,024	5,143	(352)	4,790
2025/26	28,001	(1,829)	26,172	5,202	(386)	4,816
2026/27	28,329	(1,998)	26,331	5,264	(421)	4,843
2027/28	28,627	(2,173)	26,454	5,320	(455)	4,866
10 Year Avg Gr.	276		58	57		11
Avg Gr.	1.0%		0.2%	1.1%		0.2%
2028/29	28,951	(2,345)	26,607	5,381	(487)	4,894
2029/30	29,287	(2,525)	26,762	5,445	(521)	4,924
2030/31	29,630	(2,697)	26,933	5,511	(552)	4,959
2031/32	29,991	(2,717)	27,274	5,580	(557)	5,024
2032/33	30,367	(2,742)	27,625	5,652	(561)	5,091
2033/34	30,733	(2,766)	27,967	5,722	(566)	5,156
2034/35	31,106	(2,791)	28,314	5,794	(571)	5,223
2035/36	31,492	(2,815)	28,677	5,869	(576)	5,293
2036/37	31,904	(2,839)	29,064	5,948	(580)	5,368
2037/38	32,363	(2,865)	29,498	6,035	(585)	5,450
20 Year Avg Gr.	325		181	64		35
Avg Gr.	1.1%		0.7%	1.2%		0.7%

TABLE OF CONTENTS

EXECUTIVE SUMMARY I

TABLE OF CONTENTS VI

LIST OF TABLES AND FIGURES VIII

INTRODUCTION 1

FORECAST OVERVIEW 3

- General Consumers Customer Forecast 4
- General Consumers Sales Forecast 5
- Manitoba Energy Forecast 7
- Comparison of the 2017 Forecast to Actuals 9
- Changes between the 2017 and 2018 Forecasts 11

FORECAST DETAILS 16

- Residential Basic 17
- Residential Diesel, Seasonal, and Flat Rate Water Heating 20
- General Service Mass Market 21
- General Service Top Consumers 22
- General Service Diesel, Seasonal, and Flat Rate Water Heating 26
- General Service Surplus Energy Program 26
- Plug-In Electric Vehicles 27
- Area & Roadway Lighting 30
- Total General Consumer Sales 33
- Diesel Sales 35
- Distribution Losses 36
- Construction Power 36
- Manitoba Load at Common Bus 38
- Transmission Losses 39
- Station Service 40
- Gross Firm Energy 42
- Gross Total Peak 45

VARIABILITY AND ACCURACY 49

- Weather Effect and Weather Adjustment 49
- Load Variability 50
- 5 and 10 year Forecast Accuracy 53

LOAD SENSITIVITY AND EXTREME EVENTS 56

ASSUMPTIONS 61

- Economic Assumptions 61
- Price / Income / GDP Elasticity 62
- Normal Weather Assumptions 62
- Demand Side Management (DSM) in the Forecast 63

METHODOLOGY 64

GLOSSARY OF TERMS 74

LIST OF TABLES AND FIGURES

Table 1 – Gross Energy and Peak ii
Table 2 – Change in Energy and Peak iii
Figure 1 – Gross Firm Energy v
Figure 2 – Gross Total Peak v
Table 3 – Impacts of Demand Side Management vi
Figure 3 – Components of Manitoba Electricity Use 2
Table 4 – Components of Manitoba Electric Use 3
Table 5 – General Consumers Sales Customers 5
Table 6 – General Consumer Sales Energy 7
Table 7 – Components of Manitoba Energy 9
Table 8 – 2017/18 Forecast to Actual 10
Figure 4 – Change of Res Basic Forecast 11
Table 9 – Change of Res Basic Forecast 11
Figure 5 – Change of GS Mass Market Forecast 12
Table 10 – Change of GS Mass Market Forecast 12
Figure 6 – Change of GS Top Consumer Forecast 13
Table 11 – Change of GS Top Consumer Forecast 13
Figure 7 – Change of General Consumer Sales Forecast 14
Table 12 – Change of General Consumer Sales Forecast 14
Figure 8 – Change of Energy Forecast 15
Table 13 – Change of Energy Forecast 15
Figure 9 – Change of Peak Forecast 16
Table 14 – Change of Peak Forecast 16
Figure 10 – Residential Basic Customers 17
Figure 11 – Residential Basic Sales 17
Table 15 – Residential Sales 18
Table 16 – Residential Basic Sales 18
Figure 12 – General Service Mass Market Customers 21
Figure 13 – General Service Mass Market Sales 21
Table 17 – General Service Mass Market 22
Figure 14 – General Service Top Consumer Sectors 23
Figure 15 – General Service Top Consumers Sales 23
Table 18 – General Service Top Consumers 24
Figure 16 – Plug-in Electric Vehicles 28
Table 19 – Plug-in Electric Vehicles 28
Figure 17 - Area & Roadway Lighting 30
Table 20 - Area & Roadway Lighting 31
Table 21 – Area & Roadway Lighting 32
Figure 18 – General Consumers Sales 33
Figure 19 – General Consumers Sales 33
Table 22 – General Consumers Sales 34
Table 23 – Diesel Sales 35
Figure 20 – Diesel Sales 35
Table 24 – Distribution Losses 36

Figure 21 – Distribution Losses 36
Table 25 – Construction Power 37
Figure 22 – Construction Power 37
Table 26 – Manitoba Load at Common Bus 38
Figure 23 – Manitoba Load at Common Bus 38
Table 27 – Transmission Losses 39
Figure 24 – Transmission Losses 39
Table 28 - Station Service 40
Figure 25 - Station Service 40
Table 29 – Monthly Station Service Energy 40
Table 30 – Monthly Station Service Peak 41
Figure 26 - Gross Firm Energy 42
Figure 27 - Gross Firm Energy 42
Table 31 - Gross Firm Energy 43
Table 32 – Monthly Gross Firm Energy 44
Figure 28 - Gross Total Peak 45
Table 33 – Gross Total Peak 46
Table 34 – Monthly Gross Total Peak 47
Figure 29 – Energy Variability 51
Table 35 – Energy Variability 51
Figure 30 – Peak Variability 52
Table 36 – Peak Variability 52
Figure 31 – Energy Accuracy 54
Table 37 – Energy Accuracy 54
Figure 32 – Peak Accuracy 55
Table 38– Peak Accuracy 55
Figure 33 – Gross Firm Energy (Net of DSM) 63
Figure 34 – Gross Total Peak (Net of DSM) 63

x

INTRODUCTION

This document is prepared annually as Manitoba Hydro's forecast of its future load requirements for its service area. The service area consists of the entire province of Manitoba (99.85% of sales), as well as two resale customers that supply energy to Creighton, Saskatchewan (0.12% of sales) and the Northwest Angle, Minnesota (0.03% of sales). Exports of power to other utilities are not included.

This information provided serves several purposes. Short term forecasts of sales by billing month within rate groups are needed to forecast revenue for rate design and accounting. Short term forecasts of energy and peak is needed for system operations. Long term forecasts of energy and peak are required by power planning to determine long term supply requirements.

A "customer" in this document refers to a metered electrical service. Unmetered services, such as flat rate water heating and sentinel rentals are not defined as customers. Street lighting group a number of services at the municipal and lighting type category and are each defined as one customer. A customer is not equivalent to a building structure. One building can have multiple electric services and may count as more than one customer. Likewise, multiple buildings may have only one service and will count as only one customer.

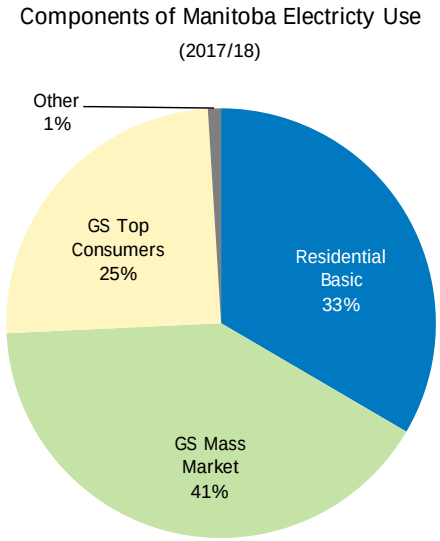
Electric consumption is read at the meter level in units of kilowatt-hours (kWh). This document reports electric use in terms of gigawatt-hours (GWh). One GWh equals one million kWh, which is approximately the energy of 100 typical residential dwellings not using electricity for heating. A residential dwelling not using electricity for heating uses approximately 10,000 kWh per year.

The highest load requirement during a time period is defined as the peak load. It is given in terms of megawatts (MW). One MW equals one thousand kilowatts (kW). A typical residential dwelling not using electricity for heating would use a maximum of about 2.5 kW sometime during the year. However, dwellings will not all be at their maximum use at the same hour. The use of all dwellings at any specific hour is defined as the coincident load. The coincident peak is the load at the hour of Manitoba's system peak. A typical dwelling not using electricity for heating would use about 1.6 kW at the coincident peak. Therefore 1.0 MW is approximately the coincident peak requirement of 600 typical dwellings not using electricity for heating.

Components of Manitoba's Electricity Use – 2017/18

General Consumers Sales (also referred to as Total Sales) includes the energy supplied to all of Manitoba Hydro's individually billed customers. During the 2017/18 fiscal year, Manitoba Hydro averaged 576,937 General Consumers Sales customers who consumed 22,573 GWh.

Figure 3 – Components of Manitoba Electricity Use



The major groups include:

i. **Residential Basic**, with 486,317 customers, who used 7,547 GWh or 33.4% of Total Sales are mostly residential structures that include single-family dwellings, multi-family dwellings and individually metered apartment suites.

ii. **General Service Mass Market**, with 68,105 customers who used 9,213 GWh or 40.8% of Total Sales are small to large Commercial and Industrial customers.

iii. **General Service Top Consumers**, with 26 customers who used 5,592 GWh or 24.8% of Total Sales are the 10 high-usage companies (some count as multiple customers) that are forecast individually.

In addition to the above major groups, there are four remaining group of customers who used 221 GWh or 1.0% of Total Sales:

i. Seasonal customers are those billed twice a year rather than on a monthly basis.

ii. Diesel customers are from four remote communities not connected to the integrated grid system.

iii. Flat Rate Water Heating customers.

iv. Area and Roadway Lighting sector which includes electricity sales for the Sentinel Lighting and Street Lighting groups.

Note: Over 50,000 of these services related to Flat Rate Water Heating and Area and Roadway Lighting do not count as customers.

Manitoba Load at Common Bus is the total load metered at all the substations in the province that supplies Manitoba Hydro's non-Diesel customers and includes Distribution Losses and Construction Power. In 2017/18, Common Bus was 23,799 GWh or about 5.4% more than Total Sales.

Gross Firm Energy is the total load needed to be generated for domestic firm load requirements on the Integrated System excluding Diesel customers. It includes Transmission Losses and Station Service. Some customers are on non-firm contracts (Surplus Energy Program), and their load is not included as part of Manitoba Hydro's generation requirement. In 2017/18, Gross Firm Energy was 25,742 GWh or about 14.0% over Total Sales.

Table 4 – Components of Manitoba Electric Use

Components of Manitoba Electricity Use 2017/18 (Customers, Actual Consumption and Average Use)				
Forecast Group	Cust/Serv	GWh	% of Sales	kWh/cust
Residential Basic	486,317	7,547	33.4%	15,519
Residential Diesel	587	8	0.0%	13,494
Residential Seasonal	19,507	65	0.3%	3,348
Residential Flat Rate Water Heating	3,129 *	16	0.1%	5,065
Total Residential	506,411	7,636	33.8%	
GS Mass Market	68,105	9,213	40.8%	135,273
GS Top Consumers	26	5,592	24.8%	215,084,080
GS Diesel	180	6	0.0%	31,285
GS Seasonal	957	5	0.0%	5,289
GS Flat Rate Water Heat	338 *	5	0.0%	16,287
GS Surplus Energy Program	31	28	0.1%	903,105
Total General Service	69,298	14,849	65.8%	
Sentinal Flat Rate	20,904 *	12	0.1%	565
Sentinal Rental	26,135 *	-	0.0%	-
Street Lighting	1,228	76	0.3%	62,123
Total Lighting	1,228	88	0.4%	
Total General Consumer Sales	576,937	22,573	100.0%	
Less Diesel Sales		(14)	-0.1%	
Distribution Losses		1,155	5.1%	
Construction Power		84	0.4%	
Manitoba Load at Common Bus		23,799	105.4%	
Transmission Losses		1,846	8.2%	
Less Non-Firm Energy		(28)	-0.1%	
Station Service		125	0.6%	
Gross Firm Energy		25,742	114.0%	

* Flat rate and rental services do not count as customers

FORECAST OVERVIEW

General Consumers Customer Forecast

In 2017/18, Manitoba Hydro had an average of 576,937 General Consumer Sales customers. These were made up of 486,317 Residential Basic customers, 68,105 General Service Mass Market customers, 26 General Service Top Consumers customers and 31 Surplus Energy Program (SEP), i.e. non-firm, customers, with the remaining customers being Diesel, Seasonal and Area and Roadway Lighting.

During the last 10 years, Residential Basic customers have grown at an average of 5,417 (1.2%) per year. Manitoba Hydro's Forecast of Key Economic and Financial Indicators provide the forecast of Residential Basic customers which is incorporated in the load forecast. Residential Basic customers are forecast to grow 5,968 (1.2%) customers per year over the next 10 years and 5,658 (1.1%) customers per year over the next 20 years.

General Service Mass Market customers have grown 425 (0.6%) per year over the last 10 years. The sector is forecast to grow 489 (0.7%) per year over the next 10 years and 490 (0.7%) per year over the next 20 years.

Residential Seasonal customers, mainly cottages with lower average energy use, experienced a reduction of customers over the past 10 years as higher energy consuming seasonal customers are transferred to the Residential Basic sector. The sector is forecast to decrease at 131 customers annually over the next 10 years and 133 customers annually over the next 20 years due to the continued transfer of higher usage seasonal customers to the Residential Basic sector.

Area and Roadway Lighting customers have grown 9 (0.7%) per year over the last 10 years. The sector is expected to grow at 6 (0.4%) customers annually over the next 10 years and 5 (0.4%) customers annually over the next 20 years.

Table 5 – General Consumers Sales Customers

General Consumer Sales (Average Customers) History and Forecast 2007/08 - 2037/38										
Fiscal	Residential			General Service					Lighting	Total
Year	Basic	Diesel	Seas	Mass Mkt	Top Cons	Diesel	Seas	SEP		Custs
2007/08	432,144	531	20,437	63,855	26	175	798	27	1,142	519,135
2008/09	437,263	540	20,648	64,140	26	178	818	24	1,175	524,811
2009/10	441,710	539	20,839	64,758	26	177	830	24	1,191	530,095
2010/11	445,882	550	20,950	65,193	26	176	842	24	1,184	534,828
2011/12	450,748	568	20,844	65,546	32	174	847	26	1,155	539,939
2012/13	456,130	577	20,731	65,974	31	175	850	28	1,164	545,660
2013/14	462,274	583	20,757	66,569	31	179	861	28	1,157	552,438
2014/15	468,499	583	20,626	67,042	30	183	872	28	1,196	559,060
2015/16	474,153	583	20,176	67,395	32	184	882	30	1,208	564,643
2016/17	480,365	586	19,707	67,676	26	181	923	30	1,218	570,712
2017/18	486,317	587	19,507	68,105	26	180	957	31	1,228	576,937
10 Year	5,417	6	-93	425	0	0	16	0	9	5,780
Avg Gr.	1.2%	1.0%	-0.5%	0.6%	0.0%	0.3%	1.8%	1.4%	0.7%	1.1%
2018/19	492,559	591	19,412	68,632	26	181	968	31	1,239	583,638
2019/20	498,806	592	19,277	69,112	26	180	983	31	1,244	590,251
2020/21	505,050	594	19,142	69,588	26	181	998	31	1,249	596,859
2021/22	511,061	597	19,007	70,066	26	181	1013	31	1,254	603,235
2022/23	516,880	599	18,872	70,560	26	181	1028	31	1,259	609,436
2023/24	522,680	602	18,737	71,062	26	181	1043	31	1,264	615,625
2024/25	528,523	604	18,602	71,547	26	182	1058	31	1,269	621,842
2025/26	534,372	607	18,467	72,027	26	182	1073	31	1,274	628,059
2026/27	540,200	609	18,332	72,510	26	182	1088	31	1,279	634,257
2027/28	545,999	612	18,197	72,996	26	183	1103	31	1,284	640,430
10 Year	5,968	2	-131	489	0	0	15	0	6	6,349
Avg Gr.	1.2%	0.4%	-0.7%	0.7%	0.0%	0.2%	1.4%	0.1%	0.4%	1.0%
2028/29	551,703	614	18,062	73,483	26	183	1118	31	1,289	646,509
2029/30	557,284	617	17,927	73,968	26	183	1133	31	1,294	652,462
2030/31	562,778	619	17,792	74,454	26	184	1148	31	1,299	658,330
2031/32	568,206	622	17,657	74,941	26	184	1163	31	1,304	664,134
2032/33	573,599	624	17,522	75,432	26	184	1178	31	1,309	669,904
2033/34	578,968	627	17,387	75,926	26	185	1193	31	1,314	675,656
2034/35	584,285	629	17,252	76,422	26	185	1208	31	1,319	681,356
2035/36	589,492	632	17,117	76,918	26	185	1223	31	1,324	686,947
2036/37	594,550	634	16,982	77,412	26	186	1238	31	1,329	692,388
2037/38	599,469	637	16,847	77,906	26	186	1253	31	1,334	697,689
20 Year	5,658	2	-133	490	0	0	15	0	5	6,038
Avg Gr.	1.1%	0.4%	-0.7%	0.7%	0.0%	0.2%	1.4%	0.0%	0.4%	1.0%

General Consumers Sales Forecast

During 2017/18, Total General Consumer Sales was 22,573 GWh. The fiscal billing year (using weather from March 16, 2017 to March 15, 2018) was significantly warmer than normal producing a weather adjustment for the year of +165 GWh. The resulting weather adjusted Total Sales value was 22,738 GWh.

Over the last 10 years, Total Sales have grown at 182 GWh (0.8%) per year. The growth was 1.4% per year in Residential Basic and 1.1% per year in General Service Mass Market, and a decline of 0.1% in General Service Top Consumers due to the economic downturn in 2009 and the loss of one Top Consumer customer. The historical growth also reflects the effect of past Demand Side Management (DSM) initiatives.

Sales are forecast to grow at 235 GWh (1.0%) per year over the next 10 years and 281 GWh (1.1%) per year over the next 20 years before accounting for future market-based DSM programs.

Most of the growth is forecast to occur in General Service Mass Market, at 166 GWh (1.5%) per year over the next 20 years, followed by Residential Basic at 103 GWh (1.2%) per year and Top Consumers at 13 GWh (0.2%) per year. Starting in 2016/17, seven of the smallest Top Consumers, totaling 404 GWh, were moved to General Service Mass Market for forecasting purposes. The historical growth rates for the General Service Mass Market and Top Consumers are adjusted to reflect the migration between both sectors.

Table 6 – General Consumer Sales Energy

General Consumer Sales (GWh) History and Forecast 2007/08 - 2037/38												
Fiscal	Residential				General Service						Lighting	Total
Year	Basic	Diesel	Seas	FRWH	Mass Mkt	Top Cons	Diesel	Seas	FRWH	SEP		Sales
2007/08	6,736	7	68	27	8,006	6,075	5	4	9	24	101	21,061
2008/09	6,847	7	74	25	8,049	6,065	5	5	8	22	102	21,210
2009/10	6,786	7	81	24	7,985	5,461	6	5	8	20	102	20,486
2010/11	6,952	8	77	23	8,258	5,324	5	5	8	24	103	20,786
2011/12	6,818	8	83	22	8,162	5,531	5	5	8	25	103	20,771
2012/13	7,223	8	81	21	8,434	5,560	5	5	7	28	103	21,477
2013/14	7,767	9	92	20	8,839	5,461	5	5	7	29	104	22,338
2014/15	7,658	9	102	19	8,771	5,750	6	6	6	27	104	22,458
2015/16	7,074	8	81	18	8,442	5,886	6	5	6	25	104	21,654
2016/17	7,158	9	66	17	8,956	5,685	6	5	6	26	92	22,025
2017/18	7,547	8	65	16	9,213	5,592	6	5	5	28	88	22,573
Weather Adj.	94	0	0	0	72	0	0	0	0	-1	0	165
2017/18 Wadj	7,641	8	65	16	9,284	5,592	6	5	5	27	88	22,738
10 Year Wadj	100	0	0	-1	174	-8	0	0	0	0	-1	182
Avg Gr.	1.4%	1.5%	-0.5%	-5.2%	1.1%	-0.1%	1.0%	1.2%	-4.4%	1.4%	-1.3%	0.8%
2018/19	7,714	8	71	15	9,468	5,250	6	5	5	28	72	22,642
2019/20	7,798	8	71	14	9,605	5,306	6	5	5	28	72	22,917
2020/21	7,891	8	70	14	9,750	5,351	6	5	5	28	72	23,199
2021/22	7,975	8	70	13	9,896	5,343	6	5	4	28	72	23,420
2022/23	8,049	8	70	12	10,077	5,343	6	5	4	28	72	23,675
2023/24	8,145	8	69	12	10,246	5,377	6	5	4	28	72	23,972
2024/25	8,245	8	69	11	10,406	5,412	6	6	4	28	72	24,265
2025/26	8,347	8	69	11	10,546	5,443	6	6	4	28	72	24,537
2026/27	8,441	8	69	10	10,710	5,474	6	6	3	28	72	24,826
2027/28	8,511	8	68	9	10,870	5,506	6	6	3	28	72	25,087
10 Year	87	0	0	-1	159	-9	0	0	0	0	-2	235
Avg Gr.	1.1%	0.4%	0.4%	-5.0%	1.6%	-0.2%	0.2%	1.3%	-5.0%	0.3%	-2.0%	1.0%
2028/29	8,597	8	68	9	11,040	5,537	6	6	3	28	72	25,373
2029/30	8,697	8	68	9	11,202	5,569	6	6	3	28	72	25,667
2030/31	8,802	8	67	8	11,366	5,601	6	6	3	28	72	25,967
2031/32	8,922	8	67	8	11,532	5,633	6	6	3	28	72	26,284
2032/33	9,045	8	67	7	11,707	5,665	6	6	3	28	72	26,613
2033/34	9,164	8	66	7	11,876	5,698	6	6	2	28	72	26,933
2034/35	9,286	8	66	7	12,048	5,731	6	6	2	28	72	27,259
2035/36	9,418	9	66	6	12,221	5,763	6	6	2	28	72	27,597
2036/37	9,560	9	65	6	12,407	5,797	6	6	2	28	72	27,957
2037/38	9,705	9	65	6	12,599	5,862	6	6	2	28	72	28,360
20 Year	103	0	0	-1	166	13	0	0	0	0	-1	281
Avg Gr.	1.2%	0.4%	0.0%	-5.0%	1.5%	0.2%	0.2%	1.2%	-5.0%	0.1%	-1.0%	1.1%

Manitoba Energy Forecast

The weather adjusted actual Gross Firm Energy was 25,870 GWh in 2017/18. Gross Firm Energy has grown 198 GWh (0.8%) per year for the past 10 years. This historical growth reflects the effect of past Demand Side Management (DSM) initiatives. Gross Firm Energy is forecast to grow to 32,363 GWh by 2037/38 at an average of 325 GWh (1.1%) per year. This does not reflect future market-based DSM programs.

Distribution Losses, which are the difference between Manitoba Hydro's substations and the customers' meters, have a wide variance from year to year. The differences have ranged between 3.5% and 5.5% of Total Sales. It is forecast to be between 4.8% and 4.9% of Sales for the entire forecast.

Transmission Losses, which are the difference between the generators and the substations, are forecast to be approximately 9.0% of Total Sales throughout the entire forecast period.

Distribution Losses and Transmission Losses, totaling almost 14%, need to be added to Total Sales to estimate Gross Firm Energy. The 14% value should be used to estimate load at generation when only load at the customer's meter is known. For example, to convert Power Smart program savings from the customer meter to generation. The exception is for large General Service customers who own their own transformation and incur minimal Distribution Losses. For these customers, a 10% value should be used.

Table 7 – Components of Manitoba Energy

Manitoba Firm Energy (GWh) History and Forecast 2007/08 - 2037/38										
Fiscal Year	General Consumer Sales less Diesel	Dist. Losses	Dist. Loss %	Const. Power	Manitoba Load at Common Bus	Trans. Losses	Trans. Loss %	Less Non Firm Energy	Station Service	Gross Firm Energy
2007/08	21,049	940	4.5%	47	22,036	1,949	9.3%	24	161	24,122
2008/09	21,198	1,052	5.0%	56	22,305	1,979	9.3%	22	154	24,417
2009/10	20,473	813	4.0%	75	21,361	1,934	9.4%	20	137	23,412
2010/11	20,773	947	4.6%	85	21,806	1,977	9.5%	25	134	23,892
2011/12	20,757	736	3.5%	67	21,560	1,939	9.3%	25	131	23,605
2012/13	21,463	1,184	5.5%	59	22,706	1,936	9.0%	28	136	24,750
2013/14	22,324	1,205	5.4%	12	23,541	1,969	8.8%	29	144	25,625
2014/15	22,443	992	4.4%	15	23,450	1,949	8.7%	26	132	25,505
2015/16	21,640	791	3.7%	28	22,460	2,107	9.7%	25	123	24,665
2016/17	22,010	1,043	4.7%	62	23,115	2,014	9.2%	26	123	25,227
2017/18	22,560	1,155	5.1%	84	23,799	1,846	8.2%	28	125	25,742
Weather Adj.	165	-48		0	117	10		-1	0	128
2017/18 Wadj	22,725	1,108	4.9%	84	23,916	1,856	8.2%	27	125	25,870
10 Year Wadj	182	24		4	210	-9		0	-4	198
Avg Gr.	0.8%	2.5%		6.0%	0.9%	-0.5%		1.4%	-2.5%	0.8%
2018/19	22,628	1,097	4.8%	87	23,812	2,028	9.0%	28	123	25,935
2019/20	22,904	1,109	4.8%	77	24,090	2,051	9.0%	28	123	26,237
2020/21	23,185	1,122	4.8%	51	24,358	2,074	8.9%	28	123	26,528
2021/22	23,406	1,135	4.8%	30	24,571	2,092	8.9%	28	123	26,759
2022/23	23,661	1,149	4.9%	0	24,810	2,113	8.9%	28	123	27,018
2023/24	23,958	1,164	4.9%	0	25,122	2,139	8.9%	28	123	27,357
2024/25	24,252	1,178	4.9%	0	25,430	2,165	8.9%	28	123	27,691
2025/26	24,524	1,192	4.9%	0	25,715	2,190	8.9%	28	123	28,001
2026/27	24,812	1,206	4.9%	0	26,018	2,216	8.9%	28	123	28,329
2027/28	25,073	1,219	4.9%	0	26,292	2,239	8.9%	28	123	28,627
10 Year	235	11		-8	238	38		0	0	276
Avg Gr.	1.0%	1.0%		-100.0%	1.0%	1.9%		0.3%	-0.1%	1.0%
2028/29	25,359	1,233	4.9%	0	26,592	2,264	8.9%	28	123	28,951
2029/30	25,653	1,248	4.9%	0	26,900	2,291	8.9%	28	123	29,287
2030/31	25,953	1,263	4.9%	0	27,217	2,318	8.9%	28	123	29,630
2031/32	26,270	1,280	4.9%	0	27,550	2,346	8.9%	28	123	29,991
2032/33	26,599	1,297	4.9%	0	27,896	2,375	8.9%	28	123	30,367
2033/34	26,919	1,314	4.9%	0	28,233	2,404	8.9%	28	123	30,733
2034/35	27,245	1,332	4.9%	0	28,577	2,433	8.9%	28	123	31,106
2035/36	27,582	1,350	4.9%	0	28,933	2,464	8.9%	28	123	31,492
2036/37	27,942	1,370	4.9%	0	29,312	2,496	8.9%	28	123	31,904
2037/38	28,345	1,390	4.9%	0	29,736	2,532	8.9%	28	123	32,363
20 Year	281	14		-4	291	34		0	0	325
Avg Gr.	1.1%	1.1%		-100.0%	1.1%	1.6%		0.2%	-0.1%	1.1%

Comparison of the 2017 Forecast to Actuals

Comparison of the 2017 Forecast to the 2017/18 Weather Adjusted Actuals

The weather adjusted General Consumer Sales for 2017/18 was 22,738 GWh which was 332 GWh higher than the 2017 Forecast of 22,407 GWh after incorporating the Demand Side Management (DSM) program savings achieved in 2017/18.

The weather adjusted Residential Basic sector was 107 GWh higher than the 2017 Forecast and the weather adjusted General Service Mass Market sector was 166 GWh higher than forecast.

In 2017/18, the Top Consumers sector consumed 5,592 GWh which was 71 GWh higher than the 2017 Forecast of 5,522 GWh. The difference is primarily due to an increase in production within the Metals & Forestry sector.

Distribution Losses were 66 GWh higher than forecast and transmission losses were 181 GWh lower than forecast.

Overall, the weather adjusted Gross Firm Energy for 2017/18 was 25,870 GWh which was 194 GWh higher than the 2017 Forecast of 25,676 GWh. The normalized Gross Total Peak for 2017/18 was 4,751 MW which was 43 MW higher than the 2017 Forecast of 4,708 MW.

Table 8 – 2017/18 Forecast to Actual

2017 Forecast Compared to Weather Adjusted Actuals 2017/18 Energy (GWh) and Peak (MW)					
Forecast Group	Actuals	Weather Adjustment	Wthr Adj Actuals	2017 Forecast less DSM	WA Actuals less Forecast
Residential Basic	7,547	94	7,641	7,534	107
Residential Diesel	8	-	8	9	(1)
Residential Seasonal	65	-	65	73	(8)
Residential Flat Rate Water Heating	16	-	16	16	(0)
Total Residential	7,636	94	7,730	7,632	98
GS Mass Market	9,213	72	9,284	9,119	166
GS Top Consumers	5,592	-	5,592	5,522	71
GS Diesel	6	-	6	6	(1)
GS Seasonal	5	-	5	5	(0)
GS Flat Rate Water Heat	5	-	5	5	0
GS Surplus Energy Program	28	(1)	27	26	1
Total General Service	14,849	71	14,920	14,683	237
Sentinal Flat Rate	12	-	12	12	(0)
Sentinal Rental	-	-	-	-	-
Street Lighting	76	-	76	80	(4)
Total Lighting	88	-	88	92	(4)
Total General Consumer Sales	22,573	165	22,738	22,407	332
Less Diesel Sales	(14)	-	(14)	(15)	2
Distribution Losses	1,155	(48)	1,108	1,042	66
Construction Power	84	-	84	105	(21)
Manitoba Load at Common Bus	23,799	117	23,916	23,538	378
Transmission Losses	1,846	10	1,856	2,037	(181)
Less Non-Firm Energy	(28)	1	(27)	(26)	(1)
Station Service	125	-	125	126	(1)
Gross Firm Energy (GWh)	25,742	128	25,870	25,676	194
Gross Total Peak (MW)	4,755	(4)	4,751	4,708	43

Changes between the 2017 and 2018 Forecasts

Changes between the 2017 and 2018 Residential Basic Forecast

The 2018 Residential Basic Forecast starts 43 GWh higher compared to the 2017 Forecast. This is primarily due to the 2017/18 weather adjusted actual energy use being higher than forecast. The difference between forecasts increases to 615 GWh in 2027/28, primarily due to the change in the electric price forecast. By 2036/37, the difference between forecasts decreases to 210 GWh as the forecast of electric price reaches similar levels to those included in the 2017 Forecast.

Figure 4 – Change of Res Basic Forecast

Comparison of 2017 to 2018 Forecast

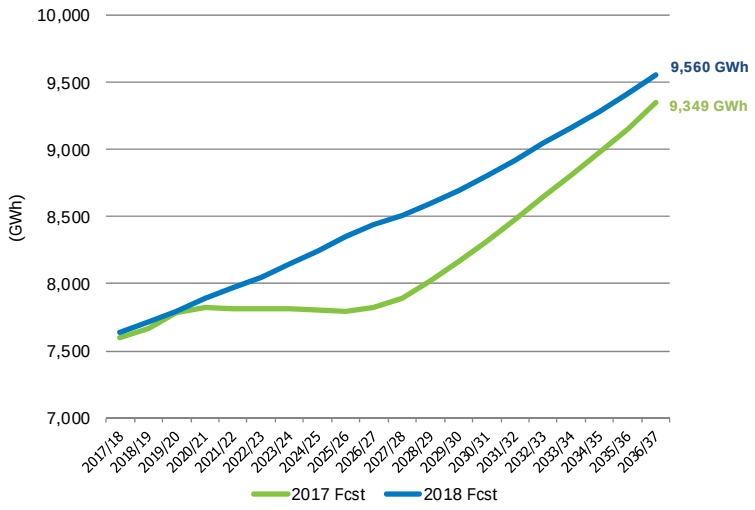


Table 9 – Change of Res Basic Forecast

Change of Residential Basic Forecast (GWh) Comparison of 2017 to 2018 Forecast				
Fiscal Year	2017 Fcst	2018 Fcst	Change	%
2017/18	7,594	7,641	47	0.6%
2018/19	7,671	7,714	43	0.6%
2019/20	7,780	7,798	19	0.2%
2020/21	7,826	7,891	65	0.8%
2021/22	7,814	7,975	161	2.1%
2022/23	7,815	8,049	235	3.0%
2023/24	7,811	8,145	334	4.3%
2024/25	7,807	8,245	438	5.6%
2025/26	7,797	8,347	550	7.1%
2026/27	7,821	8,441	620	7.9%
2027/28	7,895	8,511	615	7.8%
2028/29	8,020	8,597	577	7.2%
2029/30	8,162	8,697	534	6.5%
2030/31	8,311	8,802	492	5.9%
2031/32	8,474	8,922	448	5.3%
2032/33	8,643	9,045	402	4.7%
2033/34	8,808	9,164	356	4.0%
2034/35	8,977	9,286	309	3.4%
2035/36	9,158	9,418	260	2.8%
2036/37	**9,349**	**9,560**	**210**	**2.2%**

Major changes and energy impacts		
2036/37		
Decrease in the customer forecast of approx. 1,287 customers		
Customer forecast change	(21)	GWh
Increase in the forecast of Consumer Price Index	35	GWh
Decrease in the forecast of household income	(111)	GWh
Decrease in the short term forecast of electric price	255	GWh
Change in the starting point, which includes achieved DSM	(131)	GWh
Change in electric heat saturation	185	GWh
Change in model parameters	(72)	GWh
Average Use forecast change	161	GWh
Net effect of Natural Conservation and Codes & Standards	48	GWh
Increase in the forecast of electric vehicles	22	GWh
Other forecast change	70	GWh
Total Change	**210**	**GWh**

Changes between the 2017 and 2018 General Service Mass Market Forecast

The 2018 General Service Mass Market (GSMM) Forecast starts 36 GWh higher compared to the 2017 Forecast. The difference between forecasts increases to 563 GWh in 2027/28, primarily due to the change in the electric price forecast. By 2036/37, the difference between forecasts decreases to 371 GWh as the forecast of electric price reaches similar levels to those included in the 2017 Forecast. 371 GWh represents approximately 1.1 years of system load increase.

Figure 5 – Change of GS Mass Market Forecast

Comparison of 2017 to 2018 Forecast

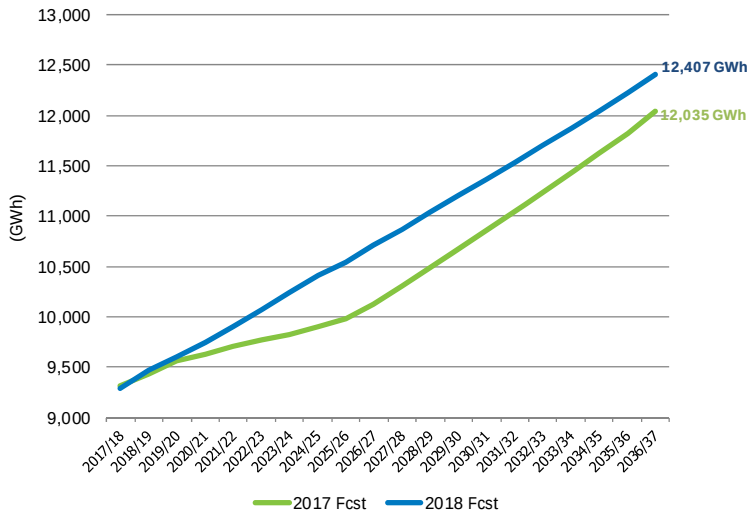


Table 10 – Change of GS Mass Market Forecast

Change of GS Mass Market Forecast (GWh) Comparison of 2017 to 2018 Forecast				
Fiscal Year	2017 Fcst	2018 Fcst	Change	%
2017/18	9,310	9,284	(25)	-0.3%
2018/19	9,432	9,468	36	0.4%
2019/20	9,557	9,605	48	0.5%
2020/21	9,622	9,750	127	1.3%
2021/22	9,703	9,896	193	2.0%
2022/23	9,773	10,077	305	3.1%
2023/24	9,820	10,246	426	4.3%
2024/25	9,899	10,406	507	5.1%
2025/26	9,982	10,546	563	5.6%
2026/27	10,128	10,710	581	5.7%
2027/28	10,307	10,870	563	5.5%
2028/29	10,488	11,040	551	5.3%
2029/30	10,671	11,202	531	5.0%
2030/31	10,857	11,366	510	4.7%
2031/32	11,045	11,532	487	4.4%
2032/33	11,235	11,707	472	4.2%
2033/34	11,427	11,876	449	3.9%
2034/35	11,623	12,048	425	3.7%
2035/36	11,822	12,221	399	3.4%
2036/37	**12,035**	**12,407**	**371**	**3.1%**

Major changes and energy impacts		
2036/37		
Increase in the customer forecast of approx. 104 customers		
Customer forecast change	11	GWh
Increase in the forecast of real GDP	118	GWh
Decrease in the short term forecast of electric price	162	GWh
Change in the starting point, which includes achieved DSM	109	GWh
Change in model parameters	(116)	GWh
Average Use forecast change	273	GWh
Net effect of Codes & Standards	95	GWh
Decrease in the forecast of electric vehicles	(8)	GWh
Other forecast change	87	GWh
Total Change	**371**	**GWh**

Changes between the 2017 and 2018 General Service Top Consumers Forecast

The 2018 GS Top Consumers Forecast is lower in the first five years (short term) based on updates sourced from industry news and publications, company prospectuses, and Manitoba Hydro's Key and Major Account Advisors. In addition, changes to the key economic variables within the Potential Large Industrial Loads (PLIL) model further contribute to the difference between forecasts to be 178 GWh lower by 2036/37.

Figure 6 – Change of GS Top Consumer Forecast

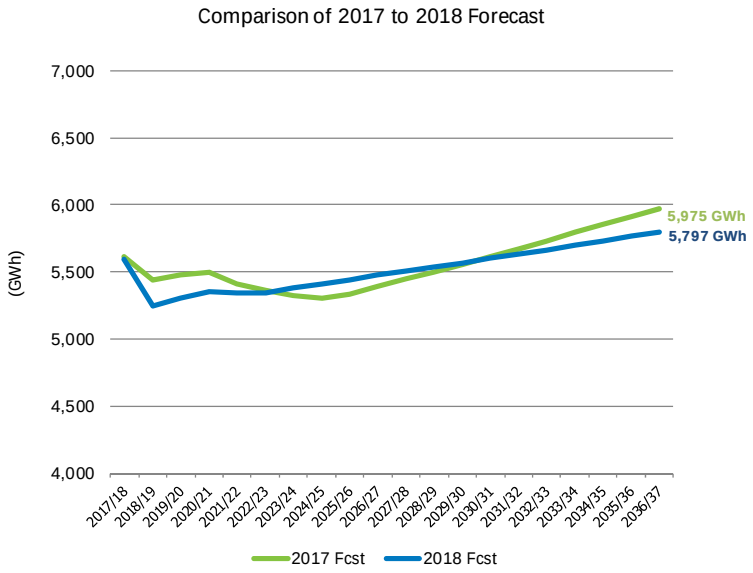


Table 11 – Change of GS Top Consumer Forecast

Change of Top Consumers Forecast (GWh) Comparison of 2017 to 2018 Forecast				
Fiscal Year	2017 Fcst	2018 Fcst	Change	%
2017/18	5,615	5,592	(23)	-0.4%
2018/19	5,440	5,250	(190)	-3.5%
2019/20	5,475	5,306	(169)	-3.1%
2020/21	5,502	5,351	(151)	-2.7%
2021/22	5,409	5,343	(66)	-1.2%
2022/23	5,365	5,343	(22)	-0.4%
2023/24	5,319	5,377	58	1.1%
2024/25	5,302	5,412	110	2.1%
2025/26	5,334	5,443	109	2.0%
2026/27	5,389	5,474	85	1.6%
2027/28	5,445	5,506	61	1.1%
2028/29	5,501	5,537	36	0.7%
2029/30	5,558	5,569	11	0.2%
2030/31	5,616	5,601	(15)	-0.3%
2031/32	5,674	5,633	(41)	-0.7%
2032/33	5,733	5,665	(68)	-1.2%
2033/34	5,792	5,698	(94)	-1.6%
2034/35	5,853	5,731	(122)	-2.1%
2035/36	5,914	5,763	(151)	-2.6%
2036/37	**5,975**	**5,797**	**(178)**	**-3.0%**

Major changes and energy impacts		
2036/37		
Reduction to the forecast in the chemical/treatment sector	(95)	GWh
Update to the forecast in the petro/oil/natural gas sector	31	GWh
Additional update to the forecast in other sectors	(2)	GWh
Short Term forecast change (Yr 1-5)	(66)	GWh
Increase in the forecast of real GDP	10	GWh
Increase in the long term forecast of electric price	(144)	GWh
Change in the starting point, which includes achieved DSM	31	GWh
Change in model parameters	(9)	GWh
Long Term (PLIL) forecast change	(112)	GWh
Total Change	**(178)**	**GWh**

Changes between the 2017 and 2018 General Consumers Sales Forecast

The General Consumers Sales Forecast starts 132 GWh lower compared to the 2017 Forecast. By 2036/37, energy use is higher by 383 GWh compared to the 2017 Forecast.

Figure 7 – Change of General Consumer Sales Forecast

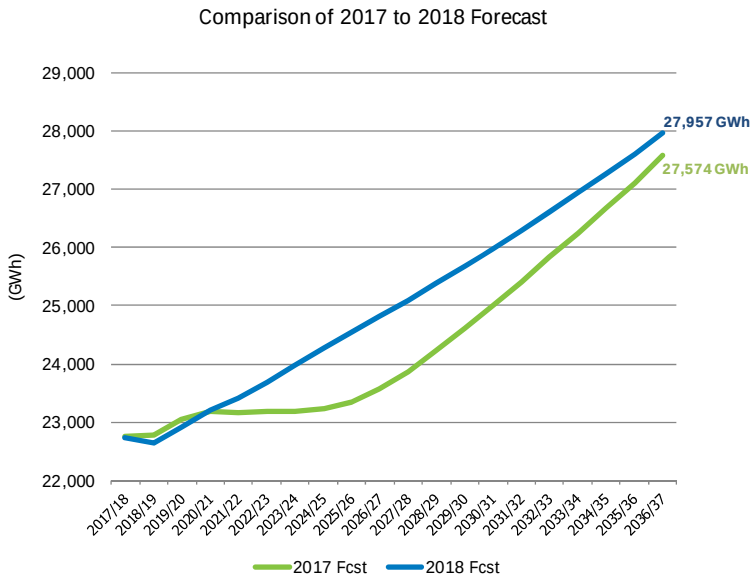


Table 12 – Change of General Consumer Sales Forecast

Change of General Consumer Sales Forecast (GWh) Comparison of 2017 to 2018 Forecast				
Fiscal Year	2017 Fcst	2018 Fcst	Change	%
2017/18	22,751	22,738	(13)	-0.1%
2018/19	22,773	22,642	(132)	-0.6%
2019/20	23,041	22,917	(124)	-0.5%
2020/21	23,179	23,199	20	0.1%
2021/22	23,153	23,420	267	1.2%
2022/23	23,179	23,675	496	2.1%
2023/24	23,176	23,972	796	3.4%
2024/25	23,232	24,265	1,033	4.4%
2025/26	23,337	24,537	1,201	5.1%
2026/27	23,561	24,826	1,265	5.4%
2027/28	23,869	25,087	1,218	5.1%
2028/29	24,229	25,373	1,144	4.7%
2029/30	24,611	25,667	1,056	4.3%
2030/31	25,002	25,967	965	3.9%
2031/32	25,411	26,284	873	3.4%
2032/33	25,828	26,613	785	3.0%
2033/34	26,243	26,933	690	2.6%
2034/35	26,669	27,259	591	2.2%
2035/36	27,109	27,597	487	1.8%
2036/37	**27,574**	**27,957**	**383**	**1.4%**

Major changes and energy impacts			
2036/37			
Primarily higher due to a decrease in the short term fcst. of electric price			
Resdiential Basic change	210	GWh	
Primarily higher due to an increase in the average use forecast			
General Service Mass Market change	371	GWh	
Primarily lower due to adjustments in customer short term plans and updates to the longer term growth forecast (PLIL)			
General Service Top Consumer change	(178)	GWh	
Increase in other sales & losses			
Other sales and losses change	(20)	GWh	
Total Change	**383**	**GWh**	

Changes between the 2017 and 2018 Gross Firm Energy Forecast

The Gross Firm Energy Forecast starts 144 GWh lower compared to the 2017 Forecast. By 2036/37, energy use is higher by 445 GWh compared to the 2017 Forecast. This is equivalent to an increase of 1.4 years of system load growth. (1 year of load growth = approximately 325 GWh).

Figure 8 – Change of Energy Forecast

Comparison of 2017 to 2018 Forecast

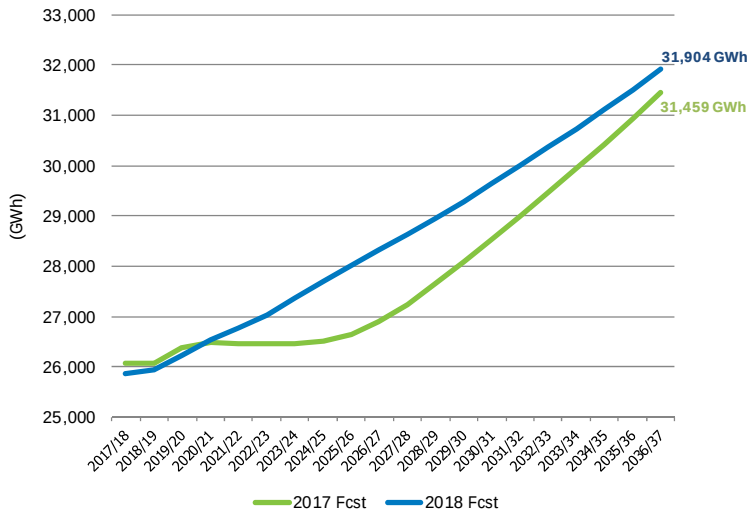


Table 13 – Change of Energy Forecast

Change of Gross Firm Energy Forecast (GWh) Comparison of 2017 to 2018 Forecast				
Fiscal Year	2017 Fcst	2018 Fcst	Change	%
2017/18	26,065	25,870	(195)	-0.7%
2018/19	26,080	25,935	(144)	-0.6%
2019/20	26,369	26,237	(132)	-0.5%
2020/21	26,483	26,528	45	0.2%
2021/22	26,459	26,759	299	1.1%
2022/23	26,453	27,018	565	2.1%
2023/24	26,453	27,357	903	3.4%
2024/25	26,519	27,691	1,171	4.4%
2025/26	26,639	28,001	1,362	5.1%
2026/27	26,892	28,329	1,437	5.3%
2027/28	27,241	28,627	1,386	5.1%
2028/29	27,650	28,951	1,301	4.7%
2029/30	28,084	29,287	1,202	4.3%
2030/31	28,529	29,630	1,101	3.9%
2031/32	28,995	29,991	997	3.4%
2032/33	29,469	30,367	898	3.0%
2033/34	29,942	30,733	791	2.6%
2034/35	30,427	31,106	679	2.2%
2035/36	30,929	31,492	563	1.8%
2036/37	**31,459**	**31,904**	**445**	**1.4%**

Major changes and energy impacts			
2036/37			
Primarily higher due to a decrease in the short term fcst. of electric price			
Resdiential Basic change	210	GWh	
Primarily higher due to an increase in the average use forecast			
General Service Mass Market change	371	GWh	
Primarily lower due to adjustments in customer short term plans and updates to the longer term growth forecast (PLIL)			
General Service Top Consumer change	(178)	GWh	
Increase in other sales & losses			
Other sales and losses change	42	GWh	
Total Change	**445**	**GWh**	

Changes between the 2017 and 2018 Gross Total Peak Forecast

The Gross Total Peak Forecast is higher by 137 MW by 2036/37 compared to the 2017 Forecast. The Peak Forecast is primarily based on the Gross Firm Energy Forecast, and as such the changes in energy impact the peak. Also contributing to the increase in gross total peak is a decrease in peak load factor from 61.8% in the 2017 Forecast to 61.2% in the 2018 Forecast. The load factor decrease is due to the reduced energy forecast of the Top Consumers sector, which has a high coincidence load factor of 91%.

The increase in peak in 2036/37 amounts to 137 MW, which is an increase of over 2.1 years of system load growth. (1 year of load growth = approximately 64 MW).

Figure 9 – Change of Peak Forecast

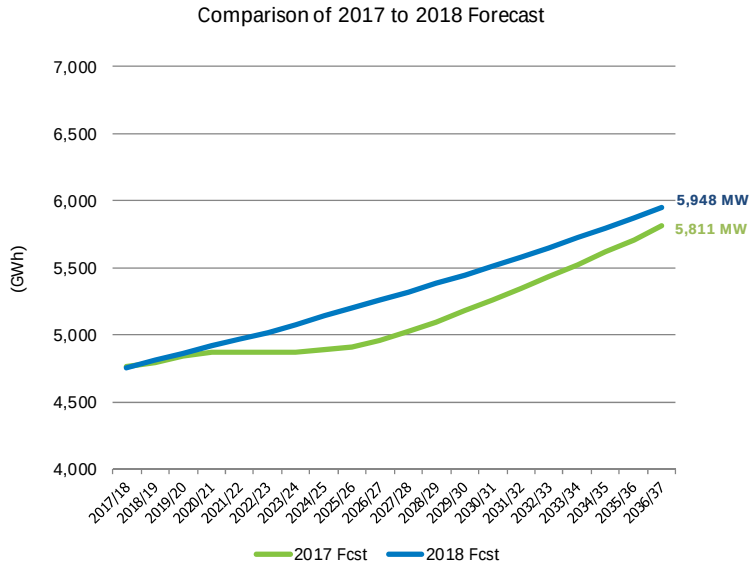


Table 14 – Change of Peak Forecast

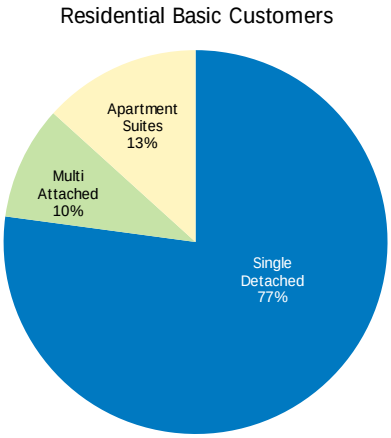
Change of Gross Total Peak (MW) Comparison of 2017 to 2018 Forecast				
Fiscal Year	2017 Fcst	2018 Fcst	Change	%
2017/18	4,767	4,751	(16)	-0.3%
2018/19	4,789	4,815	26	0.5%
2019/20	4,845	4,863	18	0.4%
2020/21	4,868	4,918	51	1.0%
2021/22	4,870	4,965	95	2.0%
2022/23	4,871	5,015	143	2.9%
2023/24	4,875	5,079	204	4.2%
2024/25	4,890	5,143	253	5.2%
2025/26	4,913	5,202	289	5.9%
2026/27	4,958	5,264	306	6.2%
2027/28	5,022	5,320	298	5.9%
2028/29	5,098	5,381	284	5.6%
2029/30	5,179	5,445	267	5.2%
2030/31	5,262	5,511	249	4.7%
2031/32	5,349	5,580	232	4.3%
2032/33	5,438	5,652	215	3.9%
2033/34	5,526	5,722	196	3.5%
2034/35	5,617	5,794	177	3.2%
2035/36	5,711	5,869	157	2.8%
2036/37	**5,811**	**5,948**	**137**	**2.4%**

FORECAST DETAILS

Residential Basic

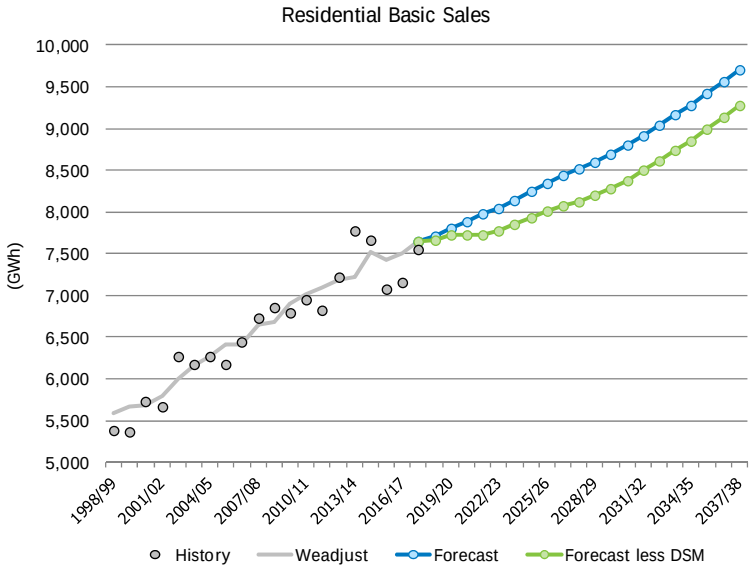
In 2017/18, there were 486,317 Residential Basic customers. Of these customers, 77% were single detached, 10% were multi-attached, and 13% were individually metered apartment suites. The majority of customers (54%) are in Winnipeg where natural gas is available, 29% are in natural gas available areas outside Winnipeg, and 17% are in areas where natural gas is not available.

Figure 10 – Residential Basic Customers



Residential Basic has grown 108 GWh (1.7%) per year for the past 20 years and 100 GWh per year (1.4%) for the past 10 years reflecting the effect of past Demand Side Management (DSM) initiatives. This sector is forecast to grow 87 GWh (1.1%) per year for the next 10 years and 103 GWh (1.2%) per year for the next 20 years, before future program-based DSM initiatives. Including program-based DSM, the sector is forecast to grow 82 GWh (1.0%) over the next 20 years. The primary driver of Residential Basic growth is population, which is forecast to grow 1.0% per year over the next 20 years.

Figure 11 – Residential Basic Sales



The following table outlines historical and forecast details including the impacts of program based Demand Side Management activity:

Table 15 – Residential Sales

Residential Basic Sales (GWh)			
Historical / Weather Adjustment			
Fiscal Year	Sales	Weather Adjust	Adjusted Sales
1998/99	5,384	197	5,580
1999/00	5,364	297	5,661
2000/01	5,737	(47)	5,690
2001/02	5,674	120	5,794
2002/03	6,266	(274)	5,992
2003/04	6,170	(10)	6,160
2004/05	6,275	2	6,276
2005/06	6,171	243	6,413
2006/07	6,443	(30)	6,413
2007/08	6,736	(90)	6,646
2008/09	6,847	(165)	6,682
2009/10	6,786	121	6,907
2010/11	6,952	63	7,015
2011/12	6,818	281	7,099
2012/13	7,223	(31)	7,192
2013/14	7,767	(554)	7,213
2014/15	7,658	(135)	7,523
2015/16	7,074	348	7,422
2016/17	7,158	344	7,503
2017/18	7,547	94	7,641
Forecast / Forecast less DSM			
Fiscal Year	Forecast	DSM (Program based)	Forecast less DSM
2018/19	7,714	(44)	7,670
2019/20	7,798	(80)	7,719
2020/21	7,891	(159)	7,732
2021/22	7,975	(242)	7,733
2022/23	8,049	(270)	7,779
2023/24	8,145	(299)	7,846
2024/25	8,245	(318)	7,927
2025/26	8,347	(338)	8,008
2026/27	8,441	(361)	8,080
2027/28	8,511	(382)	8,129
2028/29	8,597	(395)	8,202
2029/30	8,697	(410)	8,286
2030/31	8,802	(426)	8,376
2031/32	8,922	(424)	8,497
2032/33	9,045	(427)	8,618
2033/34	9,164	(428)	8,736
2034/35	9,286	(429)	8,856
2035/36	9,418	(429)	8,989
2036/37	9,560	(429)	9,130
2037/38	9,705	(431)	9,275

Table 16 – Residential Basic Sales

Residential Basic Sales History and Forecast 2017/18 - 2037/38											
Fiscal Year	Electric Heat Billed (1)			Non Electric Heat Billed (2)			Total Basic			% Elec Space Heat (3)	% Elec Water Heat (4)
	Custs	GWh	kWh/cust	Custs	GWh	kWh/cust	Custs	GWh	kWh/cust		
2017/18	191,907	4,461	23,247	294,410	3,086	10,481	486,317	7,547	15,519	39.5%	49.7%
2018/19	195,481	4,523	23,140	297,078	3,190	10,739	492,559	7,714	15,661	39.7%	50.1%
2019/20	198,899	4,570	22,977	299,907	3,228	10,764	498,806	7,798	15,634	39.9%	50.5%
2020/21	202,159	4,617	22,840	302,891	3,274	10,808	505,050	7,891	15,624	40.0%	50.8%
2021/22	205,180	4,658	22,703	305,880	3,316	10,842	511,061	7,975	15,604	40.1%	51.1%
2022/23	207,990	4,693	22,565	308,890	3,356	10,865	516,880	8,049	15,573	40.2%	51.3%
2023/24	210,722	4,736	22,473	311,958	3,409	10,929	522,680	8,145	15,583	40.3%	51.5%
2024/25	213,428	4,779	22,392	315,095	3,466	10,999	528,523	8,245	15,600	40.4%	51.7%
2025/26	216,110	4,823	22,318	318,262	3,523	11,071	534,372	8,347	15,620	40.4%	51.8%
2026/27	218,756	4,864	22,234	321,444	3,577	11,128	540,200	8,441	15,625	40.5%	52.0%
2027/28	221,377	4,894	22,109	324,622	3,616	11,140	545,999	8,511	15,587	40.5%	52.2%
2028/29	223,933	4,931	22,022	327,770	3,665	11,182	551,703	8,597	15,582	40.6%	52.3%
2029/30	226,425	4,974	21,967	330,859	3,723	11,252	557,284	8,697	15,605	40.6%	52.5%
2030/31	228,858	5,018	21,927	333,919	3,784	11,332	562,778	8,802	15,641	40.7%	52.6%
2031/32	231,252	5,068	21,916	336,954	3,854	11,437	568,206	8,922	15,702	40.7%	52.8%
2032/33	233,616	5,119	21,913	339,983	3,926	11,547	573,599	9,045	15,769	40.7%	52.9%
2033/34	235,957	5,168	21,904	343,010	3,995	11,648	578,968	9,164	15,828	40.8%	53.1%
2034/35	238,265	5,219	21,903	346,019	4,067	11,754	584,285	9,286	15,893	40.8%	53.2%
2035/36	240,521	5,273	21,925	348,971	4,145	11,877	589,492	9,418	15,977	40.8%	53.3%
2036/37	242,709	5,331	21,966	351,842	4,228	12,017	594,550	9,560	16,079	40.8%	53.4%
2037/38	244,833	5,352	21,860	354,637	4,353	12,276	599,469	9,705	16,190	40.8%	53.5%

Notes:

(1) Electric Heat Billed is defined as customers who have electric space heating included with the electric bill.

(2) Non Electric Heat Billed is defined as customers who do not have electric space heating included with the electric bill.

(3) % Electric Space Heat represents the proportion of Total Res. Basic customers who are Electric Heat Billed.

(4) % Electric Water Heat represents the proportion of Total Res. Basic customers who have Electric Water Heaters.

2017/18 GWh and kWh/cust values are not weather adjusted

The average use (kWh/customer) for Electric Heat Billed customers is decreasing as individually metered apartment suites are making up a higher proportion of the growth. The average use for Non Electric Heat Billed customers is increasing mainly due to increased use of electric water heating and miscellaneous end uses in dwellings.

Residential Diesel, Seasonal, and Flat Rate Water Heating

Residential Diesel

There were 587 Residential Diesel customers that used 8 GWh in 2017/18 averaging 13,494 kWh per year per customer. Customers are only allowed 60 amp services which will not allow for electric space heating. Space heating in the four diesel communities is mainly provided by fuel oil. The number of customers is expected to grow to 637 and usage is expected to increase 0.4% a year to 9 GWh by 2037/38. The assumption is that the communities will continue to be separate from the Integrated System.

Residential Seasonal

There were 19,507 Residential Seasonal customers that used 65 GWh in 2017/18, averaging 3,348 kWh per year per customer. The number of customers is expected decrease to 16,847 customers by 2037/38 due to transfers of higher using seasonal customers into the Residential Basic sector. Seasonal customers are billed only twice a year due to low usage, typically being a seasonal residence or cottage. The usage of Residential Seasonal customers is expected to decrease 0.02% a year to 65 GWh in 2037/38.

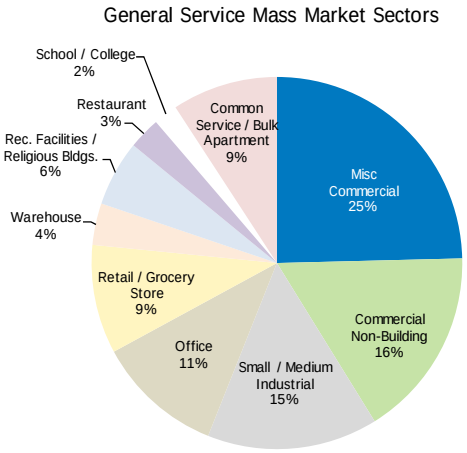
Residential Flat Rate Water Heating

Residential Water Heating is a flat rate unmetered service. This service has not been available to new customers since November 12, 1969. There were 3,129 remaining services in 2017/18. The number of services and usage is expected to decrease 5.0% per year throughout the forecast period. Usage was 16 GWh in 2017/18 and that will decrease to 6 GWh by 2037/38.

General Service Mass Market

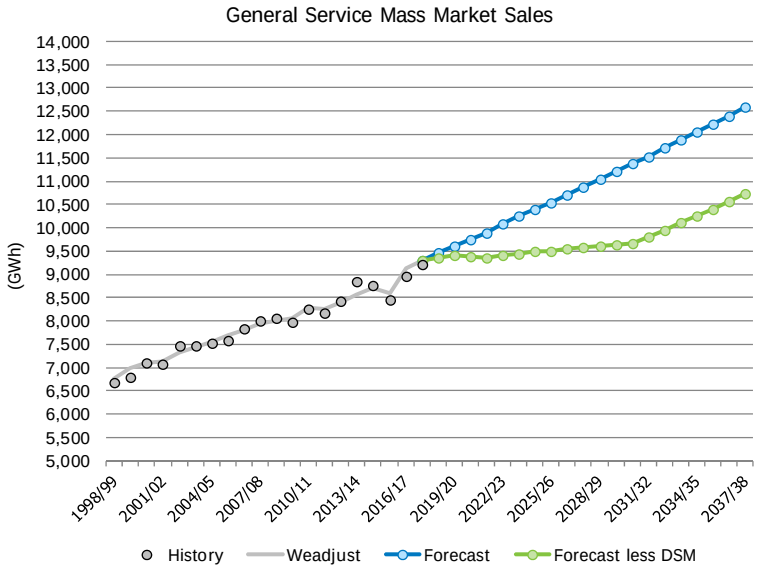
General Service Mass Market includes all Commercial and Industrial customers, excluding the General Service Top Consumers. There were 68,079 General Service Mass Market customers in 2017/18. Approximately 15% are Industrial and 85% are Commercial.

Figure 12 – General Service Mass Market Customers



GS Mass Market has grown 111 GWh (1.4%) per year for the past 20 years and 93 GWh per year (1.1%) for the past 10 years. This historical growth reflects the effect of past Demand Side Management (DSM) initiatives and includes the seven Top Consumers, totaling 404 GWh in 2015/16, who were moved into the Mass Market sector. The Mass Market Sector is forecast to grow 159 GWh (1.6%) per year for the next 10 years and 166 GWh (1.5%) per year for the next 20 years before program-based DSM initiatives. Including program-based DSM, the sector is forecast to grow 73 GWh (0.7%) over the next 20 years. The primary drivers for growth in the GS Mass Market are the population and the economy. Changes in the number of residential customers and the Manitoba Gross Domestic Product (GDP) are reflected in the GS Mass Market's electricity use.

Figure 13 – General Service Mass Market Sales



The following table outlines historical and forecast details including the impacts of program based Demand Side Management activity:

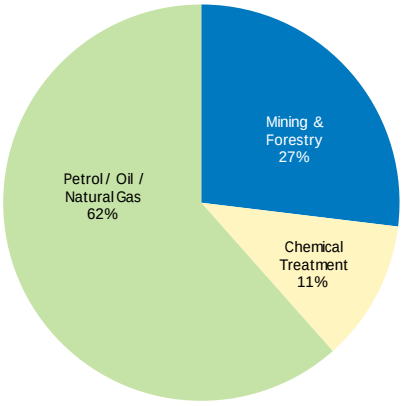
Table 17 – General Service Mass Market

General Service Mass Market (GWh)			
Historical / Weather Adjustment			
Fiscal Year	Sales	Weather Adjust	Adjusted Sales
1998/99	6,668	102	6,770
1999/00	6,796	180	6,976
2000/01	7,110	(2)	7,107
2001/02	7,084	44	7,128
2002/03	7,467	(143)	7,324
2003/04	7,460	(22)	7,437
2004/05	7,516	35	7,550
2005/06	7,587	109	7,696
2006/07	7,839	(47)	7,792
2007/08	8,006	(55)	7,951
2008/09	8,049	(52)	7,996
2009/10	7,985	86	8,070
2010/11	8,258	33	8,291
2011/12	8,162	94	8,257
2012/13	8,434	(46)	8,388
2013/14	8,839	(272)	8,566
2014/15	8,771	(64)	8,708
2015/16	8,442	159	8,601
2016/17	8,956	173	9,130
2017/18	9,213	72	9,284
Forecast / Forecast less DSM			
Fiscal Year	Forecast	DSM (Program based)	Forecast less DSM
2018/19	9,468	(103)	9,365
2019/20	9,605	(194)	9,410
2020/21	9,750	(366)	9,384
2021/22	9,896	(546)	9,350
2022/23	10,077	(678)	9,400
2023/24	10,246	(797)	9,449
2024/25	10,406	(916)	9,489
2025/26	10,546	(1,039)	9,506
2026/27	10,710	(1,166)	9,544
2027/28	10,870	(1,299)	9,571
2028/29	11,040	(1,437)	9,602
2029/30	11,202	(1,581)	9,621
2030/31	11,366	(1,716)	9,650
2031/32	11,532	(1,736)	9,796
2032/33	11,707	(1,755)	9,951
2033/34	11,876	(1,776)	10,101
2034/35	12,048	(1,796)	10,252
2035/36	12,221	(1,817)	10,404
2036/37	12,407	(1,838)	10,568
2037/38	12,599	(1,860)	10,740

General Service Top Consumers

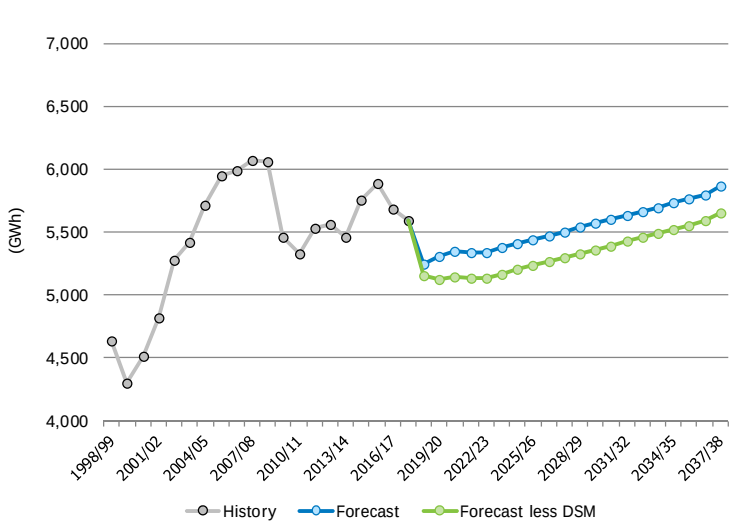
General Service Top Consumers represent the top energy consuming operations in Manitoba accounting for 25% of all General Consumers Sales. GS Top Consumers include 10 distinct companies that count as 26 customers in the Mining & Forestry, Chemical Treatment, Petrol/Oil/Natural Gas sectors.

Figure 14 – General Service Top Consumer Sectors



GS Top Consumers increased 72 GWh (1.5%) per year over the past 20 years and decreased 8 GWh per year (-0.1%) over the past 10 years. The decrease was due to the economic downturn experienced from 2008 to 2011 and the loss of one Top Consumer. The historical growth rates also reflect the shift of the seven smallest Top Consumers to the GS Mass Market Sector, totaling 404 GWh in 2015/16. These were moved because their usage patterns more closely mimic customers within the GS Mass Market sector. The Top Consumers sector is now forecast to decline at an average of 9 GWh (-0.2%) per year for the next 10 years but grow an average of 13 GWh (0.2%) per year for the next 20 years. Including program-based DSM, the sector is forecast to grow 3 GWh (0.1%) over the next 20 years. Short term reductions are expected in the Petro/Oil/Natural Gas and Chemical Treatment sectors

Figure 15 – General Service Top Consumers Sales



The following table outlines historical and forecast details including the impacts of program based Demand Side Management activity:

Table 18 – General Service Top Consumers

General Service Top Consumers (GWh) Historical / Forecast / Fcst. With PLIL / Fcst. Less DSM							
Fiscal Year	Sales	Fiscal Year	Individual	PLIL	Total	DSM (Program based)	Forecast less DSM
1998/99	4,632	2018/19	5,250	0	5,250	(90)	5,160
1999/00	4,299	2019/20	5,306	0	5,306	(180)	5,126
2000/01	4,515	2020/21	5,351	0	5,351	(208)	5,143
2001/02	4,818	2021/22	5,343	0	5,343	(208)	5,135
2002/03	5,282	2022/23	5,343	0	5,343	(208)	5,135
2003/04	5,423	2023/24	5,343	34	5,377	(208)	5,169
2004/05	5,714	2024/25	5,343	69	5,412	(208)	5,204
2005/06	5,948	2025/26	5,343	100	5,443	(208)	5,235
2006/07	5,989	2026/27	5,343	131	5,474	(208)	5,266
2007/08	6,075	2027/28	5,343	163	5,506	(208)	5,298
2008/09	6,065	2028/29	5,343	194	5,537	(208)	5,329
2009/10	5,461	2029/30	5,343	226	5,569	(208)	5,361
2010/11	5,324	2030/31	5,343	258	5,601	(208)	5,393
2011/12	5,531	2031/32	5,343	290	5,633	(208)	5,425
2012/13	5,560	2032/33	5,343	322	5,665	(208)	5,457
2013/14	5,461	2033/34	5,343	355	5,698	(208)	5,490
2014/15	5,750	2034/35	5,343	388	5,731	(208)	5,523
2015/16	5,886	2035/36	5,343	420	5,763	(208)	5,555
2016/17	5,685	2036/37	5,343	454	5,797	(208)	5,589
2017/18	5,592	2037/38	5,343	519	5,862	(208)	5,654

For the short term, General Service Top Consumers are forecast individually. Expected increases and decreases from customer's current and upcoming operating and expansion plans are compiled for the first five years of the forecast but exclude longer term plans that are uncommitted and subject to change.

For the long term, the growth of existing Top Consumers is forecast together econometrically. The econometric long term Top Consumer forecast is referred to as Potential Large Industrial Loads (PLIL). PLIL is based on the historic growth and/or retraction of the ten companies that comprise the Top Consumers as well as one former Top Consumers customer that closed in 2009. These are large companies that both drive and help define the local, national and international economies. The historical data used for modeling PLIL includes company expansions, production increases and reductions due to planned and unplanned shutdowns, cutbacks and labor disruptions. Therefore, the long term forecast implicitly includes the same expectations.

Historical growth of the Top Consumer sector is modeled using Gross Domestic Product (GDP) and electricity price as independent variables. The historic correlation between GDP, price and Top Consumer growth has been very strong and is expected to continue in the future. Future projections of GDP and price are used to forecast the long term future increase in Top Consumer growth starting from the sixth year of the forecast.

The sum of the individual company forecasts is expected to decline from 5,592 GWh in 2017/18 to 5,343 GWh in 2022/23. After 2022/23, the individual forecasts for these customers are held constant and longer term growth is considered to be included in PLIL.

PLIL is added starting in year six of the forecast. The econometric forecast for PLIL is based on an expected annual Manitoba/Canada/U.S. real GDP growth rate of 1.9%, leading to a forecast growth of 0.2% annually. Historically, the real GDP growth rate over the past 20 years was 2.3%, the Top Consumers sector growth averaged 1.5% annually.

The Top Consumers sector is expected to decline 249 GWh in the first five years based on individual customer short term plans, and then growth 519 GWh in years 6 to 20 for PLIL.

General Service Diesel, Seasonal, and Flat Rate Water Heating

General Service Diesel

In 2017/18, there were 180 General Service Diesel Full Cost customers using 6 GWh. The General Service Diesel sector is forecast to use 6 GWh by 2037/38.

General Service Seasonal

In 2017/18, there were 957 General Service Seasonal customers using 5 GWh. The General Service Seasonal sector is expected to grow to 6 GWh by 2037/38.

General Service Flat Rate Water Heating

General Service Water Heating is a flat rate unmetered service that has not been available to new customers since November 12, 1969. There were 338 remaining services in 2017/18. The number of services is expected to decrease 5.0% per year throughout the forecast period. Consumption was 5 GWh in 2017/18 and that is forecast to decrease to 2 GWh by 2037/38.

General Service Surplus Energy Program

Participants in the Surplus Energy Program (SEP) consumed 28 GWh in 2017/18 and are expected to use 28 GWh in 2018/19 and for the remainder of the forecast period. This energy is considered to be “interruptible” and thus “non-firm”. The energy used by these customers is included in Sales, but it is excluded from the Gross Firm Energy forecast.

Plug-In Electric Vehicles

This forecast includes an estimate of the future adoption of Plug-In Electric Vehicles in the Manitoba Hydro service area. This is made up of two types:

i. **Plug-In Hybrid Electric Vehicles (PHEVs)** run on an electric battery but use an internal combustion engine (ICE) or gasoline powered generator to extend the driving range when the battery charge runs low. An example is the Chevrolet Volt. As of March 1, 2018 there were 133 PHEVs registered in Manitoba.

ii. **Plug-in Electric Vehicles (PEVs)** run only on electric battery power. Pure electric plug-in vehicles include the Nissan Leaf, the Tesla, Mitsubishi MiEV, and New Flyer Xcelsior transit bus. As of March 1, 2018 there were 144 PEVs registered in Manitoba.

The forecast of electric vehicles does not include non-plug-in Hybrid Electric Vehicles (HEVs). These vehicles, such as the non-plug-in Toyota Prius, have an internal combustion engine (ICE) as well as a battery and electric motor to drive the wheels. The HEV battery is charged with power from the ICE and through regenerative breaking. It is not charged by plugging in and therefore does not affect electricity consumption in Manitoba. As of March 1, 2018 and after 18 years in the market, there were only 5,065 HEVs registered in Manitoba, representing 0.6% of all registered road motor vehicles.

In Canada, 47,800 plug-in electric vehicles were registered as on December 31, 2017 according to FleetCarma, making up 0.195% of total 24.5 million road motor vehicle registrations. In Manitoba, as of fiscal year ending 2018, there were 277 plug-in vehicles making up 0.03% of total road motor vehicle registrations. About 96% of all plug-in electric vehicles in Canada are registered in three provinces: Quebec (43%), Ontario (35%), and British Columbia (18%).

The Electric Vehicle Forecast

As of March 1st, 2018, there were a total of 277 plug-in electric vehicles, including five electric buses, registered in Manitoba with the Manitoba Public Insurance Corporation. Last year's 2017 Load Forecast predicted a total of 278 plug-in vehicles to be registered in Manitoba at fiscal year ending 2018. The latest electric vehicle forecast is adjusted to incorporate actual registrations recorded in fiscal year ending 2018.

Table 18 details the Manitoba actual and forecasted number of new vehicles per year, the total number of vehicles each year, as well as the corresponding numbers for Plug-In Electric Vehicles. The forecast incorporates passenger as well as commercial category vehicles such as Sport Utility Vehicles (SUVs), light and heavy duty trucks, and transit buses. Pull-trailers, farm equipment, motor boats and motor cycles are not included in the count. A passenger PEV consumes approximately 3,100 kWh annually, similar to the use of one residential electric hot water tank. An electric transit bus consumes 87,500 kWh annually. That is the equivalent use of three electrically heated single detached dwellings. The number of new PEVs is expected to slowly increase until it reaches about 1.1% of new vehicle sales or 800 units in 2027/28 and 10.0% of new vehicle sales or 8,975 units in 2037/38. The total number of PEVs on the road is forecasted to be 0.3% of total vehicle registrations or 3,821 units in 2027/28 increasing to 2.8% of total road motor vehicle registrations or 40,704 units by 2037/38.

Total energy use for PEVs in Manitoba is forecasted to be 15 GWh in 2027/28 and 146 GWh by 2037/38. Peak usage coincident to Manitoba Hydro's system peak is forecasted to be 1.8 MW in 2027/28 and 18.3 MW in 2037/38.

Figure 16 – Plug-in Electric Vehicles

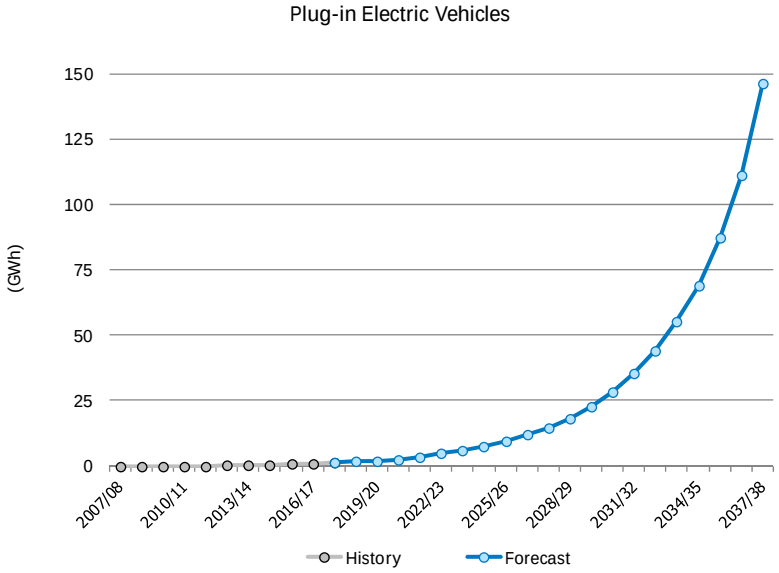


Table 19 – Plug-in Electric Vehicles

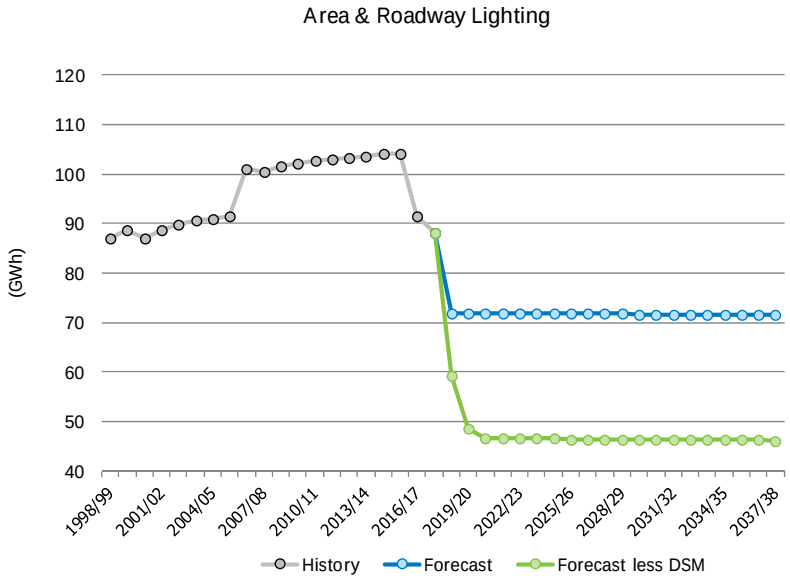
Plug-in Electric Vehicle Forecast History and Forecast 2007/08 - 2037/38								
Fiscal Year	New Vehicles Purchased	New PEV Purchased	New PEV %	Total Vehicles	Total PEV	Total % PEV	Cumul Total PEV GWh	Cumul Total PEV MW
2007/08	48,117	0	0.0%	675,685	0	0.0%	0	0.0
2008/09	45,832	0	0.0%	692,379	0	0.0%	0	0.0
2009/10	44,666	0	0.0%	703,989	0	0.0%	0	0.0
2010/11	46,475	1	0.0%	750,230	1	0.0%	0	0.0
2011/12	49,352	8	0.0%	766,267	9	0.0%	0	0.0
2012/13	52,448	28	0.1%	784,885	37	0.0%	0	0.0
2013/14	56,209	33	0.1%	797,383	70	0.0%	0	0.0
2014/15	58,376	32	0.1%	810,163	102	0.0%	1	0.1
2015/16	58,365	42	0.1%	857,029	144	0.0%	1	0.1
2016/17	58,359	60	0.1%	883,836	204	0.0%	1	0.1
2017/18	66,919	73	0.1%	896,133	277	0.03%	1	0.2
2018/19	60,640	104	0.2%	917,911	381	0.0%	2	0.2
2019/20	62,129	131	0.2%	940,223	512	0.1%	2	0.3
2020/21	63,616	164	0.3%	963,070	677	0.1%	3	0.3
2021/22	65,083	209	0.3%	986,443	886	0.1%	4	0.4
2022/23	66,554	261	0.4%	1,010,345	1,147	0.1%	5	0.6
2023/24	68,049	326	0.5%	1,034,783	1,472	0.1%	6	0.8
2024/25	69,564	407	0.6%	1,059,766	1,878	0.2%	8	1.0
2025/26	71,094	510	0.7%	1,085,298	2,386	0.2%	10	1.2
2026/27	72,637	638	0.9%	1,111,384	3,023	0.3%	12	1.5
2027/28	74,193	800	1.1%	1,138,029	3,821	0.3%	15	1.8
2028/29	75,744	1,005	1.3%	1,165,231	4,822	0.4%	18	2.3
2029/30	77,297	1,263	1.6%	1,192,991	6,082	0.5%	23	2.8
2030/31	78,856	1,592	2.0%	1,221,311	7,670	0.6%	28	3.5
2031/32	80,423	2,011	2.5%	1,250,193	9,676	0.8%	35	4.4
2032/33	82,001	2,549	3.1%	1,279,642	12,219	1.0%	44	5.5
2033/34	83,592	3,242	3.9%	1,309,663	15,454	1.2%	55	6.9
2034/35	85,187	4,142	4.9%	1,340,256	19,587	1.5%	69	8.6
2035/36	86,776	5,318	6.1%	1,371,420	24,893	1.8%	87	10.9
2036/37	88,357	6,867	7.8%	1,403,152	31,746	2.3%	111	13.9
2037/38	89,934	8,975	10.0%	1,435,450	40,704	2.8%	146	18.3

Area & Roadway Lighting

The Area and Roadway Lighting sector represents 0.4% of all sales within Manitoba. This sector includes electricity sales for the Sentinel Lighting and Street Lighting rate groups. Sentinel Lighting is an outdoor lighting service where units are available either as rentals to an existing metered service or on an unmetered, flat rate basis. Street Lighting includes all public roadway lighting in Manitoba. In 2006, a readjustment of the rate classes moved some flat rate General Service meters into the Lighting sector and starting in 2016, the street lighting LED conversion program decreased energy consumption. Only Street Lights count as customers.

For 2018/19, the Area and Roadway Lighting sector was further reduced by 16 GWh to reflect additional street lighting LED conversions. Excluding the effect of future Demand Side Management (DSM) initiatives expected to occur, the Area and Roadway Lighting sector is forecast to remain constant at 72 GWh throughout the entire forecast period.

Figure 17 - Area & Roadway Lighting



The following table outlines historical and forecast details including the impacts of program based Demand Side Management activity:

Table 20 - Area & Roadway Lighting

Area & Roadway Lighting (GWh)			
Historical / Weather Adjustment			
Fiscal Year	Sales	Weather Adjust	Adjusted Sales
1998/99	87	0	87
1999/00	89	0	89
2000/01	87	0	87
2001/02	89	0	89
2002/03	90	0	90
2003/04	91	0	91
2004/05	91	0	91
2005/06	91	0	91
2006/07	101	0	101
2007/08	101	0	101
2008/09	102	0	102
2009/10	102	0	102
2010/11	103	0	103
2011/12	103	0	103
2012/13	103	0	103
2013/14	104	0	104
2014/15	104	0	104
2015/16	104	0	104
2016/17	92	0	92
2017/18	88	0	88
Forecast / Forecast less DSM			
Fiscal Year	Forecast	DSM (Program based)	Forecast less DSM
2018/19	72	(13)	59
2019/20	72	(23)	49
2020/21	72	(25)	47
2021/22	72	(25)	47
2022/23	72	(25)	47
2023/24	72	(25)	47
2024/25	72	(25)	47
2025/26	72	(25)	47
2026/27	72	(25)	47
2027/28	72	(25)	47
2028/29	72	(25)	47
2029/30	72	(25)	46
2030/31	72	(25)	46
2031/32	72	(25)	46
2032/33	72	(25)	46
2033/34	72	(25)	46
2034/35	72	(25)	46
2035/36	72	(25)	46
2036/37	72	(25)	46
2037/38	72	(25)	46

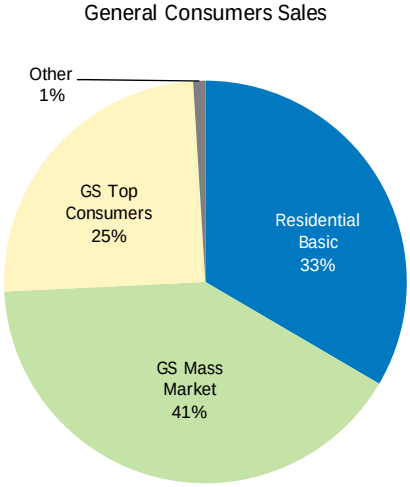
Table 21 – Area & Roadway Lighting

Area & Roadway Lighting History and Forecast 2007/08 - 2037/38								
Fiscal	Sentinal Flat Rates		Sentinal Rentals		Street Lighting		Total Lighting	
Year	(Services)	(GWh)	(Services)	(GWh)	(Custs)	(GWh)	(Custs)	(GWh)
2007/08	18,947	11	24,272	0	1,142	90	1,142	101
2008/09	19,228	11	24,542	0	1,175	91	1,175	102
2009/10	19,539	11	24,886	0	1,191	91	1,191	102
2010/11	19,835	11	25,216	0	1,184	92	1,184	103
2011/12	20,033	11	25,427	0	1,155	91	1,155	103
2012/13	20,238	12	25,613	0	1,164	92	1,164	103
2013/14	20,399	12	25,764	0	1,157	92	1,157	104
2014/15	20,495	12	25,853	0	1,196	92	1,196	104
2015/16	20,643	12	25,960	0	1,208	92	1,208	104
2016/17	20,818	12	26,093	0	1,218	80	1,218	92
2017/18	20,904	12	26,135	0	1,228	76	1,228	88
2018/19	20,993	12	26,177	0	1,239	60	1,239	72
2019/20	21,129	12	26,281	0	1,244	60	1,244	72
2020/21	21,265	12	26,385	0	1,249	60	1,249	72
2021/22	21,401	12	26,489	0	1,254	60	1,254	72
2022/23	21,537	12	26,593	0	1,259	60	1,259	72
2023/24	21,673	12	26,697	0	1,264	60	1,264	72
2024/25	21,809	12	26,801	0	1,269	59	1,269	72
2025/26	21,945	12	26,905	0	1,274	59	1,274	72
2026/27	22,081	13	27,009	0	1,279	59	1,279	72
2027/28	22,217	13	27,113	0	1,284	59	1,284	72
2028/29	22,353	13	27,217	0	1,289	59	1,289	72
2029/30	22,489	13	27,321	0	1,294	59	1,294	72
2030/31	22,625	13	27,425	0	1,299	59	1,299	72
2031/32	22,761	13	27,529	0	1,304	59	1,304	72
2032/33	22,897	13	27,633	0	1,309	59	1,309	72
2033/34	23,033	13	27,737	0	1,314	59	1,314	72
2034/35	23,169	13	27,841	0	1,319	59	1,319	72
2035/36	23,305	13	27,945	0	1,324	58	1,324	72
2036/37	23,441	13	28,049	0	1,329	58	1,329	72
2037/38	23,577	13	28,153	0	1,334	58	1,334	72

Total General Consumer Sales

General Consumers Sales includes sales to all of Manitoba Hydro's individually billed customers, but excludes export sales. This includes the total of all sales from the Residential, General Service and Lighting sectors. The General Service sector makes up about two-thirds, the Residential sector makes up about one-third and the remaining sectors are only 0.4% of all sales.

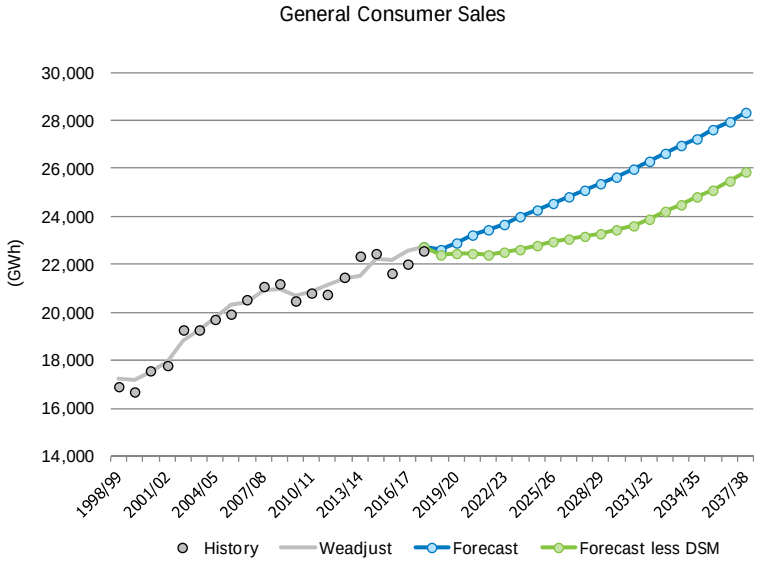
Figure 18 – General Consumers Sales



Note: Other category includes seasonal, flat rate water heating, area & roadway lighting, construction power and station service.

Weather adjusted General Consumers Sales has grown 290 GWh (1.5%) per year for the past 20 years and 182 GWh (0.8%) per year over the past 10 years. This historical growth includes the effect of past Demand Side Management (DSM) initiatives. Sales are forecast to grow 235 GWh (1.0%) per year for the next 10 years and 281 GWh (1.1%) per year for the next 20 years before program-based DSM initiatives. Including program-based DSM, the forecast is expected to grow 155 GWh (0.6%) over the next 20 years.

Figure 19 – General Consumers Sales



The following table outlines historical and forecast details including the impacts of program based Demand Side Management activity:

Table 22 – General Consumers Sales

General Consumers Sales (GWh) Historical / Weather Adjustment			
Fiscal Year	Sales	Weather Adjust	Adjusted Sales
1998/99	16,929	300	17,228
1999/00	16,696	479	17,175
2000/01	17,590	(51)	17,539
2001/02	17,805	166	17,970
2002/03	19,246	(418)	18,829
2003/04	19,280	(32)	19,248
2004/05	19,735	35	19,770
2005/06	19,935	353	20,287
2006/07	20,510	(76)	20,433
2007/08	21,061	(145)	20,917
2008/09	21,210	(219)	20,991
2009/10	20,486	207	20,693
2010/11	20,786	96	20,883
2011/12	20,771	378	21,148
2012/13	21,477	(76)	21,400
2013/14	22,338	(830)	21,508
2014/15	22,458	(199)	22,258
2015/16	21,654	509	22,163
2016/17	22,025	519	22,544
2017/18	22,573	165	22,738
Forecast / Forecast less DSM			
Fiscal Year	Forecast	DSM (Program based)	Forecast less DSM
2018/19	22,642	(250)	22,392
2019/20	22,917	(477)	22,440
2020/21	23,199	(758)	22,441
2021/22	23,420	(1,020)	22,400
2022/23	23,675	(1,181)	22,494
2023/24	23,972	(1,329)	22,643
2024/25	24,265	(1,467)	22,798
2025/26	24,537	(1,610)	22,927
2026/27	24,826	(1,760)	23,066
2027/28	25,087	(1,914)	23,173
2028/29	25,373	(2,065)	23,308
2029/30	25,667	(2,224)	23,443
2030/31	25,967	(2,375)	23,592
2031/32	26,284	(2,393)	23,891
2032/33	26,613	(2,415)	24,198
2033/34	26,933	(2,436)	24,497
2034/35	27,259	(2,459)	24,801
2035/36	27,597	(2,479)	25,118
2036/37	27,957	(2,501)	25,456
2037/38	28,360	(2,523)	25,836

Diesel Sales

There are four communities served by diesel generation in Manitoba: Brochet, Lac Brochet, Tadoule Lake and Shamattawa. Sales within these communities are included in General Consumers Sales, but are not part of the Integrated System, and are thus not part of Common Bus or Gross Firm Load.

Between 1997 and 1999, eleven communities previously served by diesel generation were connected to the Integrated System resulting in the drop in overall diesel sales. The four sites that were to remain diesel were converted from 15 amp service to 60 amp service between 1991 and 2001 causing the increase in those years.

Diesel customers do not have electric heat, which requires a minimum 200 amp service; therefore there is no weather effect.

Figure 20 – Diesel Sales

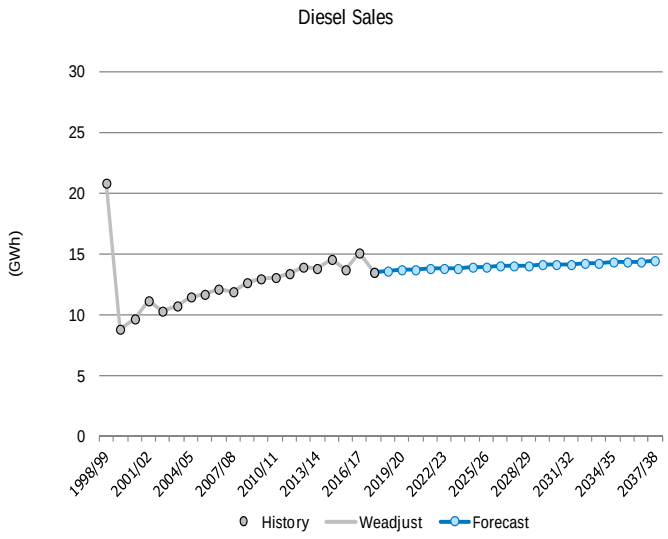


Table 23 – Diesel Sales

Diesel Sales (GWh) Historical / Weather Adjustment			
Fiscal Year	Sales	Weather Adjust	Adjusted Sales
1998/99	21	0	21
1999/00	9	0	9
2000/01	10	0	10
2001/02	11	0	11
2002/03	10	0	10
2003/04	11	0	11
2004/05	12	0	12
2005/06	12	0	12
2006/07	12	0	12
2007/08	12	0	12
2008/09	13	0	13
2009/10	13	0	13
2010/11	13	0	13
2011/12	13	0	13
2012/13	14	0	14
2013/14	14	0	14
2014/15	15	0	15
2015/16	14	0	14
2016/17	15	0	15
2017/18	14	0	14
Forecast			
Fiscal Year			Forecast
2018/19			14
2019/20			14
2020/21			14
2021/22			14
2022/23			14
2023/24			14
2024/25			14
2025/26			14
2026/27			14
2027/28			14
2028/29			14
2029/30			14
2030/31			14
2031/32			14
2032/33			14
2033/34			14
2034/35			14
2035/36			14
2036/37			14
2037/38			14

Distribution Losses

Distribution Losses are made up of the power loss between the distribution substation (Manitoba Load at Common Bus less Construction) and the customer's meter (General Consumers Sales less Diesel), as well as all other differences between what was billed and what was metered. The other differences include:

1. The offset between cycle billing (General Consumers Sales) and actual calendar month usage (Common Bus).
2. Customer Accounting adjustments,
3. Inaccuracies associated with estimated billing (including flat rate estimates),
4. The metered but unbilled consumption of Manitoba Hydro offices, and
5. Energy lost due to theft.

Distribution Losses are forecast in 2018/19 to be 4.8% of the General Consumers Sales less Diesel and remain between 4.8% and 4.9% throughout the forecast.

Figure 21 – Distribution Losses

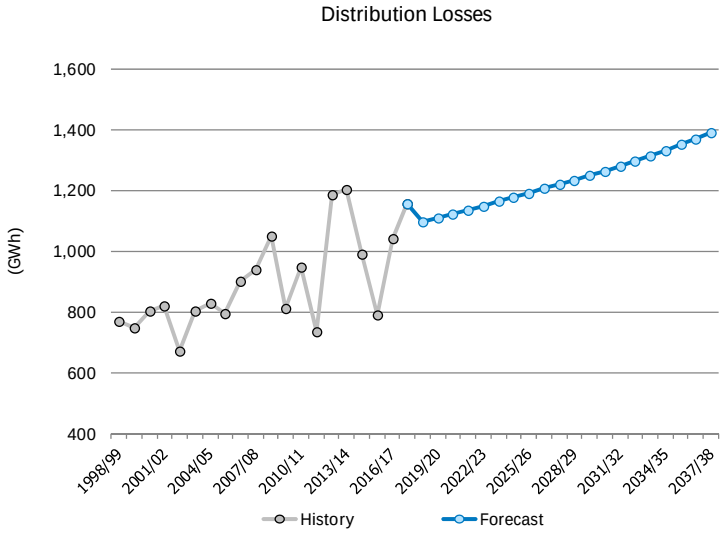


Table 24 – Distribution Losses

Distribution Losses (GWh) Historical / Percent of Sales			
Fiscal Year	Losses	Sales less Diesel	% Losses
1998/99	771	16,908	4.6%
1999/00	749	16,687	4.5%
2000/01	802	17,580	4.6%
2001/02	819	17,793	4.6%
2002/03	671	19,236	3.5%
2003/04	804	19,269	4.2%
2004/05	830	19,724	4.2%
2005/06	797	19,923	4.0%
2006/07	900	20,497	4.4%
2007/08	940	21,049	4.5%
2008/09	1,052	21,198	5.0%
2009/10	813	20,473	4.0%
2010/11	947	20,773	4.6%
2011/12	736	20,757	3.5%
2012/13	1,184	21,463	5.5%
2013/14	1,205	22,324	5.4%
2014/15	992	22,443	4.4%
2015/16	791	21,640	3.7%
2016/17	1,043	22,010	4.7%
2017/18	1,155	22,560	5.1%
Forecast / Percent of Sales			
Fiscal Year	Forecast Losses	Sales less Diesel	% Losses
2018/19	1,097	22,628	4.8%
2019/20	1,109	22,904	4.8%
2020/21	1,122	23,185	4.8%
2021/22	1,135	23,406	4.8%
2022/23	1,149	23,661	4.9%
2023/24	1,164	23,958	4.9%
2024/25	1,178	24,252	4.9%
2025/26	1,192	24,524	4.9%
2026/27	1,206	24,812	4.9%
2027/28	1,219	25,073	4.9%
2028/29	1,233	25,359	4.9%
2029/30	1,248	25,653	4.9%
2030/31	1,263	25,953	4.9%
2031/32	1,280	26,270	4.9%
2032/33	1,297	26,599	4.9%
2033/34	1,314	26,919	4.9%
2034/35	1,332	27,245	4.9%
2035/36	1,350	27,582	4.9%
2036/37	1,370	27,942	4.9%
2037/38	1,390	28,345	4.9%

Construction Power

Construction Power represents the energy used by Manitoba Hydro and its contractors in the construction of major capital works such as generating stations, converter stations and major transmission lines. Construction Power also includes Station Service until a plant is commissioned. Until 2013, about 48 GWh of heating load at the Gillam, Limestone and Kettle town sites was included in Construction Power. This energy is now included in Distribution Losses.

The Construction Power forecast includes (1) the Keeyask Generating Station and (2) the Keewatinohk Converter Station, started in January 2012 with expected completion in the spring of 2020.

Figure 22 – Construction Power

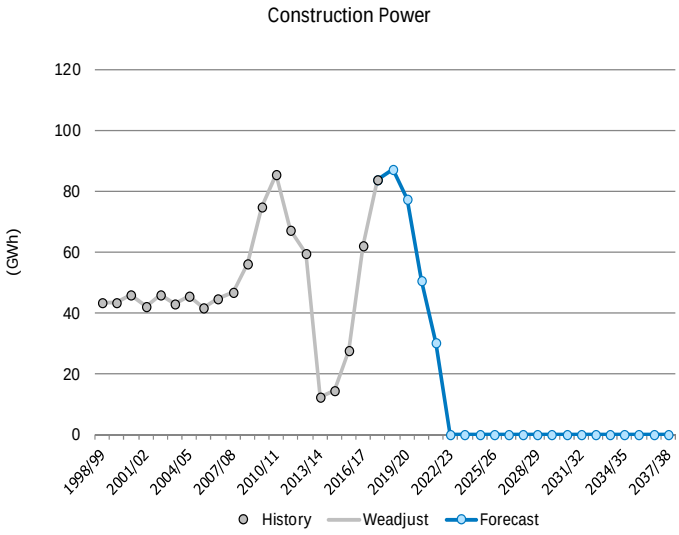


Table 25 – Construction Power

Construction Power (GWh) Historical / Weather Adjustment			
Fiscal Year	Usage	Weather Adjust	Adjusted Sales
1998/99	43	0	43
1999/00	43	0	43
2000/01	46	0	46
2001/02	42	0	42
2002/03	46	0	46
2003/04	43	0	43
2004/05	46	0	46
2005/06	42	0	42
2006/07	45	0	45
2007/08	47	0	47
2008/09	56	0	56
2009/10	75	0	75
2010/11	85	0	85
2011/12	67	0	67
2012/13	59	0	59
2013/14	12	0	12
2014/15	15	0	15
2015/16	28	0	28
2016/17	62	0	62
2017/18	84	0	84
Forecast			
Fiscal Year			Forecast
2018/19			87
2019/20			77
2020/21			51
2021/22			30
2022/23			0
2023/24			0
2024/25			0
2025/26			0
2026/27			0
2027/28			0
2028/29			0
2029/30			0
2030/31			0
2031/32			0
2032/33			0
2033/34			0
2034/35			0
2035/36			0
2036/37			0
2037/38			0

Manitoba Load at Common Bus

Manitoba Load at Common Bus is the total load measured from all the distribution points (i.e. substations) within Manitoba. It includes all energy supplied to General Consumers Sales customers, Construction Power plus associated Distribution Losses, but excludes Diesel customers, Transmission Losses and Station Service.

Common Bus is metered and totaled to correspond exactly to each calendar month. Weather adjustment is done on a calendar month basis.

Weather adjusted Common Bus has grown 308 GWh (1.5%) per year for the past 20 years and 210 GWh (0.9%) per year during the past 10 years reflecting the recent economic downturn. This historical growth also includes the effect of past Demand Side Management (DSM) initiatives. Common Bus is forecast to grow 238 GWh (1.0%) per year for the next 10 years and 291 GWh (1.1%) per year for the next 20 years before program-based DSM initiatives.

Figure 23 – Manitoba Load at Common Bus

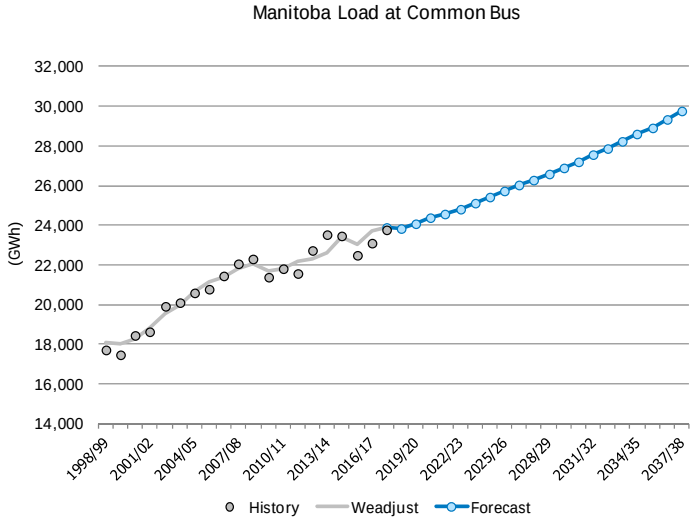


Table 26 – Manitoba Load at Common Bus

Manitoba Load at Common Bus Historical / Weather Adjustment			
Fiscal Year	Usage	Weather Adjust	Adjusted Sales
1998/99	17,722	336	18,059
1999/00	17,479	552	18,031
2000/01	18,428	(156)	18,272
2001/02	18,655	138	18,793
2002/03	19,953	(379)	19,573
2003/04	20,116	(130)	19,986
2004/05	20,600	28	20,627
2005/06	20,761	389	21,150
2006/07	21,442	(59)	21,383
2007/08	22,036	(219)	21,817
2008/09	22,305	(242)	22,064
2009/10	21,361	338	21,699
2010/11	21,806	39	21,844
2011/12	21,560	635	22,195
2012/13	22,706	(377)	22,329
2013/14	23,541	(947)	22,594
2014/15	23,450	(69)	23,381
2015/16	22,460	597	23,057
2016/17	23,115	609	23,724
2017/18	23,799	117	23,916
Forecast			
Fiscal Year			Forecast
2018/19			23,812
2019/20			24,090
2020/21			24,358
2021/22			24,571
2022/23			24,810
2023/24			25,122
2024/25			25,430
2025/26			25,715
2026/27			26,018
2027/28			26,292
2028/29			26,592
2029/30			26,900
2030/31			27,217
2031/32			27,550
2032/33			27,896
2033/34			28,233
2034/35			28,577
2035/36			28,933
2036/37			29,312
2037/38			29,736

Transmission Losses

Transmission Losses are the amount of energy lost while delivering power from the generation stations to all of the distribution substations that make up Common Bus. Transmission Losses only contains losses associated with supplying Manitoba customers. Losses attributable to exports and the gains attributable to imports are excluded. Transmission Losses are mostly losses on the High Voltage Direct Current (HVDC) lines, and are substantial because of the distance of transmission from northern generation to southern distribution points, but are much less than what AC losses would be over that distance. Transmission Losses vary year to year depending on water conditions, system configuration, outages and the magnitude of the load. High losses experienced in 2002/03 were due to two HVDC transformer failures.

Transmission Losses are forecast to be approximately 9.0% of the General Consumers Sales less Diesel Sales and do not reflect future efficiency gains from the commissioning of Bipole III as of July 2018.

Figure 24 – Transmission Losses



Table 27 – Transmission Losses

Transmission Losses (GWh) Historical / Weather Adjustment / Forecast			
Fiscal Year	Losses	Sales less Diesel	% Losses
1998/99	1,675	16,908	9.9%
1999/00	1,623	16,687	9.7%
2000/01	1,696	17,580	9.6%
2001/02	1,864	17,793	10.5%
2002/03	2,012	19,236	10.5%
2003/04	1,792	19,269	9.3%
2004/05	1,852	19,724	9.4%
2005/06	1,860	19,923	9.3%
2006/07	1,885	20,497	9.2%
2007/08	1,949	21,049	9.3%
2008/09	1,979	21,198	9.3%
2009/10	1,934	20,473	9.4%
2010/11	1,977	20,773	9.5%
2011/12	1,939	20,757	9.3%
2012/13	1,936	21,463	9.0%
2013/14	1,969	22,324	8.8%
2014/15	1,949	22,443	8.7%
2015/16	2,107	21,640	9.7%
2016/17	2,014	22,010	9.2%
2017/18	1,846	22,560	8.2%
Forecast / Percent of Sales			
Fiscal Year	Forecast Losses	Sales less Diesel	% Losses
2018/19	2,028	22,628	9.0%
2019/20	2,051	22,904	9.0%
2020/21	2,074	23,185	8.9%
2021/22	2,092	23,406	8.9%
2022/23	2,113	23,661	8.9%
2023/24	2,139	23,958	8.9%
2024/25	2,165	24,252	8.9%
2025/26	2,190	24,524	8.9%
2026/27	2,216	24,812	8.9%
2027/28	2,239	25,073	8.9%
2028/29	2,264	25,359	8.9%
2029/30	2,291	25,653	8.9%
2030/31	2,318	25,953	8.9%
2031/32	2,346	26,270	8.9%
2032/33	2,375	26,599	8.9%
2033/34	2,404	26,919	8.9%
2034/35	2,433	27,245	8.9%
2035/36	2,464	27,582	8.9%
2036/37	2,496	27,942	8.9%
2037/38	2,532	28,345	8.9%

Station Service

Station Service is the energy used by power plants to generate power and service their own load. Manitoba energy or peak without Station Service is referred to as “Net”, and with Station Service as “Gross”.

Station Service energy is forecast to be 123 GWh and Station Service peak is forecast to be 21 MW from 2018/19 to 2037/38.

Station Service for Keeyask and for future non-committed plants is excluded from this forecast.

Figure 25 - Station Service

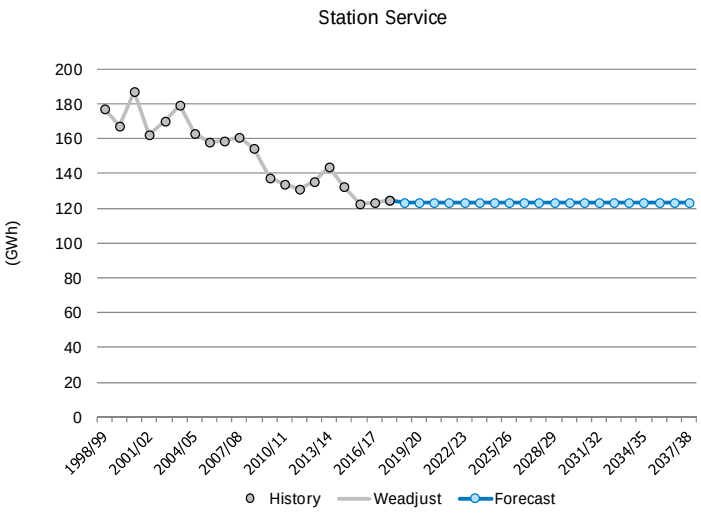


Table 28 - Station Service

Station Service (GWh) Historical / Weather Adjustment			
Fiscal Year	Usage	Weather Adjust	Adjusted Sales
1998/99	177	0	177
1999/00	167	0	167
2000/01	187	0	187
2001/02	162	0	162
2002/03	170	0	170
2003/04	179	0	179
2004/05	163	0	163
2005/06	158	0	158
2006/07	159	0	159
2007/08	161	0	161
2008/09	154	0	154
2009/10	137	0	137
2010/11	134	0	134
2011/12	131	0	131
2012/13	136	0	136
2013/14	144	0	144
2014/15	132	0	132
2015/16	123	0	123
2016/17	123	0	123
2017/18	125	0	125
Forecast			
Fiscal Year			Forecast
2018/19			123
2019/20			123
2020/21			123
2021/22			123
2022/23			123
2023/24			123
2024/25			123
2025/26			123
2026/27			123
2027/28			123
2028/29			123
2029/30			123
2030/31			123
2031/32			123
2032/33			123
2033/34			123
2034/35			123
2035/36			123
2036/37			123
2037/38			123

Table 29 – Monthly Station Service Energy

Monthly Station Service Energy (GWh) History and Forecast													
Fiscal Year	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Total
2007/08	15.7	12.1	9.1	8.2	8.4	7.3	8.7	14.7	19.2	18.6	19.7	18.8	160.5
2008/09	13.8	9.4	7.5	9.5	10.4	7.1	10.6	15.1	20.1	20.4	14.9	15.5	154.2
2009/10	11.8	10.3	7.9	7.2	7.4	7.2	10.8	14.2	18.8	15.5	13.3	12.7	137.1
2010/11	10.2	9.9	7.3	6.7	7.2	7.4	9.5	12.9	16.4	17.1	14.4	15.0	134.1
2011/12	12.0	9.9	7.5	7.1	7.3	6.7	9.5	13.1	15.1	16.0	13.8	13.1	131.3
2012/13	11.0	9.4	7.7	7.0	6.7	6.4	11.4	14.3	16.2	16.6	13.7	15.2	135.5
2013/14	12.6	11.1	7.0	7.5	7.6	6.9	11.2	13.5	17.8	17.0	15.8	15.8	143.8
2014/15	12.1	9.6	7.7	7.5	7.2	7.0	8.9	13.2	14.4	16.1	15.0	13.7	132.4
2015/16	10.6	8.9	6.8	6.3	7.1	7.9	8.5	13.4	13.7	13.9	13.1	12.5	122.6
2016/17	11.3	8.6	7.0	6.9	8.0	6.9	10.2	10.5	15.6	13.3	12.2	12.6	123.1
2017/18	10.3	8.4	6.9	6.4	6.5	7.4	9.4	14.0	14.1	14.4	13.4	13.4	124.7
2018/19 - 2037/38	10.7	8.6	6.9	6.5	7.2	7.4	9.4	12.6	14.4	13.9	12.9	12.8	123.3

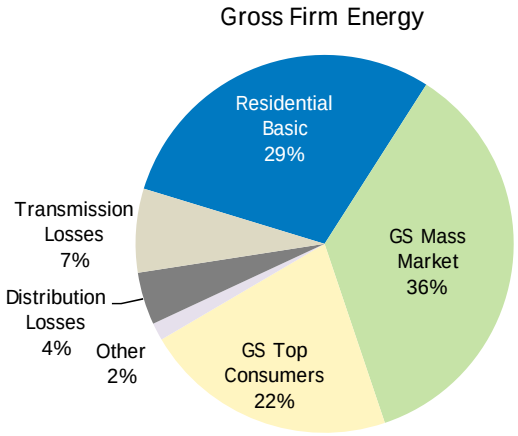
Table 30 – Monthly Station Service Peak

Monthly Station Service Peak (MW) History and Forecast													
Fiscal Year	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Annual
2017/18 Actual	16	12	9	8	9	11	15	23	21	21	21	18	23
2018/19 - 2037/38	17	12	10	10	8	12	13	21	20	21	21	19	21

Gross Firm Energy

Gross Firm Energy is the energy required to serve Manitoba Hydro's customers on the Integrated System. It excludes exports, interruptible (non-firm) loads, Diesel Sales and Station Service for Keeyask and non- committed plants.

Figure 26 - Gross Firm Energy

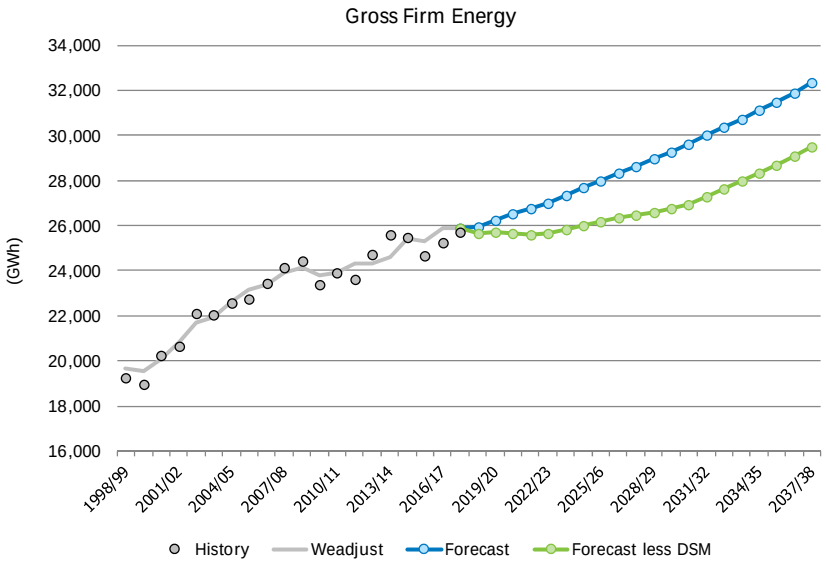


Note: Other category includes seasonal, flat rate water heating, area & roadway lighting, construction power and station service.

Gross Firm Energy has grown steadily during the past twenty years, except during the economic slowdown in the 1990's and more recently in 2009.

Weather adjusted Gross Firm Energy has grown 328 GWh (1.5%) per year for the past 20 years and 198 GWh (0.8%) per year during the past 10 years reflecting the recent 2008 global economic downturn. This historical growth includes the effect of past Demand Side Management (DSM) initiatives. Energy is forecast to grow 276 GWh (1.0%) per year for the next 10 years and 325 GWh (1.1%) per year for the next 20 years before program-based DSM initiatives. Including program-based DSM, the forecast is expected to grow 181 GWh (0.7%) over the next 20 years.

Figure 27 - Gross Firm Energy



The following table outlines historical and forecast details including the impacts of program based Demand Side Management activity:

Table 31 - Gross Firm Energy

Gross Firm Energy (GWh)			
Historical / Weather Adjustment			
Fiscal Year	Sales	Weather Adjust	Adjusted Sales
1998/99	19,273	367	19,639
1999/00	18,971	604	19,575
2000/01	20,262	(166)	20,096
2001/02	20,656	151	20,807
2002/03	22,110	(417)	21,694
2003/04	22,069	(144)	21,925
2004/05	22,589	31	22,620
2005/06	22,757	422	23,179
2006/07	23,464	(65)	23,399
2007/08	24,122	(236)	23,886
2008/09	24,417	(260)	24,156
2009/10	23,412	369	23,781
2010/11	23,892	44	23,937
2011/12	23,605	689	24,294
2012/13	24,750	(410)	24,339
2013/14	25,625	(1,020)	24,605
2014/15	25,505	(74)	25,431
2015/16	24,665	650	25,315
2016/17	25,227	663	25,890
2017/18	25,742	128	25,870
Forecast / Forecast less DSM			
Fiscal Year	Forecast	DSM (Program based)	Forecast less DSM
2018/19	25,935	(285)	25,651
2019/20	26,237	(541)	25,696
2020/21	26,528	(861)	25,667
2021/22	26,759	(1,158)	25,601
2022/23	27,018	(1,341)	25,677
2023/24	27,357	(1,509)	25,847
2024/25	27,691	(1,666)	26,024
2025/26	28,001	(1,829)	26,172
2026/27	28,329	(1,998)	26,331
2027/28	28,627	(2,173)	26,454
2028/29	28,951	(2,345)	26,607
2029/30	29,287	(2,525)	26,762
2030/31	29,630	(2,697)	26,933
2031/32	29,991	(2,717)	27,274
2032/33	30,367	(2,742)	27,625
2033/34	30,733	(2,766)	27,967
2034/35	31,106	(2,791)	28,314
2035/36	31,492	(2,815)	28,677
2036/37	31,904	(2,839)	29,064
2037/38	32,363	(2,865)	29,498

Table 32 – Monthly Gross Firm Energy

Monthly Gross Firm Energy (GWh) History and Forecast 2007/08 - 2037/38													
Fiscal Year	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Total
2007/08	1,842	1,701	1,663	1,820	1,727	1,650	1,836	2,108	2,490	2,584	2,427	2,273	24,122
2008/09	1,881	1,737	1,662	1,730	1,787	1,681	1,874	2,154	2,652	2,702	2,226	2,331	24,417
2009/10	1,861	1,744	1,671	1,667	1,644	1,672	1,888	1,935	2,560	2,524	2,213	2,032	23,412
2010/11	1,699	1,692	1,611	1,716	1,698	1,638	1,778	2,129	2,563	2,682	2,322	2,364	23,892
2011/12	1,862	1,751	1,603	1,789	1,741	1,643	1,814	2,125	2,435	2,526	2,251	2,064	23,605
2012/13	1,802	1,698	1,688	1,869	1,727	1,606	1,941	2,265	2,665	2,766	2,342	2,383	24,750
2013/14	2,041	1,754	1,650	1,766	1,725	1,657	1,914	2,258	2,884	2,895	2,553	2,527	25,625
2014/15	2,048	1,837	1,690	1,788	1,778	1,703	1,909	2,424	2,638	2,770	2,581	2,339	25,505
2015/16	1,940	1,799	1,724	1,868	1,775	1,728	1,873	2,137	2,469	2,695	2,418	2,239	24,665
2016/17	2,007	1,741	1,726	1,826	1,809	1,720	1,986	2,093	2,754	2,740	2,350	2,472	25,227
2017/18	1,946	1,774	1,733	1,874	1,804	1,741	1,963	2,399	2,759	2,822	2,569	2,357	25,742
17/18 Wadj	1,983	1,828	1,747	1,933	1,876	1,755	2,007	2,309	2,692	2,886	2,498	2,357	25,870
2018/19	1,979	1,817	1,762	1,886	1,837	1,747	1,991	2,313	2,743	2,893	2,514	2,453	25,935
2019/20	2,002	1,838	1,783	1,910	1,861	1,768	2,014	2,339	2,773	2,925	2,542	2,480	26,237
2020/21	2,024	1,859	1,802	1,933	1,884	1,788	2,035	2,364	2,803	2,958	2,570	2,507	26,528
2021/22	2,041	1,875	1,818	1,950	1,901	1,803	2,053	2,385	2,828	2,984	2,592	2,527	26,759
2022/23	2,060	1,894	1,836	1,970	1,920	1,821	2,072	2,408	2,855	3,013	2,617	2,550	27,018
2023/24	2,086	1,917	1,859	1,995	1,944	1,844	2,098	2,439	2,891	3,052	2,650	2,582	27,357
2024/25	2,111	1,941	1,882	2,019	1,968	1,866	2,124	2,468	2,926	3,089	2,683	2,613	27,691
2025/26	2,135	1,962	1,903	2,042	1,990	1,887	2,147	2,496	2,959	3,124	2,713	2,642	28,001
2026/27	2,160	1,985	1,925	2,066	2,013	1,909	2,172	2,525	2,994	3,161	2,745	2,673	28,329
2027/28	2,183	2,006	1,946	2,088	2,034	1,929	2,195	2,552	3,025	3,194	2,774	2,701	28,627
2028/29	2,207	2,029	1,968	2,111	2,057	1,951	2,220	2,581	3,059	3,230	2,805	2,732	28,951
2029/30	2,233	2,052	1,991	2,136	2,081	1,974	2,245	2,611	3,095	3,268	2,838	2,764	29,287
2030/31	2,259	2,076	2,014	2,161	2,105	1,997	2,271	2,641	3,131	3,307	2,872	2,796	29,630
2031/32	2,286	2,101	2,038	2,187	2,131	2,021	2,299	2,674	3,170	3,348	2,907	2,830	29,991
2032/33	2,314	2,127	2,064	2,214	2,157	2,046	2,327	2,707	3,210	3,391	2,944	2,866	30,367
2033/34	2,342	2,152	2,088	2,240	2,183	2,070	2,355	2,740	3,249	3,433	2,980	2,900	30,733
2034/35	2,370	2,178	2,113	2,267	2,209	2,095	2,383	2,773	3,289	3,475	3,017	2,936	31,106
2035/36	2,399	2,205	2,139	2,295	2,236	2,120	2,412	2,808	3,331	3,519	3,055	2,972	31,492
2036/37	2,430	2,233	2,167	2,325	2,265	2,147	2,444	2,845	3,375	3,566	3,096	3,011	31,904
2037/38	2,465	2,265	2,198	2,358	2,297	2,178	2,479	2,886	3,424	3,618	3,141	3,055	32,363

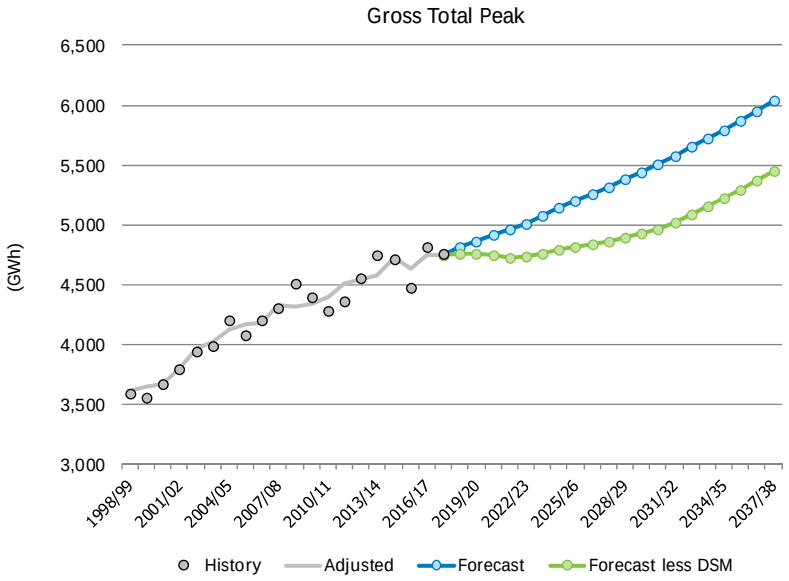
Gross Total Peak

Gross Total Peak is the maximum integrated average hourly load required to serve Manitoba Hydro's customers on the Integrated System. It excludes exports and Diesel Sales. It includes Station Service and Curtailable Loads.

Typically, the peak occurs on a very cold winter weekday either in the morning (often from 8 a.m. to 9 a.m.) or in the afternoon (from 5 p.m. to 6 p.m.). Electric heating is a main contributor to the peak on one of the coldest days, whereas the operation or lack thereof of large industrials often makes the difference as to the specific day and peak hour.

The adjusted Gross Total Peak has grown from 3,610 MW in 1998/99 to 4,751 MW in 2017/18 at an average growth of 60 MW or 1.5% per year. It is forecast to grow to 6,035 MW at 64 MW (1.2%) per year by 2037/38 years before program-based DSM initiatives. Including program-based DSM, the forecast is expected to grow 35 MW (0.7%) over the next 20 years.

Figure 28 - Gross Total Peak



The following table outlines historical and forecast details including the impacts of program based Demand Side Management activity:

Table 33 – Gross Total Peak

Gross Total Peak (MW)			
Historical / Weather Adjustment			
Fiscal Year	Peak	Adjustment	Adjusted Peak
1998/99	3,596	14	3,610
1999/00	3,555	90	3,645
2000/01	3,672	5	3,677
2001/02	3,797	(4)	3,793
2002/03	3,948	24	3,972
2003/04	3,994	31	4,025
2004/05	4,201	(72)	4,129
2005/06	4,085	84	4,169
2006/07	4,208	(26)	4,182
2007/08	4,304	21	4,325
2008/09	4,509	(195)	4,314
2009/10	4,393	(56)	4,336
2010/11	4,286	106	4,392
2011/12	4,367	146	4,514
2012/13	4,559	(13)	4,547
2013/14	4,743	(165)	4,578
2014/15	4,713	10	4,723
2015/16	4,479	155	4,634
2016/17	4,822	(71)	4,751
2017/18	4,755	(4)	4,751
Forecast / Forecast less DSM			
Fiscal Year	Forecast	DSM (Program based)	Forecast less DSM
2018/19	4,815	(53)	4,762
2019/20	4,863	(99)	4,763
2020/21	4,918	(169)	4,749
2021/22	4,965	(238)	4,727
2022/23	5,015	(283)	4,732
2023/24	5,079	(319)	4,760
2024/25	5,143	(352)	4,790
2025/26	5,202	(386)	4,816
2026/27	5,264	(421)	4,843
2027/28	5,320	(455)	4,866
2028/29	5,381	(487)	4,894
2029/30	5,445	(521)	4,924
2030/31	5,511	(552)	4,959
2031/32	5,580	(557)	5,024
2032/33	5,652	(561)	5,091
2033/34	5,722	(566)	5,156
2034/35	5,794	(571)	5,223
2035/36	5,869	(576)	5,293
2036/37	5,948	(580)	5,368
2037/38	6,035	(585)	5,450

Table 34 – Monthly Gross Total Peak

Monthly Gross Total Peak (MW) History and Forecast 2007/08 - 2037/38													
Fiscal Year	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Annual
2007/08	3,494	2,736	3,042	3,294	3,033	2,777	2,979	3,996	4,078	4,304	4,289	4,095	4,304
2008/09	3,221	2,893	2,952	2,920	3,110	2,726	3,159	3,804	4,427	4,509	4,196	4,223	4,509
2009/10	3,196	2,933	3,000	2,758	2,933	2,982	3,054	3,297	4,393	4,256	4,092	4,235	4,393
2010/11	2,905	2,843	2,805	2,991	3,163	2,709	3,056	3,927	4,195	4,286	4,250	4,169	4,286
2011/12	3,183	2,886	3,056	3,278	3,189	3,045	3,129	3,756	4,095	4,367	4,270	3,608	4,367
2012/13	3,328	2,775	3,161	3,260	3,253	2,870	3,312	4,087	4,410	4,559	4,543	4,013	4,559
2013/14	3,622	3,129	3,103	3,179	3,276	3,227	3,448	4,026	4,656	4,743	4,579	4,541	4,743
2014/15	3,754	2,955	2,967	3,094	3,190	2,938	3,382	4,391	4,532	4,713	4,573	4,390	4,713
2015/16	3,447	3,000	3,114	3,351	3,314	3,427	3,134	3,858	4,021	4,479	4,424	4,247	4,479
2016/17	3,663	2,934	3,103	3,333	3,132	2,958	3,228	3,622	4,616	4,822	4,469	4,435	4,822
2017/18	3,348	2,780	3,121	3,319	3,177	3,242	3,534	4,041	4,666	4,755	4,740	3,915	4,755
17/18 Norm	3,464	2,991	3,151	3,278	3,323	3,090	3,345	4,005	4,493	4,673	4,582	4,339	4,751
2018/19	3,511	3,031	3,193	3,322	3,368	3,132	3,391	4,059	4,554	4,736	4,644	4,398	4,815
2019/20	3,554	3,069	3,235	3,367	3,414	3,171	3,431	4,107	4,598	4,783	4,690	4,450	4,863
2020/21	3,592	3,103	3,270	3,407	3,455	3,207	3,468	4,152	4,650	4,838	4,743	4,496	4,918
2021/22	3,624	3,132	3,300	3,439	3,488	3,236	3,499	4,189	4,693	4,884	4,787	4,535	4,965
2022/23	3,660	3,163	3,335	3,476	3,526	3,270	3,534	4,232	4,740	4,933	4,834	4,577	5,015
2023/24	3,707	3,204	3,377	3,521	3,571	3,312	3,579	4,285	4,801	4,996	4,896	4,636	5,079
2024/25	3,753	3,243	3,419	3,565	3,616	3,353	3,623	4,339	4,861	5,059	4,957	4,693	5,143
2025/26	3,795	3,280	3,459	3,606	3,657	3,391	3,664	4,388	4,916	5,117	5,014	4,747	5,202
2026/27	3,841	3,319	3,500	3,649	3,702	3,432	3,708	4,440	4,975	5,178	5,075	4,804	5,264
2027/28	3,882	3,355	3,538	3,688	3,742	3,469	3,747	4,488	5,028	5,233	5,129	4,855	5,320
2028/29	3,927	3,393	3,579	3,731	3,785	3,509	3,790	4,539	5,085	5,294	5,188	4,911	5,381
2029/30	3,973	3,433	3,622	3,775	3,830	3,550	3,835	4,593	5,146	5,356	5,250	4,970	5,445
2030/31	4,020	3,474	3,665	3,821	3,876	3,593	3,880	4,648	5,207	5,421	5,313	5,029	5,511
2031/32	4,070	3,517	3,710	3,868	3,925	3,637	3,928	4,706	5,273	5,489	5,380	5,092	5,580
2032/33	4,121	3,561	3,758	3,917	3,975	3,683	3,978	4,766	5,340	5,560	5,449	5,158	5,652
2033/34	4,172	3,604	3,804	3,965	4,024	3,728	4,027	4,825	5,406	5,629	5,517	5,222	5,722
2034/35	4,223	3,648	3,851	4,014	4,074	3,774	4,076	4,884	5,474	5,699	5,586	5,287	5,794
2035/36	4,276	3,694	3,899	4,065	4,125	3,821	4,127	4,946	5,544	5,772	5,657	5,354	5,869
2036/37	4,333	3,742	3,951	4,119	4,180	3,871	4,182	5,013	5,619	5,851	5,734	5,426	5,948
2037/38	4,395	3,796	4,008	4,178	4,240	3,927	4,242	5,085	5,701	5,936	5,817	5,505	6,035

Peak load is measured and recorded differently than energy data. The system load at every hour is calculated by System Operations as:

Hourly Gross Total Peak (t)

= Hourly Total Generation (t)

- Hourly Metered Exports (t) + Hourly Metered Imports (t)

- Losses Associated with Exports (t) + Gains Associated with Imports (t)

+ Curtailments (t)

Losses for exports and gains for imports are only known on a monthly energy basis. The hourly value is obtained by using the ratio of exports/imports for the hour to the total exports/imports for the month and applying that to the total metered loss/gain for the month. The remaining difference between the balance of the load and Common Bus is taken as the Transmission Losses associated with Manitoba load.

Curtailments for individual customers are calculated as the difference between what the customer would have used if not curtailed versus what they actually used.

Annual Peak

The forecast annual peak is higher than the maximum of the monthly peaks. This is because the peak can occur in any one of the winter months. The same characteristic is apparent in historical peaks. The average historical annual peak is higher than the maximum of the highest average monthly peaks. For studies requiring yearly data, the annual peak should be used.

16 Hour Peak

The peaks in this document are integrated hourly peaks. For some studies and analysis of avoided cost or DSM savings, an estimate of the average peak during on-peak hours (from 6 a.m. to 10 p.m.) may be desired. To convert hourly peak to 16 hour peak, multiply the hourly peak in the associated month by the following percentages:

Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
94.4%	94.9%	95.8%	96.0%	96.3%	96.0%	96.6%	95.6%	95.8%	96.6%	95.6%	95.5%	94.8%

VARIABILITY AND ACCURACY

Weather Effect and Weather Adjustment

The weather effect is determined in any sector every year by regressing the previous two years of actual monthly energies against the actual HDD and CDD for the month. This results in a GWh per HDD effect and a GWh per CDD effect for that sector for that year.

Only sectors whose major variation is due to weather can have a weather effect estimated. Sectors that vary primarily due to industrial output levels or seasonal but non-weather reasons may yield false weather effects if estimated. Weather effects are not determined for the GS Top Consumers, Seasonal, Diesel, Water Heating and Lighting sectors.

For sectors where a weather effect is calculated, this document shows energy as the reported value and as a weather adjusted value. Forecasts are based on the weather adjusted values. The calculations are:

Weather Adjustment = HDD weather effect * (HDD actual - HDD normal) + CDD weather effect * (CDD actual - CDD normal)

Weather Adjusted Actual = Actual - Weather Adjustment

Following are the HDD and CDD weather effect factors by sector:

Weather Effect Factors by sector		
Sector	GWh/DDH	GWh/DDC
Residential Basic	0.6	1.1
GS Mass Market	0.3	1.0
General Consumers Sales	0.9	2.1
Gross Firm	1.2	2.7
	Winter @ -30°C MW/Deg	Summer @ 30°C MW/Deg
Gross Total Peak	49	112

Load Variability

Uncertainty is an inherent characteristic of forecasting. The load will vary both year to year and long term because of underlying changes in population growth, economic growth, changes in the operations of Top Consumers, and overall use patterns. An economic recession will slow energy growth and an economic boom will increase it. Cycles cannot be predicted in advance so some appropriate midpoint must be chosen as the forecast.

This forecast was created as Manitoba Hydro's best estimate of Manitoba's future energy requirement with an expectation of a 50% chance that actual growth will be higher than the forecast, and a 50% chance that actual growth will be lower than the forecast. This can also be called the P50 (50th Percentile) or Base Forecast.

To evaluate the potential for variation, historic load variability has been analyzed using a probabilistic-based approach. Doing this provides an estimate of the magnitude of the potential load variation from the forecast due to population, economy and other effects. 10% and 90% confidence bands (-/+ 1.28 standard deviations), also known as P10 and P90, were selected to be a proxy for the Low and High Load Forecast Scenarios for use in risk analysis studies. They are calculated as follows:

Load = Base Forecast -/+ 1.28 x Standard Deviation

For other probability points, substitute for the 1.28 the following numbers:

Prob	0.1%	2.5%	10.0%	20.0%	50.0%	80.0%	90.0%	97.5%	99.9%
Z(Prob)	-3.09	-1.96	-1.28	-0.84	0.00	0.84	1.28	1.96	3.09

This calculation gives the variability due to long term economic effects. It does not include variability due to weather which was removed through the use of weather adjusted load. The standard deviation of the weather variation has been found to be approximately 2% of both the energy and peak. Annual weather variations tend to be independent of the economy, so if a combined variance is desired, then the variance due to weather can be added to the variance without weather to derive an overall variance that includes weather.

The following four charts and tables summarize the variability for energy and peak. By 2037/38, the Load Forecast has an 80% probability of being accurate to within ± 1,743 GWh or ±5.5%. Due to the inherent variability of the load, this is the best level of accuracy possible.

The overall economic standard deviation in 2037/38 is 1,262 GWh or 3.9% of the forecast energy. Analyzed individually, the economic standard deviation of the Top Consumers sector is 1,305 GWh (22.3%), Residential is 487 GWh (5.0%) and Mass Market is also 474 GWh (3.8%), showing that the Top Consumers sector is the majority of the variance.

Figure 29 – Energy Variability

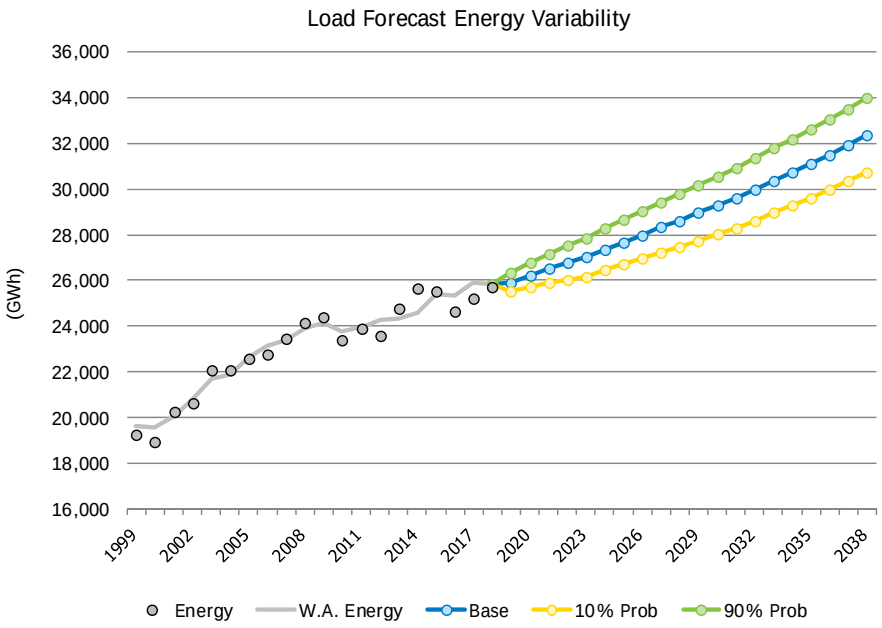


Table 35 – Energy Variability

Energy Variablility (GWh)				
Fiscal Year	Gross Firm Base Fcst	Long Term Economic Std Dev	10.0% Prob Point	90.0% Prob Point
2018/19	25,935	298	25,554	26,317
2019/20	26,237	417	25,702	26,772
2020/21	26,528	508	25,876	27,179
2021/22	26,759	584	26,010	27,508
2022/23	27,018	651	26,184	27,852
2023/24	27,357	711	26,446	28,267
2024/25	27,691	765	26,710	28,672
2025/26	28,001	816	26,955	29,047
2026/27	28,329	864	27,222	29,436
2027/28	28,627	908	27,463	29,791
2028/29	28,951	951	27,733	30,170
2029/30	29,287	991	28,017	30,556
2030/31	29,630	1,029	28,311	30,949
2031/32	29,991	1,066	28,625	31,358
2032/33	30,367	1,102	28,955	31,779
2033/34	30,733	1,136	29,277	32,189
2034/35	31,106	1,169	29,608	32,604
2035/36	31,492	1,201	29,953	33,031
2036/37	31,904	1,232	30,325	33,482
2037/38	32,363	1,262	30,746	33,980

Figure 30 – Peak Variability

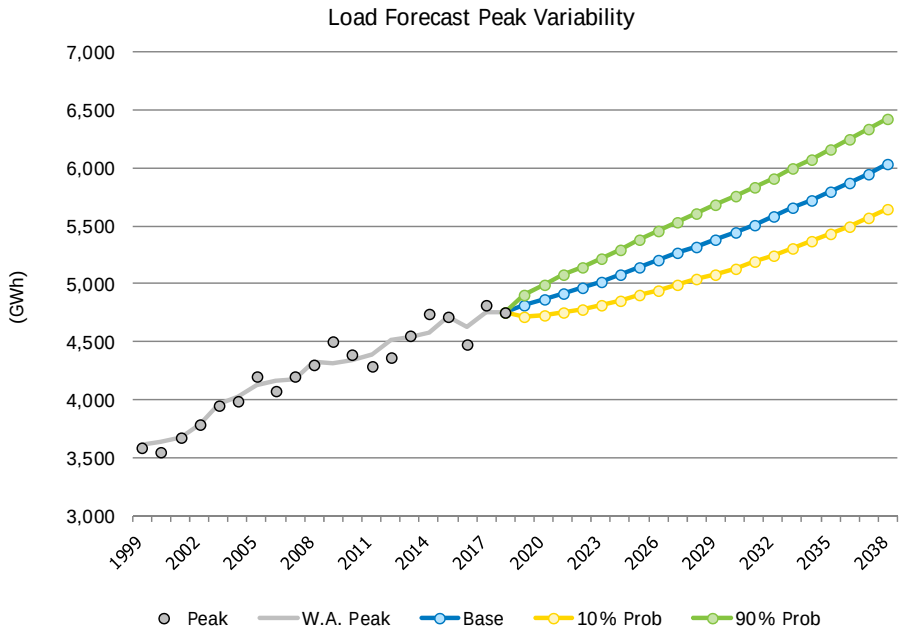


Table 36 – Peak Variability

Peak Variablility (MW)				
Fiscal Year	Gross Firm Base Fcst	Long Term Economic Std Dev	10.0% Prob Point	90.0% Prob Point
2018/19	4,815	72	4,723	4,908
2019/20	4,863	101	4,733	4,992
2020/21	4,918	123	4,760	5,076
2021/22	4,965	142	4,783	5,146
2022/23	5,015	158	4,812	5,217
2023/24	5,079	172	4,858	5,300
2024/25	5,143	186	4,905	5,381
2025/26	5,202	198	4,948	5,455
2026/27	5,264	209	4,996	5,532
2027/28	5,320	220	5,038	5,602
2028/29	5,381	231	5,086	5,677
2029/30	5,445	240	5,137	5,753
2030/31	5,511	250	5,191	5,831
2031/32	5,580	259	5,249	5,912
2032/33	5,652	267	5,310	5,995
2033/34	5,722	276	5,369	6,076
2034/35	5,794	284	5,431	6,157
2035/36	5,869	291	5,495	6,242
2036/37	5,948	299	5,565	6,331
2037/38	6,035	306	5,643	6,428

5 and 10 year Forecast Accuracy

Due to the load variation caused by population growth and economic growth, there is only a certain level of accuracy possible. Using the load variability estimates of the previous section, due to economic variability alone, there is only an 80% chance that a 5 year energy forecast will be within 3.2% of the actual, and an 80% chance that a 10 year energy forecast will be within 4.5% of the actual.

Recognizing this inherent uncertainty of the forecast, historic forecast variation has been tracked. The following four figures and tables compare previous load forecasts to actual results 5 and 10 years later.

The energy savings achieved under Manitoba Hydro's market-based DSM programs between the year the forecast was prepared and the year being forecast was subtracted first from the forecast value. The remaining difference is taken as an estimate of the accuracy of the forecast.

The following figures and tables may suggest cycles in the forecast made up of alternating periods of over-forecasting and under-forecasting. These are not so much due to a bias in the forecast as they are due to unexpected periods of recession or economic growth. Once one of these unexpected periods occur, the accuracy of the previous five 5-year forecasts for 5 years, and the accuracy of the previous ten 10-year forecasts for ten years will be affected thus causing periods of over- or under-forecasting.

Compensation for these periods of over and under-forecasting cannot be applied until after the events occur and only then can they be identified and quantified. The forecast assumes average expected economic conditions. When economic conditions are abnormal, the forecast will be high or low.

The weather adjusted Gross Firm Energy is shown in two separate columns in the Energy Accuracy table (Table 35) and they vary in each year due to the difference in weather normals used in each of the respected forecasts.

Figure 31 – Energy Accuracy

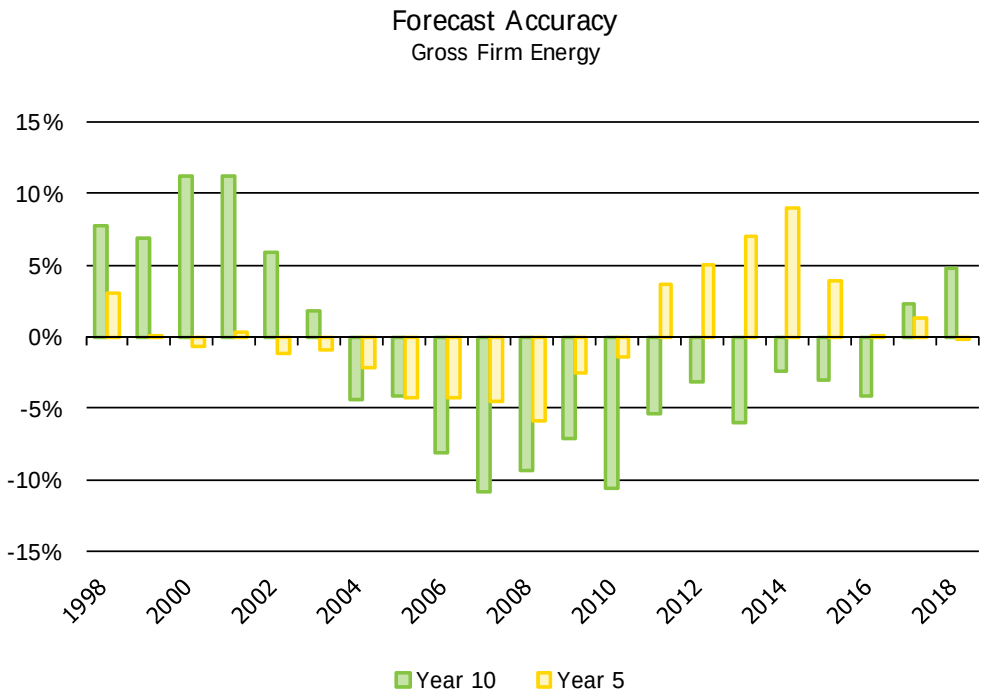


Table 37 – Energy Accuracy

Energy Accuracy (GWh)							
Fiscal Year	Actual Gross Firm Energy	Forecast Prepared 5 Years Previous	W.A. Gross Firm Energy	5 Year Percent Accuracy	Forecast Prepared 10 Years Previous	W.A. Gross Firm Energy	10 Year Percent Accuracy
1996/97	19,321	19,395	18,810	3.1%	20,174	18,716	7.8%
1997/98	19,014	19,455	19,429	0.1%	20,661	19,320	6.9%
1998/99	19,273	19,675	19,818	-0.7%	21,919	19,708	11.2%
1999/00	18,971	19,767	19,703	0.3%	21,833	19,629	11.2%
2000/01	20,262	20,018	20,241	-1.1%	21,300	20,103	6.0%
2001/02	20,656	20,783	20,980	-0.9%	21,364	20,979	1.8%
2002/03	22,110	21,395	21,861	-2.1%	20,916	21,868	-4.4%
2003/04	22,069	21,134	22,062	-4.2%	21,191	22,107	-4.1%
2004/05	22,589	21,693	22,664	-4.3%	20,870	22,714	-8.1%
2005/06	22,757	22,216	23,277	-4.6%	20,812	23,346	-10.9%
2006/07	23,464	22,107	23,489	-5.9%	21,395	23,595	-9.3%
2007/08	24,122	23,353	23,962	-2.5%	22,328	24,034	-7.1%
2008/09	24,417	23,926	24,259	-1.4%	21,756	24,320	-10.5%
2009/10	23,412	24,734	23,850	3.7%	22,611	23,892	-5.4%
2010/11	23,892	25,239	24,020	5.1%	23,299	24,071	-3.2%
2011/12	23,605	25,909	24,202	7.1%	22,924	24,376	-6.0%
2012/13	24,750	26,464	24,270	9.0%	23,844	24,433	-2.4%
2013/14	25,625	25,510	24,538	4.0%	23,936	24,696	-3.1%
2014/15	25,505	25,491	25,469	0.1%	24,455	25,508	-4.1%
2015/16	24,665	25,707	25,366	1.3%	25,999	25,405	2.3%
2016/17	25,227	25,902	25,936	-0.1%	26,984	25,747	4.8%

Figure 32 – Peak Accuracy

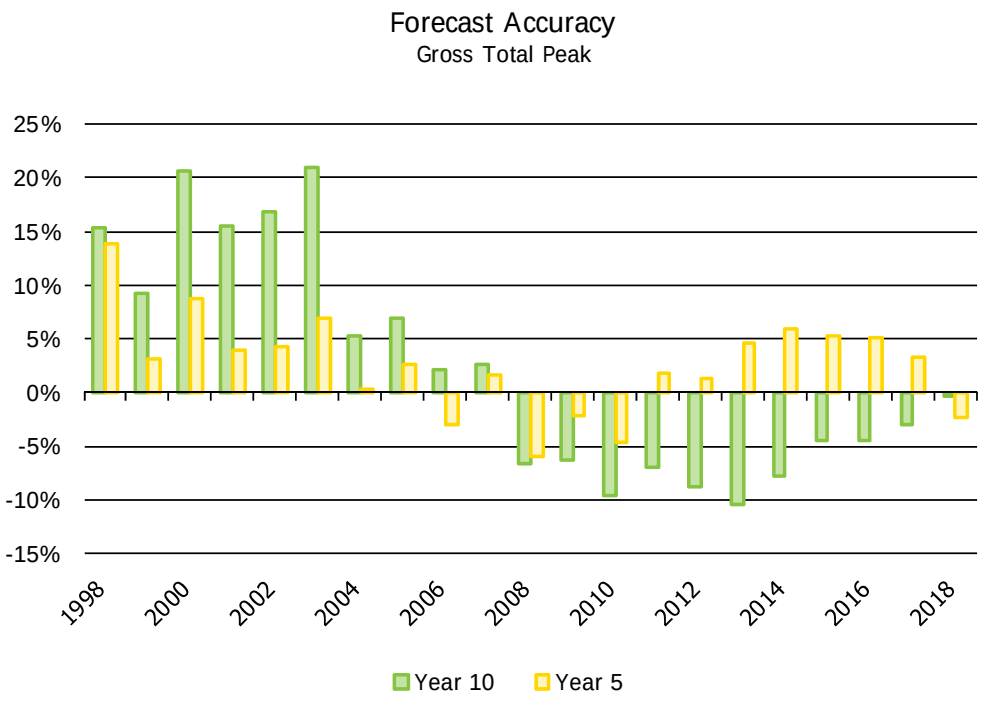


Table 38– Peak Accuracy

Peak Accuracy (MW)							
Fiscal Year	Actual Gross Total Peak	Forecast Prepared 5 Years Previous	Normalized Gross Total Peak	5 Year Percent Accuracy	Forecast Prepared 10 Years Previous	Normalized Gross Total Peak	10 Year Percent Accuracy
1996/97	3,444	3,906	3,432	13.8%	3,962	3,432	15.4%
1997/98	3,525	3,768	3,654	3.1%	3,990	3,654	9.2%
1998/99	3,596	3,703	3,404	8.8%	4,108	3,404	20.7%
1999/00	3,555	3,738	3,597	3.9%	4,152	3,597	15.4%
2000/01	3,672	3,758	3,603	4.3%	4,210	3,603	16.8%
2001/02	3,797	3,759	3,516	6.9%	4,251	3,516	20.9%
2002/03	3,948	3,801	3,790	0.3%	3,989	3,790	5.2%
2003/04	3,994	3,833	3,733	2.7%	3,990	3,733	6.9%
2004/05	4,201	3,817	3,936	-3.0%	4,023	3,936	2.2%
2005/06	4,085	3,860	3,799	1.6%	3,899	3,799	2.6%
2006/07	4,208	3,894	4,145	-6.0%	3,868	4,145	-6.7%
2007/08	4,304	4,097	4,191	-2.2%	3,927	4,191	-6.3%
2008/09	4,509	4,161	4,367	-4.7%	3,948	4,367	-9.6%
2009/10	4,393	4,371	4,295	1.8%	3,993	4,295	-7.0%
2010/11	4,286	4,398	4,344	1.2%	3,959	4,344	-8.9%
2011/12	4,367	4,606	4,403	4.6%	3,942	4,403	-10.5%
2012/13	4,559	4,705	4,441	5.9%	4,098	4,441	-7.7%
2013/14	4,743	4,523	4,296	5.3%	4,106	4,296	-4.4%
2014/15	4,713	4,658	4,430	5.2%	4,233	4,430	-4.4%
2015/16	4,479	4,735	4,588	3.2%	4,451	4,588	-3.0%
2016/17	4,822	4,616	4,726	-2.3%	4,708	4,726	-0.4%

LOAD SENSITIVITY AND EXTREME EVENTS

Manitoba Hydro examines the effect of possible events on the load. The information presented here provides planners with an understanding of what the potential scale of these individual events may have on the system load requirements.

The individual effects of each event can be included in scenario or sensitivity analysis if the need arises. Each change in assumption can be individually applied to the forecast as required to capture the annual energy and peak effect of the desired assumption in any given year. All values are listed at Generation and include transmission and distribution losses.

The sensitivities provide an estimate of what effect a change in assumption will have on the annual energy and peak over the 20 year forecast period.

Effects are summarized below, and the details of each effect follow.

Sensitivity of the Load to an Assumption Change

Change in 20 year average annual growth rate	Energy (GWh)	Peak (MW)
0.1% Increase/Decrease in Population	± 303	± 56
0.1% Increase/Decrease in Income	± 52	± 9
0.1% Increase/Decrease in GDP	± 178	± 33
0.1% Increase/Decrease in Electricity Price	∓137	∓25
Climate Change per Degree Celsius Warmer	+30	-49

Evaluation of Extreme Events	Energy (GWh)	Peak (MW)
All Natural Gas in Manitoba to Electricity	+ 16,000	+ 7,000
Increase/Decrease of One Very Large Industrial Customer	± 1,500	± 180
Maximum Potential Effect of Increased Online Shopping	- 775	- 143
Additional Load if 100% Electric Vehicle Saturation Rate	+ 12,124	+ 1,516
Illustrated Effect of Grid Parity (e.g. Solar Panels)	- 857	0

In context, one year of energy growth is 325 GWh and one year of peak growth is 64 MW.

Population / Economic / Price Changes

The population, economy and prices are the most significant drivers of the load in Manitoba. These effect of each driver based on the coefficients found in the models is summarized below.

Population: A one-time 1% increase in population (13,422 people) results in a 1% increase in the number of Residential Basic customers (4,863 customers representing 75 GWh) and a 0.32% change in the number of GS Mass Market customers (215 customers representing 59 GWh). The total effect on Manitoba Gross Firm Energy would be 152 GWh (0.59%) for any given year. Assuming a 0.1% change in the annual average population growth rate over the 20 year forecast period, the total effect would be a change of 303 GWh in the 20th year of the forecast.

Income: A one-time 1% increase in real income results in a 0.30% increase in Residential average use (47 kWh per customer and 23 GWh overall). On Manitoba Gross Firm Energy it is 26 GWh (0.10%). Assuming a 0.1% change in the annual average income growth rate over the 20 year forecast period, the total effect would be a change of 52 GWh in the 20th year of the forecast.

GDP: A one-time 1% increase in Manitoba GDP results in a 0.55% increase in GS Mass Market Small and Medium average use (564 kWh per customer totaling 38 GWh). A 1% increase in MB/Canada/US blended GDP results in 0.29% increase in GS Large Customer average use (18,754 kWh per customer totaling 6 GWh) and a 0.62% increase in Top Consumers use (35 GWh). The total effect of a 1% increase in GDP on Manitoba Gross Firm Energy is 89 GWh (0.34%). Assuming a 0.1% change in the annual average GDP growth rate over the 20 year forecast period, the total effect would be a change of 178 GWh in the 20th year of the forecast.

Electricity Price: A one-time 1% increase in real electricity price results in a 0.28% decrease in Residential average use (-43 kWh per customer totaling -21GWh). It will also result in a 0.13% decrease in GS Mass Market Small and Medium average use (-133 kWh per customer totaling -9 GWh), a 0.46% decrease in GS Mass Market Large average use (-29,747 kWh per customer totaling -10 GWh) and a 0.37% decrease in GS Top Consumers use (-21 GWh). The total effect of a 1% increase in real electricity price on Manitoba Gross Firm Energy is -68 GWh (-0.26%). Assuming a 0.1% change in the annual average price growth rate over the 20 year forecast period, the total effect would be a change of 137 GWh in the 20th year of the forecast.

Below is a summary of the 20 year impact to the forecast should a change of 0.1% to the annual growth rate for each of the economic assumption is assumed.

Change in 20 year average annual growth rate	Energy (GWh)	Peak (MW)
0.1% Increase/Decrease in Population	± 303	± 56
0.1% Increase/Decrease in Income	± 52	± 9
0.1% Increase/Decrease in GDP	± 178	± 33
0.1% Increase/Decrease in Electricity Price	∓137	∓25

Climate Change

The Intergovernmental Panel on Climate Change projects an increase in global temperature as a result of rising concentrations of greenhouse gases in the atmosphere. Changes to temperature and extreme events have the potential to influence future energy demands. This section quantifies the general effect caused by a 1°C increase in average daily temperature throughout the year.

In Manitoba Hydro's case, if Winnipeg experienced a uniform 1°C warming throughout the year, winter months would be subject to less heating while summer months would be subject to more cooling. Over 200 winter days, every degree Celsius of temperature rise above average conditions will result in an approximate decrease of 200 Heating Degree Days (HDD) per year, and a corresponding approximate increase of 100 Cooling Degree Days (CDD) per year over 100 summer days.

Applying the Weather effect for Manitoba Hydro at Generation gives:

Decrease of 200 HDD ➔ -240 GWh and -49 MW in the winter
Increase of 100 CDD ➔ +270 GWh and +112 MW in the summer

The resulting total effect of every one degree increase in temperature would be:

	Energy (GWh)	Peak (MW)
Climate Change per Degree Celsius Warmer	+30	-49

Conversion of all Natural Gas Use to Electricity

Currently, about 275,000 Residential and General Service customers use natural gas as a fuel for space heating, water heating, cooking, etc. Given possible future green initiatives that could implement carbon taxes on fossil fuels, a scenario to consider is the conversion of all natural gas used as a fuel to electricity. The maximum additional load required over the current forecast for 100% saturation is 16,000 GWh (44 years of load growth) and 7,000 MW (about 108 years of peak growth).

Assumptions exclude industries using natural gas as an ingredient, not as a fuel, and use a fuel efficiency averaging 82% and a load factor of 26%.

	Energy (GWh)	Peak (MW)
All Natural Gas in Manitoba to Electricity	+ 16,000	+ 7,000

Potential Changes in Load from Very Large Industrial Customers

Manitoba Hydro's largest customer currently uses in excess of 1,500 GWh annually and has a coincident peak load of about 180 MW. It is feasible that one or more customers of this size could decide to start up in Manitoba in the next 20 years.

Similarly, it is possible that one or more very large customers may discontinue operations in Manitoba. This could also be the equivalent of losing Manitoba Hydro's largest customer.

	Energy (GWh)	Peak (MW)
Increase/Decrease of One Very Large Industrial Customer	± 1,500	± 180

Maximum Potential Load Effect of Increased Online Shopping

Online shopping is a growing service offering by many retailers. It is possible that this trend could lead to fewer retail establishments if online shopping becomes pervasive. The potential load reduction of such a scenario will be the electricity use of about 5,800 General Service customers in the Retail sector who currently use about 680 GWh. At generation, this represents a potential total of 775 GWh and 143 MW (using a 62% load factor). This assumes that the structures used for retail are torn down or are refurbished with other businesses that would otherwise have built a new structure.

	Energy (GWh)	Peak (MW)
Maximum Potential Effect of Increased Online Shopping	- 775	- 143

Potential Load from High Adoption of Electric Vehicle Technology

This forecast includes the expected impact due to adoption of electric vehicles within Manitoba over the next twenty years. The specifics have been detailed in the Electric Vehicle Forecast section of this document.

It is possible that the current technological challenges will be solved, price will match those of internal combustion vehicles, and range anxiety will be alleviated. If or when these issues are resolved, it is possible that electric vehicles may eventually grow to be the dominant vehicle.

The maximum load required, if 100% of all new passenger and commercial vehicles purchased every year within the forecast period are Plug-In Electric Vehicles (PEVs), would be 12,270 GWh of energy and 1,534 MW of load. Currently, the forecast for electric vehicles load by 2037/38 is 146 GWh and 18 MW. Therefore the maximum additional load required over the current forecast for 100% saturation is 12,124 GWh (37 years of load growth) and 1,516 MW (about 24 years of peak growth).

	Energy (GWh)	Peak (MW)
Additional Load if 100% Electric Vehicle Saturation Rate	+ 12,124	+ 1,516

Illustrated Effect of Grid Parity

Grid Parity is when a customer will have an economic option to provide some or all of the electricity needs their home or business requires with an alternative energy source. Grid parity requires the self-generated kWh cost to be competitive with utility power when considering operating, maintenance costs and a reasonable amortization period for capital costs.

Solar photovoltaic installations are frequently referenced in discussions related to grid parity as costs continue to decline. Initial adoption rates may be gradual and may take years to mature. For illustrative purposes, the effect at utility generation if 100,000 residential (2 kW system) and 10,000 commercial (50 kW system) customers added solar panels would be:

	Energy (GWh)	Peak (MW)
Illustrated Effect of Grid Parity (e.g. Solar Panels)	- 857	0

ASSUMPTIONS

Economic Assumptions

Economic forecast assumptions are taken from the economic variables that become part of Manitoba Hydro's Forecast of Key Economic and Financial Indicators and Energy Price Forecast.

Residential Customers - The number of Residential Basic customers in Manitoba is forecast to increase by 1.3% or 6,242 units in 2018/19 and averages 1.1% per year over the forecast period. This compares to a historical average increase of 1.2% per year over the last ten years. Residential customers are used in the Residential and GS Mass Market customer forecasts.

Electricity and Natural Gas Prices - The electricity price forecast is based on the Consumer Price Index (CPI) and rate increase projections contained in the Integrated Financial Forecast. The nominal electricity price is forecast to increase annually by 3.6% in 2018/19, 3.7% from 2019/20 to 2035/36 and then reduce to a 2% for the remaining 2 years of the forecast. In real terms, this will translates to an annual increase of 1.5% in 2018/19, between 1.6% and 1.8% from 2019/20 to 2035/36 and then reduce to 0% for the remaining 2 years of the forecast. Manitoba Hydro views the natural gas price forecast as commercially sensitive information. Consistent with the Clean Environment Commission and Electric General Rate Application, this information will not be publicly disclosed. The ratio of natural gas price to electric price is used in the Residential Basic forecast.

Manitoba Disposable Income - Real Manitoba disposable income per Residential Basic customer grew on average 1.6% over the past 20 years and 1.5% over the past 10 years. It is forecast to grow 0.6% annually for the next 20 years. Manitoba disposable income is used in the Residential Basic forecast.

Gross Domestic Product (GDP) - Real economic growth in Manitoba averaged 2.3% annually for the past 20 years and 2.1% annually for the past 10 years. Real Manitoba GDP is expected to grow 1.8% in 2018/19 and average 1.7% annually for the next 20 years. Real economic growth in Canada averaged 2.4% annually for the past 20 years and 1.7% annually for the past 10 years. It is forecast to grow 2.1% in 2018/19 and average 1.9% annually for the next 20 years. Real economic growth in US averaged 2.2% annually for the past 20 years and 1.4% annually for the past 10 years. It is forecast to grow 2.6% in 2018/19 and average 2.1% annually for the next 20 years. GDP is used in the GS Mass Market and GS Top Consumer forecasts.

Price / Income / GDP Elasticity

The economic effects of price, income and GDP have been incorporated into the 2017 forecast. The elasticity of each has been estimated from econometric modeling. A summary of the elasticities found is:

	Price Elasticity	Real Income Elasticity	Real GDP Elasticity
Residential Basic	-0.33	0.31	-
GS Mass Mkt Small/Medium	-0.12	-	0.55
GS Mass Mkt Large	-0.43	-	0.30
GS Top Consumers	-0.34	-	0.62
Gross Firm Energy	-0.28	0.11	0.36

See the Methodology section for more details.

Normal Weather Assumptions

Historical weather adjusted actuals are the foundation of the underlying historical information used in the Residential Average Use and General Service Mass Market Average Use models. Manitoba Hydro forecasts with the assumption of normal weather. The process of adjusting annual historical usage to reflect the same weather pattern reduces the inherit variability caused by weather in the underlying data in each respective model.

Demand Side Management (DSM) in the Forecast

The base forecast reflects future DSM savings associated with existing Provincial building codes and improved equipment efficiency standards and regulations (Codes and Standards) and is the only effect of DSM initiatives that is specifically accounted for in the forecast. Savings due to DSM programs to date are embedded in the historical data that is the basis for this forecast with the current level of past achieved DSM savings is assumed to remain in place throughout the future. Future DSM savings arising from future DSM offerings and market engagement above the current level and incremental to the above mentioned Codes and Standards are not reflected in this forecast. They are accounted for separately in Manitoba Hydro's DSM Plan and Power Resource Plan. As a result, historical growth rates in this document are not directly comparable to future growth rates because the history includes the effect of past program-based DSM initiatives, but the forecast does not. For customers involved in Load Displacement and Alternative Energy initiatives, the forecast excludes the effect of the initiatives, and projects the load without the savings due to the initiatives.

Figure 33 – Gross Firm Energy (Net of DSM)

Although not explicitly included in the base forecast, the program-based DSM has a significant impact on the future load growth expected in Manitoba. Program-based DSM reduces the Gross Firm Energy in 2037/38 from 32,363 GWh to 29,498 GWh, lowering the average growth of 325 GWh or 1.1% per year to an average growth of 181 GWh or 0.7% per year.

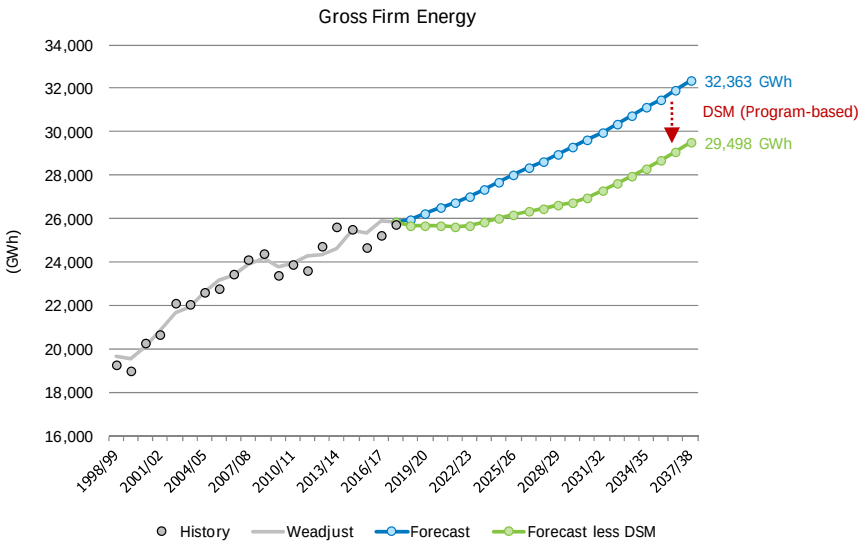
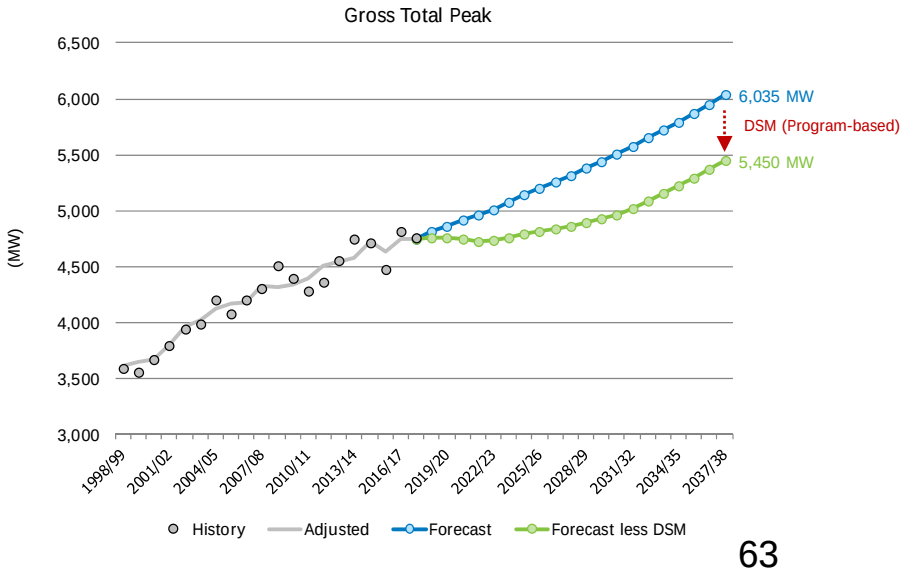


Figure 34 – Gross Total Peak (Net of DSM)

Program-based DSM reduces the Gross Total Peak in 2037/38 from 6,035 MW to 5,450 MW, lowering the average growth of 64 MW or 1.2% per year to an average growth of 35 MW or 0.7% per year.



METHODOLOGY

Residential Basic Methodology

Several different models and forecasts were used to determine the Residential Basic Model. These are the steps to produce the forecast:

i. **Forecast Residential Dwellings** - The forecast of Manitoba residential customers in Manitoba Hydro's Forecast of Key Economic and Financial Indicators was used for the total number of Residential Basic customers for the 2018/19 to 2037/38 period. The customer forecast was based on the average of several Manitoba population forecasts from various external agencies multiplied by a forecast of the people per residential customer ratio. The customer forecast was reduced by about 0.5% to account for customers with multiple services to obtain the forecast of individual dwellings.

ii. **Forecast Existing Dwellings** – Existing dwellings were broken down by dwelling type (single detached, multi attached, and Individually metered apartment suites) within each fuel region (Winnipeg, Gas Available outside Winnipeg and No Gas Available). The rate of change due to demolitions and type change (e.g. bulk apartments to individually metered) as well as customer switches of their space heating fuel were taken into account.

iii. **Historical Space Heating Systems** – The number of historical dwellings by type and region were each divided into nine space heating systems: Electric Forced Air Furnace, Electric Baseboard, Electric Ground Source Heat Pump, Electric Boiler, Gas High-Efficiency Furnace, Gas Mid-Efficiency Furnace, Gas Standard-Efficiency Furnace, Gas Boiler, and Other heat that is not billed for gas or electric. Percentages of each heat type in existing dwellings were based on the 2014 Residential Energy Use Survey.

iv. **Forecast of Space Heating Systems in New Dwellings** – Econometric equations were developed to forecast the number of electric space heating systems in new single detached and multi attached dwellings by region as follows:

Model: **Single Detached, Winnipeg**

Equation: Logit (Percentage of New Dwellings (t)) = -6.72 + 2.38 * T + 4.34 * PGEFF (lag(t))

Results:

Model R-Squared	Variable	Coefficient	t-stat
77.8%	Constant	-6.72	-13.45
	Trend	2.38	8.45
	PGEFF	4.34	6.03

Model: **Single Detached, Gas Available**

Equation: Logit (Percentage of New Dwellings (t)) = -2.06 + 1.49 * T + 2.89 * PGEFF (lag(t))

Results:

Model R-Squared	Variable	Coefficient	t-stat
92.2%	Constant	-2.06	-13.90
	Trend	1.49	10.86
	PGEFF	2.89	13.10

Model: **Multi Attached, Winnipeg**

Equation: Logit (Percentage of New Dwellings (t)) = -10.04 + 6.38 * T + 11.27 * PGEFF (lag(t))

Results:

Model R-Squared	Variable	Coefficient	t-stat
51.4%	Constant	-10.04	-4.96
	Trend	6.38	4.79
	PGEFF	11.27	3.88

Model: **Multi Attached, Gas Available**

Equation: Logit (Percentage of New Dwellings (t)) = -3.21 + 1.84 * T + 5.79 * PGEFF (lag(t))

Results:

Model R-Squared	Variable	Coefficient	t-stat
66.9%	Constant	-3.21	-5.62
	Trend	1.84	3.79
	PGEFF	5.79	7.07

Term definitions:

Logit - A log transformation of percentages used for saturation analysis
T - A trend variable capturing the effect of natural gas price changes
PGEFF - Ratio of the gas to electricity price for high efficiency furnaces
lag(t) - The weighted average (50%, 10%, 12%, 28%) of the 1,3, 4 and 5 year lags

The 2014 Residential Energy Use Survey was used to break the forecast of new electric heat dwellings and new non-electric-heat dwellings within single detached, multi attached and individually metered apartment suites across Winnipeg, Gas Available and No Gas Available areas into specific furnace types.

v. **Forecast of Space Heating Systems in Existing Dwellings** – The average age of heating systems in existing dwellings was determined from the 2014 Residential Energy Use Survey. The number of annual replacements was estimated using a Weibull distribution based on the average age of each furnace type. Fuel switching was estimated using survey respondents in older dwellings with newer heating systems and included saving estimates from the Heating Fuel Choice initiative.

vi. **Forecast of Water Heating Systems in New and Existing Dwellings** – Electric and natural gas water heater saturations and average age were estimated for dwellings with and without natural gas space heat using information from the 2014 Residential Energy Use Surveys. The number of annual replacements was forecast using a Weibull distribution based on the average age of water heaters and switches between fuels were taken into account when forecasting future numbers of water heaters. Saving estimates from the Heating Fuel Choice initiative were included.

vii. **Other End Uses** – Other major uses of residential electricity were forecast by dwelling type, including central air conditioning, major appliances, televisions and lighting using the saturation data from the 2014 Residential Energy Use Survey.

viii. **Determine Overall Average Use** – An econometric model was used to forecast the average annual electricity use per customer of the Residential Basic sector. The Average Use per customer without Demand Side Management (DSM) programs and Codes & Standards (C&S) savings was used as the dependent variable in the model. Historical data from 1992/93 to 2017/18 was modeled.

The resulting model and parameters are:

Model: **Overall Average Use**

Equation: Ln (Total Usage + DSM programs + C&S savings) / Customers

= 6.25 + 1.39 x Saturation – 0.33 x Ln (Price) + 0.31 x Ln (Income) + 0.01 x T(t)

Results:

Model R-Squared	Variable	Coefficient	t-stat
99.5%	Constant	6.25	6.77
	Saturation	1.39	2.16
	Price	-0.33	-5.50
	Income	0.31	3.33
	Trend	0.01	4.51

Term definitions:

Saturation - Electric Heat Customer Count / Total Res Basic Customer Count
Price - Manitoba Real Residential Electricity Price lagged 2.5 years
Income - Manitoba Real Income per Res Basic Customer
T - A trend variable capturing increases in electric use and house size

ix. **Appliance Use and Balancing** – Conditional Demand Analysis using the 2014 Residential Survey data combined with customer annual use from billing data was used to derive average annual energy use by type of heating system and appliance for existing and new dwellings. These average uses were multiplied by the number of each type of system and appliance to get the total energy use. This was balanced against Step 8 results to ensure reasonableness.

x. **Determine Total GWh used** – The forecast number of dwellings multiplied by the overall average use determined the GWh forecast. The forecast of energy savings from Codes and Standards as outlined in Manitoba Hydro's Power Smart Plan were subtracted. Additional energy savings due to the higher adoption of LED lights, and the future adoption of Electric Vehicles in the Residential sector were included. The end result was the forecast of Residential Basic customer total energy use. Excluded are savings attributable to future Demand Side Management initiatives.

General Service Mass Market Methodology

i. **General Service Mass Market Customer Forecast -** Econometric analysis of historical sales data was used to develop models to forecast the number of General Service Mass Market customers. Forecasts of Manitoba Gross Domestic Product (GDP) and Manitoba Hydro Residential Basic Customers were then input into the models to generate forecasts for the number of customers for each year of the forecast period. The number of Small Non-Demand, Small Demand and Medium customers was modeled using yearend historical customer data from 1985/86 to 2017/18.

The resulting model and parameters are as follows:

Model: **GS Mass Market Customer Forecast (Small ND, Small Demand and Medium)**

Equation: Number of Customers at yearend (t) = 35,877 + 0.21 x MGDP + 0.04 x RES

Results:

Model R-Squared	Variable	Coefficient	t-stat
	Constant	35,887	19.63
99.6%	MGDP	0.21	7.99
	RES	0.04	5.67

Term definitions:

MGDP - Manitoba Real Gross Domestic Product
RES - Year end number of Residential Basic Customers

General Service Mass Market customer growth was assigned to Small Non Demand, Small Demand and Medium classes by using their 3 year average use by class and allocating the customers appropriately.

The number of General Service Large customers was modeled using yearend historical customer data from 1989/90 to 2017/18. The resulting model and parameters are as follows:

Model: **GS Mass Market Customer Forecast (Large)**

Equation: Number of Customers at yearend (t) = -298 + 0.01 x CrGDP + 0.0011 x RES

Results:

Model R-Squared	Variable	Coefficient	t-stat
	Constant	-298	-6.48
98.8%	CrGDP	0.01	3.78
	RES	0.0011	6.93

Term definitions:

CrGDP - Manitoba / Canada / U.S. Blended Real Gross Domestic Product
RES - Year end number of Residential Basic Customers lagged 2 years

ii. **General Service Mass Market Average Use Forecast -** Historical Average Use per General Service customer was calculated after removing the effects of DSM and Codes & Standards. The average use of the combined Small Non-Demand (SND), Small Demand (SD) and Medium classes were forecast using an econometric regression model that included Electricity Price and Manitoba GDP. Historical data from 1989/90 to 2017/18 was used.

The resulting model and parameters are as follows:

Model: **GS Mass Market Average Use Forecast (Small ND, Small Demand and Medium)**

Equation: Ln Average Use per GS SND, SD and Medium

= 5.88 – 0.12 x Ln (Elec Price) + 0.55 x Ln (MGDP) + 0.04 x Dummy

Results:

Model R-Squared	Variable	Coefficient	t-stat
98.9%	Constant	5.88	18.94
	Elec Price	-0.12	-3.13
	MGDP	0.55	22.38
	Dummy	0.04	5.08

Term definitions:

Elec Price - SND, SD and Medium Average Real Electricity Price lagged 2 years
MGDP - Manitoba Real Gross Domestic Product
Dummy - "1" up to 2005/06 due to a billing system change causing a reclassification of customers in 2006/07

The Average Use for Large Mass Market customers was forecast in an econometric regression model that used Electricity Price and a blended Manitoba, Canadian, and U.S Real GDP as explanatory variables. Historical data from 1989/90 to 2017/18 was modeled.

The resulting model and parameters are as follows:

Model: **GS Mass Market Average Use Forecast (Large)**

Equation: Ln Average Use per GS Large

= 13.75 – 0.43 x Ln (Elec Price) + 0.30 x Ln (CrGDP) + 0.06 x Dummy

Results:

Model R-Squared	Variable	Coefficient	t-stat
96.6%	Constant	13.75	35.91
	Elec Price	-0.43	-5.79
	CrGDP	0.30	9.75
	Dummy	0.06	5.81

Term definitions:

Elec Price - GS Large Average Real Electricity Price lagged 2 years
CrGDP - Manitoba / Canada / U.S. Blended Real Gross Domestic Product
Dummy - Included from 1999/00 to 2005/06 to reflect the average use of the 750V-30kV group being higher for those years by about 250,000 kWh

The GS Mass Market Small, Medium and Large groups are further subdivided into rate groups that are based on customer's usage. If usage by an individual customer increases (or decreases) sufficiently then they are re-assigned to the appropriate rate group. This action results in the average use of each group to remain relatively stable. For the forecast, the average use of each rate group is held constant. The number of customers in each group is adjusted so that both the total number of customers and overall average use forecast by these models is achieved.

iii. **General Service Mass Market Total Use Forecast** - Total GWh for the General Service Mass Market sector was forecast by multiplying the forecast number of customers in each rate group by the forecast average use. The forecast of energy savings from Codes and Standards as outlined in Manitoba Hydro's Power Smart Plan were subtracted, and the future use of Electric Vehicles in the GS Mass Market sector was added.

General Service Top Consumers Methodology

There are 10 companies counting as 26 customers in the Top Consumers category, covering four industry sectors. Each customer is forecasted individually based on information collected on individual operating plans, including short-term expansion or contraction plans. The sources of information are derived from industry news and publications, company prospectuses, and from Manitoba Hydro's Key and Major Account Advisors. The information collected is used in the preparation of company specific short term forecasts for committed projects. The short- term plans are forecasted to occur within the first five years. For the long-term beyond year five, the energy in year six of each customer is held constant for the remainder of the forecast period.

To account for unexpected load increases or decreases for the current Top Consumers beyond year five, the Potential Large Industrial Loads (PLIL) category was created. PLIL is as an alternative to attempting long-term forecasts for individual Top Consumers. It is based on analyzing the historical changes in energy of the Top Consumers as a group rather than on focusing on individual customers. PLIL endeavors to account for long-term future growth or contraction, including unexpected major expansions, contractions, or potential loss of existing Top Consumer customers.

PLIL is forecast using an econometric model of Top Consumers historical energy activity from 1983/84 to 2017/18. During the historical period, 3 customers joined the Top Consumers sector and only the variations in operating activities were included in the analysis. The model fits the energy to the specific Top Consumers Electricity Price and to a blended Manitoba, Canadian, and U.S Real GDP.

The resulting model and parameters are as follows:

Model: **GS Top Consumer Forecast (PLIL)**

Equation: Ln Total Load = 3.35 – 0.34 x Ln (Top Price) + 0.62 x Ln (CrGDP)

Results:

Model R-Squared	Variable	Coefficient	t-stat
	Constant	3.35	4.43
89.9%	Top Price	-0.34	-2.05
	CrGDP	0.62	9.78

Term definitions:

Top Price - Manitoba Top Consumers Real Electricity Price lagged 1 year
CrGDP - Manitoba / Canada / U.S. Blended Real Gross Domestic Product

The forecasted growth from this model was used in years 6 through 20 as PLIL.

Electric Vehicles

The methodology for forecasting Electric Vehicles trends uses historical data supplied by Statistics Canada and Manitoba Public Insurance on automobile purchases and registrations per year in Manitoba. To help estimate future trends, appropriate assumptions from recent relevant literature were applied to Manitoba's situation. The forecast section on Electric Vehicles provides further details.

Other Sectors

Seasonal, Water Heating, Lighting

Most of the smaller sales sectors, including Seasonal, Flat Rate Water Heating and Area and Roadway Lighting were forecast by analysis of the changes in the number of customers or services and in changes in average use per customer or service. Growth rates were applied based on history and a best estimate as to what the future will bring.

Diesel

Each of the diesel generated supplied communities was individually forecast and included in the forecast under the assumption that these communities are not anticipated to be connected to the Integrated System during the forecast period.

Monthly Sales Allocations

Monthly percentages of customer growth through the year and GWh for each month of the year were averaged for the past three to five years. The most appropriate growths were applied to the forecasts of annual customers and GWh to get the monthly forecasts.

Monthly and Annual Gross Firm Energy and Gross Total Peak

The 5 year monthly percentage of Common Bus and Station Service are applied to their annual energy to calculate their monthly values. Transmission Losses are calculated using a 5 year average of their ratio to Common Bus. Monthly Common Bus, Transmission Losses and Station Service are added up to give the Monthly System Energy. Monthly Common Bus, Transmission Losses, Station Service and Gross Firm Energy are totaled to give the Annual Gross Firm Energy.

The Gross Total Peak is calculated from Load Factors applied to the forecast monthly Gross Total Energy. Prior to calculating the Load Factors, the Top Consumer energy and peak are subtracted because the Top Consumers have a higher average hourly energy relative to their peak value than the Residential and General Service Mass Market Customers. A 10 year historical average Load Factor is calculated for the remaining energy and is applied to the forecast monthly energy to get the peaks for the remaining energy. The Top Consumer peaks are added using a 92% Load Factor applied to the Top Consumer monthly energy.

The annual Gross Total Peak is calculated using the 3 winter months of December, January and February when the actual peak has typically occurred and applied a ratio from the January peak to be used as the annual peak.

Historical weather adjusted energy is used to calculate the annual Load Factor. The historical trend of the load factor increasing 0.08% per year is applied to the forecast in the winter months when the annual system peak occurs. The number of hours in each month is used to calculate monthly Load Factors.

Growth Rates

Annual GWh/year growth rates in this document are linear growth rates, calculated as: GWh growth / number of years.

Annual percentage growth rates in this document are compound growth rates calculated as: (final GWh / initial GWh) ^ (1 / number of years) – 1.

GLOSSARY OF TERMS

Area and Roadway Lighting sector - includes electricity sales for the Sentinel Lighting and Street Lighting rate groups.

Common Bus - is the total load measured from all the distribution points (i.e. substations) within Manitoba. It includes all energy supplied to General Consumers Sales customers, Construction Power plus associated Distribution Losses, but excludes Diesel customers, Transmission Losses and Station Service.

Customer – Most metered electrical services count as a customer. Unmetered services such as flat rate water heating and sentinel rental services do not count as a customer. Street lighting counts all the services grouped as a premise as one customer.

Codes and Standards – A Demand Side Management (DSM) initiative associated with existing Provincial building codes and improved equipment efficiency standards. This is the only DSM initiative that is specifically accounted for in the forecast.

Curtailable - is a load that can be curtailed on short notice. A discount is given for subscribing to this program. Curtailable loads can affect peak demand because some periods of curtailment may be at or near the system peak.

Gas Available Area – A city or town in Manitoba where customers have natural gas service available and can choose to heat their dwelling with either natural gas or electricity. Approximately 83% of Residential Basic customers, including the entire city of Winnipeg, have gas available.

General Consumers Sales - includes the energy supplied to all of Manitoba Hydro's individually billed customers. It excludes export sales.

General Service Mass Market - includes all Commercial and Industrial customers, excluding the Top Consumers group.

General Service Sector - made up of sales to Commercial and Industrial businesses served by Manitoba Hydro. This sector consists of five rate groups (Basic, Diesel, Seasonal, Flat Rate Water Heating and Surplus Energy Program).

General Service Top Consumers - is made up of the largest electricity users of Manitoba Hydro.

Gross Firm Energy - is the energy required to serve Manitoba Hydro's customers on the Integrated System. It excludes exports, interruptible (non-firm) loads and diesel customers.

Gross Total Peak - is the maximum integrated (i.e. average) hourly load required to serve Manitoba Hydro's customers on the Integrated System. It excludes exports and diesel customers. It includes curtailable loads.

GWh (gigawatt-hour) - The unit of energy primarily used in this document. One GWh equals one million kWh (kilowatt-hours), which is approximately equal to the energy of 100 typical dwellings not using electricity for heating, or 40 dwellings that use electricity for heating.

Integrated System - is the power grid that connects Manitoba Hydro's generation sources to its customers. All Manitoba Hydro's customers except diesel are on the Integrated System.

Interruptible (Non-Firm) Energy - includes all energy sold to Manitoba customers on a non-firm basis. Currently, the only rate group for this is the Surplus Energy Program (SEP).

kWh/cust (kilowatt-hours per customer) - The unit of energy primarily used in this document to represent the average use of one customer. The total usage in GWh of a group of customers is divided by the number of customers and then multiplied by one million.

Load Factor - is the ratio of the average hourly energy over a period, usually a year, divided by the energy used at a specific hour, usually the hour of system peak. A load factor of 25% means that the average energy is one-quarter of what is used at system peak. A load factor greater than 100% means that the average hourly energy is more than what is used at system peak. Given a specific energy, a lower load factor means a higher peak. The equation is:

Load Factor = (Total Energy / Hours) / (Energy over the hour of system peak)

Manitoba Load at Common Bus - is the total load measured from all the distribution points (i.e. substations) within Manitoba. It includes all energy supplied to General Consumers Sales customers plus associated Distribution Losses, but excludes diesel customers, Transmission Losses and Station Service.

MW (megawatt) - The unit of peak demand primarily used in this document. One MW is a million watts. One thousand MW of peak demand for one hour equals one GWh of energy. Alternatively, one MW for a thousand hours also equals one GWh of energy.

Net Firm Energy and Net Total Peak - are the same as Gross Firm Energy and Gross Total Peak except they exclude Station Service. The reporting of Manitoba Load in the Load Forecast used "Net" until 2008. It presented both until 2011. Starting with the 2012 forecast, only the "Gross" is presented. Net can be calculated when needed by subtracting Station Service from the Gross.

Residential Basic – is the primary residential customer group made up of single detached and multi attached dwellings as well as individually metered apartment suites.

Residential sector - made up of sales to residential customers for non-business operations. The Residential sector is comprised of four rate groups (Basic, Diesel, Seasonal, and Flat Rate Water Heating).

Station Service - is the energy used by power plants to generate power and service their own load.

2018 Electric Load Forecast

*Manitoba Hydro is a licensee of the Trademark and Official Mark.

Tab 58

Demand Side Management (DSM) in the Manitoba Public Utility Board's (PUB's)Needs-For and Alternatives-To (NFAT) Review of Manitoba Hydro's (MH's)Development Plan

Russ Houldin

Elenchus Research Associates

April 2, 2014

Overview

- Purpose of evidence
  - To address the issues in the MPUB Scope of Work (SOW) on DSM
- General issues
  - Key messages
- Scope of Work (SOW) responses

Key Messages

- MH's approach to DSM is reasonable
  - Comparable to other North American utilities
- DSM on its own has minimal impact on the timing of Keeyask
- MH's approach could be improved
  - Move back to full Integrated Resource Planning (IRP)
    - Change delivery model (government decision)
  - Conduct studies to check assumptions
  - Model uncertainty explicitly
  - Multiple accounts evaluation could be made more complete
- The suggested improvements could affect Conawapa In-Service Date (ISD)
  - An opportunity for MH to keep up with the evolution of the incorporation of EE into system planning

Energy Efficiency Lexicon

- Energy Efficiency (EE) – use of technologies that use energy more efficiently
- Conservation – education to change consumer behaviour
- Soft path – combination of EE and renewables
- Conservation and Demand Management (CDM) – programs that combine EE and conservation
- DSM – programs that deliver estimated customer savings through EE measures
- END-USE – the energy used by energy services
- Energy services- the services that energy performs (heating, cooling, lighting, mechanical action, process-specific, electricity specific)
- MEASURE - a component of a CDM or DSM program
- IRP – a method of treating supply and demand-side measures equivalently

Conceptual Framework

DSM SAVINGS AT TIME T *= SUM OVER ALL END-USE MEASURES OF:
(REFERENCE END-USE MEASURE TERTIARY ENERGY MINUS
EFFICIENT END-USE MEASURE TERTIARY ENERGY)*
(NUMBER OF END-USE MEASURES)

*E.G. 2014

TERM IN THIS BRACKET CANNOT BE MEASURED DIRECTLY; INFERRED FROM EITHER, BASELINE DATA OR ENGINEERING ASSUMPTIONS OR BOTH

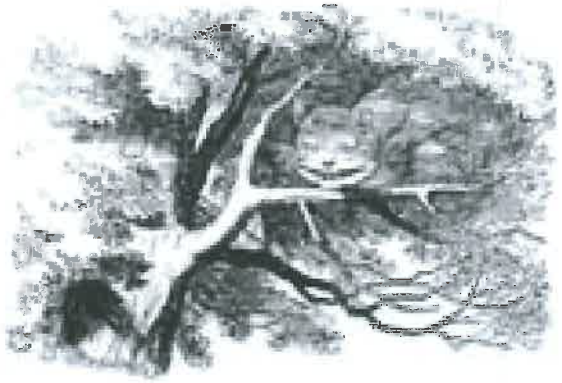
NUMBER OF END-USE MEASURES IS USUALLY DECOMPOSED AS:
NUM BER OF END-USE MEASURES = POPULATION OF SERVICES
PROVIDED BY END-USE MEASURE*SATURATION LIMIT (%)*PENETRATION (%)

THESE TERMS REQUIRE ASSUMPTIONS ABOUT MARKET BEHAVIOUR

DSM SAVINGS AT T+1 = DSM SAVINGS AT TIME T*DECAY RATE(%)

The Cheshire Cat: Central Concern with DSM

- DSM is the preferred institutional form of Energy Efficiency
  - Other forms; Energy Service Companies (ESCOs), pure incentive programs, education, codes and standards
- DSM savings cannot be measured
  - We cannot observe what might have happened
- Using baseline or engineering estimates has an inherent uncertainty
  - Underlying tertiary energy use
  - Assumptions about market response

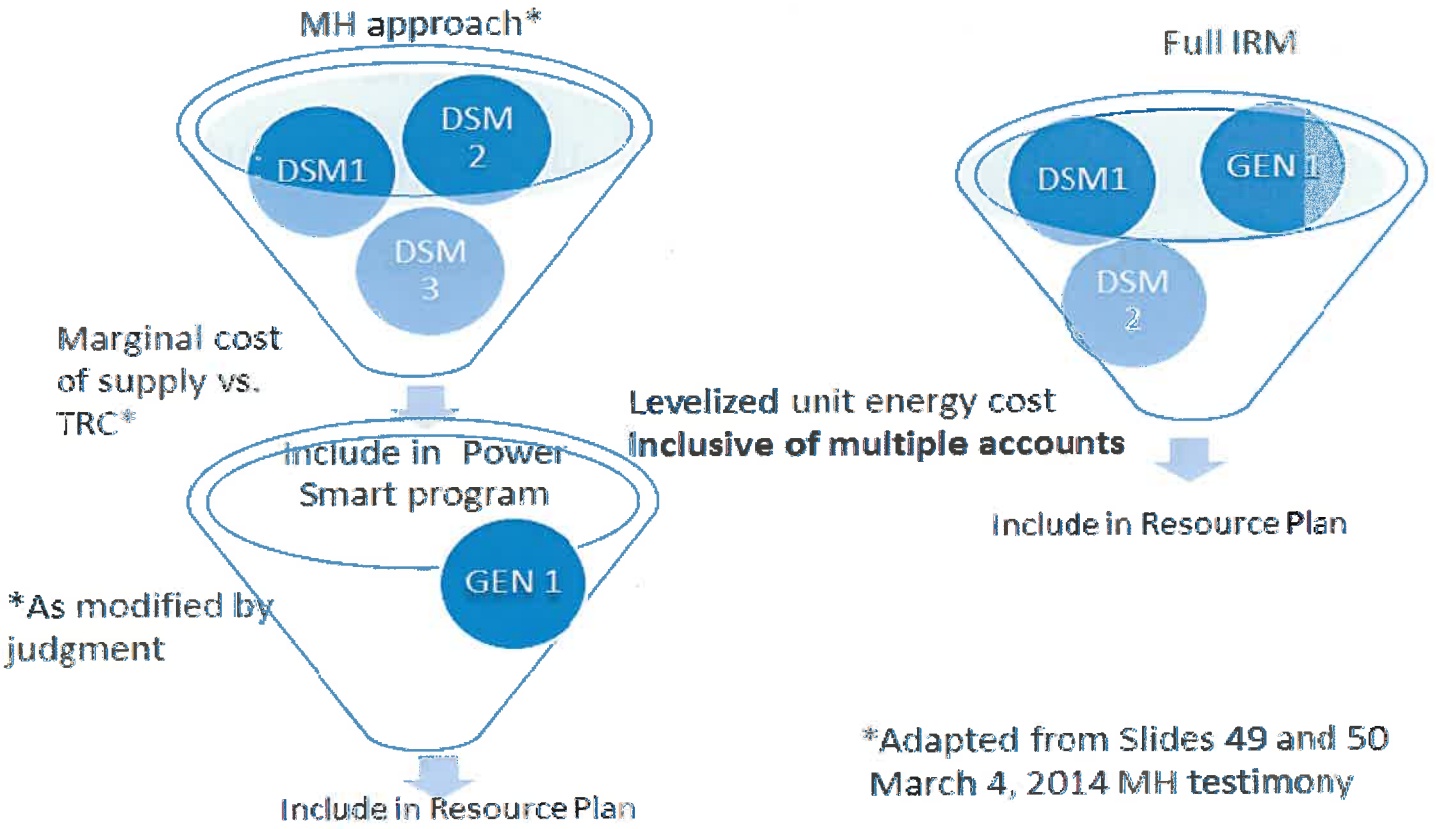


Elenchus

DSM and System Planning

- A fundamental asymmetry between DSM savings estimates and supply estimates
- If DSM is underestimated capacity is not dispatched
  - Cost: underutilization
  - For MH firm export opportunities may be foregone
- If DSM is overestimated and capacity is not built this may increase the risks of brownouts and-or blackouts

How Does MH's DSM Approach Differ From "Full" IRP ?



*Adapted from Slides 49 and 50 March 4, 2014 MH testimony

elenchus

Coherence and Load factors

- Load factor suggested as a qualitative diagnostic tool for NFAT
  - Not "DSM demand and energy savings must be in the same proportions as system load"(MH Rebuttal p42l36)
  - Do the bottom-up DSM savings projections from Power Smart "hang together" with system planning and with 'top down' stress testing?
    - MH's system load factor is coherent
    - The system load factor and DSM load factors are coherent
      - Other than Curtailable Rates program, load factor differences are plausible

Projected & Historical Load & Capacity Factors & Capacity Reserve

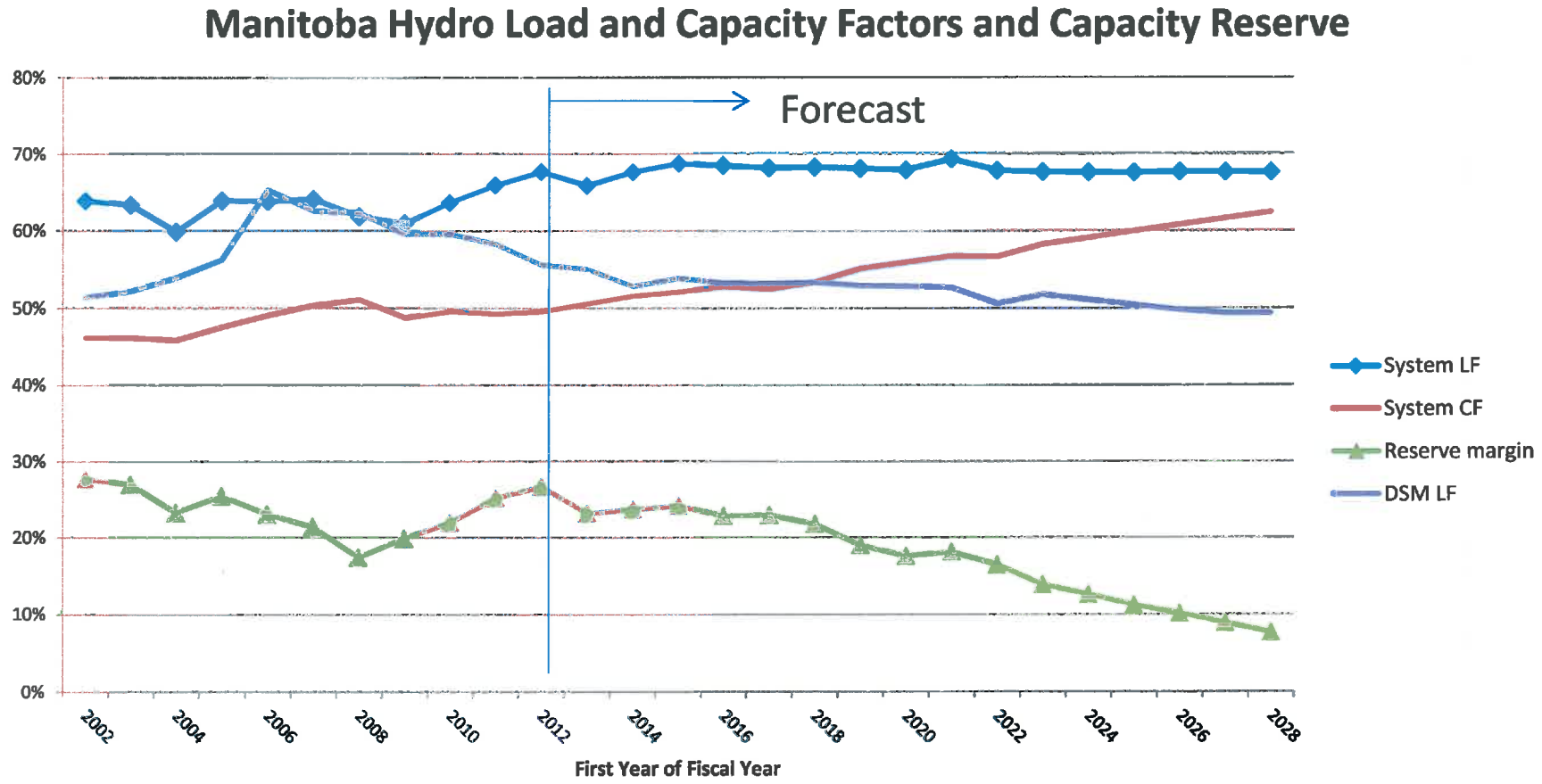


Figure 2 Elenchus DSM Report p 4

elenchus

What Are the Uncertainties of DSM Savings Estimates?

- While there is no doubt that rates of load growth have declined from the 1950-70 rates, there is no consensus on the relative contributions of:
  - Price effects (including substitution);
  - Income effects (including the rebound effect);
  - Autonomous technological change ;
  - Customer preferences;
  - Impact of 'conservation' messages;
  - Codes and standards; and
  - DSM and other EE programs.

How Can DSM Uncertainties Be Handled?

- Need to acknowledge explicitly the uncertainties and the asymmetry problem
- Treat DSM estimates similarly to wind power
  - System operators are building up knowledge of the statistical distributions of wind output and use this to establish **expected values** for wind output that are equivalent to generation
  - Use methods from experimental theory
  - Improve knowledge of tertiary end use energy by retrospective statistical studies of DSM participants and non-participants

Why then, Should you Accept Dunsky and ENERNOC`s Evidence?

- The evidence of Dunsky and ENERNOC are "state of the art" for DSM
- But there are concerns with DSM
  - Measurability problem
  - Assumptions about markets
  - Institutional ambiguity
- This creates inherent uncertainty
- Should not throw out specific EE with the general DSM bathwater

Babies and Bathwater

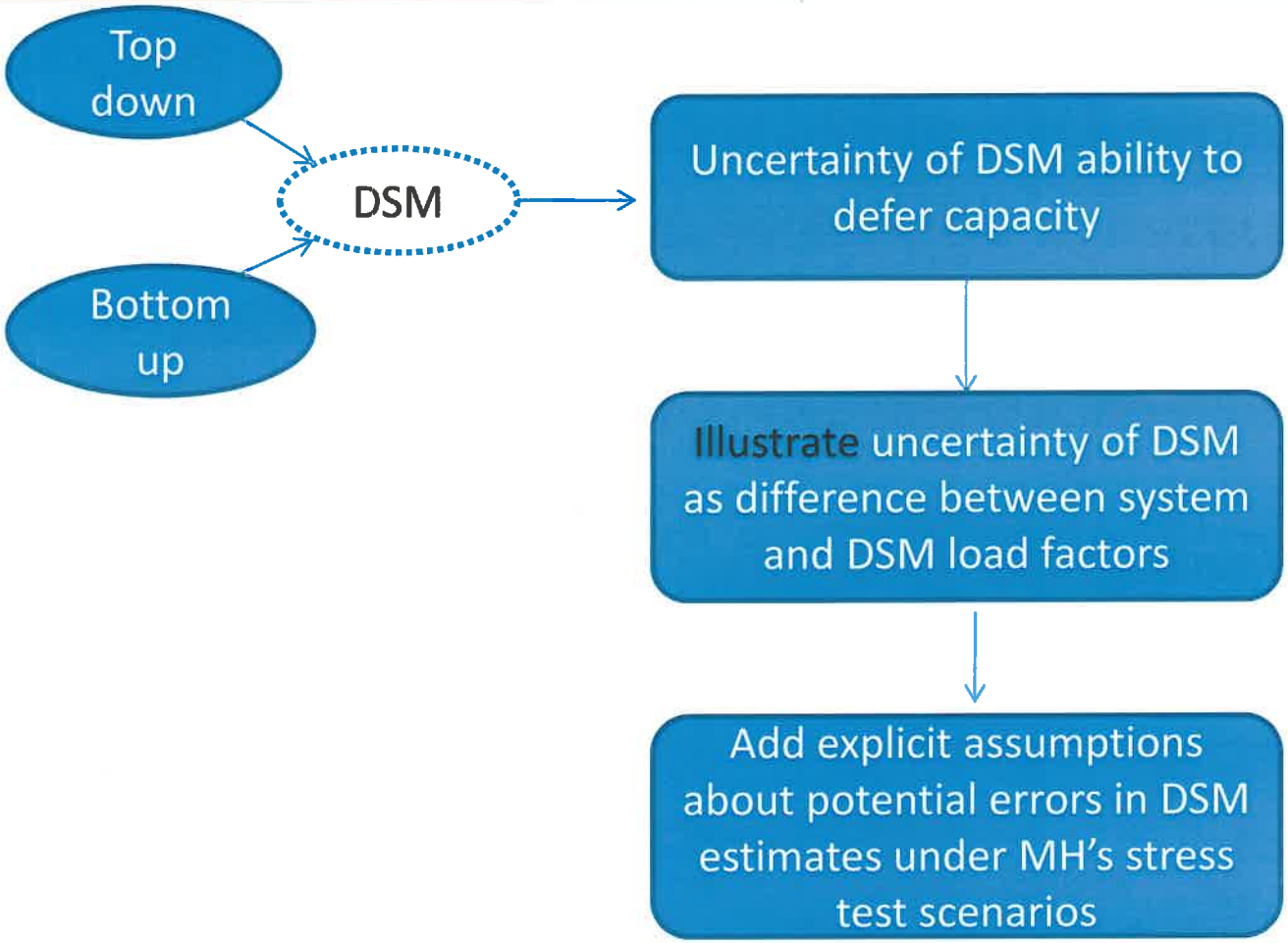
- The flaws of DSM and its uncertainties should not blind utilities to the value of EE
- There is a large body of evidence that EE can `supply` a substantial amount of electricity services below the cost of new generation
  - While "barriers" to DSM analysis overstates the issues, it is reasonable to provide some degree of public support for EE
- Need simply to apply the best available evidence of DSM savings with an acknowledgement of uncertainties and the asymmetry problem, preferably with IRP

Stress Testing

- Elenchus' stress-testing builds on MH's top-down analysis
  - 1.5, 2, 3 and 4 times DSM (not multiples of spending on DSM*)
  - No imports or exports
- Under the assumption that the difference between system and DSM load factors results in overestimate of capacity (versus energy) as an **illustration** of uncertainty
- **Illustrative** examples of introducing arbitrary uncertainty assumptions – impact on capacity reserve
  - Manitoba only, no credit for load curtailment

*See SOW 12: MH's analysis was not based on multiples of spending (Exec Summary p31l25)

Logic of Stress Test



Heuristic Stress Test of MH's DSM Analysis (Updated)

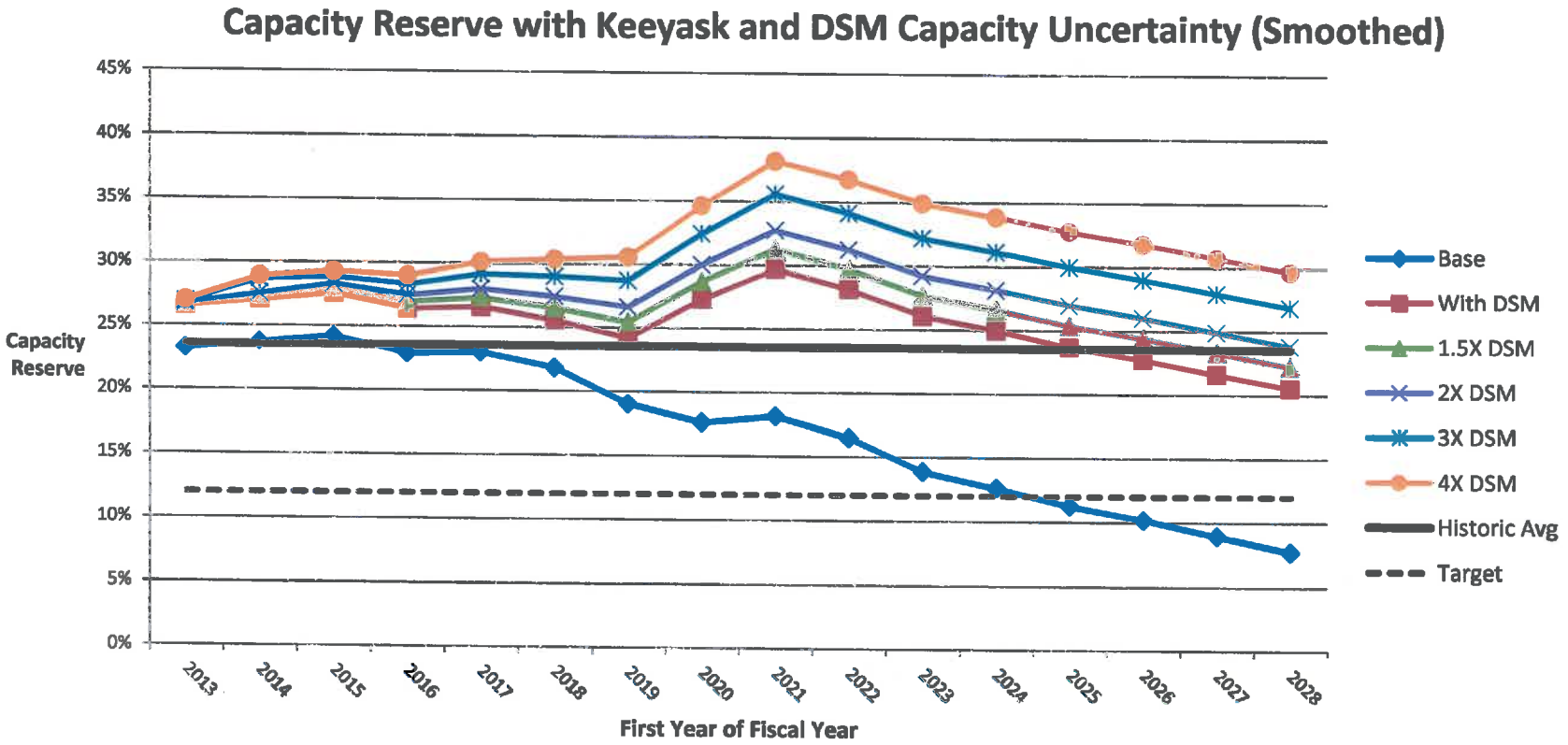
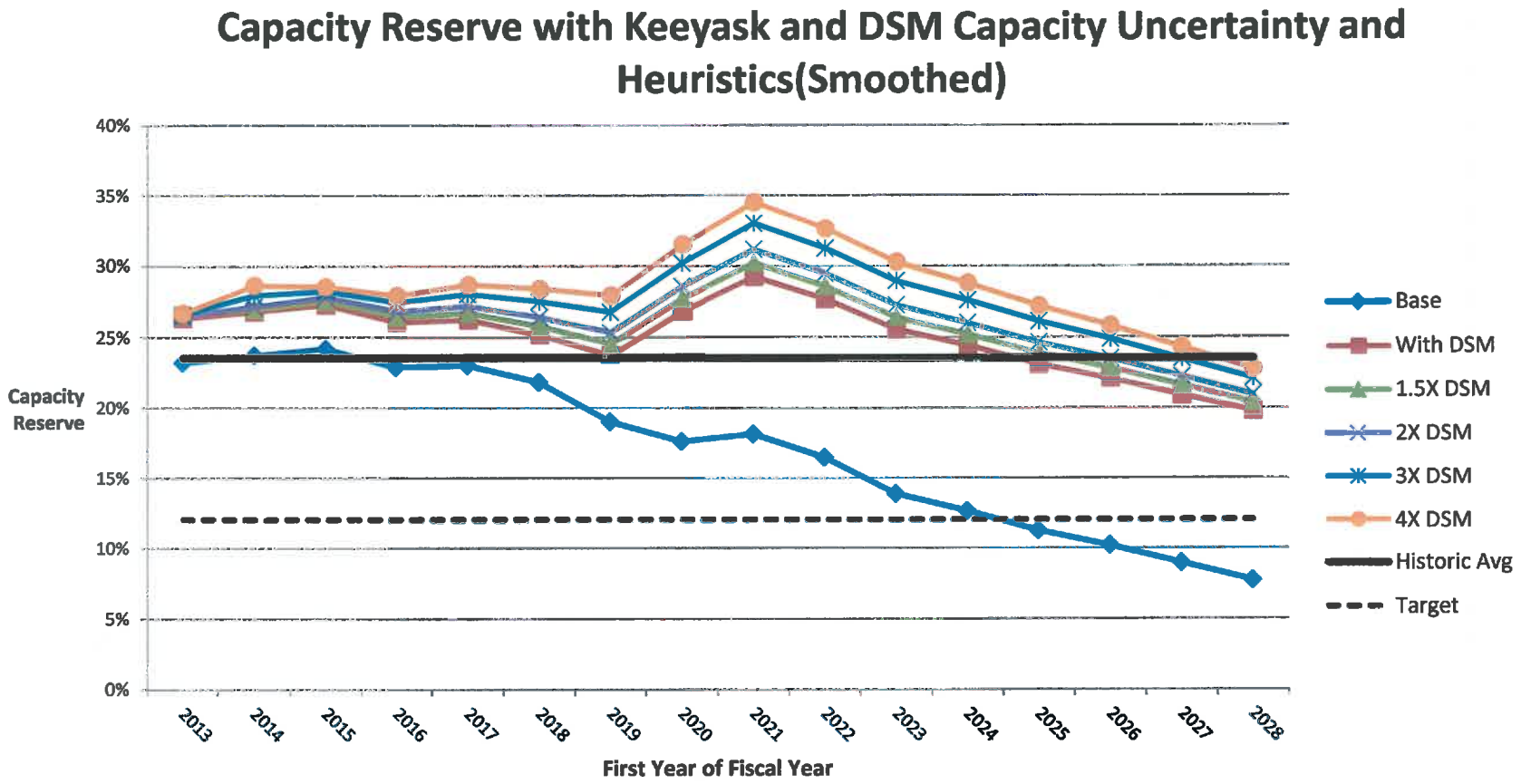


Figure 6 Elenchus DSM Report p 24

Heuristic Stress Test of MH's DSM Analysis (Updated)



Achievable potential declines at 2% pa for 1.5X case, 2.5% for 2X,3% for 3X and 3.5% for 4X

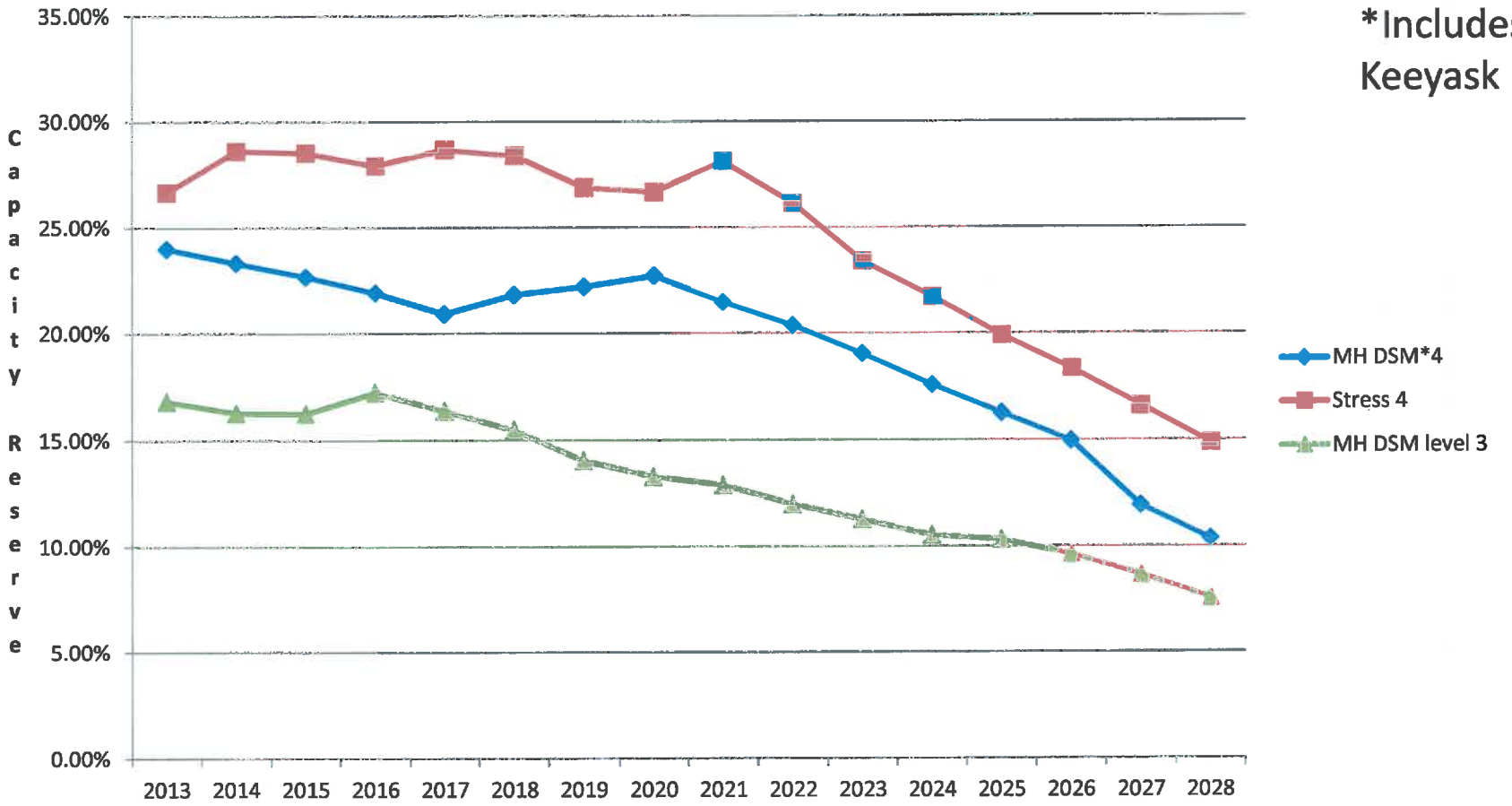
elenchus

Figure 7 Elenchus DSM Report p 25

Stress Testing Conclusions

- Simulations of uncertainties for top-down DSM savings scenarios show that MH`s analysis is robust
- DSM has a minimal impact on the timing of Keeyask
- Conawapa could be modestly affected
- Conclusions unaffected by new MH DSM analysis

Comparison of Updated Business Plan MH Scenarios (No New Resources) and Elenchus*



*Includes Keeyask

Refs:DSM4-Appendix 4.2p154;
Levl 3 - pp 21 and 23 of Exh 104-3

Elenchus

Ecological Footprint (EF)

- EF is only one methodology
- Two types: index or qualitative or single metric, e.g.
  - Single metric
    - Economic benefit-cost analysis ($s)
    - Net energy analysis (GJ, kWh etc.)
  - Index or qualitative
    - Environmental impact matrix
    - Sustainability analysis
- MH's multiple accounts approach is incomplete
  - MH's rebuttal also incomplete (p113 l14-22)
    - Good to avoid being driven to greater levels of detail
    - But need to evaluate all alternatives on commensurate data

Are Manitoba Hydro's Demand-Side Management Factors Complete, Reasonable and Accurate?

- Yes
- While MH does not itself refer to "DSM factors", MH's approach to DSM is complete, reasonable and accurate.

SOW 1; Elenchus DSM Report section 3.2.2

elenchus

Review MH's assessment of technical, economic and real DSM and energy efficiency opportunities relative to other jurisdictions

- MH's assessment of DSM opportunities is comparable to other North American jurisdictions.

SOW 2; Elenchus DSM Report sections 3.2.2 , 3.3.2.2 and 3.3.2.3

Review the extent to which MH has designed and implemented large utility DSM and energy efficiency programs at the residential, commercial and industrial levels in a manner consistent with other North American jurisdictions where such programs have been implemented

- MH's DSM programs for the major customer segments (residential, commercial and industrial) are consistent with utility practices in North America.

SOW 3; Elenchus DSM Report sections 3.2.1 and 3.2.2

Comment on the proper use of TRC and RIM evaluation tools as well as a TSC and benefit analysis from DSM and energy efficiency opportunities

- MH uses TRC, RIM and TSC in manner consistent with North American utility practices in relation to DSM and its consideration of other benefits is reasonable.

SOW 4; Elenchus DSM Report sections 3.2.1 and 3.2.2

Comment on MH's approach to measuring actual DSM and energy efficiency savings

- MH follows accepted industry protocols but these could be improved.
- Specifically, industry protocols do not adequately recognize inherent uncertainties due to un-observability of DSM savings

SOW 5; Elenchus DSM Report sections 3.3. 1.1 and 3.3.2.1

Comment on the appropriateness of MH's adoption of smart grid technologies for DSM

- MH's adoption of smart grid technologies for DSM is appropriate

SOW 6; Elenchus DSM Report section 3.4

Comment on MH's approach to determining marginal costs for measuring DSM

- MH follows accepted industry practice in basing its estimates of DSM marginal costs on reference standard technologies. However, this approach adds to the uncertainty of estimates of actual DSM potential.

SOW 7; Elenchus DSM Report sections 3.2.1.1 and 3.2.2.1

Comment on MH's approach to managing DSM and energy efficiency lost opportunity revenues

- MH includes estimated export revenues in its evaluation of DSM opportunities as part of its multiple metrics approach
- While reasonable, this also adds to uncertainty

SOW 8; Elenchus DSM Report section 3.3.2.6

Comment on the reasonableness, thoroughness and soundness of MH's DSM and conservation forecasts

- MH's DSM forecasts are reasonable, thorough and sound but their uncertainty could be made more explicit and addressed in an improved way.

SOW 9; Elenchus DSM Report sections 3.3.1 and 3.3.2

Comment on whether the preferred and alternative resource and conservation evaluations are complete, accurate, thorough, reasonable and sound.

- The preferred and alternative resource and conservation evaluations are largely complete, accurate, thorough, reasonable and sound.
- There is uncertainty over the accuracy of DSM savings and the evaluation would be more complete if the environmental impacts of DSM programs were evaluated.

SOW 10; Elenchus DSM Report sections 3.3.1, 3.3.2 and 4

Critically Assess Manitoba Hydro's DSM Potential Study

- The DSM Potential Study is a state-of-the-art study but its approach glosses over key uncertainties.
  - Fundamentally DSM savings estimates cannot be falsified
  - Market barriers analysis overstates importance of barriers
  - Evidence from private ESCOs suggests consumers are not willing to pay for DSM for savings kevels typically reported by participating utilities

SOW 11; Elenchus DSM Report section 3.3.2.2

Perform independent stress testing of Demand-Side Management levels and an assessment of the reasonableness of Manitoba Hydro's stress testing of 1.5 and 4 times Demand-Side Management spending

- Elenchus' stress testing of DSM levels supports MH's conclusion that DSM programs are not sufficient to justify the deferral of new hydro-electric capacity

SOW 12; Elenchus DSM Report section 3.3.2.4

Examine Manitoba Hydro's current and potential use of Demand-Side Management investments in terms of:

a) System Capacity Dispatchability

- MH treats DSM capacity as non-dispatchable and 100% dependable. Elenchus suggests that DSM should be treated as a non-dispatchable resource subject to **explicit** dependability factors.

SOW 13a; Elenchus DSM Report sections 3.3.1.2 and 3.3.2.5

Examine Manitoba Hydro's current and potential use of Demand-Side Management investments in terms of:

b) Dependable Energy Dispatchability

- MH treats DSM energy as non-dispatchable and 100% dependable. Elenchus suggests that DSM should be treated as a non-dispatchable resource subject to **explicit** dependability factors.

SOW 13b; Elenchus DSM Report sections 3.3.1.2, 3.3.2.5 and 3.3.2

Examine Manitoba Hydro's current and potential use of Demand-Side Management investments in terms of:

c) Backup Resources Required

- MH makes no provision for backup. For operating reserve this is appropriate but for capacity reserve MH should treat DSM as a non-dispatchable resource subject to **explicit** dependability factors.

SOW 13c; Elenchus DSM Report sections 3.3.1.2 and 3.3.2.5

Examine Manitoba Hydro's current and potential use of Demand-Side Management investments in terms of:

d) Cost Effectiveness

- MH considers the cost effectiveness of DSM in terms of the Total Resource Cost (TRC), Total Societal Cost (TSC),Levelized Utility Cost (LUC). These are appropriate tests.

SOW 13d; Elenchus DSM Report sections 3.2.1, 3.2.2, 3.2.1.1 and 3.2.2.1

Examine Manitoba Hydro's current and potential use of Demand-Side Management investments in terms of:

e) Carbon Dioxide Footprint

- While MH has made a thorough assessment of the CO2 impacts of new generation it has not looked at the lifecycle impacts of DSM
- If MH conducts a new assessment of Conawapa could consider an Ecological Footprint analysis as an alternative to its "multiple accounts" approach

SOW 13e; Elenchus DSM Report section 3.5

Examine Manitoba Hydro's current and potential use of Demand-Side Management investments in terms of:

f) The role of the Curtailable Rate (*sic*) (CR) Program (Peak)

- The Curtailable Rates program should play no role in since reliance on the capacity reductions would be imprudent
- Elenchus makes no comment on its other purposes
- MH's position on the treatment of (LC) as part of the DSM program is unclear
  - "Manitoba Hydro does not include the demand benefits available from the Curtailable Rates Program in the assessment and development of its Resource Plan." rebuttal p47l10
  - "Given industry-wide acceptance of demand response as a recognized DSM initiative, it would also appear to be reasonable to then also consider Manitoba Hydro's Curtailable Rates Program as a DSM initiative." p43l18

SOW 13f; Elenchus DSM Report sections 3.2.1.2 and 3.2.2.2

Examine Manitoba Hydro's current and potential use of Demand-Side Management investments in terms of:

g) The Role of the Surplus Energy (SE) Program

- The SE program plays no role in DSM.
- Elenchus makes no comment on its other purposes.

SOW 13g; Elenchus DSM Report sections 3.2.1.3 and 3.2.2.3

Examine Manitoba Hydro's current and potential use of Demand-Side Management investments in terms of:

h) Location of DSM

- MH uses qualitative factors as well as metrics in designing its DSM programs. Location could be a factor but Elenchus is not aware of this.

SOW 13h; Elenchus DSM Report section 3.3.2.7

Identify the potential of DSM or energy efficiency to defer new generation in Manitoba, including Keeysak G.S. and or Conawapa G.S. alone or in conjunction with other non-hydraulic resources

- DSM is not likely to defer Keeyask or Conawapa, alone or in conjunction with other non-hydraulic resources

SOW 14; Elenchus DSM Report section 3.3.2.4

Review and comment on the evidence with respect to Demand-Side Management arising from the last Manitoba Hydro General Rate Application, including the role of Demand-Side Management in deferral of Generation Investments put forth by the Consumer Association of Canada (Manitoba) Inc.'s expert witness. (Dunsky)

- Elenchus agrees with Dunsky's benchmarking of MH's DSM programs

SOW 15; Elenchus DSM Report section 3.3.2.3

Thank You!

Tab 59

A Review of Manitoba Hydro's Electric Load Forecasting
a 5 January 2018 presentation to the Manitoba Public Utilities Board
delivered by Dr. Garland Laliberte on behalf of the Bipole III Coalition
in the matter of Manitoba Hydro's 2017-18 and 2018-19 General Rate Application

Preamble:

For several years, Manitoba Hydro filed forecasts for electric load in support of its General Rate Applications that were well above forecasts published by other utilities in North America and that turned out to be well above actual experience as time advanced.[1] Its filed forecasts for Demand Side Management (DSM), on the other hand, have been inconsistent, frequently changing during hearings conducted in connection with these applications.

This presentation will show that the pattern of over-forecasting, in evidence for several years beginning about a decade ago, began to change shortly after Manitoba Hydro obtained approval for system expansion and licenses were granted for key elements of that expansion even though there was evidence for several prior years that electric load forecasts were not being met. It documents Manitoba Hydro's current and recent forecasts for electric load comparing them with historic records. Both Gross Firm Energy and Gross Total Peak are considered.

It also documents the impact of DSM as planned by Manitoba Hydro and as mandated by the Efficiency Manitoba Act. In all cases, at-generation values of electric load are used. Except for DSM mandated by Efficiency Manitoba, all data used are taken directly or calculated from Manitoba Hydro's submissions to the Manitoba Public Utilities Board (PUB).

The Efficiency Manitoba Act sets targets for energy but fails to set targets for peak load. DSM mandated by Efficiency Manitoba for energy is projected forward at 1.5% per year beginning with a 2017/18 value of Gross Firm Energy calculated from regressed weather-adjusted values reported by Manitoba Hydro for the most recent 10 historic years. No DSM savings for peak load are calculated for Efficiency Manitoba.

[1] Presentation by the Bipole III Coalition to the Needs For and Alternatives To (NFAT) review of Manitoba Hydro's Preferred Expansion Plan by the Public Utilities Board submitted on February 3, 2014 and accessible at http://www.pubmanitoba.ca/v1/nfat/pdf/bipole_3_nfat_presentation.pdf.

Recent Electric Load Forecasts Compared to 20-year Historic Data:

Figures 1 and 2 present graphs of 20 years of historic weather-adjusted data for Gross Firm Energy[2] and Gross Total Peak[3], respectively. Figures 1 and 2 also present graphs of (at-generation) values of Gross Firm Energy and Gross Total Peak forecast by Manitoba Hydro in 2015[4], 2016[5] and 2017.[6] The forecast values for 2015 and 2016 are identified in these figures as MH15 Forecast (orange line) and MH16 Forecast (grey line), respectively. For clarity, the current forecast, referenced as either MH16 or MH16 Update in Manitoba Hydro's submissions for the current Application, is identified, in this presentation, as MH17 Forecast (yellow line). The data for these graphs are presented in Tables 1 and 2 at the end of this presentation.

---

2 Weather-adjusted values for Gross Firm Energy from Manitoba Hydro 2017/18 and 2018/19 General Rate Application Tab 7: Appendix 7.1 (2016 Electric Load Forecast), Table 29, page 47/82, and also Tab 11: Public Utilities Board (PUB) Minimum Filing Requirements, PUB MFR 65 (Updated) (2017 Electric Load Forecast), Table 1, page 404/1382.

3 Weather-adjusted values for Gross Total Peak from Manitoba Hydro 2017/18 and 2018/19 General Rate Application Tab 7: Appendix 7.1 (2016 Electric Load Forecast), Table 32, page 49/82, and also Tab 11: Public Utilities Board (PUB) MFRs, PUB MFR 65 (Updated) (2017 Electric Load Forecast), Table 1, page 404/1382.

4 MH15 Forecast values of Gross Firm Energy and Gross Total Peak from Manitoba Hydro 2015/16 and 2016/17 General Rate Application Attachment 25 (2015 Electric Load Forecast and Power Smart Plans MFR 1), Table 2, page 6/81, and also from Manitoba Hydro 2017/18 and 2018/19 General Rate Application Tab 7, Appendix 7.1 (2016 Electric Load Forecast), Table 2, page 6/82, updated in PUB-MH I-56a-c Revised) filed by Manitoba Hydro as Exhibit MH70 on 7 December 2017.

5 MH16 Forecast values for Gross Firm Energy and Gross Total Peak from Manitoba Hydro 2017/18 and 2018/19 General Rate Application Tab 7, Appendix 7.1 (2016 Electric Load Forecast), Table 1, page 5/82, and Table 2, page 6/82, updated in PUB-MH I-56a-c Revised) filed by Manitoba Hydro as Exhibit MH70 on 7 December 2017.

6 MH17 Forecast values of Gross Firm Energy from Manitoba Hydro 2017/18 and 2018/19 General Rate Application Tab 11: Public Utilities Board (PUB) Minimum Filing Requirements, PUB MFR 65 (Updated) (2017 Electric Load Forecast), Table 1, page 404/1382, updated in PUB-MH I-56a-c Revised) filed by Manitoba Hydro as Exhibit MH70 on 7 December 2017.

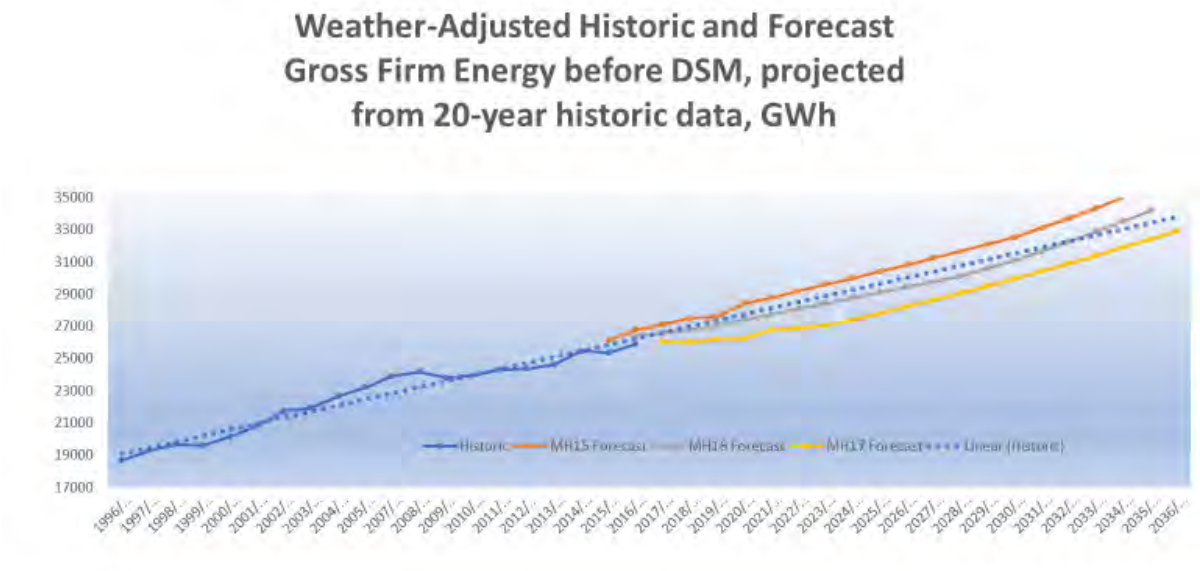


Figure 1: Weather-adjusted historic and forecast Gross Firm Energy before DSM, projected from 20-year historic data.

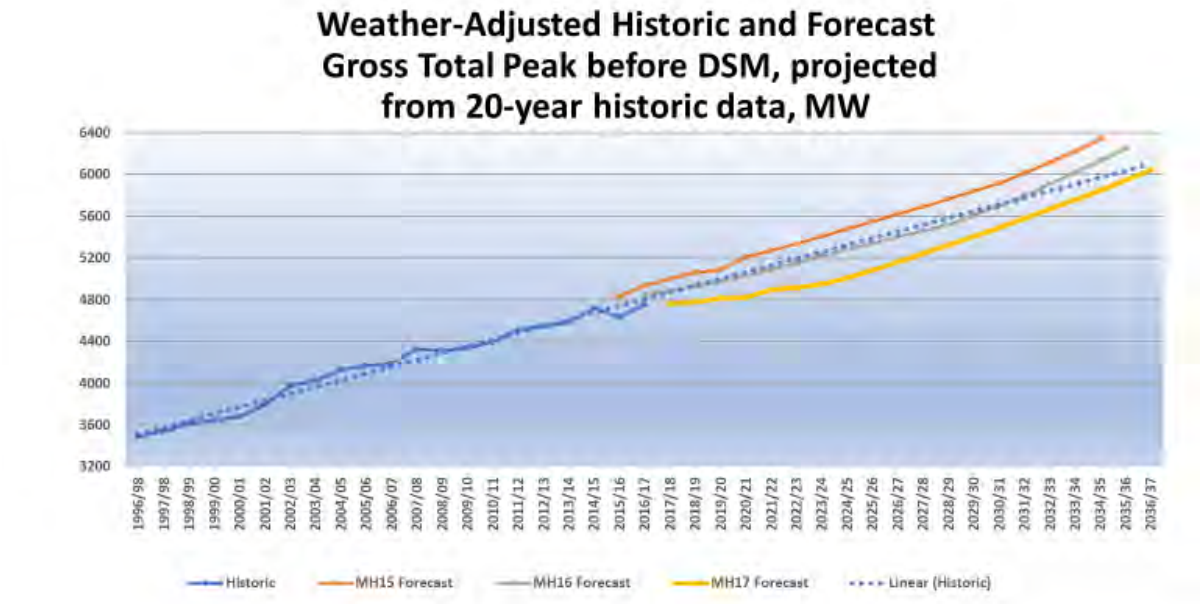


Figure 2: Weather-adjusted historic and forecast Gross Total Peak before DSM, projected from 20-year historic data.

The dotted line identified in both Figure 1 and Figure 2 as “Linear (Historic)” is the result of linear regression analyses of 20 years of data for Gross Firm Energy and Gross Total Peak, respectively.

The linear regression lines are extended forward to allow comparison of forecasts in 2015, 2016 and 2017 with past historic trends.

Some observations are possible from these graphs.

- Manitoba Hydro's recent forecasts for Gross Firm Energy and Gross Total Peak (2015 to 2017) are a reasonable reflection of the past, as long as 20 years of history is considered.

- Manitoba Hydro's forecasts of both Gross Firm Energy and Gross Total Peak have been decreasing in recent years.

- Generally, values forecast for both Gross Firm Energy and Gross Total Peak for several future years of its 2015 forecast are now not expected to be reached until two to seven years later.

- If the historic trends are examined more closely, growth for both Gross Firm Energy and Gross Total Peak does not appear to have been uniform over the 20-year historic period. For both energy and peak power but particularly for Gross Firm Energy, growth appears to have slowed down in the second half of this 20-year period compared to the first half.

Because recent trends are more likely to be a reasonable basis for forecasting than trends that are up to 20 years old, comparison of recent forecasts of electric load with more recent historic trends is strongly suggested.

Recent Electric Load Forecasts Compared to 10-year Historic Data:

Figures 3 and 4 present 10 years of recent historic weather-adjusted data for Gross Firm Energy and Gross Total Peak. Respectively, they also present (at-generation) values of Gross Firm Energy and Gross Total Peak forecast by Manitoba Hydro for 2015, 2016 and 2017. These are the same forecasts as those already presented in Figures 1 and 2 and all data supporting them are from Manitoba Hydro data appearing in Tables 1 and 2 at the end of this presentation.

The dotted line in Figures 3 and 4 is different from the dotted line in Figures 1 and 2 although both lines are identified as "Linear Historic". In Figures 1 and 2, the dotted line derives from a linear regression analysis of 20 years of historic data for Gross Firm Energy and Gross Total Peak, respectively. The linear regression line is extended forward to allow for comparison of forecasts in 2015, 2016 and 2017 with past historic trends. In Figures 3 and 4, the dotted line derives from a linear regression analysis of only the 10 most recent historic years for Gross Firm Energy and Gross Total Peak. It is notable that 10 years matches closely with the timeline since the 2008 recession. That match may not be the entire reason for the deflection in the electric load curve 10 years ago. But the recession could be a factor.

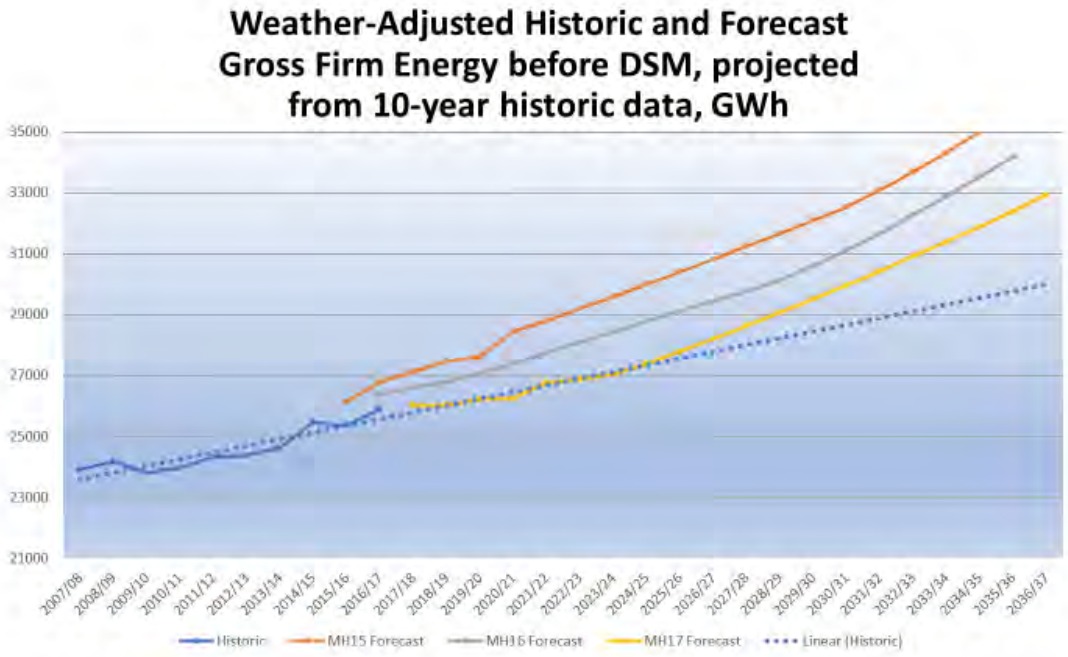


Figure 3: Weather-adjusted historic and forecast Gross Firm Energy before DSM, projected from 10-year historic data.

The slope of the dotted line in Figure 3 is 220.7 GWh per year (0.86% of the 25,583 GWh regressed value of Gross Firm Energy in 2016/17). The slope of the dotted line in Figure 4 is 52.1 MW per year (1.10% of the 4,746 MW regressed value of Gross Total Peak in 2016/17).

It is readily apparent from Figure 3 that, although recent forecasts of Gross Firm Energy before DSM have been adjusted downward in recent years, the current forecast (yellow line) reflects recent trends for only the next seven or eight years. Beyond then, Manitoba Hydro's forecasts for energy begin to depart significantly from a projection of recent trends. For example, Manitoba Hydro is currently forecasting energy levels for 2030 that recent trends would suggest are not likely to be reached until five years later. Manitoba Hydro forecasts a 20-year average annual growth rate of 1.2%, a figure that is inclusive of a growth rate in the first 10 years declared by Manitoba Hydro to be 0.9%.[7] But that masks an average annual growth rate of almost 1.7% in the final 10 years,

Whether or not this departure has a significant effect on domestic revenue will be examined later.

[7] MH17 Forecast values of Gross Firm Energy from Manitoba Hydro 2017/18 and 2018/19 General Rate Application Tab 11: Public Utilities Board (PUB) Minimum Filing Requirements, PUB MFR 65 (Updated) (2017 Electric Load Forecast), Table 1, page 404, page 417, and Table 6, page 418/1382, updated in PUB-MH I-56a-c Revised) filed by Manitoba Hydro as Exhibit MH70 on 7 December 2017.

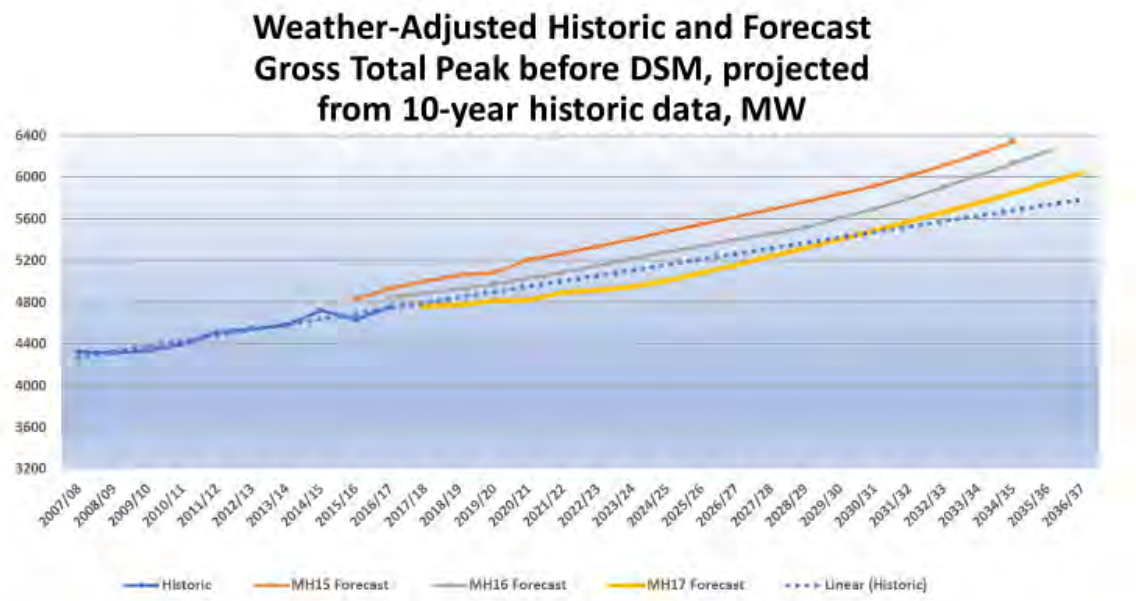


Figure 4: Weather-adjusted historic and forecast Gross Total Peak before DSM, projected from 10-year historic data.

Figure 4 reveals that Manitoba Hydro's current forecast of peak power (yellow line) more closely reflects recent trends than its forecast of energy does. However, Manitoba Hydro's peak power forecast does begin about 15 years out to depart from what past trends would indicate is likely.

Current Electric Load Forecast Net of Demand Side Management:

DSM has the potential to affect operating budgets. It can also delay when the next resource, possibly generation, is required, sometimes referenced as the year of need. Currently, responsibility for DSM is fluid in that The Efficiency Manitoba Act passed in the Legislature and given Royal Assent in 2017 has transferred responsibility for DSM to a new crown corporation called Efficiency Manitoba. At the present time, the appointment of a board for Efficiency Manitoba has not been announced and no programming appears to have been launched. In the circumstance, Manitoba Hydro has forecast DSM as part of its business plan, acknowledging, however, that responsibility for DSM will change as Efficiency Manitoba becomes operative.

It should be noted in this analysis that the Bipole III Coalition accepts Manitoba Hydro's logic that only program-based DSM should be applied to load forecasts. Further, Manitoba Hydro's rationale is accepted that, if DSM savings attributable to codes and standards are included in records of DSM, those savings should be first subtracted before applying the DSM values to load forecast. Finally, the Coalition also accepts Manitoba Hydro's logic that historic DSM savings should be considered to have a continuing effect going forward but that future DSM savings should be considered as reducing load that has to be served.

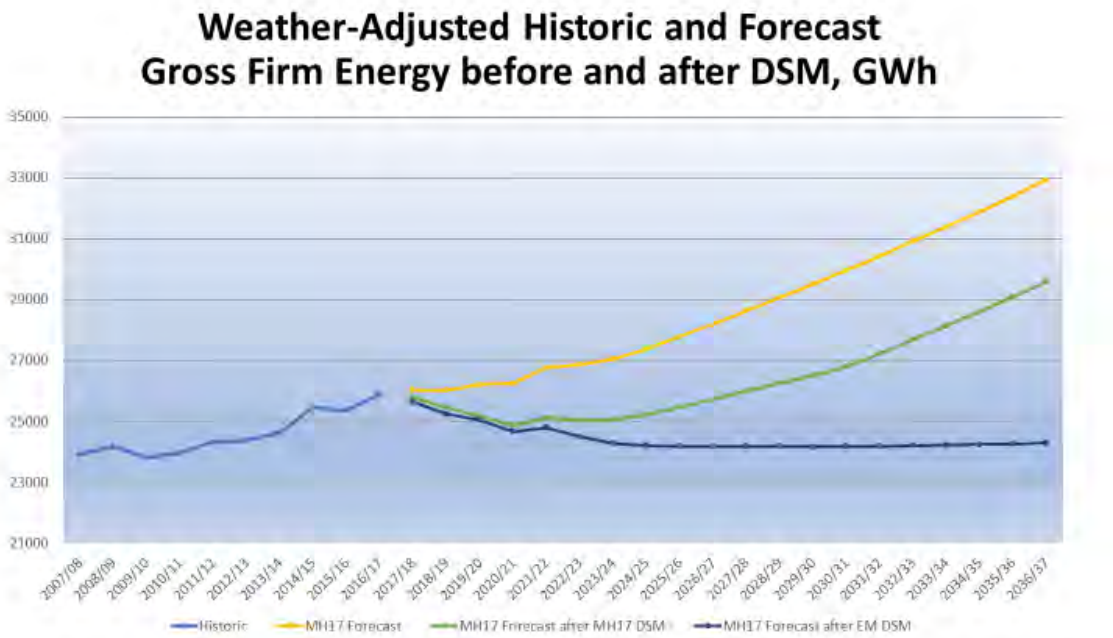


Figure 5: Weather-adjusted historic and forecast Gross Firm Energy before and after DSM.

Figure 5 presents the most recent historic 10 years of weather-adjusted data for Gross Firm Energy (blue line) and Manitoba Hydro's current 20-year forecast for Gross Firm Energy (yellow line). It also presents Manitoba Hydro's current 20-year forecast for Gross Firm Energy net of Manitoba Hydro's DSM forecast (green line).

The Efficiency Manitoba Act mandates 15-year targets for energy totaling 22.5%, to be achieved in yearly increments of 1.5%. Figure 5 also presents a forecast of Gross Firm Energy net of Efficiency Manitoba's 1.5% per year mandated target for DSM extended 20 years forward (navy line).

It needs to be emphasized here that the starting point in this analysis for determining Gross Firm Energy net of DSM is Manitoba Hydro's current forecast for Gross Firm Energy. As such, this analysis of the energy load that has to be served is independent of the Bipole III Coalition's perspective on Manitoba Hydro's energy load forecast.

It is evident from Figure 5 that DSM has the potential to create a significant impact on Gross Firm Energy. Moreover, Figure 5 reveals how much more aggressive Efficiency Manitoba's mandated targets for DSM are compared to Manitoba Hydro's. Both plans depress Gross Firm Energy below its current value in the intermediate term (for the next 10 years). Efficiency Manitoba's mandated targets force Gross Firm Energy well below its current value in the longer term (even beyond 20 years).

Whether or not the differential impact of Manitoba Hydro's DSM plan and Efficiency Manitoba's has a significant effect on domestic revenue will be examined later.

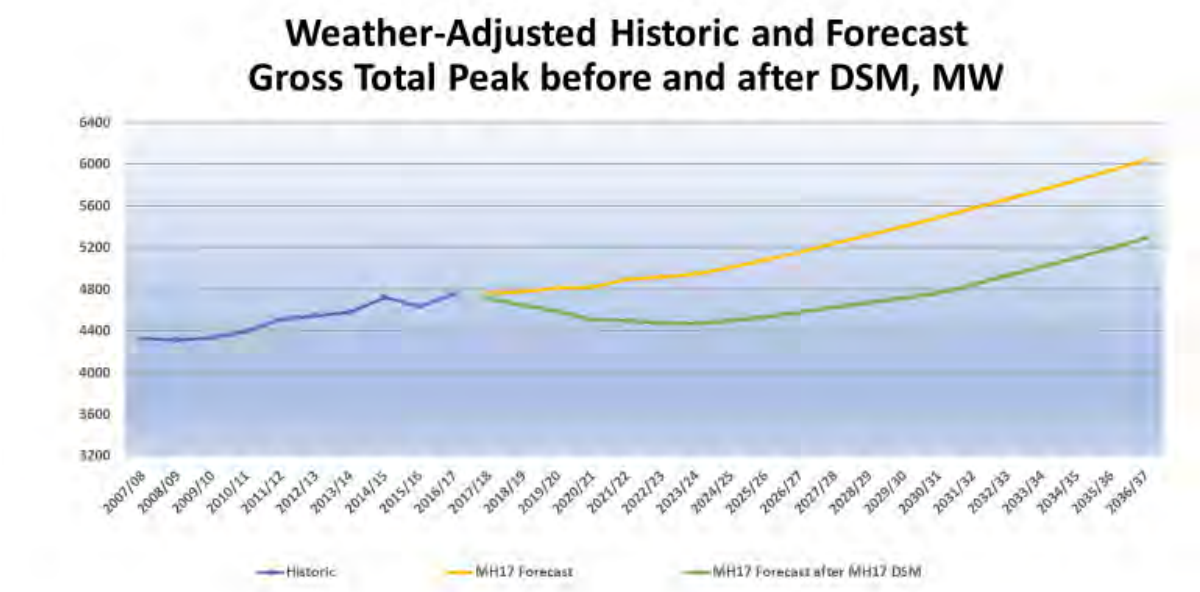


Figure 6: Weather-adjusted historic and forecast Gross Total Peak before and after DSM.

Figure 6 presents the most recent historic 10 years of weather-adjusted data for Gross Total Peak (blue line) and Manitoba Hydro's current 20-year forecast for Gross Total Peak (yellow line). It also presents Manitoba Hydro's current 20-year forecast for Gross Total Peak net of Manitoba Hydro's DSM forecast (green line). The Efficiency Manitoba Act is silent on targets for peak power, so it is not possible to present Gross Total Peak net of DSM as envisioned by Efficiency Manitoba.

It is evident from Figure 6 that DSM has the potential to create a significant impact on Gross Total Peak. Even with Manitoba Hydro's comparatively non-aggressive DSM forecast, Gross Total Peak can be expected to be depressed below its current value for the next 14 years. It is unclear what the impact of Efficiency Manitoba's mandated targets for energy will be on Gross Total Peak but it is highly probable that, as with Gross Firm Energy, they will drive Gross Total Peak below its current value even further into the future than the next 14 years.

Load Variability and Forecast Accuracy:

Turning our attention to the accuracy of load forecasts, Figure 7 extracts graphical and digital data used to support Manitoba Hydro's analysis of the accuracy of its forecasts of Gross Firm Energy[8].

[8] Forecast accuracy for Gross Firm Load from Manitoba Hydro 2017/18 and 2018/19 General Rate Application Tab 11: Public Utilities Board (PUB) Minimum Filing Requirements, PUB MFR 65 (Updated) (2017 Electric Load Forecast), Figure 22 and Table 35, page 457/1382.

Figure 22 - Energy Accuracy

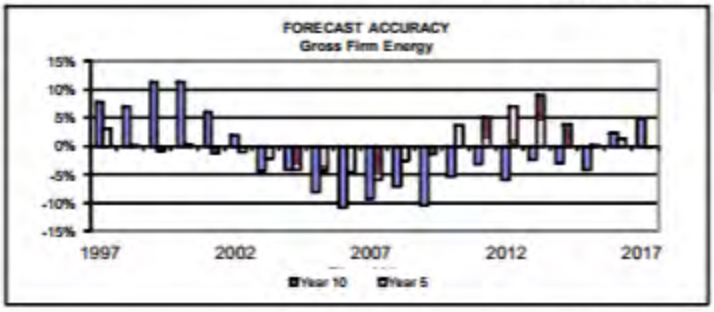


Table 35 - Energy Accuracy

Fiscal Year	Actual Gross Firm Energy	Forecast Prepared 5 Years Previous	W.A. Gross Firm Energy	5 Year Percent Accuracy	Forecast Prepared 10 Years Previous	W.A. Gross Firm Energy	10 Year Percent Accuracy
1996/97	19,321	19,395	18,810	3.1%	20,174	18,716	7.8%
1997/98	19,814	19,455	19,429	0.1%	20,661	19,320	6.9%
1998/99	19,273	19,675	19,818	-0.7%	21,919	19,788	11.2%
1999/00	18,971	19,767	19,703	0.3%	21,833	19,629	11.2%
2000/01	20,262	20,818	20,241	-1.1%	21,300	20,183	6.0%
2001/02	20,656	20,783	20,980	-0.9%	21,364	20,979	1.8%
2002/03	22,110	21,395	21,861	-2.1%	20,916	21,868	-4.4%
2003/04	22,069	21,134	22,062	-4.2%	21,191	22,107	-4.1%
2004/05	22,589	21,693	22,664	-4.3%	20,870	22,714	-8.1%
2005/06	22,757	22,216	23,277	-4.6%	20,812	23,346	-10.9%
2006/07	23,464	22,107	23,489	-5.9%	21,395	23,595	-9.3%
2007/08	24,122	23,353	23,962	-2.5%	22,328	24,034	-7.1%
2008/09	24,417	23,926	24,259	-1.4%	21,756	24,320	-10.5%
2009/10	23,412	24,734	23,858	3.7%	22,611	23,892	-5.4%
2010/11	23,892	25,239	24,020	5.1%	23,299	24,071	-3.2%
2011/12	23,605	25,989	24,282	7.1%	22,924	24,376	-6.0%
2012/13	24,750	26,464	24,270	9.0%	23,844	24,433	-2.4%
2013/14	25,625	25,518	24,538	4.0%	23,936	24,696	-3.1%
2014/15	25,505	25,491	25,469	0.1%	24,455	25,508	-4.1%
2015/16	24,665	25,707	25,366	1.3%	25,999	25,405	2.3%
2016/17	25,227	25,902	25,936	-0.1%	26,984	25,747	4.8%

Figure 7: Graphical and digital support extracted from Manitoba Hydro's analysis of the accuracy of its energy forecasts (Source: Manitoba Hydro).

At the outset of any discussion on load variability and forecast accuracy, it is important to recognize that Manitoba Hydro acknowledges that load variability is a significant challenge to forecast accuracy. It cites "underlying changes in the population growth, economic growth, changes in the operations of Top Consumers, and overall use patterns" as important contributors to load variability.[9] All sources of variability considered, Manitoba Hydro's current load forecast is considered to have only "an 80% probability of being accurate within ±1,737 GWh or ±5.1%" by 2035/36. Manitoba Hydro declares that "Due to the inherent variability of the load, this is the best level of accuracy possible".[10]

[9] Manitoba Hydro 2017/18 and 2018/19 General Rate Application Tab 11: Public Utilities Board (PUB) Minimum Filing Requirements, PUB MFR 65 (Updated) (2017 Electric Load Forecast), page 453/1382.

[10] Discussion of load forecast accuracy in Manitoba Hydro 2017/18 and 2018/19 General Rate Application Tab 11: Public Utilities Board (PUB) Minimum Filing Requirements, PUB MFR 65 (Updated) (2017 Electric Load Forecast), page 453/1382.

It is a conundrum for Manitoba Hydro that it recognizes the shortcomings and of its load forecasts, yet load forecasts are necessary for financial and resource planning. To illustrate, the confidence interval of ±1,737 GWh that Manitoba Hydro places on its forecast for Gross Firm Energy represents almost eight years of growth at the 220.7 GWh annual growth rate in recent years. not the sign of a very accurate forecast.

A problem with the approach that Manitoba Hydro uses to generate its load forecasts is that the sectoral forecasts employ subjective assessments of variables that are regarded as driving the forecasts. Some of these variables, such as population forecasts and forecasts of per capita consumption, while subjective in nature, can be mathematically linked to some of the sectoral forecasts, for example, the residential and general service mass market sectors. Most though do not benefit from an algorithm tying them to the load. They can be said only to "inform" what in the end is a subjective guess at a forecast value. The rhetoric that Manitoba Hydro to describe the methodology on which its load forecasts are based bears testimony to this observation and to the limitation on the confidence that should be placed in these forecasts.[11,12]

Another problem with the approach that Manitoba Hydro uses to assess the accuracy if its load forecasts is that the analysis does not evaluate the accuracy of current forecasts as would be desirable. Instead, its five-years-ahead forecasts are at least five-years old and the ten-years-ahead forecast are at least 10 years old when their accuracy is judged. Most five-years-ahead and ten-years-ahead forecasts are even older.

Moreover, there is absolutely no evaluation of the accuracy of load forecasts further than 10 years out. It is understandable that, given the vagaries of electric load forecasting, no attempt is made to evaluate the accuracy of forecasts further into the future. At the same time, it should be noted that an outcome of this constraint is that, without any analysis of accuracy in the longer term, long-term forecasts are "immune" from accountability for being inaccurate, on either the high side or the low.

Examining nearer-term forecasts, the most recent five-years-ahead forecast evaluated in this General Rate Application was produced in 2012. All other five-years-ahead forecasts were produced even earlier than 2012. Likewise, the most recent 10-years-ahead forecast evaluated in this Application was produced in 2007. All others are even older. When it comes to forecasting accuracy, the performance of forecasts five and 10 years ago is gauged but present performance gets a pass. For example, there is not even a review of the accuracy of last year's load forecast.

These serious deterrents to accurate forecasting notwithstanding, let's examine Figure 7 to judge how well Manitoba Hydro's electric load forecasts have been performing. An assessment of Gross Firm Energy forecast accuracy in Figure 7 reveals that the accuracy of Manitoba Hydro's five-

---

[11] MH17 Forecast values of Gross Firm Energy from Manitoba Hydro 2017/18 and 2018/19 General Rate Application Tab 11: Public Utilities Board (PUB) Minimum Filing Requirements, PUB MFR 65 (Updated) (2017 Electric Load Forecast), pages 426 to 429/1382, updated in PUB-MH I-56a-c Revised) filed by Manitoba Hydro as Exhibit MH70 on 7 December 2017.

[12] Manitoba Public Utilities Board Transcript of Proceedings, Manitoba Hydro 2017/18 and 2018/19 General Rate Application, pages 24 to 26/255.

years-ahead forecasts ranged from -5.9% to +9.0% for the 21 years for which the analyses could be performed. That is a pretty wide range. Between 2005 and 2012, the forecasts ranged from 0.1% low to 9.0% high. It is not surprising to the Bipole III Coalition which warned the Public Utilities Board[13] of the trend toward over-forecasting back in 2014. It also validates the calculations in Table 3 to be considered momentarily in this presentation.

Apart from the inaccurate picture of domestic revenue produced by a forecast that is, for example, 9.0% high, perhaps an even more serious result is the distortion it causes for resource planning. If the recent average annual growth rate for Gross Firm Energy of 0.86% is a valid indicator of future growth, a forecast that is 9.0% high signals a need for new resources more than 10 years earlier than they are actually needed.

Seven out of the eight five-years-ahead forecasts during the period between 2005 and 2012 were high. This is unfortunate because that period coincided with the period when Manitoba Hydro's expansion plan was most actively being developed. Over-optimism about the domestic consumption of electricity during those years is no doubt one factor among many for Manitoba Hydro's current financial predicament.

Turning to the ten-years-ahead forecasts, the accuracy ranged from -10.9% to +12.5% over the 21 years analyzed. Except for 2006 and 2007, forecasts of Gross Firm Energy have essentially been low every year since 1992. Of course, no measures of accuracy for 10-years-ahead forecasts since 2007 are available because those more recent forecast have not "matured" to a point when they can be judged. But, if 2006 and 2007 are any indication, it is looking like 10-years-ahead forecasts may have also been heading into a period of over-forecasting starting in 2006. This too would have unjustifiably fed the enthusiasm for system expansion in those critical years.

As mentioned earlier, Table 1 at the end of this presentation presents a comparison of Manitoba Hydro's current forecast of Gross Firm Energy with values that would be predicted by a straight-line extrapolation of recent historical values of the variable. The year-by-year differential between these two future values of Gross Firm Energy is calculated in the fourth column in Table 3.

It is notable that the +2,623 GWh result (32,398 GWh minus 29,775 GWh) for the differential in 2035/36 between Gross Firm Energy as would be suggested by a straight-line extrapolation of this variable and Manitoba Hydro's 2027 forecast is well outside Manitoba Hydro's 80% probability envelope of ±1,737 GWh for 2035/36. With an annual growth rate of 220.7 GWh, a differential of +2,623 GWh represents 12 years of growth. This finding challenges further Manitoba Hydro's claim that an 80% window is sufficient to gauge the accuracy of its electric load forecasts.

It is clear that the range of load variability considered by Manitoba Hydro in its analyses is not nearly wide enough. It is also significant that, in Table 3, 16 of the 20 values of the differential in the later years bear a + sign, indicating that Manitoba Hydro's forecasts tend to overpredict

[13] Presentation by the Bipole III Coalition to the Needs For and Alternatives To (NFAT) review of Manitoba Hydro's Preferred Expansion Plan by the Public Utilities Board submitted on February 3, 2014 and accessible at http://www.pubmanitoba.ca/v1/nfat/pdf/bipole_3_nfat_presentation.pdf.

regularly. With the scaling back of the 2017 load forecast significantly below the load forecasts for 2015 and 2016, it is likely that those earlier forecasts overpredicted on an even greater scale.

As noted previously, Manitoba Hydro's forecasts for electric load have been well above forecasts published by other utilities in North America for several years. Daymark Energy Advisors (formerly La Capra Associates), in a report currently before the PUB[14], identified several issues that distort Manitoba Hydro's current load forecast.

Among them are: exclusion of three Potentially Large Industrial Loads from the top consumers sector, "multi-collinearity issues", use of trend and dummy variables in the average usage models for both residential and general service mass market sectors, suppression of price elasticity effects in the top consumers sector, use of third party population forecasts that are too low, failure to use "scenario analysis" to permit insights into the impact of future alternative scenarios, absence of consideration of the impact of fuel switching and differing treatment in consecutive forecasts of DSM attributable to codes and standards.

Given the significant number of issues identified by Daymark, it is not surprising that Manitoba Hydro's approach to load forecasting would produce a result that is different than the one presented here which extrapolates from recent past experience.

Impact of Load Forecast on Domestic Revenue:

The question arises as to how important the impact of load forecasting is on future domestic revenue. Beyond presenting energy differentials resulting from differing future values of Gross Firm Load, Table 3 presents the opportunity for an analysis that puts a dollar value on the over-forecast energy. The area in Figure 3 between Manitoba Hydro's current forecast of Gross Firm Energy (yellow line) and an extrapolation of recent historic weather-adjusted values into the future (dotted line) is a proxy of the relative magnitude of the impact.

Manitoba Hydro has models that allow it to perform such an analysis easily. Because those models were not available to the Bipole III Coalition, we devised a methodology that evaluated, year-by-year, the at-meter values of energy (consumer sales). This would be the fundamental methodology that would allow the impacts to be cumulated over time.

First though, at-meter values of the energy differential were calculated by applying a factor of 0.86 to Manitoba Hydro's MH17 forecast values for Gross Firm Energy. This was necessary because Manitoba Hydro does not sell energy at generation.

[14] Daymark Energy Advisors, Independent Consultant Report: Load Forecast Review, November 15, 2017, PUB Exhibit DEA-2.

This calculation allowed the exclusion of transmission and distribution line losses, station service, construction usage and other-non-revenue-producing consumption, estimated to average 14%, in estimating approximate at-meter values of the energy differential.[15]

Next, we calculated annual unit values of energy at the meter, averaged over all sectors, relying on values for forecast consumer sales revenue available from the Projected Operating Statement in the 20-year Outlook for Manitoba Hydro's Electric Operations.[16]

The average annual unit values of the energy differential ($M/GWh) were the applied to the year-by-year values of the energy differential (GWh) to produce annual dollar values of the energy differential ($M) over the 20-year future period for which data were available. The result is presented in the last column of Table 3 identified as Revenue Differential (due to differing load forecasts).

Mathematically, the arithmetic sum $R_{\Delta LOAD}$ of the Revenue Differential over the 20-year future period (attributable to the departure of Manitoba Hydro's current load forecast from what would be suggested by recent history) is given by the equation.

$$R_{\Delta LOAD} = \sum_{n=2018}^{n=2037} (0.86\ \Delta E_n\ P_n) \qquad \text{(Eq. 1)}$$

where

0.86 is a factor reflecting the difference between Gross Firm Energy and Total Consumer Sales introduced to reflect system losses and usage that does not produce revenue,

ΔE_n is the Gross Firm Energy differential, in a given year, between Manitoba Hydro's current forecast and an extrapolation of recent 10-year historic values, in this presentation called Linear (Historic),

P_n is the unit price at the meter, in a given year, of energy, and

n is the year (identified in terms of the year end).

Table 3 shows that, over a period of 20 years, the arithmetic sum of the Revenue Differential $R_{\Delta LOAD}$ resulting from a forecast of Gross Firm Energy which exceeds a straight-line extrapolation of recent history is $2.329 million. Moreover, it demonstrates that, the annual revenue differential is much larger toward the end of the 20-year period and that it is growing each year. This analysis

[15] MH17 Forecast values of Gross Firm Energy from Manitoba Hydro 2017/18 and 2018/19 General Rate Application Tab 11: Public Utilities Board (PUB) Minimum Filing Requirements, PUB MFR 65 (Updated) (2017 Electric Load Forecast), page 427/1382, updated in PUB-MH I-56a-c Revised) filed by Manitoba Hydro as Exhibit MH70 on 7 December 2017.

[16] Domestic revenue from Manitoba Hydro 2017/18 and 2018/19 General Rate Application Appendix 3.3 Electric Operations (MH16 20-Year Outlook) Projected Operating Statement, pages 1 and 2/6.

indicates that **over-forecasting of load could result in over-predicting domestic revenue by more than $2.3 billion over a 20-year period**.

It should be acknowledged that the value of the energy not consumed domestically will not be entirely lost because the energy will be available for sale on the export energy market. But, at current prices, the offset will be only about one third of the foregone value.

It is important also to recognize that the foregone revenue will actually have a greater impact on retained earnings in 2036/37 than the simple arithmetic sum produced by this analysis indicates. To calculate the actual impact of over-forecasting electric load on retained earnings in 2036/37, a future value analysis should be conducted that brings all annual values for revenue differential forward to 2036/37.

Another (undesirable) impact of an overstated load forecast (beside its effect on the balance sheet) is that it advances unrealistically the year of need for the next energy resource. To illustrate, a close inspection of Figure 3 reveals that some values of Gross Firm Energy currently forecast by Manitoba Hydro would be reached up to six years earlier than would be predicted by a linear extrapolation of weather-adjusted Gross Firm Energy. Clearly, an over-stated load forecast has negative consequences for system resource planning.

The range of load considered by Manitoba Hydro in the load variability and accuracy analyses reported in this Application is insufficiently wide to circumscribe a linear extrapolation of recent historic experience.[17] This has been a pattern in the Bipole III Coalition's experience for some time, including its 2014 presentation to the NFAT review.[18]

Daymark Energy Advisors, in its report currently before the PUB[19] notes the narrowness of the range of load forecast contemplated by Manitoba Hydro. Daymark suggests an approach that would be more robust than Manitoba Hydro's methodology which relies on the P10 and P90 levels of base load. The more sophisticated approach suggested by Daymark would evaluate, with the help of probabilistic risk assessments, the inherent characteristics of each fundamental variable that contributes to base load. Manitoba Hydro should re-evaluate its approach to load forecasting.

---

[17] Load variability from Manitoba Hydro 2017/18 and 2018/19 General Rate Application Tab 7: Appendix 7.1 (2016 Electric Load Forecast), pages 54 to 59/82, and corroborated by Tab 11: Public Utilities Board (PUB) Minimum Filing Requirements, PUB MFR 65 (Updated) (2017 Electric Load Forecast), pages 453 to 458/1382.

[18] Presentation by the Bipole III Coalition to the Needs For and Alternatives To (NFAT) review of Manitoba Hydro's Preferred Expansion Plan by the Public Utilities Board submitted on February 3, 2014 and accessible at http://www.pubmanitoba.ca/v1/nfat/pdf/bipole_3_nfat_presentation.pdf.

[19] Daymark Energy Advisors, Independent Consultant Report: Load Forecast Review, November 15, 2017, PUB Exhibit DEA-2.

Impact of Demand Side Management on Domestic Revenue:

As with load forecast accuracy, the question arises as to how important the impact of DSM is on future domestic revenue. The area in Figure 5 between Manitoba Hydro's current forecast for Gross Firm Energy (yellow line) and Gross Firm Energy under its current DSM Plan (green line) invites a calculation that can evaluate that impact. Table 4 presents an analysis that evaluates the dollar value of domestic revenue foregone by Manitoba Hydro's current DSM Plan. But it also evaluates the dollar difference between Manitoba Hydro's current DSM Plan and Efficiency Manitoba's more aggressive DSM Plan. Neither analysis considers the delivery cost of these DSM Plans.

The methodology we devised for this analysis puts year-by-year values on projections of at-meter energy (consumer sales). The methodology shares some common approaches with the methodology we devised to evaluate the impact of load forecast differences on domestic revenue. It starts with Manitoba Hydro's current forecast of load so that any impact on domestic revenue will not reflect load forecast assumptions.

Mathematically, the arithmetic sum $R_{\Delta DSM}$ of the Revenue Differential over the 20-year future period attributable to the choice of DSM Plan is given by the equation

$$R_{\Delta DSM} = \sum_{n=2018}^{n=2037} (0.86\ \Delta E_n\ P_n) \qquad \text{(Eq. 2)}$$

where

0.86 is a factor reflecting the difference between Gross Firm Energy and Total Consumer Sales introduced to reflect system losses and usage that does not produce revenue,

ΔE_n is the Gross Firm Energy differential, in a given year, between Manitoba Hydro's current DSM Plan and Efficiency Manitoba's DSM Plan,

P_n is the unit price at the meter, in a given year, of energy, and

n is the year (identified in terms of the year end).

Table 4 reveals that, over a period of 20 years, the cumulative impact on domestic revenue of Manitoba Hydro's current DSM Plan can be expected to be in excess of $5.7 billion. It also reveals that, over a period of 20 years, the cumulative impact on domestic revenue of Efficiency Manitoba's more aggressive DSM Plan can be expected to be in excess of $10.8 billion. **The additional cumulative impact on domestic revenue of Efficiency Manitoba's Demand Side Management Plan above Manitoba Hydro's current DSM Plan is about $5.1 billion**. Coincidentally, this is about the value of the current cost estimate for Bipole III. This is much more serious than perhaps has been understood as the Government proceeded with passing the Efficiency Manitoba Act in the summer of 2017.

Like load forecast, a future value analysis of the choice of DSM Plan would show an even larger impact on retained earnings in 2036/37 than is indicated by an arithmetic approach. Also, like load forecast, the 'lost' revenue would be somewhat offset by revenue from additional sales on the energy export market. However, unlike load forecast, this analysis does not consider the additional cost of Efficiency Manitoba's more aggressive DSM Plan. If the Government passes the cost of Efficiency Manitoba's DSM Plan to Manitoba Hydro as is provided for in The Efficiency Manitoba Act, the additional delivery cost of that Plan will show up as a further negative impact on Manitoba Hydro's retained earnings. Table 4 demonstrates that most of that impact will occur in later years.

The transfer of responsibility for DSM from Manitoba Hydro to the Government is probably the least understood action this Government has taken. Its financial impact is on a par with the previous Government's routing decision for Bipole III, now roundly regarded as a serious mistake.

Outcomes:

For several years now, the linear extrapolation approach described in this presentation has consistently produced projected load that is in the same ballpark as load forecasts in other North American jurisdictions. Until the past few years, Manitoba Hydro's forecast has produced load forecasts that are an outlier among load forecasts in other relevant jurisdictions. Even today, Manitoba Hydro's load forecast is still well above what the majority is projecting.

Prior to 2015, Manitoba Hydro produced load forecasts with annual growth in the range 1.5% to 1.6%, well above recent historic trends.[20] Currently, Table 1 in this analysis demonstrates that Manitoba Hydro is forecasting 10-year growth for Gross Firm Energy at 0.81%, expressed by Manitoba Hydro as 0.9%. This is significantly down from earlier forecasts and from 1.46% in 2014[21]. Annual growth of 0.9% for the next 10 years is close to the 0.86% indicated by a linear extrapolation of recent historic values of weather-adjusted Gross Firm Energy presented here.

However, it is concerning that Manitoba Hydro's current forecast features a decided upturn in growth at the end of this 10-year forecast period. Manitoba Hydro's forecast for the second 10-year forecast period (2026/27 until 2036/37 in Table 1) reflects an annual growth rate of 1.7% during this 10-year period. Expressing growth rate over 20 years masks the highly optimistic forecast in the final 10 years of the forecast period. Manitoba Hydro justifies the upturn in terms of a return to 20-year historic growth patterns as a result of forecast population increases and a recovery from price elasticity impacts driven by seven years of 7.9% rate hikes currently under review.[22]

---

[20] Presentation by the Bipole III Coalition to the Needs For and Alternatives To (NFAT) review of Manitoba Hydro's Preferred Expansion Plan conducted by the Public Utilities Board submitted on February 3, 2014 and accessible at http://www.pubmanitoba.ca/v1/nfat/pdf/bipole_3_nfat_presentation.pdf.

[21] Daymark Energy Advisors, Independent Consultant Report: Load Forecast Review, November 15, 2017, PUB Exhibit DEA-2.

[22] Manitoba Public Utilities Board Transcript of Proceedings, Manitoba Hydro 2017/18 and 2018/19 General Rate Application, page 24/255.

It is significant how far out of line Manitoba Hydro's forecasts continue to be with relevant projections by reputable agencies. The U. S. Energy Information Administration, for example, is projecting annual growth rates out to 2040 for electricity use in the United States in the range from 0.6% to 1.0%.[23] This metric includes not only sales but also direct use. Comparing Manitoba Hydro's forecast of 1.2% annual growth in domestic energy consumption between now and 2036/37 reveals how overstated Manitoba Hydro's load forecast likely still is, even after scaling back since 2015.

The cumulative impact on domestic revenue of Manitoba Hydro's current DSM Plan, over the next 20 years, is $5.8 billion. Presumably, that impact and the cost of delivering that Plan is reflected in the current Integrated Financial Forecast. However, the additional impact on domestic revenue attributable to the Government's decision to establish legislatively mandated energy savings targets adds an additional $5.1 billion to that cost. In addition to absorbing the impact on domestic revenue, Manitoba Hydro will have to cover program delivery costs given that these costs are planned to be passed on from Efficiency Manitoba. These financial impacts are not reflected in the Integrated Financial Forecast. These impacts should be part of Manitoba Hydro's discussion with the Government to safeguard its financial health.

Consequences:

The combined cumulative impact on domestic income over the next 20 years attributable to load forecast choices and the more aggressive DSM Plan mandated by The Efficiency Manitoba Act is $7.4 billion ($2,3 billion plus $5.1 billion). Neither of these impacts are reflected in Manitoba Hydro's current Integrated Financial Forecast. Both are future impacts. Unless alternate funding sources are found, Manitoba Hydro will be requesting 7.9% rate increases even farther into the future than 2024.

Future Work:

Manitoba Hydro's focus for the past 18 months has been primarily on debt management. It does not appear to have devoted very much effort to increasing consumption of the glut of energy that it will own once Keeyask is in service. Electric energy export markets are uneconomical at current low export market prices, benefiting economies outside of Manitoba while not being useful to develop our own provincial economy. A concerted effort to advance electric transportation (cars, trucks and buses) and to promote a western Canadian transmission grid could change the prospects for both domestic revenue and extra-provincial revenue based on the potentially more profitable capacity and energy imbalance markets. Future work should reflect those opportunities.

The analysis in this presentation takes into account price elasticity only to the extent that the forecast values of Total Consumer Sales embedded in Manitoba Hydro's Integrated Financial

[23] U. S. Energy Information Administration Annual Energy Outlook 2017 with projections to 2050, Electricity Use growth projections (three-year rolling average) out to 2040, pages 67 to 88 but, in particular, page 75.

Forecast used in the analysis takes that factor into consideration.[24] A future analysis should assess whether price elasticity is adequately considered in Manitoba Hydro's electric load forecasting. Given that even short-term forecasts of load are currently at about the same level as recent historic trends when rate increases have been half or less of the 7.9% rate increases being requested for the next seven years, price elasticity impacts appear to be inadequately reflected.

Recommendations:

1. **The Public Utilities Board should direct Manitoba Hydro to revise its electric load forecast downward to more adequately reflect recent historic experience, price elasticity impacts and insights into factors driving load forecasts in other North American jurisdictions for consideration in its current General Rate Application.**

2. **The Public Utilities Board should direct Manitoba Hydro to conduct its own analysis of the impact on Manitoba Hydro's balance sheet of the Government's legislated plan for Demand Side Management of electric energy and to report its findings to the Public Utilities Board as part of its next General Rate Application.**

About the Bipole III Coalition:

The Bipole III Coalition is a grass-roots organization of concerned citizens established in November 2010 to promote public awareness among Manitobans that a route for Manitoba Hydro's planned Bipole III transmission line on the east side of Lake Winnipeg would be superior to the route chosen on the west side of the province. Soon after its establishment, the Bipole III Coalition broadened its mission in order to promote public awareness of its concern that Manitoba Hydro's corporate plan is not very well aligned with the interests of its ratepayers and not even with the interests of the citizens of Manitoba. It is concerned that Manitoba Hydro's corporate plan is not very well aligned with market challenges and opportunities. The Bipole III Coalition is not affiliated with any political party.

The presenter, Dr. Garland Laliberte, is Vice-President of the Bipole III Coalition.

[24] Manitoba Hydro 2017/18 and 2018/19 General Rate Application, transcript of proceedings for public hearing, pages 213-219 and 244-247 containing testimony on 7 December 2017 by Lois Morrison and Jamie McCallum of Manitoba Hydro confirming that, despite that the Chair of the Manitoba Hydroelectric Board had been publicly warning about the need for double-digit annual rate increases as early as 21 September 2016, the analysis of price elasticity impact on load forecasts included in filings on 5 May 2017 and in later summer updates, those forecasts contemplated a maximum annual rate increase of only 3.95% and not 7.9% as is presently being requested.

Table 1: Historic and forecast values of Gross Firm Energy before and after Manitoba Hydro and Efficiency Manitoba Demand Side Management Plans

Year	Gross Firm Energy, GWh[1]					DSM, GWh[7]		Gross Firm Energy Net of DSM, GWh			
	Historic[2]	MH15	MH16	MH17	Linear	MH Plan	EM Plan	MH17 Forecast		Linear (Historic)	
		Forecast[3]	Forecast[4]	Forecast[5]	(Historic)[6]	Forecast[8]	Forecast[9]	MH plan[10]	EM plan[11]	MH plan[12]	EM plan[13]
1996/97	18674										
1997/98	19286										
1998/99	19660										
1999/00	19597										
2000/01	20119										
2001/02	20830										
2002/03	21716										
2003/04	21948										
2004/05	22641										
2005/06	23200										
2006/07	23423										
2007/08	23910										
2008/09	24181										
2009/10	23808										
2010/11	23965										
2011/12	24321										
2012/13	24367										
2013/14	24634										
2014/15	25461	25505									
2015/16	25355	26145	24665								
2016/17	25896	26792	26385	25227	25583						
2017/18		27126	26596	26029	25803	238	390	25791	25639	25565	25413
2018/19		27486	26785	26026	26024	570	781	25456	25245	25454	25243
2019/20		27600	27060	26220	26245	1052	1174	25168	25046	25193	25071
2020/21		28449	27410	26238	26465	1368	1568	24870	24670	25097	24897
2021/22		28786	27729	26766	26686	1657	1969	25109	24797	25029	24717
2022/23		29197	28082	26877	26907	1837	2372	25040	24505	25070	24535
2023/24		29590	28435	27055	27127	2006	2778	25049	24277	25121	24349
2024/25		29999	28785	27389	27348	2163	3189	25226	24200	25185	24159
2025/26		30408	29110	27780	27569	2325	3606	25455	24174	25244	23963
2026/27		30823	29447	28208	27789	2482	4029	25726	24179	25307	23760
2027/28		31243	29762	28641	28010	2647	4458	25994	24183	25363	23552
2028/29		31664	30106	29068	28231	2818	4894	26250	24174	25413	23337
2029/30		32094	30602	29510	28451	2993	5337	26517	24173	25458	23114
2030/31		32531	31108	29962	28672	3163	5787	26799	24175	25509	22885
2031/32		33101	31666	30428	28893	3195	6243	27233	24185	25698	22650
2032/33		33684	32273	30914	29113	3227	6707	27687	24207	25886	22406
2033/34		34317	32896	31399	29334	3257	7178	28142	24221	26077	22156
2034/35		35011	33532	31895	29555	3285	7656	28610	24239	26270	21899
2035/36			34193	32398	29775	3311	8142	29087	24256	26464	21633
2036/37				32930	29996	3337	8636	29593	24294	26659	21360

Explanatory Notes appear on next page.

Explanatory Notes:
[1] Gross Firm Energy at generation net of forecast savings attributable to codes and standards.
[2] Weather-adjusted values of Gross Firm Energy from Manitoba Hydro 2017/18 and 2018/19 General Rate Application Tab 7: Appendix 7.1
(2016 Electric Load Forecast), Table 29, page 47/82 and Tab 11: Public Utilities Board (PUB) Minimum Filing Requirements, PUB MFR 65
(Updated) (2017 Electric Load Forecast), Table 1, page 404/1382.
[3] MH15 Forecast values of Gross Firm Energy from Manitoba Hydro 2015/16 and 2016/17 General Rate Application Attachment 25 (2015
Electric Load Forecast and Power Smart Plans MFR 1), Table 2, page 6/81, updated in PUB-MH 1-56a-c (Revised) filed by Manitoba Hydro as
Exhibit MH70 on 7 December 2017.
[4] MH16 Forecast values of Gross Firm Energy from Manitoba Hydro 2017/18 and 2018/19 General Rate Application Appendix 7.1 (2016 Electric
Load Forecast), Table 1, updated in PUB-MH 1-56a-c (Revised) filed by Manitoba Hydro as Exhibit MH70 on 7 December 2017.
[5] MH17 Forecast values of Gross Firm Energy from Manitoba Hydro 2017/18 and 2018/19 General Rate Application Tab 11: Public Utilities
Board (PUB) Minimum Filing Requirements, PUB MFR 65 (Updated) (2017 Electric Load Forecast), Table 1, page 404/1382 updated in
PUB-MH I-56a-c Revised) filed by Manitoba Hydro as Exhibit MH70 on 7 December 2017.
[6] Values produced by extrapolating a linear regression of weather-adjusted values of Gross Firm Energy for the 10-year period from 2007/08
to 2016/17. The slope of this regression line is 220.7 GWh/year (0.86% of the 25,583 GWh calculated value for 2016/17).
[7] Planned program-based Demand Side Management.
[8] Impacts (at generation) exclusive of contribution from codes and standards from Manitoba Hydro 2017/18 and 2018/19 General Rate Appli-
cation: Response on 5 September 2017 updated in PUB-MH 1-56a-c (Revised) filed by Manitoba Hydro as Exhibit MH70 on 7 December 2017.
[9] Assumed DSM programming by Efficiency Manitoba beginning in 2017/18 and incremented upward each year by 1.5% of Manitoba Hydro's
2017 Load Forecast for that year.
[10] MH17 Forecast for Gross Firm Energy minus Manitoba Hydro's current DSM Plan.
[11] MH17 Forecast for Gross Firm Energy minus Efficiency Manitoba's DSM Plan.
[12] Linear (Historic) values for Gross Firm Energy minus Manitoba Hydro's current DSM Plan.
[13] Linear (Historic) values for Gross Firm Energy minus Efficiency Manitoba's DSM Plan.

Table 2: Historic and forecast values of Gross Total Peak before and after Manitoba Hydro and Efficiency Manitoba Demand Side Management Plans

Year	Gross Total Peak, MW[1]					DSM, MW	Gross Total Peak Net of DSM, MW	
	Historic[2]	MH15 Forecast[3]	MH16 Forecast[4]	MH17 Forecast[5]	Linear (Historic)[6]	MH17 Forecast MH Plan[7]	MH17 Forecast[8]	Linear (Historic)[9]
1996/97	3486							
1997/98	3640							
1998/99	3610							
1999/00	3645							
2000/01	3677							
2001/02	3793							
2002/03	3972							
2003/04	4025							
2004/05	4129							
2005/06	4169							
2006/07	4182							
2007/08	4325							
2008/09	4314							
2009/10	4336							
2010/11	4392							
2011/12	4514							
2012/13	4547							
2013/14	4578							
2014/15	4723	4713						
2015/16	4634	4829	4479					
2016/17	4751	4936	4850	4822	4746			
2017/18		5000	4885	4759	4798	52	4707	4746
2018/19		5063	4928	4778	4850	130	4648	4720
2019/20		5086	4971	4816	4902	229	4587	4673
2020/21		5210	5033	4820	4954	314	4506	4640
2021/22		5267	5089	4895	5007	396	4499	4611
2022/23		5337	5154	4916	5059	441	4475	4618
2023/24		5406	5218	4949	5111	478	4471	4633
2024/25		5476	5282	5009	5163	512	4497	4651
2025/26		5547	5341	5081	5215	547	4534	4668
2026/27		5619	5402	5161	5267	582	4579	4685
2027/28		5692	5458	5242	5319	617	4625	4702
2028/29		5765	5520	5321	5371	652	4669	4719
2029/30		5840	5608	5403	5424	688	4715	4736
2030/31		5915	5696	5487	5476	722	4765	4754
2031/32		6012	5796	5574	5528	728	4846	4800
2032/33		6112	5905	5665	5580	733	4932	4847
2033/34		6220	6017	5756	5632	739	5017	4893
2034/35		6341	6131	5848	5684	744	5104	4940
2035/36			6250	5943	5736	749	5194	4987
2036/37				6043	5788	754	5289	5034

Explanatory Notes appear on next page.

Explanatory notes:
[1] Gross Total Peak at generation net of forecast savings attributable to codes and standards.
[2] Weather-adjusted values of Gross Total Peak from Manitoba Hydro 2017/18 and 2018/19 General Rate Application Tab 7: Appendix 7.
(2016 Electric Load Forecast), Table 32, page 49/82 and Tab 11: Public Utilities Board (PUB) Minimum Filing Requirements, PUB MFR 65
(Updated) (2017 Electric Load Forecast), Table 1, page 404/1382.
[3] MH15 Forecast values of Gross Total Peak from Manitoba Hydro 2015/16 and 2016/17 General Rate Application Attachment 25 (2015
Electric Load Forecast and Power Smart Plans MFR 1), Table 2, page 6/81, updated in PUB-MH I-56a-c (Revised) filed by Manitoba
Hydro as Exhibit MH70 on 7 December 2017.
[4] MH16 Forecast values for Gross Total Peak from Manitoba Hydro 2017/18 and 2018/19 General Rate Application Appendix 7.1 (2016
Electric Load Forecast), Table 1, page 5/82, updated in PUB-MH I-56a-c (Revised) filed by Manitoba Hydro as Exhibit MH70 on
7 December 2017.
[5] MH17 Forecast values for Gross Total Peak from Manitoba Hydro 2017/18 and 2018/19 General Rate Application: Tab 11: Public
Utilities Board (PUB) MFRs, PUB MFR 65 (Updated) (2017 Electric Load Forecast), Table 1, page 404/1382, updated in PUB-MH I-56a-c
(Revised) filed by Manitoba Hydro as Exhibit MH70 on 7 December 2017.
[6] Values produced by extrapolating a linear regression of weather-adjusted values of Gross Total Peak for the 10 years from 2007/08
to 2016/17. The slope of this regression line is 52.1 MW/year (1.10% of the 4,746 MW calculated value for 2016/17).
[7] Impacts (at generation) exclusive of contribution from codes and standards from Manitoba Hydro 2017/18 and 2018/19 General Rate
Application: Response on 5 September 2017 to Information Request Round 1 COALITION/MH I-40a-d pages 186-188/1268, updated in
PUB-MH I-56a-c (Revised) filed by Manitoba Hydro as Exhibit MH70 on 7 December 2017.
[8] MH17 Forecast for Gross Total Peak minus Manitoba Hydro's current DSM Plan.
[9] Linear (Historic) values for Gross Total Peak minus Manitoba Hydro's current DSM Plan.

Table 3: Domestic revenue differential resulting from the differential between Manitoba Hydro's 2017 Forecast of Gross Firm Energy and a linear extrapolation of the most recent 10-year historic record of weather-adjusted Gross Firm Energy

Fiscal	Forecast Gross Firm Energy			Consumer	Forecast Consumer Sales Revenue			Unit	Revenue
Year	MH17[1]	Linear (Historic)[2]	Differential	Sales Differential[3]	Approved[4]	Additional[5]	Total	Price[6]	Differential[7]
	GWh	GWh	GWh	GWh	$M	$M	$M	$M/GWh	$M
2017/18	26029	25803	226	194	1569	88	1657	0.074706	17
2018/19	26026	26024	2	2	1561	255	1816	0.082952	0
2019/20	26220	26245	-25	-22	1552	397	1949	0.090046	-2
2020/21	26238	26465	-227	-195	1551	551	2102	0.098278	-22
2021/22	26766	26686	80	69	1552	717	2269	0.105077	8
2022/23	26877	26907	-30	-26	1559	766	2325	0.107967	-3
2023/24	27055	27127	-72	-62	1567	817	2384	0.110667	-8
2024/25	27389	27348	41	35	1577	870	2447	0.112794	5
2025/26	27780	27569	211	181	1584	923	2507	0.114520	24
2026/27	28208	27789	419	360	1593	979	2572	0.116252	49
10-yr total	268588	267963	625	538	15665	6363	22028		67
2027/28	28641	28010	631	543	1599	1034	2633	0.117782	74
2028/29	29068	28231	837	720	1608	1093	2701	0.119646	100
2029/30	29510	28451	1059	911	1623	1158	2781	0.121949	129
2030/31	29962	28672	1290	1109	1639	1225	2864	0.124267	160
2031/32	30428	28893	1535	1320	1667	1304	2971	0.126855	195
2032/33	30914	29113	1801	1549	1698	1389	3087	0.129647	233
2033/34	31399	29334	2065	1776	1730	1478	3208	0.132550	274
2034/35	31895	29555	2340	2012	1762	1571	3333	0.135462	317
2035/36	32398	29775	2623	2256	1796	1669	3465	0.138518	363
2036/37	32930	29996	2934	2523	1829	1773	3602	0.141533	415
20-yr total	575733	557993	17740	15256	32616	20057	52673		2329

Explanatory Notes:

[1] MH17 Forecast values of Gross Firm Energy from Manitoba Hydro 2017/18 and 2018/19 General Rate Application Tab 11: Public Utilities Board (PUB) Minimum Filing Requirements, PUB MFR 65 (Updated) (2017 Electric Load Forecast), Table 1, page 404/1382, and updated in PUB-MH 1-56a-c (Revised) filed by Manitoba Hydro as Exhibit MH70 on 7 December 2017.

[2] Values produced by extrapolating a linear regression of weather-adjusted values of Gross Firm Energy for the 10 years from 2007/08 to 2016/17. The slope of this regression line is 220.7 GWh/year (0.86% of the 25,583 GWh value calculated for 2016/17.

[3] Forecast Gross Firm Load Differential x 0.86 to reflect 14% system losses, station service and construction usage.

[4] Domestic revenue at approved rates from Manitoba Hydro 2017/18 and 2018/19 General Rate Application Appendix 3.3 Electric Operations (MH16 20-Year Outlook) Projected Operating Statement, pages 1 and 2/6; estimated value for 2036/37.

[5] Domestic revenue additional from Manitoba Hydro 2017/18 and 2018/19 General Rate Application Appendix 3.3 Electric Operations (MH16 20-Year Outlook) Projected Operating Statement, pages 1 and 2/6; estimated value for 2036/37.

[6] Forecast Total Consumer Sales Revenue divided by (Forecast Gross Firm Energy Net of Manitoba Hydro's DSM Plan multiplied by 0.86).

[7] Revenue Differential attributable to the MH17 Forecast compared to Linear (Historic) values calculated as Forecast Gross Firm Energy.

Table 4: Reduction in domestic revenue attributable to Manitoba Hydro's and Efficiency Manitoba's Demand Side Management Plans

Fiscal Year	MH17[1]	DSM		MH17 Net of DSM	MH17 Net of DSM	Unit Price[6]	Revenue Differential attributable to DSM	
		MH Plan[2]	EM Plan[3]	MH Plan[4]	EM Plan[5]		MH Plan[7]	EM Plan[8]
	GWh	GWh	GWh	GWh	GWh	$M/GWh	$M	$M
2017/18	26029	238	390	25791	25639	0.074706	18	29
2018/19	26026	570	781	25456	25245	0.082952	47	65
2019/20	26220	1052	1174	25168	25046	0.090046	95	106
2020/21	26238	1368	1568	24870	24670	0.098278	134	154
2021/22	26766	1657	1969	25109	24797	0.105077	174	207
2022/23	26877	1837	2372	25040	24505	0.107967	198	256
2023/24	27055	2006	2778	25049	24277	0.110667	222	307
2024/25	27389	2163	3189	25226	24200	0.112794	244	360
2025/26	27780	2325	3606	25455	24174	0.114520	266	413
2026/27	28208	2482	4029	25726	24179	0.116252	289	468
10-yr total	268588	15698	21856	252890	246732		1687	2365
2027/28	28641	2647	4458	25994	24183	0.117782	312	525
2028/29	29068	2818	4894	26250	24174	0.119646	337	586
2029/30	29510	2993	5337	26517	24173	0.121949	365	651
2030/31	29962	3163	5787	26799	24175	0.124267	393	719
2031/32	30428	3195	6243	27233	24185	0.126855	405	792
2032/33	30914	3227	6707	27687	24207	0.129647	418	869
2033/34	31399	3257	7178	28142	24221	0.132550	432	951
2034/35	31895	3285	7656	28610	24239	0.135462	445	1037
2035/36	32398	3311	8142	29087	24256	0.138518	459	1128
2036/37	32930	3337	8636	29593	24294	0.141533	472	1222
20-yr total	575733	46931	86894	528802	488839		5726	10846

Explanatory Notes:

[1] MH17 Forecast values of Gross Firm Energy from Manitoba Hydro 2017/18 and 2018/19 General Rate Application Tab 11: Public Utilities Board (PUB) Minimum Filing Requirements, PUB MFR 65 (Updated) (2017 Electric Load Forecast), Table 1, page 404/1382 and updated in PUB-MH 1-56a-c (Revised) filed by Manitoba Hydro as Exhibit MH70 on 7 December 2017.

[2] Impacts (at generation) exclusive of contribution from codes and standards from Manitoba Hydro 2017/18 and 2018/19 General Rate Application: Response on 5 September 2017 and updated in PUB-MH 1-56a-c (Revised) filed by Manitoba Hydro as Exhibit MH70 on 7 December 2017.

[3] Assumed DSM programming by Efficiency Manitoba beginning in 2017/18 and incremented upward each year by 1.5% of Manitoba Hydro's 2017 Load Forecast for that year.

[4] MH17 Forecast for Gross Firm Energy minus Manitoba Hydro's DSM Plan.

[5] MH17 Forecast for Gross Firm Energy minus Efficency Manitoba's DSM Plan.

[6] Domestic revenue additional from Manitoba Hydro 2017/18 and 2018/19 General Rate Application Appendix 3.3 Electric Operations (MH16 20-Year Outlook) Projected Operating Statement, pages 1 and 2/6.

[7] Manitoba Hydro's DSM Plan multiplied by Unit Price.

[8] Efficiency Manitoba's DSM Plan multiplied by Unit Price.

Tab 60

PUBLIC UTILITIES BOARD

WRITTEN FINAL ARGUMENT OF MANITOBA HYDRO

2017/18 & 2018/19 GENERAL RATE APPLICATION

February 5, 2018

Manitoba Hydro

Table of Contents

1. REQUESTED APPROVALS AND SUMMARY OF REASONS FOR THE RATE INCREASES 1

1.1 Background and Overview of Approvals Sought 1

1.1 Organization of the Final Argument 3

2 A 7.9% RATE INCREASE CANNOT BE WRONG 5

2.1 Manitoba Hydro Needs the Rate Increases Requested in this Application 5

2.1.1 Bipole III Reliability Project Entering Service 5

2.1.2 Current Rates Not Covering Current Costs and Cash Needs 7

2.1.3 Impact of Keeyask on future cost structure must be taken into consideration 12

2.1.4 Electricity Rates will continue to be Competitive 14

3 MANITOBA HYDRO'S NEW FINANCIAL PLAN 17

3.1 Taking Action on Unsustainable Debt Levels 17

3.1.1 Greater flexibility 18

3.1.2 Lessening interest rate risk 19

3.2 Interveners have a Lack of Comprehension with respect to Role and Ownership of Equity 24

3.3 Ratepayer Benefits 28

3.4 A 20-Year Financial Plan does not work 31

3.4.1 Prolonged and unmitigated exposure to interest rate increases 31

3.4.2 Cannot Forecast Breakeven or Negative Income 34

3.4.3 Prudent Financial Plans Do Not Depend on the Back-End of a Twenty Year Financial Forecast Proving Accurate 38

3.4.4 Capital markets are growing more concerned 40

3.4.5 Intergenerational Equity argument is flawed and hypocritical 41

3.5 Changing assumptions in the Financial Model in order to defer the need for rate increases is not prudent 43

3.5.1 Assumption of Capacity Values for Uncommitted Firm Energy. 43

3.5.2 Change regulatory accounting policy to increase income in the near term. 44

3.5.3 Assume 12 Year WATM. 44

3.5.4 Curtail DSM spending assumptions. 45

3.5.5 Curtail government payments. 45
3.6 MH15 Rate Plan Fails 46
4 THE FINANCIAL OUTLOOK HAS DETERIORATED SIGNIFICANTLY 49
4.1 Export Revenues Are Materially Lower 49
4.2 Domestic Load Growth and Revenues are Materially Lower 50
4.3 Debt Has Gone Up 51
5 WITHOUT HIGHER RATE INCREASES MANITOBA HYDRO CANNOT SUPPORT ITS DEBT 56
5.1 Cost of Debt Financing is Manitoba Hydro's Largest Expense 56
5.2 No Precedent for Pending Level of Debt Burden on Domestic Customers 57
5.3 Debt Management Can't Mitigate Longer Term Risk 61
5.4 Debt to EBITDA is a Troubling Metric 62
5.5 Capital Markets Are Concerned with Rate Inadequacy 65
5.6 Financial Targets Are Not Met Without Higher Rate Increases 66
5.6.1 EBITDA to Interest 68
5.6.2 EBIT to Interest 73
5.6.3 Capital Coverage Ratio 74
5.6.4 EBITDA to Cash Burdens 75
5.7 Past Leverage Levels of No Current Relevance 76
6 FINANCIAL TARGETS AND THE ROLE OF RESERVES IN MANAGING FINANCIAL HEALTH 78
6.1 Overview of Financial Targets 78
6.1.1 Equity Ratio: 78
6.1.2 Interest Coverage Ratio: 78
6.1.3 Capital Coverage Ratio: 79
6.2 Financial Targets are a Measure of Financial Health 79
6.3 There is No Need to Adjust Targets for Purposes of Ratemaking 80
6.4 The Role of Reserves in Managing Manitoba Hydro's Risks 82
6.5 Debt Markets Care about Debt:Equity Ratio 91
6.6 The Importance of Manitoba Hydro Being Viewed as Self-Supporting 92
6.7 What a Supportive Regulatory Regime Really Means 96

7 MYTH OF THE 3.95% RATE PROMISE 98
8 PROJECTED REVENUES ARE DOWN 102
8.1 Overview 102
8.2 Load Forecast 102
8.2.1 Future Manitoba Load Forecast is Trending Down 102
8.2.2 Load Forecast Methodology is Reasonable 104
8.2.3 Top Consumers and Potential Large Industrial Load ("PLIL") 106
8.2.4 Population Forecast 107
8.2.5 Price Elasticity well within Literature Review 108
8.2.6 Evidence presented during public presentations 108
8.2.7 Demand Side Management and Efficiency Manitoba 110
8.2.8 Forecast Conclusion 111
8.3 Export Revenue Projections are Reasonable 111
8.3.1 Consensus Price Forecast Process is Reasonable 111
8.3.2 Other Export Revenue Projections are Reasonable 112
8.3.3 Manitoba Hydro Uses Multiple Sources in its Short-Term Export Price Forecast ... 113
8.3.4 Review of SaskPower Sale and Transmission Construction Deemed Beneficial 114
8.3.5 No Additional Capacity Resources Required in MISO Until 2023 Time Frame 114
8.3.6 Long Term Dependable Product Premium No Longer Exists 115
8.3.7 Value of Generation Capacity in the Future is Uncertain 116
8.3.8 Export Prices are Continuing to Fall 117
8.3.9 Manitoba Hydro's Unit Export Revenue has Historically Been Overestimated 118
8.3.10 Impact of Potential Longer Term Premium and Generation Capacity Revenue Doesn't Change Current Rate Needs 120
8.3.11 Current Water Conditions Have Not Changed Significantly from IFF16 Forecast and Are Less Favourable Than IFF16 Update. 122
8.4 Interest Rate Outlook 123
9 SUSTAINING CAPITAL 125
9.1 All Business Operations Capital investments in the test year are required for the sustainable, safe and reliable operations to the benefit of Manitoba Hydro's customers. ... 125

9.2 Forecasts of future expenditures will be tested in future General Rate Applications 128
9.3 Asset Management Practices are being Enhanced 129
9.4 METSCO's Recommendations for Additional Regulatory Oversight Must Be Reviewed According to the PUB's Regulatory Mandate and the Incremental Cost of Reporting 130
10 MAJOR CAPITAL PROJECTS 133
10.1 Overview 133
10.2 Keeyask Generating Station Project 137
10.2.1 Complex project 138
10.2.2 Economics 138
10.2.3 Awarding of the General Civil Contract 139
10.2.4 2016 Issues and Recovery Plan 141
10.2.5 Amending Agreement #7 - Key aspects 143
10.2.6 2017 Outcomes 144
10.2.7 Current Forecast at Completion 146
10.2.8 2018 Plan and key upcoming activities 147
10.2.9 Summary on the Keeyask Project 148
10.3 Bipole III Transmission Reliability Project 148
10.4 Manitoba-Minnesota Transmission Project 149
10.5 Great Northern Transmission Line Project 150
11 12-YEAR VERSUS 20-YEAR DEBT TERMING STRATEGY 152
12 NO SAVINGS TO BE FOUND IN OPERATING AND MAINTENANCE EXPENSE 156
13 IMPACT ON MANITOBA ECONOMY 160
13.1 Job Creation 160
13.2 City of Winnipeg 163
14 MANITOBA HYDRO IS COMMITTED TO WORK WITH STAKEHOLDERS TO DEVELOP APPROPRIATE AND COST EFFECTIVE SOLUTIONS THAT WILL ADDRESS CHALLENGES OF LOW INCOME AND AFFORDABILITY 165
14.1 Income Sufficiency and Energy Poverty are Complex Issues 165
14.2 Manitoba Hydro's Role in Addressing Affordability Issues 168
14.3 Legal Issues to be Considered 169

14.4 Bill Affordability Collaborative Process 178
14.5 Manitoba Hydro's Affordability Programs 181
14.5.1 Bill Management Activities 181
14.5.2 Neighbours Helping Neighbours 182
14.5.3 Affordable Energy Program ("AEP") 183
14.5.4 Indigenous Power Smart Program 186
14.6 Demand Side Management Programming and Efficiency Manitoba 188
15 COST OF SERVICE AND RATE DESIGN 191
15.1 Rate Setting Process 191
15.2 COST OF SERVICE 192
15.2.1 Intervenors Have Endorsed the PCOSS18 Implementation of the Directives from Order 164/16 192
15.2.2 Eliminating Non Cost Casual Factors from PCOSS Requires a Revision to the Zone of Reasonableness 194
15.2.3 Revising the Method of Calculating RCC Would Require an Expansion to the Zone of Reasonableness 195
15.2.4 Outcomes of PCOSS18 196
15.2.5 RCC Evaluation Should Not Ignore Impact of Bipole III Coming in Service 197
15.2.6 Cost of Service Treatment of Bipole III Reserve Account Revenues 200
15.3 Rate Design 201
15.3.1 Residential Rate Design 201
15.3.2 Rate Design for General Service Large Customer Classes 203
15.3.3 The Relevance of Demand Charges in Rate Design 206
16 RATE SHOCK 208
16.1 Manitoba Hydro's Rate Request Does Not Represent Rate Shock 208
17 REGULATORY DEFERRAL ACCOUNTS AND INTERIM APPROVALS 212
17.1 Regulatory Deferral Accounts 212
17.1.1 Conawapa Generating Station 213
17.1.2 Depreciation Methodology 214
17.1.3 Ineligible Overhead 216

17.1.4 Gains and Losses on the Disposition of Assets 218
17.1.5 Bipole III Revenue Deferral 219
17.2 Interim Orders 221

Appendices

14.1 Legislative Assembly of Manitoba, Debates and Proceedings, 2nd Session 37th Legislature, May 30, 2001 at page 2505 (Hon. Greg Selinger)
14.2 *Advocacy Centre for Tenants-Ontario v. Ontario Energy Board*, 2008 CanLII 23487 (Ont Sup Ct J)
14.3 *Dalhousie Legal Aid Service v. Nova Scotia Power Inc.*, 2006 NSCA 74 at paragraph 24, leave to appeal to SCC refused 31627 (January 18, 2007)
14.4 *British Columbia Old Age Pensioners' Organization v British Columbia Utilities Commission,* 2017 BCCA 400
17.1 List of Public Utilities Board Ex-Parte and Interim Orders

1. REQUESTED APPROVALS AND SUMMARY OF REASONS FOR THE RATE INCREASES

1.1 Background and Overview of Approvals Sought

In its 2017/18 & 2018/19 General Rate Application ("GRA"), Manitoba Hydro is seeking final approval of the 3.36% across-the-board rate increases implemented effective August 1, 2016 and August 1, 2017 (approved on an interim basis in Orders 59/16 and 80/17), as well as final approval of a 7.9% across-the-board rate increase effective April 1, 2018.

On November 18, 2015, Manitoba Hydro filed its 2016/17 Supplemental Filing seeking approval of an across-the-board rate increase of 3.95% effective April 1, 2016. The review of Manitoba Hydro's application resulted in Order 59/16, issued April 28, 2016, approving an across-the-board rate increase of 3.36% effective August 1, 2016.

On May 5, 2017, Manitoba Hydro filed its 2017/18 & 2018/19 GRA seeking approval of rate schedules reflecting an across-the-board rate increase of 7.9% applied to all components of the rates for all customer classes, effective in each of August 1, 2017 and April 1, 2018. As part of its GRA, Manitoba Hydro requested that the PUB approve the rate increase of 7.9% on an interim basis effective August 1, 2017. On July 31, 2017 the PUB issued Order 80/17 approving an across-the-board rate increase of 3.36% effective August 1, 2017.

In addition, Manitoba Hydro's GRA is seeking approval of the following:

- Final approval of the Light Emitting Diode ("LED") rates for the Area and Roadway Lighting class (Outdoor Lighting) approved on an interim basis in Order 79/14, and approval of new LED rates for the Area and Roadway Lighting class (Sentinel Lighting), and approval to remove the Area and Roadway Lighting (Festoon Lighting) and the Area & Roadway Lighting (Christmas Lighting) from Manitoba Hydro's rate schedule. Manitoba Hydro's evidence on this topic is contained in Tab 9 of the Application. PUB Counsel touched briefly on these topics, however, no intervenors have addressed the topic during the evidentiary portion of the proceeding;
- Endorsement of modifications to the Terms and Conditions of Option 1 of the Surplus Energy Program ("SEP") that were accepted on an interim basis in Order 43/13, as outlined in Tab 9 of the Application;

- Final approval of all SEP interim ex parte rate Orders as set forth in Tab 10 of this Application, as well as any additional SEP ex parte Orders as set out in Appendix 17.1 to Manitoba Hydro's Written Final Argument and issued subsequent to this filing and prior to the PUB's Order in this matter;
- Final approval of Curtailable Rate Program ("CRP") ex parte Order 54/16 as well as any additional ex parte Orders in respect of the CRP issued subsequent to this filing and prior to the PUB's Order in this matter;
- Endorsement of the proposed deferral and subsequent amortization of costs incurred with respect to the Conawapa Generating Station project, as discussed in Tab 3 of Manitoba Hydro's Application; and
- Endorsement of the proposed amortization period for disposition of the regulatory deferral accounts established to capture differences between overhead costs as well as gains and losses on disposition of assets calculated for financial reporting purposes based on International Financial Reporting Standards, and the amounts calculated for rate-setting purposes reflecting Order 73/15. Further details are outlined in Section 17.
- Endorsement of the proposed time frame for the recognition into revenue of the Bipole III deferral account established by Manitoba Hydro consistent with the direction provided by the PUB in Order 43/13. Further details are outlined in Section 17.
- Manitoba Hydro is not seeking final approval of the amortization period for the disposition of differences in depreciation methodology at this time. Manitoba Hydro is supportive of finding an alternate process where the requirements of the depreciation directives as set out in Order 43/13 can be discussed and resolution of this issue can be achieved. Further details are outlined in Section 17.

Manitoba Hydro notes that it is not seeking final approval of Orders 17/04, 46/04,/159/04, 176/04, 1/10, 134/10, 1/11, 148/11, 116/12 or 117/12 related to various interim Diesel Zone Orders. Manitoba Hydro's initial request set out in its Letter of Application filed on May 5, 2017 was made subject to confirmation that MKO has provided the parties to the Diesel Settlement Agreement with the required affidavits from representatives of signatories to the Agreement. Such confirmation has not been filed in this proceeding.

Manitoba Hydro accepts that it is difficult to impose a further rate increase to recover the shortfall in revenue arising from the difference between the requested 7.9% interim rate increase requested for August 1, 2017 and the interim rate increase of 3.36% approved by the PUB in Order 80/17 (Transcript page 805-806). As such, consistent with the evidence of both Kelvin Shepherd and Jamie McCallum, Manitoba Hydro is not seeking additional rate increases for fiscal 2017/18, recognizing the impact of the requested rate increase on consumers.

1.1 Organization of the Final Argument

Manitoba Hydro's Final Argument is organized as follows:

- Section 1 provides an overview of the approvals requested in the 2017/18 & 2018/19 GRA;
- Section 2 provides an overview of the facts supporting Manitoba Hydro's requested 7.9% rate increase;
- Section 3 provides an overview of Manitoba Hydro's financial plan, the role and ownership of equity and why a 20-year plan to address the Corporation's financial condition does not work;
- Section 4 outlines the reasons for the deterioration in Manitoba Hydro's financial outlook;
- Section 5 provides an overview of the significant increase in debt levels and exposure to interest rate risk, and the need for rate increases in order to meet financial targets;
- Section 6 provides an overview of Manitoba Hydro's financial targets and the role of reserves in managing Manitoba Hydro's risks;
- Section 7 outlines the limited value of long-term forecasts and the myth of "promised" 3.95% rate increases;
- Section 8 outlines the reasons for the decrease in projected revenues, including an overview of the load forecast, export revenues and price forecast, and interest rate outlook;
- Section 9 provides an overview of business operations capital, Manitoba Hydro's plans regarding asset management initiatives, and a response to recommendations for additional regulatory oversight;
- Section 10 outlines Manitoba Hydro's position with respect to various issues related to the Keeyask Generating Station, Bipole III, Manitoba-Minnesota Transmission Line, and the Great Northern Transmission Line;

- Section 11 outlines Manitoba Hydro's debt management strategy and the importance of cash flows generated through rate increases;
- Section 12 provides an overview of Manitoba Hydro's Operating & Maintenance cost reduction measures, and Manitoba Hydro's response to recommendations related to performance metrics;
- Section 13 provides Manitoba Hydro's position regarding the evidence on rate increases on the Manitoba Economy;
- Section 14 provides an overview of Manitoba Hydro's initiatives to address bill affordability;
- Section 15 provides Manitoba Hydro's response to Cost of Service and rate design issues raised during the proceedings;
- Section 16 outlines why Manitoba Hydro's requested rate increases do not constitute rate shock; and,
- Section 17 provides an overview of the approvals requested with regards to regulatory deferral accounts and the finalization of PUB Interim Orders.

2 A 7.9% RATE INCREASE CANNOT BE WRONG

2.1 Manitoba Hydro Needs the Rate Increases Requested in this Application

It is essential that the 7.9% rate increase that Manitoba Hydro has requested for April 1, 2018 be approved. There has been no evidence presented that contradicts the necessity of this increase. Regardless of conclusions on the appropriate capital targets and timing for achievement, on a cost recovery basis the present and immediate future circumstances of Manitoba Hydro give the PUB ample justification for an even greater increase to current rates than Manitoba Hydro is requesting for the 2018/19 fiscal year.

The requested April 1, 2018 rate increase is supported by the facts discussed in the following sections.

2.1.1 Bipole III Reliability Project Entering Service

The April 1, 2018 rate request of 7.9% is justified on the basis that it will not even address the entirety of the increase to Manitoba Hydro's revenue requirement due to the imminent in-service of Bipole III.

The Bipole III Reliability Project enters service in August 2018, which is less than six months following the conclusion of the hearing. Bipole III is an essential and necessary addition to Manitoba Hydro's system to ensure continued reliability. Bipole III adds effectively no revenue to the Manitoba Hydro system. No evidence has been presented disputing that the incremental carrying costs of this capital addition are properly added to revenue requirement to be borne by current ratepayers.

The incremental revenue requirement from Bipole III is substantial. PUB MFR 20 shows annual incremental revenue requirement (excluding amortization of the Bipole III reserve) of over $360 million per year. As shown in Manitoba Hydro's Written Rebuttal Evidence, page 31 (Exhibit MH-52), net of additional opportunity export revenues of $15 million from reduced line losses and depreciation of $20 million for the in-service Riel AC sectionalisation, the ongoing carrying costs of Bipole III are estimated to be approximately $332 million per year. Manitoba Hydro's domestic revenue in the nearly complete 2017/18 test year is estimated at $1,464 million net of rates allocated to the Bipole III reserve. On this basis, a 22.7% rate increase would be required to meet the incremental costs.

Current approved rates however include 11.1% of past increases which are being allocated to the Bipole III reserve account (inclusive of the August 1, 2017 3.36% interim increase as directed in Order 80/17). Therefore, upon in-service of Bipole III, Manitoba Hydro will begin to recognize in domestic revenue this portion of current rates. This incremental revenue will only offset approximately half of the incremental revenue requirement. An additional rate increase of approximately 10% is required in order to maintain cost recovery from current ratepayers. The requested 7.9% rate increase falls short of meeting this need.

In oral testimony (Transcript Page 6417, Lines 9-16), Mr. Bowman made the following statements:

> *"….we already have customers paying somewhere between 11 and 12 percent towards the Bipole project even though it's not in service. The first time I heard the idea, I wasn't favourable to it. I think in hindsight it was a very wise move by this Board and it's help phase that in and, as a result,* ***when Bipole comes into service there's very little more impact into rates that's isn't already built in****."* (Emphasis Added)

Mr. Bowman's erroneous assertion is based on his flawed analysis included in response to MH/MIPUG-6. Mr. Bowman includes in his analysis the benefit of amortization of the Bipole III reserve in determining the necessary rate increase over and above the 11.1% already embedded in today's rates. This is not appropriate. Manitoba Hydro corrected his analysis in on pages 30 to 31 of Exhibit MH-52 and it is reproduced below. The amortization of the Bipole III reserve reflects the accounting treatment of past rates paid already imbedded in the rate increases being deducted in determining incremental rate requirement. Mr. Bowman is effectively *"double counting"*. Moreover, the amortization is non-cash and unsustainable. It reflects a five year amortization of cash already received.

The Figure below (Figure 1.18 from Exhibit MH-52) compares Mr. Bowman's assertions to the corrected analysis which clearly supports at least a 7.9% rate increase solely in contemplation of the near immediate in-service of Bipole III.

Figure 2.1: Bipole III Rate Increases to Recover Revenue Requirement

$Millions		MH/MIPUG-6 2022	Restated PUB MFR 20 2022
Finance Expense		223	223
OM&A Costs		13	13
Depreciation		107	107
Amortization of BPIII Reserve		(71)	(80)
Capital Tax		24	24
		296	287
Add: Amort of Bipole III Deferral		71	80
		367	367
Less: Revenue assoc. with lower line losses		(15)	(15)
Less: Costs assoc. with Riel Stn.		(40)	(20)
Less: Amort of Bipole III Deferral		(71)	-
Annual Bipole III Revenue Requirement		241	332
Bipole III Total Rate Impact	1,595	**15.1%**	**20.8%**
Annual Bipole III Revenue Requirement in Current I	**11.12%**	(177)	(177)
Annual Bipole III Revenue Requirement Shortfall		64	155
Bipole III Revenue Requirement Shortfall to be Recovered in Rates		**4.0%**	**9.7%**

Source: Exhibit MH-52

2.1.2 Current Rates Not Covering Current Costs and Cash Needs

On a normalized basis, Manitoba Hydro has been experiencing effectively zero or negative net income for several years notwithstanding the growth of its asset base. This means that there has been no contribution to reserves from rates notwithstanding both Manitoba Hydro's governing legislation and the evidence of Morrison Park Advisors ("MPA") emphasizing the importance of rates including a contribution to reserves. Even excluding the essential need to make ongoing contributions to reserves, Manitoba Hydro has not been receiving sufficient rate revenue to meet its costs.

The following chart is taken from Manitoba Hydro's Policy Panel Presentation, Exhibit MH-64:

Figure 2.2 Adjusted Net Income/(Loss)

(In Millions of Dollars)	2014/15	2015/16	2016/17	2017/18
Net Income Attributable to MH	111	37	53	93
Non-Recurring Gain	-	-	(20)	-
Income Impact of Bipole III Capitalization	(8)	(15)	(32)	(54)
Above Average Water	(70)	(62)	(87)	(35)
Adjustment to Current Outlook	-	-	-	(63)
Restructuring Expenses	-	-	4	50
Adjusted Net Income/(Loss)	**33**	**(40)**	**(82)**	**(9)**

Source: Exhibit MH-64, Slide 44

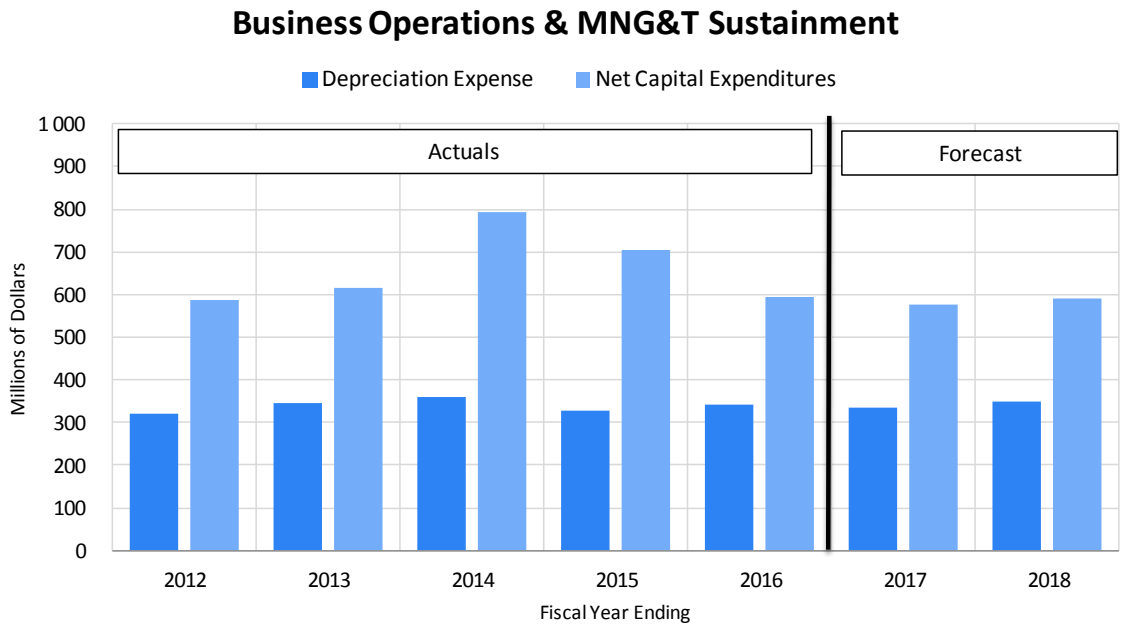
As shown in Figure 2.2, excluding the impacts of non-sustainable contributions such as above average water flows, Manitoba Hydro is in a loss-making position at current rates.

Manitoba Hydro has additional ongoing (often perpetual) payment obligations each year on account of mitigation liabilities and the purchase of Winnipeg Hydro that are only minimally captured in revenue requirement through depreciation expense. Both MPA (MH/Coalition (MPA)-2(b)) and Mr. Bowman (at Transcript Page 6398) acknowledge these costs that must be included in the calculation of rates. As noted in Figure 1.10 on page 15 of Exhibit MH-52, these obligations totaled $42 million in 2015/16, $39 million in 2016/17 and are estimated at $75 million in 2017/18. Adding these costs to revenue requirement pushes the deficiency at current rates to between $84 million and $120 million over the last three years. On its own this would support a rate increase of approximately 6% to 7% simply to restore rates to where Manitoba Hydro is meeting its revenue requirement needs as determined by the income statement and ongoing liability payments associated with its current operations and without any contribution to reserves.

Manitoba Hydro submits that the PUB should not ignore the actual cash needs of Manitoba Hydro to continue its current operations. Some accounting in rates must be made for the fact that the actual replenishment costs of the system are significantly greater than what Manitoba Hydro current recognizes in revenue requirement through depreciation expense.

In order to meet its mandate to serve existing customers and extend service to new customers, Manitoba Hydro must continually reinvest in its system. Significant portions of Manitoba Hydro's current infrastructure were built decades ago. Manitoba Hydro has provided evidence at Tab 2 of the Application, pages 15 and 18 (reproduced below) that it has a material ongoing cash shortfall at present rates due in part to a substantial difference - over $250 million a year - between what it recovers in revenue requirement through annual depreciation charges and what it must expend annually to maintain, replace and enhance existing infrastructure in the normal course. The issue is that depreciation expense is determined based on the historical cost of assets when they were first installed. Manitoba Hydro's reality is that the cost of replacing these assets as they expire is an ongoing cash need that comes in the form of today's costs which, due to the age of its infrastructure and inflation in construction costs, bears almost no relationship to historical cost.

Figure 2.3



Source: Tab 2 of the Application, Page 15

Arguments opposing accommodating in rates the need to replenish the system are not valid. The suggestion that the cost of replacement equipment, while substantially more than the original cost of the assets being replaced, will be recovered in depreciation

over the life of the assets ignores cost and capital structure realities faced by the Corporation. Rate-making principles will be referenced in support of that argument. However, the principles cited are only sustainable in a rate of return based environment, not a cost recovery environment. A rate of return framework allows the utility to maintain adequate equity capitalization such that it does not need to increase only its debt simply to fund its operations. Manitoba Hydro has no such luxury. Without the support of rate revenue (i.e. net income and contribution to reserves), all investment in the ongoing core system in excess of depreciation expense must be debt funded which has, and will continue to, drive the debt of the Corporation ever higher at a rate significantly greater than its customer base or domestic load is growing. This is particularly acute in Manitoba Hydro's situation given the stagnant growth environment Manitoba Hydro finds itself in and the age of its asset fleet. Declining interest rates and above average water conditions have helped to obscure this issue but lack of rate support for reinvestment capital has become a critical matter for Manitoba Hydro's finances. In Manitoba Hydro's view, the PUB must consider the current costs of replacing the assets current ratepayers are depleting. A proper reading of the Bonbright principles finds no fault in doing so[1], particularly in the absence of a rate of return principle by which the Corporation can attract capital and remain financially sustainable (also a key Bonbright criterion[2]).

Bonbright discusses whether rate base should be set at historical cost less depreciation, or at some proxy for replacement value noting that this debate is the *"most widely disputed legal issue in the history of American public utility regulation."*[3] Bonbright does not take the position that replacement value based regulation is indefensible as suggested by Intervenors. To the contrary, Bonbright reviews the difficult question of determining value and the relative merits of different approaches, in different circumstances. Manitoba Hydro must wait to see how Intervenors address these various approaches and their application to Manitoba Hydro's unique corporate structure, in their final submissions in order to make informed comment. At this juncture, Manitoba Hydro would argue that all Bonbright requires is that the application of his various and sometimes competing principles be guided by the overarching public interest principle

[1] Principles of Public Utility Rates, James C. Bonbright, 1961, Chapters 11, 12 and 15.
[2] Principles of Public Utility Rates, James C. Bonbright, 1961, page 385.

[3] Principles of Public Utility Rates, James C. Bonbright, 1961, page 159.

(Bonbright's *"assumed goal of ratemaking"*[4]), and that the application of regulatory principles should never cause a utility to become financially unstable.

When the actual cash costs of replacing system assets are properly considered, a picture of substantial cash deficiency emerges as shown at page 15 of Exhibit MH-52, Figure 1.10, reproduced below:

Figure 2.4 Cash Flow (Deficiency)/Surplus

millions of dollars

	Actual		Forecast									
	2016	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Receipts from Customers	1 907	1 997	2 152	2 170	2 173	2 371	2 577	2 734	2 821	2 931	2 897	3 011
Payments to Suppliers and Employees	(736)	(933)	(892)	(843)	(870)	(885)	(894)	(903)	(935)	(953)	(952)	(966)
Interest Paid (Net of All Capitalized Interest)	(520)	(536)	(528)	(641)	(711)	(789)	(889)	(1 155)	(1 227)	(1 239)	(1 241)	(1 266)
Bipole III and Other Business Operations Capitalized Interest*	(107)	(141)	(197)	(93)	(21)	(18)	(16)	(19)	(19)	(19)	(18)	(20)
Business Operations and Deferred Capital Expenditures:												
Business Operations Capital Expenditures**	(616)	(578)	(586)	(566)	(554)	(544)	(525)	(532)	(544)	(601)	(627)	(646)
Demand Side Management	(54)	(50)	(55)	(97)	(92)	(87)	(85)	(64)	(58)	(60)	(64)	(68)
Mitigation and Other Deferred Expenditures	(22)	(5)	(27)	(26)	(23)	(23)	(22)	(22)	(21)	(22)	(21)	(22)
Ineligible Overhead	(20)	(20)	(20)	(20)	(20)	(20)	(20)	(20)	-	-	-	-
Cash From Operations Less Capex	**(167)**	**(267)**	**(153)**	**(116)**	**(119)**	**5**	**126**	**19**	**16**	**38**	**(26)**	**24**
Mitigation, Major Development & Other Liability Payments	(26)	(13)	(59)	(46)	(36)	(79)	(98)	(88)	(84)	(84)	(71)	(70)
City of Winnipeg Payments	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)
Cash Flow (Deficiency)/Surplus	**(209)**	**(296)**	**(228)**	**(178)**	**(170)**	**(89)**	**12**	**(85)**	**(84)**	**(62)**	**(113)**	**(62)**
Cumulative Cash Flow (Deficiency)/Surplus			**(228)**	**(406)**	**(576)**	**(665)**	**(653)**	**(739)**	**(823)**	**(884)**	**(998)**	**(1 060)**

*Bipole III and Other Sustaining Capitalized Interest does not include any capitalized interest associated with Keeyask, MMTP or GNTL.
**Represents Business Operations Capital Expenditures and MNG&T Capital Expenditures of a sustaining nature (excluding Bipole III costs).

Source: Exhibit MH-52, Page 52

The projections above are based on MH15 rates (i.e. 3.95% per year) for 2019 and beyond. However, the table clearly denotes that Manitoba Hydro has, in the last two years and the current year, been operating with a cash deficiency of between $153 million and $267 million. This alone would represent rate inadequacy of 10% to 18%. Adding the above noted costs for liability payments (mitigation, City of Winnipeg) brings the deficit range from $209 million to $296 million indicating rate insufficiency of approximately 14% to 20%. The results for 2015/16 and 2016/17 include the contributions from significantly above average water flow conditions. Likewise, the figures above for the 2017/18 and 2018/19 fiscal years assume high water flow conditions and have not been adjusted for Manitoba Hydro's updated outlook after a relatively dry summer. Manitoba Hydro has provided evidence (Exhibit MH-64, Slide 19)

[4] Principles of Public Utility Rates, James C. Bonbright, 1961, Chapter 2.

that above average water flow conditions contributed $62 million and $87 million in 2015/16 and 2016/17 respectively and, in the MH16 Update with Interim forecast, were anticipated to contribute $91 million in 2017/18. Cash flows should also be adjusted for non-recurring restructuring charges. Together, this pushes the cash deficit from operations, on a normalized basis, to between $271 million and $379 million representing rate inadequacy of between 17% and 25% (as summarized in Figure 2.5 below).

Figure 2.5 Rate Insufficiency

($ millions)	2015/16	2016/17	2017/18
Cash from Operations less capex	(167)	(267)	(153)
Liability Payments	(42)	(39)	(75)
Cash Flow Deficiency	($209)	($296)	($228)
Adjustment for Water Conditions	(62)	(87)	(91)
Restructuring Costs	--	4	50
Normalized Cash Deficiency	($271)	($379)	($269)
Domestic Rate Revenue*	$1,450	$1,515	$1,615
Rate Insufficiency	***18.9%***	***25.0%***	***16.7%***

* Including contributions to Bipole III reserve

Therefore, by any measure the 7.9% rate increase requested for April 1, 2018 is justified by the need to address rate inadequacy today.

2.1.3 Impact of Keeyask on future cost structure must be taken into consideration

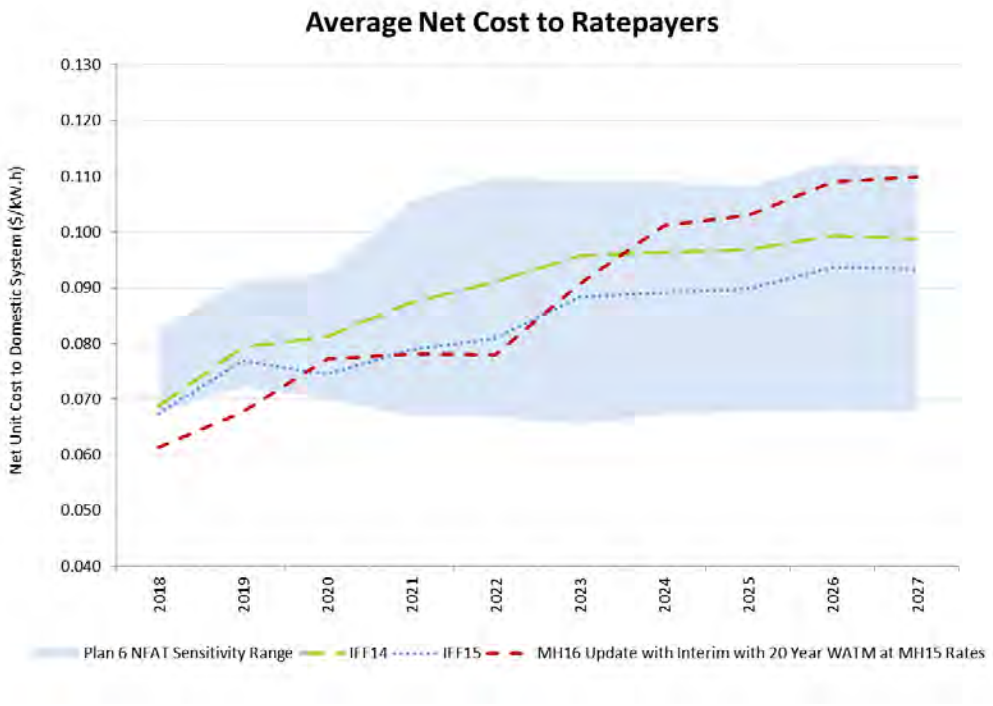
The Keeyask Generating Station is anticipated to provide first power in August of 2021 and be essentially fully in-service by the end of the 2022/23 fiscal year. Once this occurs, the incremental revenue, operating and carrying costs will impact Manitoba Hydro revenue requirement. Unfortunately, based on the current capital cost estimate and outlook for export prices, it is anticipated that the net impact to Manitoba Hydro's revenue requirement going forward will be negative and substantial. As identified in PUB MFR 20, the 2023/24 incremental costs of Keeyask will be $581 million which is anticipated to be more than double the incremental export revenue assuming normal

water conditions. The erosion of forecast load growth since NFAT has now pushed the date at which Keeyask is required to serve domestic load until at least the early 2030s. Given the outlook for export prices there results a significant cost for excess capacity which must be borne by ratepayers.

Manitoba Hydro asserts that the PUB, as it wisely did with Bipole III, must take a strong step now by approving the 7.9% rate request so as to begin incorporating into rates the pending impact of Keeyask. This is particularly so given the risk of further capital cost increases, the loss of an assumed major new load due to an energy sector project cancellation and further delayed recovery of export prices. Manitoba Hydro has provided testimony on these factors, none of which are reflected in MH16 Update with Interim.

The following chart from slide 70 of Exhibit MH-64 reflects net unit costs (costs net of export revenues) on a forecast basis:

Figure 2.6



Source: Exhibit MH-64, Slide 70

As can be seen above, unit costs are increasing sharply over the next six years driven by the in-service of the major capital projects. As demonstrated in Figure 1.1 of MH Exhibit 52 at page 2, net costs are estimated to increase 65% between 2017/18 ($0.061 per kWh of domestic load) and 2023/24 ($0.100 per kWh). It should be recognized that net unit costs do not include any contribution to reserves which might address capital renewal, debt retirement and rate stability. It is this net unit cost Manitoba Hydro must presumably, at a minimum, recover in rates. A 65% rate increase over six years is equivalent to 8.7% per year. On this basis, a first step of 7.9% as requested for April 1, 2018 is fully justified. It may even prove inadequate considering some of the potential risks to unit costs from the more up-to-date outlook for load growth and export prices and ongoing risks with Keeyask capital costs.

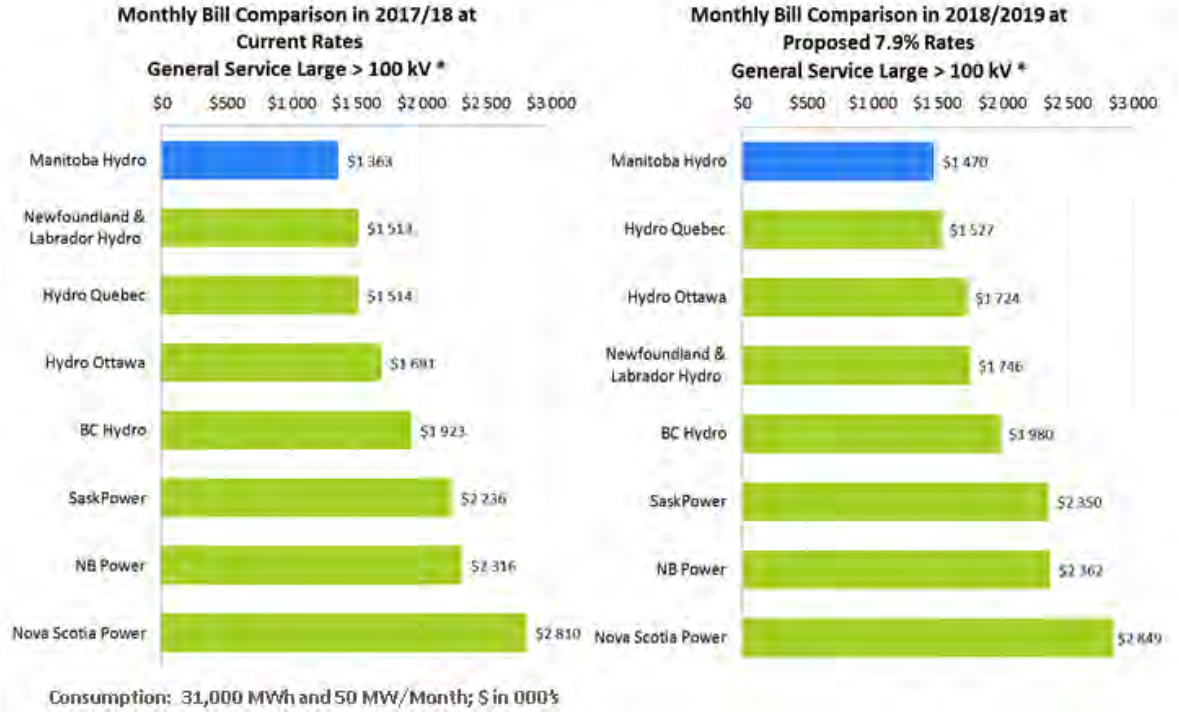
2.1.4 Electricity Rates will continue to be Competitive

Manitoba Hydro's domestic electricity rates are among the lowest in North America and support the competitiveness of Manitoba businesses. Manitobans will continue to enjoy a distinct advantage over most other Canadian jurisdictions with respect to the average monthly bills of residential and business customers. As shown in **Figure 2.7** (Exhibit MH-64, Slide 12) and **Figure 2.8** below (Exhibit MH-64, Slide 13), this advantage continued after implementation of the 3.36% effective August 1, 2017 and will continue with the proposed 7.9% rate increase effective April 1, 2018.

Figure 2.7



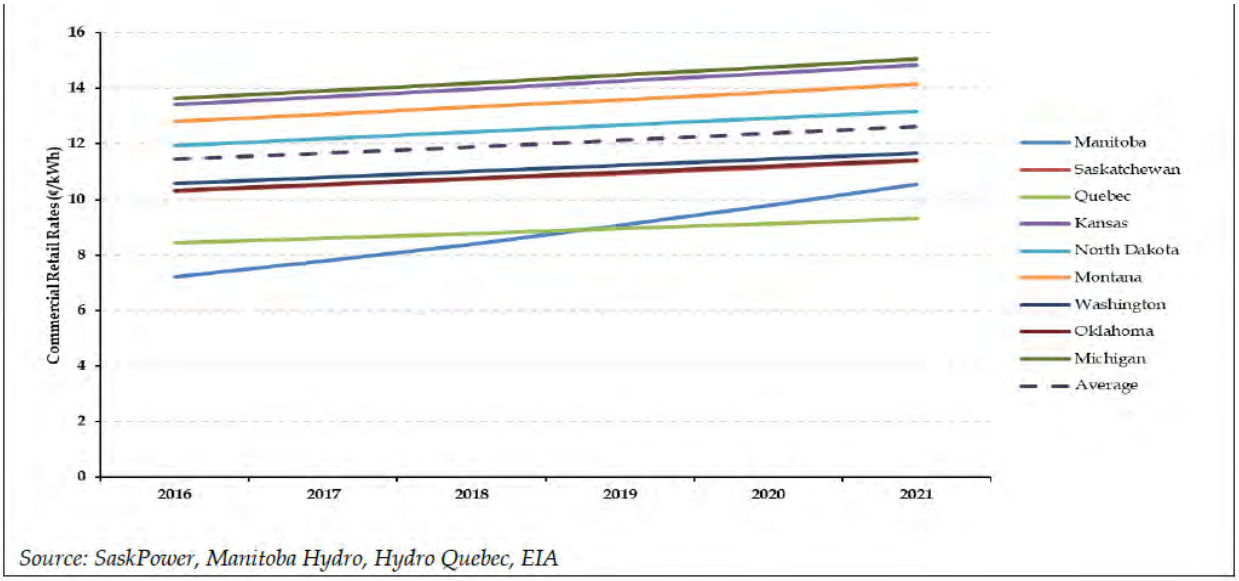
Figure 2.8



The reality of rate increases above inflation is not confined to Manitoba customers. As noted by Mr. Shepherd at Transcript Page 145, *"broadly speaking, electricity costs are going up at rates higher than inflation as utilities throughout North America grapple with changing demand patterns, higher regulatory costs, aging infrastructure, and for many, the transition from carbon generating sources to renewables."* While Manitoba Hydro is seeking rate increases in this proceeding that are above the rate of inflation, the evidence demonstrates that Manitoba customers will continue to be in a much better position in terms of electricity costs than customers in other jurisdictions, and that rates have considerable room to grow before Manitoba Hydro becomes even an average jurisdiction.

This is further demonstrated by the evidence provided by London Economic International ("LEI") in this proceeding. While LEI suggests in its evidence, filed on behalf of General Service Small and General Service Medium Customer Classes, Exhibit GSS-9, at page 16 that annual rate increases of 7.9% over five years will erode Manitoba Hydro's competitive margin on commercial rates compared to other jurisdictions, the same figure demonstrates that Manitoba Hydro will continue to be in the lowest quartile of commercial retail rates even after five years of indicative 7.9% rate increases.

Figure 2.9. Commercial retail rates of Manitoba compared to other jurisdictions



Source: SaskPower, Manitoba Hydro, Hydro Quebec, EIA

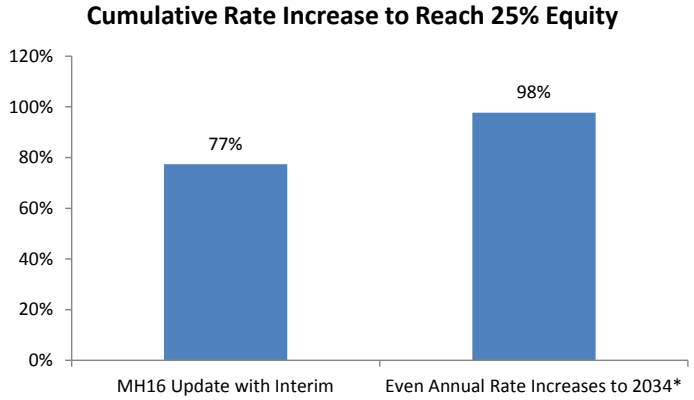
3 MANITOBA HYDRO'S NEW FINANCIAL PLAN

3.1 Taking Action on Unsustainable Debt Levels

Manitoba Hydro's new financial plan is necessary to ensure the financial sustainability of the Corporation. In doing so it ensures that, in the intermediate and long-term, customers will benefit from more rate certainty, less rate volatility and overall lower rates. While short term adjustment is required, the broader Manitoba economy benefits from a higher level of long term cost certainty for existing and new businesses considering investment in addition to the certainty of lower rates in the long term relative to plans that see Manitoba Hydro carrying a larger debt burden and for longer.

Manitoba Hydro's plan represents an acceleration of rate increases but, overall, the ability to keep rates lower in the long run as seen in **Figure 3.1** below:

Figure 3.1 Even Annual Rate Increases of 4.14% To Reach 25% Equity Ratio By 2033/34



Source: Coalition/MH II-19,

Manitoba Hydro's plan is centered on taking action on the growth of debt to unsustainable levels. It does so by setting a rate plan which, when coupled with far more aggressive cost efficiency measures already implemented by Manitoba Hydro, enables the Corporation to generate positive net income and positive cash flow which can be used to modestly slow the accumulation of debt while Keeyask is completed and reduce debt once the project is in service. By taking more aggressive action now and over the next decade, the following is achieved:

3.1.1 Greater flexibility

MH16 Update with Interim is a financial plan based on numerable assumptions. It is a balanced best estimate of an unknowable future. The value of taking stronger rate action now is to provide greater flexibility to make different choices as the future unfolds.

The pattern of prior forecasts demonstrates a history of successive downward revisions to export price expectations and load growth forecasts. Likewise, expectations of capital costs have increased. The situation has not become more dire only by virtue of interest rates having declined in comparison to prior outlooks and the benefits of 14 years of higher than average water flows.

By implementing stronger rate action now, Manitoba Hydro is building its balance sheet to be more resilient in the face of uncertainty. As noted by Mr. Shepherd, Manitoba Hydro has more hydrology and export price risk than any other Crown-owned, hydro-based utility:

> *"No other major hydroelectric utility has the volatility in water conditions we face, nor does anyone else have such a small reservoir relative to their operations. Our exposure to mother nature in that respect is quite extreme. By just about any measure, we are heading towards having more debt than almost anyone else in our industry, and certainly more debt relative to the size of our business than potentially we have ever had"* (Transcript Page 196).

Mr. Shepherd further noted that while not exposed to fuel price volatility similar to a coal or natural gas utility, by financing itself in such an extreme manner, Manitoba Hydro is effectively replacing commodity price volatility with interest price volatility:

> *"We can't borrow at a fixed rate for the seventy (70) or a hundred years our generators are expected to last, so we are perpetually exposed to interest rate risk, all of which is borne by a relatively small customer base"* (Transcript Page 196)

The risks Manitoba Hydro needs net income and positive cash flow to address are not theoretical. Rising interest rates, softening export prices, slower load growth and low

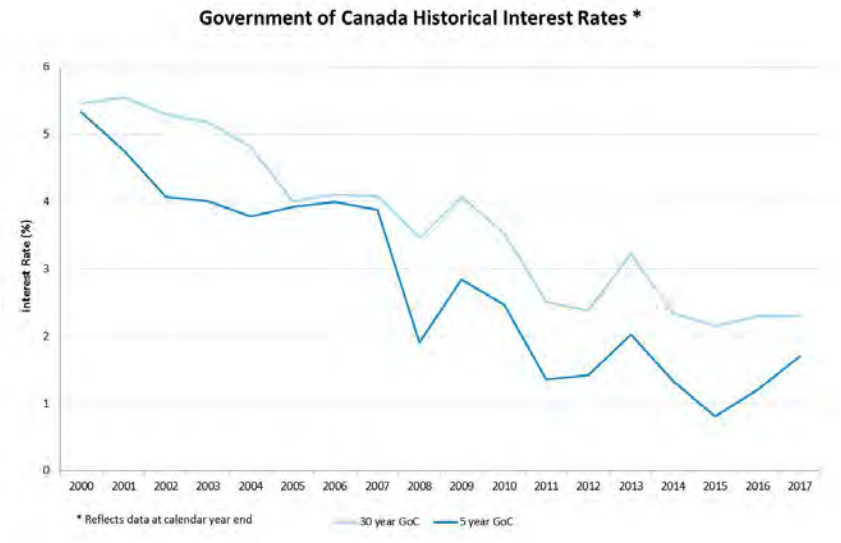
water conditions have all been experienced before. A financial plan that does not include meaningful net income (relative to the scale of the assets and debt) offers no flexibility for the utility and its regulator to consider measured, patient responses to key planning assumptions being wrong.

3.1.2 Lessening interest rate risk

Annual interest payments will be, by a factor of two, the single largest burden on the Corporation by 2023/24. Even under the Manitoba Hydro plan, interest costs will consume $1.14 billion per year as shown in Appendix 3.8 of the Application. Current domestic rate revenues are $1.6 billion (including amounts allocated to the Bipole III reserve). Therefore without rate increases, interest will consume approximately 70% of each ratepayer dollar. With this level of interest expense relative to overall costs and revenues, Manitoba Hydro has no latitude to be wrong on interest rates.

As the **Figure 3.2** shows, interest rates have declined significantly since 2000:

Figure 3.2



Source: Exhibit MH-64, page 68

With interest rates at multi-generational lows already and practically speaking unable to go to 0%, it is clear that the risks of interest rate volatility are asymmetrical in nature. There is an extremely limited amount by which rates can go down further and an unlimited potential for increase. Exposing the Corporation, its customers and the

Province of Manitoba to this level of risk over 20 years is imprudent. History has shown – as does the chart above – that interest rates can often move 3 to 5% or more in a 10 or 15 year period. Almost all of Manitoba Hydro's debt is exposed to interest rate risk over the next 10 years (Manitoba Hydro's Written Rebuttal Evidence, Exhibit MH-52, Pages 11 to 14). An unforeseen interest rate increase of even 1% could cost Manitoba Hydro ratepayers an additional $200 million or more per year by the end of the next decade. A more focused approach to debt reduction helps mitigate part of this risk.

Address cash flow

While noting the apparent migration in views since NFAT (CAC/MPA I-002), Morrison Park Advisors ("MPA") asserts that cash flow is the principle concern of capital market participants in assessing Manitoba Hydro (in the context of their rating of the credit quality of the Province of Manitoba). As noted in MPA Evidence filed on behalf of the Consumer's Coalition, Exhibit CC-17, page 3, lines 35-37:

> *"It is apparent from reading various financial market reports that a primary focus is on the expected sufficiency of cash flows to satisfy debt obligations."*

Coalition/MH I-68f includes a cash flow from operations to CapEx table which updates Figure 2.16 from the Tab 2 of the Application for MH16 Update with Interim. That table only captures a portion of the cash flow deficiency in that payments on account of mitigation and City of Winnipeg liabilities are not captured. The following table in **Figure 3.3** augments Figure 2.16 (Updated) from Coalition/MH I-68f.

Figure 3.3

($ millions)

	MH16 Update with Interim				
	2018	**2019**	**2020**	**2021**	**2022**
Cash Flow Deficiency / Surplus	**(151)**	**(35)**	**49**	**269**	**501**
Mitigation, Major Development & Other Liability Payments	(59)	(46)	(36)	(79)	(98)
City of Winnipeg Payments	(16)	(16)	(16)	(16)	(16)
Cash flow from Operations	**(226)**	**(98)**	**(2)**	**174**	**387**
Cumulative Cash Flow Deficiency / Surplus	**(226)**	**(324)**	**(326)**	**(152)**	**235**

Source: Coalition/MH I-68f

The analysis above shows that the Manitoba Hydro plan takes a prudent, measured and multi-year approach to addressing the ongoing cash flow shortfall the Corporation is enduring at current rates. In the fourth year of the plan, Manitoba Hydro returns to a

cash flow positive condition. However, for the first five years of the plan, in aggregate Manitoba Hydro is essentially cash flow breakeven with only a modest $235 million being made available for debt reduction. This amounts to approximately 1% of Manitoba Hydro's forecast net debt of $23.6 billion in 2022 under the MH16 Update with Interim rate path.

Operating for at least three years with continued negative cash flow and taking five years to be cumulatively breakeven is, in Manitoba Hydro's assessment, at the outer bounds of credible as a commitment to having ratepayers meet the obligations of operating the utility and servicing its debts. The recent past has shown that outlooks can change and deteriorate quickly. In that context and in a quickly evolving utility industry, a willingness to endure multi-year cash flow shortfalls should not be expected to be well received by the debt investors who Manitoba Hydro seeks to have fund its balance sheet.

<u>Cap maximum debt at NFAT levels</u>

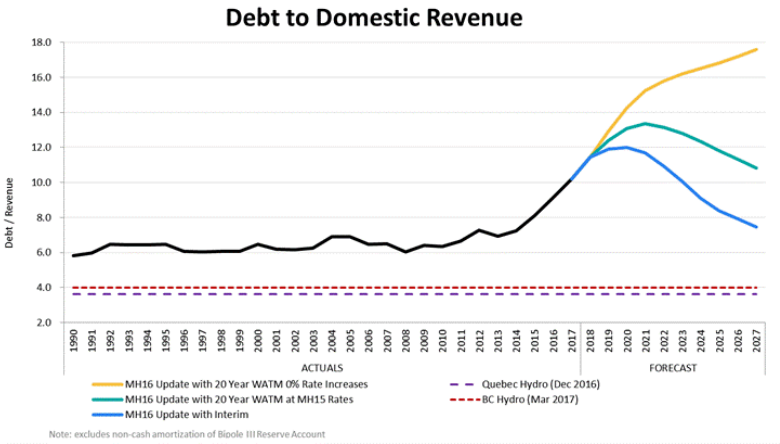
The overall deterioration of the outlook for Manitoba Hydro is discussed at Section 4. However, the consequence of the increase in capital costs, reduction in load growth and weaker export pricing is that net debt levels will peak at significantly higher levels than under any prior forecast (as shown in Manitoba Hydro Follow-up to Undertakings 7 & 8, Exhibit MH-93, Page 14).

The Manitoba Hydro plan takes action to address debt growth beyond forecast levels in NFAT. Under the NFAT Plan 5, net debt would peak at $21.6 billion in 2022/23, roughly three years after the then planned in-service of Keeyask. Under MH16 Update with Interim, the *"Manitoba Hydro Plan"*, debt grows to $23.6 billion which is 9% higher than the NFAT plan. It should be noted that this is to be supported by a domestic load that is expected to be 7% smaller than under the NFAT projection thus compounding the vulnerability of Manitoba Hydro and its customers to a debt that will grow to at least 12 multiples of domestic revenues.

The chart below in **Figure 3.4** from Manitoba Hydro's Policy Panel Presentation (Exhibit MH-64) demonstrates the relationship between debt and revenue dating back to the early 1990's when the Limestone Generating Station was brought into service. Even

under the Manitoba Hydro Plan, debt levels will still be, on a relative basis, roughly 30% higher than they were in the period from 1990 to 2010.

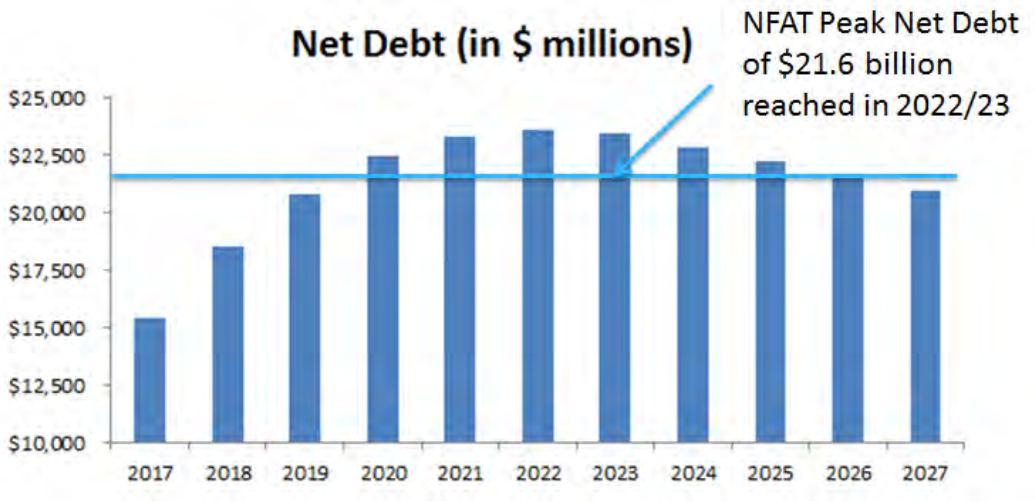
Figure 3.4



Source: Exhibit MH-64, Page 28

The chart below in **Figure 3.5** demonstrates how the Manitoba Hydro Plan will restore debt to levels contemplated under NFAT (Page 14 of Exhibit MH-93) on a longer time frame (5 years after first in service of Keeyask) than anticipated under NFAT and, as noted above, still requiring support from a smaller domestic rate base than assumed under NFAT. The Manitoba Hydro plan takes positive steps toward prudent debt management but should not by any means be understood to leave the Corporation and its customers at anything other than very high risk levels.

Figure 3.5



Source: Appendix 3.8 of the Application, Page 3

Expectation of sub-inflationary increases or better

Manitoba Hydro provided a fulsome discussion of the long-term benefits of proactively addressing Manitoba Hydro's weak and weakening balance sheet in its response to PUB/MH II-21. A reduction of debt translates to interest expenses avoided which results in reduced revenue requirement relative to plans that do not address unsustainable debt load. While Manitoba Hydro acknowledges its customers pay higher rates during the period of recovery, a residential customer using 1,000 kWh per month would experience lower bills over the period from 2017/18 to 2033/34, as shown in the table below.

Figure 3.6

	25% Equity Ratio Achieved	Cumulative Increase To 2026/27	Cumulative Increase To 2033/34	Average Monthly Bill - 2033/34	Cumulative Bills 2017/18 to 2033/34
PUB/MH II-21b Scenario based on MH16 - Update with Interim	2026/27	77.4%	38.8%	$121	$25,173
Coalition / MH II-19 Scenario even annual rate increases to 2033/34	2033/34	48.9%	97.7%	$172	$25,881
Difference			-60.3%	-29.9%	-2.7%

Source: PUB/MH II-21

This advantage applies even more so in a rising interest rate environment which has to be expected at some point in the next 20 years if not sooner. With significantly less debt to service and a healthier financial condition, Manitoba Hydro and its regulator will have established the flexibility to consider future rate changes with a then much clearer understanding of load growth, export pricing, interest rates and reinvestment needs for the years beyond 2027 than is available today.

Due to the inherent uncertainty associated with attempting to forecast results in the 2028 to 2036 time frame, it is impossible to predict the measures Manitoba Hydro would propose to abate equity growth to unnecessary levels. However, should Manitoba Hydro find itself in a relatively stable operating environment but with significant capital investment needs on the near to intermediate term horizon, it is reasonable to expect the pace and extent of rate increases necessary to support major renewal and growth investments will be significantly abated by entering this period with a balance sheet and rate levels capable of absorbing incremental debt financing needs.

In the alternative, without major expansion or other capital needs during or just beyond the 2028-2036 horizon, rate relief may be affordable and prudent. What ends up being appropriate in terms of rate action 10 or 15 years from now will be a function of events between now and 2027. PUB/MH II-21b demonstrates how dramatically different the future can be where the only difference is the time taken to restore the Corporation's financial health. The long term interests of ratepayers and the economy is served by taking steps today to bring debt back to levels that allow Manitoba Hydro to absorb risk.

3.2 Interveners have a Lack of Comprehension with respect to Role and Ownership of Equity

Manitoba Hydro's review of Intervener evidence reveals fundamental misunderstandings about the role of equity. A principal argument put forward by MPA and Mr. Bowman (Transcript Pages 4916, and 6420 to 6424) is that Manitoba Hydro's equity need only be scaled in some proportion to the financial erosion anticipated from a five or seven year drought. This argument continues that Manitoba Hydro's plan to build its equity to $6.9 billion by the end of 2026/27 is excessive in the face of losses on a five or seven year drought that are in the order of $1.2 billion to $1.5 billion.

The reality is that equity is not cash. MPA and Mr. Bowman both acknowledge this (Transcript Pages 5114 and 6382). Mr. Bowman also acknowledges that of Manitoba Hydro's $2.9 billion of equity, 90% was created more than 5 years ago and 75% was created during and before 2009 (Transcript Pages 6380 to 6382).

Equity in and of itself is of no useful service to Manitoba Hydro in the event of financial distress. Regardless of the equity recorded on the balance sheet, in the absence of rate adequacy to cover its costs, Manitoba Hydro will have to borrow money or raise rates. Equity is not a reserve funded with cash that can be drawn down to absorb losses. The value of a strong equity balance is it represents debt not borrowed and therefore interest payments that do not need to be made. The notion, put forward by MPA that equity represents Manitoba Hydro's capacity to borrow further and up to the value of its assets (Transcript Page 4859) is preposterous. It suggests there is no consequence to simply adding to the Corporation's debt burden in times of distress, forecast error or otherwise. A fundamental principal of Manitoba Hydro's Application is that debt growth in dollar terms must be curbed.

The financial risk facing Manitoba Hydro, its customers and the Province of Manitoba is driven by the absolute level of debt on its balance sheet. The customers of Manitoba Hydro are a finite group. $25 billion of debt represents the actual liability of the Company that must be met with cash payments of interest each year. It is a substantial burden for the customers of Manitoba Hydro to bear regardless of the notional equity balance (which is, in the Corporation's case, an accounting construct representing the aggregate net income of the Corporation since its inception).

The Interveners are caught in a myopic worldview that drought is Manitoba Hydro's largest financial risk and therefore reserves must only be scaled accordingly. In the short term, drought is Manitoba Hydro's largest potential financial loss. But drought will presumably have an end and therefore the erosion has a limit. Absent the rate adequacy Manitoba Hydro is proposing, a drought will be entirely debt funded and, in the 5 year example, add $1.2 billion (PUB/MH II-40 Figure 2) to Manitoba Hydro's $25 billion debt. This is dwarfed in comparison by the effectively limitless and perpetual damage that will be delivered upon Manitoba Hydro's ratepayers if steps are not taken to address the $25 billion debt balance while it is still manageable (i.e. before interest rates rise). If Manitoba Hydro and its customers find themselves on the wrong side of a long-term systemic rise in interest rates, the financial consequences are almost impossible to quantify. As can be seen in the response to MIPUG/MH II-19a, 10 years ago, the Government of Canada long bond yield was 200 basis points (2%) higher than it is today and 20 years ago it was over 500 basis points (5%) higher. On $25 billion of debt, even a return of interest rates to long term historical averages could cost Manitoba Hydro ratepayers hundreds of millions of dollars per year and, unlike with drought, no expectation of relatively near term abatement.

Manitoba Hydro's pursuit of the 75:25 Debt:Equity ratio is driven entirely by the need to reduce absolute levels of debt to levels consistent with NFAT (i.e. $21.5 billion)(Exhibit MH-93) albeit further in the future which presents incremental risk. Were it not for the importance of balancing rate action with customer impacts, more prescriptive action would be advocated.

The PUB clearly understood the intrinsic relationships between the concepts of the equity ratio, absolute debt levels, financial risk to ratepayers and ratepayer impacts in Order 90/08, pages 3-7:

"Notwithstanding the Board's appreciation of the negative implications of rate increases for MH's customers, and the Board's particular and on-going concern for low-income households, particularly, in this case, those relying on electricity for space heating, the Board will provide MH with a greater increase than the Corporation sought. This, because of a combination of concerns that are briefly cited below, matters the Board will elaborate on in more detail in a subsequent Order:

a) In its application, MH advised that its proposed series of 2.9% increases were required to maintain progress towards the eventual attainment of the Corporation's financial targets, primarily the achievement of the long-sought but not achieved target debt to equity ratio of 75:25. MH projected that notwithstanding its forecasts of annual rate increases and the assumption of continuing success with export markets, and taking into account forecast net income for 2007/09 to achieve or exceed $300 million, it still did not expect to achieve the debt:equity financial target of 75:25 by 2017/18 (let alone the current or previous earlier target dates);

Herein, and to be discussed in considerable depth in the subsequent Order, ***the Board reconfirms the validity of the targeted debt:equity ratio of 75:25, while expressing concern as to the likelihood of its achievement.***

b) MH's plans for capital expenditures may involve the expenditure of $18 billion or more over the next 15 years, expenditures predicated in part on what may or may not be overly optimistic export prices – ***this level of capital expenditure will result in significantly increased debt levels, export commitments and general business risks****;…*

g) ***Continuing business risks related to interest rates (now at recent historic lows)****, the risk of further currency fluctuations, drought, inflation, market access problems, and other concerns…*

> ***The Board is focused on the risks that lie ahead and determined to ensure as reasonably as possible that MH has the financial strength to meet the risks."*** (Emphasis Added)

MPA's views in this hearing on the value of equity during a drought, as canvassed by Mr. Ghikas during cross-examination of Mr. Colaiacovo at Transcript Page 4992, stand in contrast to views during NFAT when MPA was an Independent Expert Consultant ("IEC") to the PUB. At that time its concern with debt levels was more apparent as noted at CAC/MPA I-013

> *"The critical issue is the magnitude of outstanding debt on the balance sheet, not the size of the retained earnings. In the event of a persistent revenue shortfall caused by prolonged drought, for example, interest charges related to a large outstanding debt represent a real call on cash flow. A large pool of retained earnings in this environment would be beneficial in that the company balance sheet potentially could sustain a series of annual losses, but balance sheet retained earnings bear little relationship to the availability of cash resources."*

A further confusion amongst the Interveners is the idea that Manitoba Hydro's equity represents customer contributions *"held in trust"* and for their benefit as there is no *"shareholder per se"*. Therefore, such contributions must be limited to the greatest extent possible so as to minimize the opportunity cost to ratepayers of having their funds tied up in the reserves or retained earnings of the Corporation. This is false. Manitoba Hydro has an owner. It is the Province of Manitoba. Even in a *"cost-recovery"* framework, any residual revenue collected in excess of costs accrues to the equity holder. Manitoba Hydro gave considerable testimony during the direct evidence of its Policy Panel (Transcript Pages 230 to 236) regarding the nature of the relationship between Manitoba Hydro, its customers and the Province of Manitoba as shareholders. The Province of Manitoba is the beneficiary of Manitoba Hydro's equity as its owner. While it does not earn a return (or dividend) on such equity, it is still entitled to the assurance of sufficient reserves to be retained in the utility to severely limit the risk of being called upon to assist in the funding and support of the utility. Therefore, the duty of the ratepayer is to fund such reserve contribution with no expectation of refund or return.

Funding of net income through rates is the cost of providing for the buffer (i.e. net income reserves) that must be maintained and added to proportionately as the Corporation's asset base and debt grows so as to limit the likelihood of taxpayer funded intervention at any point including one of financial distress. This is the *"quid pro quo"* of Manitoba Hydro's relationship with the Province of Manitoba under which it is able to obtain financing at highly preferential terms to that which the Corporation could on its own and all for the benefit and account of the ratepayer. Absolute dollar levels of equity comprised of historical retained earnings are irrelevant to the fiscal management of the Corporation. It is the addition to equity reserves from regular and sufficient net income that abates the absolute level of debt which is the essential driver of Manitoba Hydro's financial risk.

3.3 Ratepayer Benefits

MPA's assertion on page 55 of Exhibit CC-17 that Manitoba Hydro's *"equity is essentially dead money. It earns no return, but nevertheless has been taken out of the hands of ratepayers who could otherwise use it"* is also erroneous. This stands in contrast to MPA's evidence at NFAT as a PUB IEC wherein the response to CAC/MPA 1-012(d) they stated:

> *"If Manitoba Hydro has a larger balance sheet, then it would be better able to absorb shorter term or less severe financial shocks, without the risk that it might be perceived as being no longer financially self-supporting. A more robust corporation could simply wait for fortunes to turn, rather than immediately seeking financial relief through higher rates. In this sense, a larger balance sheet can be understood as a ratepayer benefit."*

MPA later confirms in this hearing (Transcript Page 5115) that debt does have a cost and insofar as retained earnings result in avoided debt, ratepayers benefit in the form of not having to pay the cost of that avoided debt. In other words, while the ratepayer is duty bound to contribute to net income (in normal water years) as a trade-off for the Province of Manitoba providing access to low-cost capital and standing still on a rate of return, there is still substantial ratepayer benefit. It comes in the form of future interest savings which accrue to ratepayers at the Corporation's cost of debt. While in 2016/17

the Corporation's average cost of debt (used to capitalize interest) was 4.89%[5] which is a modest discount to the 5.0% *"social discount rate"* advocated by Morrison Park as a ratepayer cost of capital, it is entirely plausible in a prospective rising interest rate environment that the savings provided by having reduced debt will exceed this notional concept of a social discount rate. Moreover, the true benefit to ratepayers (and the broader Manitoba economy) of rate stability from lower debt levels is not captured anywhere in this calculus but is certainly a tangible benefit to customers.

Mr. Colaiacovo asserts at Transcript Page 5129 with respect to reserves:

> *"So yes. If the 7.9 percent method -- rate is going to build up larger reserves, then you will be able to resist more of the types of events that require reserves, but that doesn't necessarily mean it's a good idea to build up those reserves because you have to look at what the probability of those events are going to be and your actual requirement for those reserves before you decide to build them up."*

The purpose of building up financial strength through sufficient positive net income and cash flow, as Manitoba Hydro is proposing, is to limit the growth of debt and abate it to more sustainable levels relative to the size of its customer base and the inherent risks in its business. The benefit is not only derived from higher resistance to possible or even probable negative events. The benefit is the interest savings in and of itself and the relative rate stability that ensues. In PUB/MH II-21b, pages 4-23, Manitoba Hydro demonstrates how this benefit holds regardless of actualities that present in comparison to forecast.

MPA produced an analysis which compares the present value to customers of two alternate rate paths and concluded that at a *"social discount rate"* of above 4.93%, the 3.95% rate path is preferable at least by this measure (Exhibit CC-17, Pages 47 to 48). This conclusion is unsupportable, given the fundamental misunderstandings of the role, ownership and benefits of equity described above.

Manitoba Hydro demonstrated in its Rebuttal Evidence that, with the appropriate Weighted Average Term to Maturity ("WATM"), 3.95% rate increases are required

[5] see Note 7 on page 66 of Manitoba Hydro Electric Board 66th Annual Report for the year ended March 31, 2017, filed in the response to PUB MFR 13 Updated)

throughout the forecast period in order to restore the 25% equity ratio (Exhibit MH-52, Appendix 1.6 and 1.7). On this basis, the *"equalizing"* discount rate of the two compared rate paths climbs to 6.4%, well above the 5% MPA asserts as the appropriate social discount rate. At a social discount rate below 6.4%, the rate path assumed in PUB/MH II-21(b) produces present value benefits to ratepayers in addition to any advantages to Manitoba economic development that may stem from the prospect of lower, more stable rates sooner.

Manitoba Hydro has also noted that it is inappropriate to attribute the same discount rate to two rate paths with a wholly different likelihood of occurring. MPA confirmed in its response to MH/Coalition-(MPA) 20(a) that the 3.95% rate path has a higher likelihood of unexpected/unplanned rate action. Using the same discount rate to compare two scenarios with a different risk profile is inconsistent with financial theory.

The 3.95% rate scenario places increased risk on ratepayers. Even in the base case, equity falls to a level of 10% and is maintained for years. The PUB has indicated in the past its discomfort with 10% equity levels as noted on pages 2 and 23 of Order 43/13:

> *"The Board is concerned with the projected future deterioration of Manitoba Hydro's financial targets, in particular the debt-to-equity ratio that will fall from a current level of 75:25 to 90:10 by 2021, even with projected annual rate increases of approximately 4%, which is twice the projected level of inflation. This deterioration will put Manitoba Hydro in a weaker financial position given its planned capital spending over the next two decades."*
>
> *…*
>
> *"The Board is concerned that, by moving towards a 90:10 debt-to-equity ratio by the end of the decade, there will be an insufficient retained earnings reserve to deal with droughts and other risks such as infrastructure failure or rising interest rates."*

The PUB further noted the significance of maintaining capital adequacy to alleviate pressure on the Province of Manitoba in PUB Order 101/04 page 29:

> *"With a debt:equity ratio of 75:25 ratepayers would have increased assurance of future rate stability. Increased retained earnings would provide for a*

continuation of advantageous interest rates and finance costs. It would also provide increased confidence that a direct financial contribution to MH's capital would not be sought from the Province."

3.4 A 20-Year Financial Plan does not work

In the face of a rapidly changing industry, significantly higher capital investment needs and a deteriorated growth outlook, the 20 year path to addressing Manitoba Hydro's financial condition by 2033/34 advocated at NFAT and in the 2015/16 & 2016/17 General Rate Application ("GRA") is imprudent and unworkable.

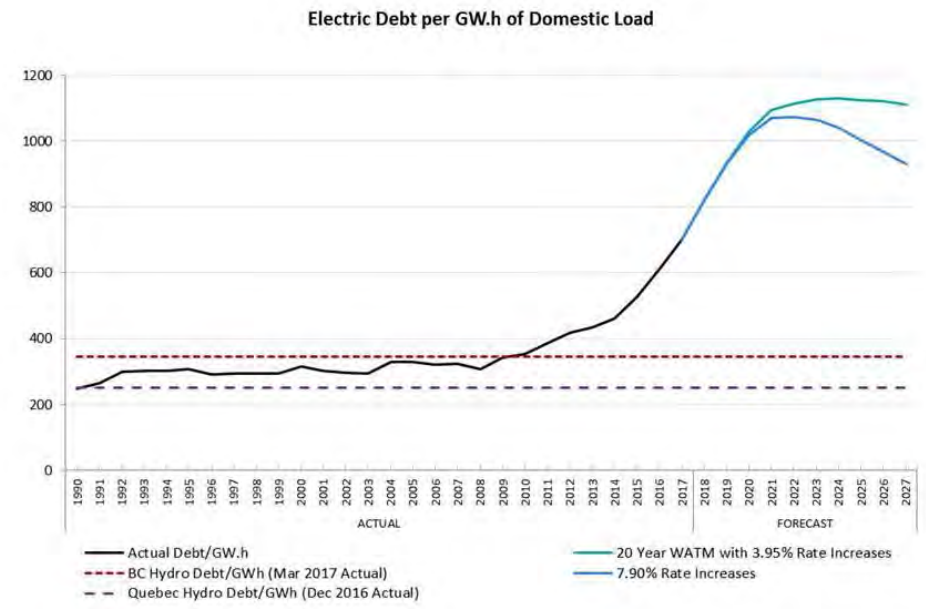
While unpleasant, the reality is that Manitoba Hydro does not appear poised to grow its way into the significantly increased and unsustainable levels of debt it is incurring to complete major capital projects, such as the Keeyask Generating Station and the Bipole III Reliability Project. As such, earlier and more aggressive action than what was contemplated in previous 20-year financial plans is required to address a debt load that, left unchecked, could compromise rate stability and affordability for generations of Manitoba Hydro electricity customers.

Taking almost two decades to address Manitoba Hydro's weak capitalization fails for a number of reasons which are discussed in the sections that follow.

3.4.1 Prolonged and unmitigated exposure to interest rate increases

Section 3.2 above provides a discussion of the role of equity and net income in maintaining Manitoba Hydro's financial stability. The issue with Manitoba Hydro is not too little equity. The real issue is that too large a debt burden is being carried by a stagnant customer base. **Figure 3.7** below demonstrates that absolute levels of debt will grow to almost 4 times as indebted as Manitoba Hydro was immediately following Limestone. This is clearly out of all historical proportion to the size of Manitoba Hydro's business. Likewise, the debt burden on Manitoba Hydro's customers will be larger than any previous plan brought in front of the PUB. Stronger action must be taken to address this significant and unavoidable debt.

Figure 3.7



Source: Exhibit MH-52, Page 25

Under the 3.95% rate path, net debt will grow to $24.8 billion by the end of 2023/24 at which point the Keeyask Generating Station is fully in-service. Notwithstanding intervener conjecture (page 4-5 of Exhibit MIPUG-13) that Manitoba Hydro will be *"rapidly"* retiring debt, in fact net debt builds in the six years after Keeyask In-Service to $25.1 billion at the end of 2026/27 under a 3.95% rate plan. It is of note that despite cumulative rate increases of almost 50% by the end of that period under the MH15 rate plan (3.95% until 2028/29) debt remains within roughly 5% of this peak level until 2033/34 - 16 years from now (Exhibit MH-52, Appendix 1.3). The failure to make any appreciable repayment of debt in the face of such cumulative rate increases demonstrates the inadequacy of the 3.95% plan.

In financial terms, Manitoba Hydro has no greater risk than rising interest rates. Once Keeyask is in service, Manitoba Hydro will have annual interest expense of approximately $1.25 billion per year, assuming its projection for both interest rates and the final capital needs of the major projects prove accurate. This compares to $2.0 billion of domestic revenue in 2023/24 following the 3.95% rate path. In other words, Manitoba Hydro will be consuming 62.5% of every domestic revenue dollar paying interest expense (i.e. $0.63 of every dollar, as shown on Slide 21 of Exhibit MH-64). On $25 billion of debt, even a 1% increase in interest rates would have dire consequences.

Manitoba Hydro will see immediate and material increases in its revenue requirement should interest rates begin a path back from historic low levels to long-term average levels.

It has been of great benefit to Manitoba Hydro ratepayers to undertake such a significant expansion program with the benefit of low interest rates. However, it would be highly imprudent to not take action now to curb debt growth given the clear danger and unaffordable consequences of unplanned interest rate escalation. The presumption that interest rates will stay within sight of historic lows for more than the next decade is too large a wager to expose ratepayers to. As seen on in the chart on page 10 of Appendix 3.5 to the Application, interest rates have historically demonstrated the capacity to increase and decrease significantly over 10 year time frames let alone 15 or 20 years.

The need to address the impact of lower forecast domestic load growth cannot be overlooked. One way of considering debt load at the customer level is the amount of debt per kWh of consumption. This is appropriate as the interest servicing of each dollar of incremental debt load must be absorbed in customer rates which are expressed in cents per kWh. At NFAT, when net debt crested at $21.6 billion in 2022/23 (Exhibit MH-93, page 14), domestic load (at generation) was forecast at 26,567 GWh (PUB/MIPUG 1, page 4). Net debt/GWh of domestic load (at generation) was therefore forecast at $813,000/GWh. Manitoba Hydro's current forecast sees only 25,175 GWh of domestic load (at generation) in 2022/23 (PUB/MIPUG 1) which compares to forecast net debt of $24.8 billion (Appendix 1.3 to Exhibit MH-52). This translates to Debt/GWh (at generation) of $984,000. The consequence is that much greater debt is being shouldered by much lower customer volumes. On a proportional basis to domestic load, peak net debt per GWh will be almost 21% higher in 2022/23 under MH16 Update with Interim (i.e. 7.9% rate path) as compared to NFAT.

MH16 Update with Interim, notwithstanding higher rate increases, is still reflective of more financial risk than was contemplated at NFAT. The higher rate path assumed in MH16 Update with Interim, beginning with the 7.9% rate increase effective April 1, 2018 requested by Manitoba Hydro in this GRA, is essential in order to abate debt growth to levels more consistent with prior plans notwithstanding taking several years longer to do so.

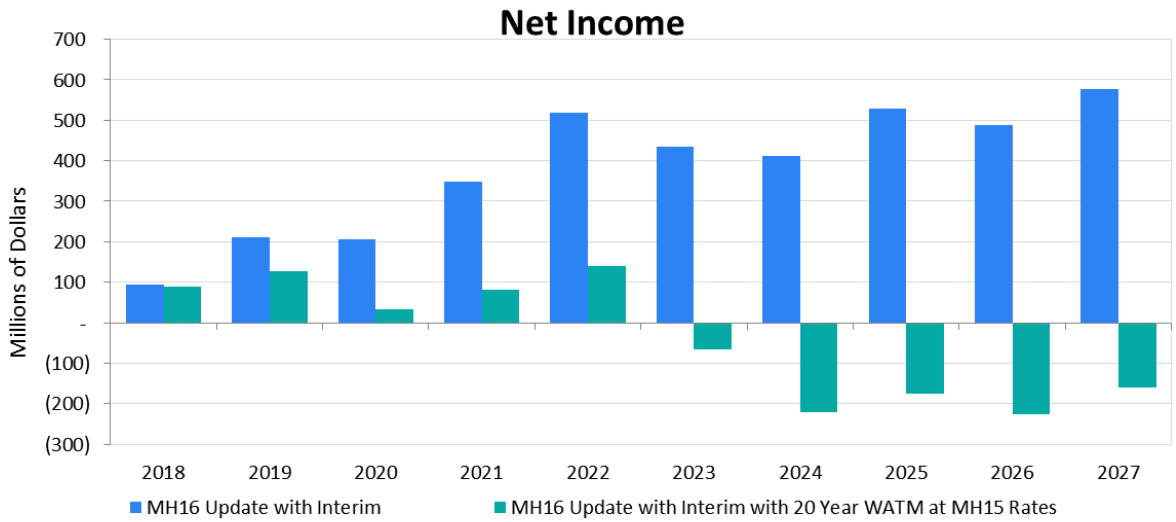
3.4.2 Cannot Forecast Breakeven or Negative Income

All of Manitoba Hydro's integrated financial forecasts, including MH16 Update with Interim, are founded on the assumption of normal water conditions. Manitoba Hydro has been clear that it believes it is imprudent, as a planning matter, to pursue a rate strategy with a goal of negative net income in any one year let alone for a sustained period. It would appear that Mr. Colaiacovo from MPA agrees:

> *"And if the rates are high enough, well, then, that helps guide you to a- -- a decision that those rates are sufficient. Then, you would also ask yourself, if water was at more typical levels over that period, over that five (5) or seven (7) year period, what would be the effect? Would it be --* ***would we be making progress on our financial targets more broadly? Would be -- we be repaying capital?*** *Right?.... So, you know, you always want to make sure that in a challenging scenario, you have enough reserves,* ***but you also want to pay attention to what happens when water is at typical levels*** *and -- and -- and that -- that kind of an analysis, I think, would guide you to making a rate decision."* (Emphasis Added) (Transcript page 4941)

In the years following Keeyask ISD, implementation of the MH15 rate path results in: a) substantial, sustained net losses; b) significant deterioration in the equity ratio; and, c) increasing net debt levels.

Figure 3.8



Source: Exhibit MH-64, Slide 26

Given Mr. Colaiacovo's advice noted above, it is difficult to comprehend how he could endorse a plan that would see Manitoba Hydro losing in the range of $200 million per year with Keeyask in service.

Manitoba Hydro must have sufficient domestic revenue that is recovered from ratepayers such that it can expect to make meaningful, positive net income in normal water conditions. When the unforeseen arises, net income can flex downward to avoid the need for immediate borrowing or rate response. If the planned net income is achieved, this income can be contributed toward debt retirement. However, it is acknowledged by both MPA (transcript page 5114) and Mr. Bowman (Transcript Page 6382) that equity is not cash reserves and that in the absence of net income, Manitoba Hydro will have no choice but to raise rates or increase debt in the event of below forecast conditions let alone drought or sharply rising interest rates.

The scale of targeted net income must take into account the scope of Manitoba Hydro's activities. A decade ago, Manitoba Hydro earned net income in the order of $250 million to $350 million on net plant in service of approximately $7.5 billion. (Exhibit MH-64, Slide 66). The PUB acknowledged the importance of net income relative to Manitoba Hydro's scale when it wrote, in Order 143/04, on page 84:

"While net income levels of $50 million are significant in absolute dollar terms, they are modest for a Corporation with the assets, debts, retained earnings and responsibilities of MH. MH's debt to equity ratio is below the Corporation's target and generally accepted industry standards."

At the time of that Order, Manitoba Hydro had net plant in service of approximately $7 billion and net debt of approximately the same amount. When Keeyask comes into service, Manitoba Hydro's net plant in service will be roughly four times greater ($27 billion) with debt, following the MH15 rate path, of $25 billion. The MH15 rate path produces a net loss in 2023/24 of $222 million and continuing to follow this plan does not lead to net income of greater than $100 million before 2030/31.

In the same Order, at page 86, the PUB noted:

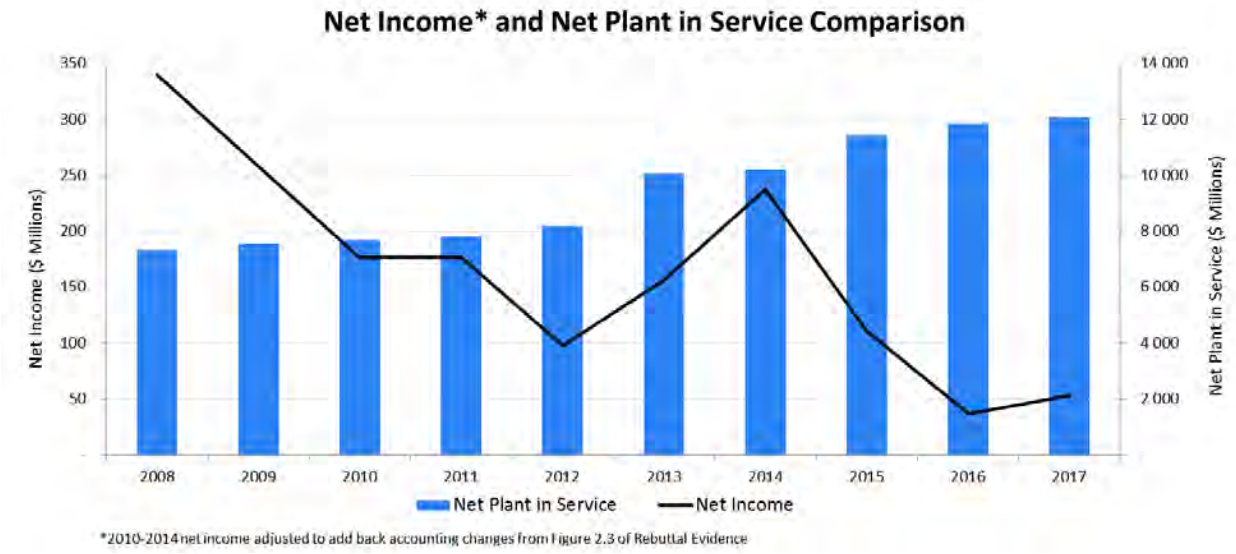
"MH explained during the hearings that even in the absence of another drought it would not reach its targeted debt to equity ratio by 2013/14, and provided no plan to achieve its target within this 10-year planning horizon. The Board believes that this situation is not reasonable."

Manitoba Hydro notes the PUB's concern with both the debt to equity ratio and the 10 year path. Manitoba Hydro does not believe that the cause of the capital deficiency (drought vs. a major period of expansion) impacts the requisite steps to address the PUB's well documented concerns in PUB Orders 101/04, 143/04 and 90/08 regarding the risks of inadequate reserves and levels of debt. For example, in Order 90/08 page 18

"It is not reasonable to assume that a Utility can expend over $18 billion in new capital expenditures without an up-front investment in its capital structure, higher rate increases will provide that additional capital and reduce to some extent the debt that MH will have to take on to complete these projects. Debt comes with costs, interest and annual principle payments, and, as well, is associated the risk of future increases in interest rates. The Corporation's risks rise as its export opportunities, investments and debts increase. In the Board's view, this warrants a larger rate increase."

Accepting a path of rate increases that are insufficient to generate positive net income would be a concerning continuation of a trend wherein net income (and therefore, reserve contribution and balance sheet management) have been systemically eroded while the assets and debts of the business continued to expand as demonstrated in **Figure 3.9** below. It should be noted as well that this erosion occurred not withstanding above average water conditions in every year since 2004/05 and sharply declining interest rates throughout the period.

Figure 3.9



Source: Exhibit MH-64, Slide 66

When normalized for water conditions and other unusual items, Manitoba Hydro has already been in a loss-making position for several years as discussed in detail in Section 2.1.2.

Net income is an essential feature of prudent financial planning for a business of the scale, complexity, importance and volatility of Manitoba Hydro. The PUB recognized this in Order 90/08, on page 7 when it wrote:

> *"It is prudent that known risks are addressed now, in part through the provision of additional revenue, so as to best ensure adequate financial reserves ahead of uncertain times."*

3.4.3 Prudent Financial Plans Do Not Depend on the Back-End of a Twenty Year Financial Forecast Proving Accurate

Forecasting is inherently unreliable. Manitoba Hydro believes limited value should be ascribed to forecasts a decade or more in the future as the potential for volatility in key assumptions, many of which are beyond Manitoba Hydro's ability to control, reduces the second half of a twenty year forecast to little more than a hypothetical modeling exercise. The further out the forecast goes, the less likely it is to be accurate. As noted by Mr. Shepherd:

> *"A decade is a long time. In any business I've been around, forecasting ten (10) years in the future, let alone fifteen (15) or twenty (20), is very difficult, perhaps nearly impossible. So a plan that has you walking down a tightrope of essentially no net income until the early 2030s is begging for trouble, especially when your outlook for growth is as weak as ours has become. So in taking up to twenty (20) years to deal with a serious problem, you're choosing to take insufficient action upfront, action that is required to be in the position where you have some flexibility to make different choices as the future unfolds.*
>
> *Our previous plans relied to -- to far too great an extent on nothing adverse happening over a very long period of time. That's relying on hope.* ***Put another way, your financial strategy is to stay lucky for a very long time****."* (Emphasis Added) (Transcript Page 163)

Consider the response to PUB/MH II-41 wherein the range of net income outcomes on 918 model runs is charted under the MH16 Update with Interim at MH15 Rate Increases scenario. By 2027, the financial model under average of all 102 water flow conditions shows a net loss of $160 million; however, that level of net income is below the mid-point of a range from a $500 million net loss to $230 million in net income. In other words, with all the variables and assumptions that go into a financial forecast, actually achieving a forecast level of net income 10-20 years from now will be as much a matter of happenstance and luck as prescient forecasting. Therefore, Manitoba Hydro is of the view that assuming achievement of a plan over such a long horizon is not a prudent course of action.

Ratepayers should also take no confidence in such a plan. Businesses looking to invest or expand in Manitoba will be well aware that Manitoba Hydro's interest expense alone will be unpredictable and uncontrollable given the roughly $20 billion in new borrowing and refinancing Manitoba Hydro must execute in the next 10 years (Appendix 3.5 of the Application). They will see that interest expense of $1.251 billion (Appendix 1.3 of Exhibit MH-52), in a normal water year and once Keeyask is in service, will represent 40% of Manitoba Hydro's cost structure, 44% of its total revenue and 60% of its domestic revenues. The latter metric will be deeply concerning knowing that Manitoba Hydro has no ability to increase its export pricing and therefore the domestic customer will bear all of the volatility in interest rates. While a lengthy pattern of 3.95% rate increases may, when presented in a spreadsheet, appear steady and predictable, businesses will understand that more debt will foster more risk to rates. The 3.95% rate path (or any derivative thereof) will rightly be thought of as academic and an aberration. While conceptually interesting, it has a very low possibility of actually occurring.

Nonetheless, as demonstrated in the response to Coalition /MH II-19, the 20 year/3.95% plans make inconsequential progress toward the Corporation's financial goals in the first decade notwithstanding assumptions of significant rate growth, sustained low interest rates, appreciating export prices, normal water conditions and no further deterioration in capital costs. MH16 Update with Interim at MH15 Rates (Appendix 1.3 to Rebuttal Evidence) is indicative. Debt does not actually peak until the 10th year of 2026/27 which is well after the Keeyask in-service date of August 2021. The equity ratio deteriorates steadily and unabated. The EBITDA to Interest target, which Manitoba Hydro notes is favored by MPA, never comes close to being met. In the five years following the in-service of Keeyask, Manitoba Hydro actually loses close to $1 billion, increases its debt, sees its equity ratio drop to 10% and moves further away rather than closer to its financial goals.

It should not escape notice that Mr. Bowman's preferred 3.57% plan is based on the achievement of the 25% equity ratio by 2035/36. This is two years subsequent to the initial 2033/34 year time frame established at NFAT and repeated in IFF14 that was reviewed as part of the 2015 GRA. As well, Mr. Harper proposes continuing the 3.95% path for *"a few more years"* (five are actually required) in order to achieve the 25% target in 2035/36. MPA also acknowledges the 3.95% path needs to continue for longer time frames than forecast under NFAT, IFF14 or IFF15. The pattern should be clear. At

each rate application brought to the PUB for review, the advice will be to start working toward achievement of its financial targets anew with another 20 year plan.

In addition to taking yet another two years, Mr. Bowman's preferred plan is also characterized by requiring $793 million of net income in its penultimate year (2034/35) followed by $883 million in its final year (2035/36) as two more years of 3.57% rate increases are compounded on the 81% cumulative increases of the next 17 years (Exhibit MH-93). This level of annual net income is respectively 62% and 59% higher than under the Manitoba Hydro plan for 2025/26 and 2026/27 as it likewise completes the restoration of its fiscal health and reaches 25% equity. See Section 3.4.5 for a discussion of intergenerational equity paradoxes of Mr. Bowman's preferred plan. Nonetheless, on this path endorsed by Mr. Bowman, the regulator would be accepting that Manitoba Hydro would defer positive net income post-Keeyask until 2028/29. If the regulator were prepared to accept that level of financial weakness for that length of time, in Manitoba Hydro's view, it seems unlikely that the regulator would support the kind of rate increases and net income projected from 2030 onward in Mr. Bowman's preferred plan.

The end game is clear. The kinds of forecast errors that can befall such a razor-thin financial plan are not imaginary or implausible. Each of the major risks – rising interest rates, soft export prices, low water conditions or drought and capital overruns – have all happened before. Manitoba Hydro arguably bears more financial risk than any other Canadian hydro-based utility given its relative exposure to interest rate increases, hydrology and export prices. A willingness to tolerate such a plan signals a bias to not act proactively but rather wait until a crisis inevitably presents. It is ironic that the same parties who have for many years criticized Manitoba Hydro's forecasting abilities are now effectively encouraging the PUB to attribute a high degree of confidence in the back end of a twenty year forecast.

3.4.4 Capital markets are growing more concerned

The principal benefit of dealing with Manitoba Hydro's unsustainable debt is the payoff of lower, more stable electricity rates in the long run. There is no plausible future scenario wherein lower debt levels do not return lower rates to Manitoba Hydro's customers. PUB/MH II-21 provides some illustrative examples to demonstrate this benefit. A corollary benefit of addressing absolute debt levels which are now set to grow

beyond any previous forecast level is the continued support and confidence of capital markets participants which is vital to the Province of Manitoba and Manitoba Hydro's borrowing programs and interest costs.

Credit rating agencies are a reasonable proxy for the types of analysis debt investors undertake and the opinions they form. Any impartial review of recent credit rating agency reports demonstrates clear and urgent signaling that markets are concerned with the continued deterioration of Manitoba Hydro's financial profile.

3.4.5 Intergenerational Equity argument is flawed and hypocritical

The 19 year plan advocated by Mr. Bowman sees Manitoba Hydro building to $25 billion in debt post-Keeyask only to decline to below $24 billion in the 2032/33 fiscal year, which is over 15 years from today. The exposure to interest rate increases over that timeframe is immense. Even by 2032/33, at which time this plan would result in having implemented 75% cumulative increases while still not having increased equity beyond 17%, net debt will be more than 8 times domestic revenue (Exhibit MH-52, Appendix 1.3, Pages 2 and 4). Interest expense of $1.24 billion will be consuming 40% of domestic revenues even having increased rates cumulatively by 75% by that point. The argument in favour of this is *"intergenerational equity"*. In general terms, the theory is that it is unfair for current ratepayers (and those of the next 10 years) to be unduly contributing to the carrying costs of constructing the major new assets. Mr. Bowman's argument is paradoxical in that the consequence of not having today's ratepayer make any contribution to the continued erosion of the Corporation's balance sheet is exacerbated risk and cost to the next generation. To do so in the name of intergenerational fairness is disingenuous.

It is further hypocritical when the patterns of costs borne by ratepayers in each of the first decade (2018-2027) and the second decade (2028-2036) are compared (see Figure below):

Figure 3.10

	MH Plan 2018-2027	Bowman 3.57% Plan 2018-2027	Bowman 3.57% Plan 2028-2036
Cumulative Net Income	$3.8 billion (over 10 years)	$0.2 billion (over 10 years)	$3.7 billion (over 9 years)
Net Debt post Keeyask	$2.4 billion decrease (2023-27)	$0.3 billion **increase** (2023-27)	$3.6 billion decrease (9 years 2028-36)
Net Income in year target is achieved	$577 million (2027)	Equity ratio and EBITDA/Interest targets not achieved	$883 million (2036)
Cumulative Rate Increase	77.4% (to 2027)	41.7% (to 2027)	94.3% (to 2036)

Source: Manitoba Hydro Plan Appendix 3.8 and Mr. Bowman 3.57% Plan Exhibit MH-93

As can be seen from **Figure 3.10** above, notwithstanding 42% cumulative rate increases, Mr. Bowman's proposed plan makes no contribution to progress on financial targets or debt reduction, in fact the opposite. Debt increases during the period post-Keeyask while the equity ratio declines from 14% to 12% due to sustained net losses. Mr. Bowman's plan only produces positive, albeit immaterial, net income in aggregate in its first 10 years due to the impact of arbitrary accounting choices and the assumption of an ill-advised debt terming strategy. Even so, the plan produces $405 million of cumulative losses from 2022/23 to 2026/27.

Further, the profile of net income and debt reduction borne by the first decade's ratepayers under the Manitoba Hydro Plan (MH16 Update with Interim) is exactly the same as or better than the profile of net income and costs borne by the ratepayers in the second decade (in fact even further condensed into 9 years from 10) under Mr. Bowman's 3.57% plan. In other words, Mr. Bowman is proposing to take essentially the same pattern of reserve contribution and cash contribution Manitoba Hydro is proposing to be shouldered over the next 10 years and instead bestowing it on the ratepayers of the following 9 years and doing so in the name of intergenerational equity. In fact, there is no sharing or spreading of the costs of restoring Manitoba Hydro's financial health due to the simple fact that Manitoba Hydro's financial health not only does not improve in the first 10 years of Mr. Bowman's plan, it deteriorates. Mr. Bowman is simply making a choice of which generation to park the responsibility on. The next generation has the added burden of now paying rates 94% higher than today

(and only if things have gone to *"plan"* for more than a decade) and having done little to nothing before the early 2030's to reduce the rate volatility inherent in leaving debt unchecked.

3.5 Changing assumptions in the Financial Model in order to defer the need for rate increases is not prudent

The PUB has heard argument in favor of numerous alternate (and lower) trajectories supported by questionable assumptions inserted into a forecast scenario with the sole objective of providing support for deferring the rate action now required. A financial forecast is a compilation of hundreds of assumptions all of which can be modestly changed to engineer any outcome a party desires. Manitoba Hydro has put forward in MH16 Update with Interim its best effort at a baseline forecast from which to make longer term rate planning decisions. As the PUB has made clear, at issue is effectively one rate increase, the request for 7.9% to take effect on April 1, 2018. The actual path of future rate increase requests will be a function of updated assumptions and events between now and Manitoba Hydro's subsequent rate application(s).

However, it would be imprudent to make today's rate decision – in the context of important signaling on longer term financial goals the PUB wishes to support – based on overly optimistic assumptions particularly in matters well beyond Manitoba Hydro's or the PUB's ability to control. For example:

3.5.1 Assumption of Capacity Values for Uncommitted Firm Energy.

The proposition that there is capacity value recognized in the marketplace is not something Manitoba Hydro takes issue with. However, to build a financial plan incorporating such values in the absence of a contracted counterparty adds unnecessary risk to the financial plan. Manitoba Hydro has given evidence (PUB/MH I-50) that the likelihood of engaging a counterparty in the next 5 years is extremely low owing to the planning horizons of these kind of bilateral agreements. Daymark endorsed this view as follows:

> *"MS. MARLA BOYD: And I understood your evidence to be that that wouldn't be a significant source of revenue until -- at least for the next five (5) years, and perhaps 2025?*

*MR. DANIEL PEACO: We did not find a lot of evidence in -- in either individual counterparties or the MISO market generally being short of capacity until that time, right." (*Transcript Pages 4280 to 4281*)*

Beyond 5 years, it must be recognized that simply having the firm energy available provides no assurance of entering into a contractual agreement. Further, Manitoba Hydro's uncommitted firm energy is a depleting resource particularly beyond the 10 year forecast horizon when Manitoba load growth starts absorbing excess supply.

3.5.2 Change regulatory accounting policy to increase income in the near term.

The frenzied debate over depreciation methodologies has obscured the fact that the transition to IFRS has substantially reduced annual depreciation expense (even under IFRS ELG) due to the removal of negative net salvage value. Nonetheless, as noted in Exhibit MH-93, the proposed changes by Mr. Bowman, including 12 year debt, indefinite capitalization of ineligible overheads amortized over 30 years and ELG/ASL depreciation methodology differences not amortized at all, make an immaterial (0.15%) difference to the annual rate path and no difference whatsoever to the critical debt and cash flow issues facing Manitoba Hydro. Mr. Harper acknowledged the impact would be minimal in the test years:

MS. PATTI RAMAGE: Okay, fair enough. You'd agree that if the Board adopted these recommendations, it would have minimum impact on the requested rate increases in this proceeding?
MR. WILLIAM HARPER: Yes, in terms of the two -- of the two -- of the two (2) specific years we're looking at, yes.
(Transcript Page 5359)

Further commentary regarding Manitoba Hydro's proposed treatment of existing Regulatory deferral accounts can be found in Section 17.

3.5.3 Assume 12 Year WATM.

Mr. Bowman opined that Manitoba Hydro's actions regarding reducing the WATM of Debt are sensible and appropriate (Exhibit MIPUG-13, page 5-11) but took issue with Manitoba Hydro's position that this strategy is only prudent under Manitoba Hydro's

7.9% financial plan and instead argued a 12 year WATM is an appropriate debt management strategy when coupled with 3.95% rate increases.

Manitoba Hydro notes that Mr. Bowman acknowledges having no experience in capital markets (Transcript Page 6202) nor does his CV indicate treasury management experience. His willingness to place over $9 billion of refinancing risk into the 2023 – 2027 timeframe in the absence of any prospective cash flow to manage the risk is cavalier and indicative of an ongoing desire to maintain artificially low rates in the near term, regardless of the risk it may impose on future ratepayers.

3.5.4 Curtail DSM spending assumptions.

The Efficiency Manitoba Act has been enacted in order to establish Efficiency Manitoba, a new Crown Corporation charged with pursuing long range electricity savings targets that are meaningfully in excess of the projected savings in Manitoba Hydro's integrated financial forecast. The Efficiency Manitoba Act mandates cumulative 22.5 % energy savings over 15 years, a figure well in excess of Manitoba Hydro's current plan of 17.3% over 15 years.

Mr. Bowman's argument that Manitoba Hydro should assume lower DSM investment and projected savings, as a path to lower rate increases, on the basis that *"it is appropriate to consider that Efficiency Manitoba, its Minister, or the PUB will make a finding that continuing large scale DSM is not cost effective for at least the next 5-7 or so years"* (Pre-Filed Testimony of Patrick Bowman, Exhibit MIPUG-13, Page 6-25) is in the face of mandatory legislation to the contrary is untenable and self-serving. In reality, it is entirely plausible that once Efficiency Manitoba is formed and operational, that its plans may require more investment and create greater load loss. Against that backdrop, to assume significant savings on programming that is transitioning from Manitoba Hydro's control (but not financial responsibility as a means to support lower rate increases) is imprudent. For additional information regarding Manitoba Hydro's Demand Side Management program and Efficiency Manitoba see Section 8.2.7.

3.5.5 Curtail government payments.

A number of Intervenors have suggested the PUB recommend the Province of Manitoba forego certain payments currently required be made by Manitoba Hydro to the Province. To be clear, absent a signal from the Province of Manitoba of a willingness to

accommodate lower water rental, debt guarantee fees or capital tax payments from Manitoba Hydro, it would be irresponsible to factor such an assumption into any forecast underpinning a rate decision.

3.6 MH15 Rate Plan Fails

MPA concludes at page 34 of their report that, *"…the 3.95% rate path is reasonably robust from a cash flow perspective"* by relying on the modeling results of the EBITDA interest coverage ratio. MPA reaches this conclusion despite shortcomings of the EBITDA to interest coverage metric identified at page 9 of Exhibit CC-17:

> *"This measure alone does not clarify whether the company's debt is increasing,* ***since there is no information captured in this metric about the size of capital expenditures*** *(if capital expenditures are greater than 0.8x Net Finance expense, then Manitoba Hydro will have to borrow additional funds, but if capital expenditures are less than 0.8x Net Finance Expense, then the corporation could actually retire some debt principal). By the same token, this ratio provides no information on whether the Debt : Equity Ratio is rising or falling."* (Emphasis Added)

Manitoba Hydro annually funds $500 to $600 million a year in Business Operations Capital to continue to maintain and increase the capacity of the current system to meet customers' needs and to support its revenue projection. Additionally, Manitoba Hydro must fund other costs like mitigation and other liability payments that do not flow directly through the income statement and, therefore, EBITDA. In the very short term, Manitoba Hydro may defer some costs to future periods but at the end of the day these expenditures are not discretionary. Manitoba Hydro cannot defer system maintenance and replacement indefinitely or the Corporation will not be able to meet the service and reliability expectations of its customers. When system failure rates rise, Manitoba Hydro is unable to maximize all the revenue it is able to generate and puts downward pressure on the sufficiency of future revenues. Further, costs are deferred to periods when replacement is generally more expensive. As a result, EBITDA to interest does not provide a complete picture because it does consider whether the Corporation has enough cash to continue to run its operation, and therefore, it does not inform as to whether debt is going up or going down.

Regardless of the EBITDA to interest coverage metric limitations, the following table reproduced from Exhibit MH-64 shows that the ratio under the MH16 Interim with Update and MH15 Rate Increases scenario is well below the target of 1.80 times even before considering required investments in Business Operations Capital.

Figure 3.11

Financial Ratios:	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27
Equity Ratio (Target > 25%)										
MH16 Update with Interim	15%	14%	14%	15%	17%	17%	19%	21%	23%	25%
MH15 Rates	15%	14%	13%	13%	13%	12%	12%	11%	10%	10%
Capital Coverage Ratio (Target > 1.20x)										
MH16 Update with Interim	1.40 x	1.48 x	1.47 x	1.88 x	2.34 x	2.25 x	2.37 x	2.34 x	2.20 x	2.29 x
MH15 Rates	1.39 x	1.33 x	1.15 x	1.36 x	1.59 x	1.30 x	1.21 x	1.20 x	1.10 x	1.18 x
EBITDA Interest Coverage Ratio (Target > 1.80x)										
MH16 Update with Interim	1.54 x	1.71 x	1.72 x	1.84 x	2.01 x	2.03 x	2.08 x	2.22 x	2.24 x	2.36 x
MH15 Rates	1.53 x	1.61 x	1.54 x	1.58 x	1.64 x	1.54 x	1.47 x	1.52 x	1.49 x	1.54 x

Other Metrics:	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27
EBIT Interest Coverage Ratio (Target > 1.20x)										
MH16 Update with Interim	1.10 x	1.21 x	1.20 x	1.31 x	1.45 x	1.38 x	1.36 x	1.47 x	1.45 x	1.54 x
MH15 Rates	1.10 x	1.13 x	1.03 x	1.07 x	1.12 x	0.95 x	0.83 x	0.86 x	0.82 x	0.88 x
Net Debt										
MH16 Update with Interim	$ 18 473	$ 20 743	$ 22 407	$ 23 296	$ 23 609	$ 23 388	$ 22 831	$ 22 201	$ 21 613	$ 20 947
MH15 Rates	$ 18 474	$ 20 825	$ 22 657	$ 23 809	$ 24 496	$ 24 761	$ 24 811	$ 24 877	$ 24 994	$ 25 060

Source: Exhibit MH-64, Slide 53

The table above also depicts Manitoba Hydro's former target ratio EBIT to interest coverage. Mr. Bowman points to this ratio as a critical test of rates sufficiency. The table shows that the 3.95%rate path that Mr. Bowman argues is adequate, grossly fails his own preferred test.

When the EBITDA to interest calculation is adjusted to incorporate Business Operations Capital and other non-discretionary cash needs as in the following table reproduced from Exhibit MH-64, the ratio of EBITDA to ongoing cash burdens is consistently below 1.0 times in all 10 years of the forecast period indicating that revenues are insufficient to fund interest and capital expenditures and the deficient portion must be borrowed. These tables demonstrate unequivocally that the 3.95 percent rate plan simply does not work.

Figure 3.12

(In Millions of Dollars)	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27
MH16 Update with Interim:										
EBITDA (Numerator)	**1439**	**1676**	**1795**	**2068**	**2307**	**2308**	**2384**	**2495**	**2435**	**2508**
Interest	936	982	1041	1121	1145	1138	1148	1125	1089	1060
Capital and Other Cash Needs	763	772	740	769	766	742	723	783	799	822
Cash Burdens (Denominator)	**1700**	**1754**	**1782**	**1890**	**1911**	**1880**	**1871**	**1908**	**1888**	**1882**
EBITDA / Ongoing Cash Burdens	**0.85 x**	**0.96 x**	**1.01 x**	**1.09 x**	**1.21 x**	**1.23 x**	**1.27 x**	**1.31 x**	**1.29 x**	**1.33 x**
Equity Ratio	**15%**	**14%**	**14%**	**15%**	**17%**	**17%**	**19%**	**21%**	**23%**	**25%**
At MH15 Rates:										
EBITDA / Ongoing Cash Burdens	**0.85 x**	**0.91 x**	**0.91 x**	**0.95 x**	**1.01 x**	**0.96 x**	**0.94 x**	**0.94 x**	**0.92 x**	**0.95 x**
Equity Ratio	**15%**	**14%**	**13%**	**13%**	**13%**	**12%**	**12%**	**11%**	**10%**	**10%**

Source: Exhibit MH-64, Slide 54

4 THE FINANCIAL OUTLOOK HAS DETERIORATED SIGNIFICANTLY

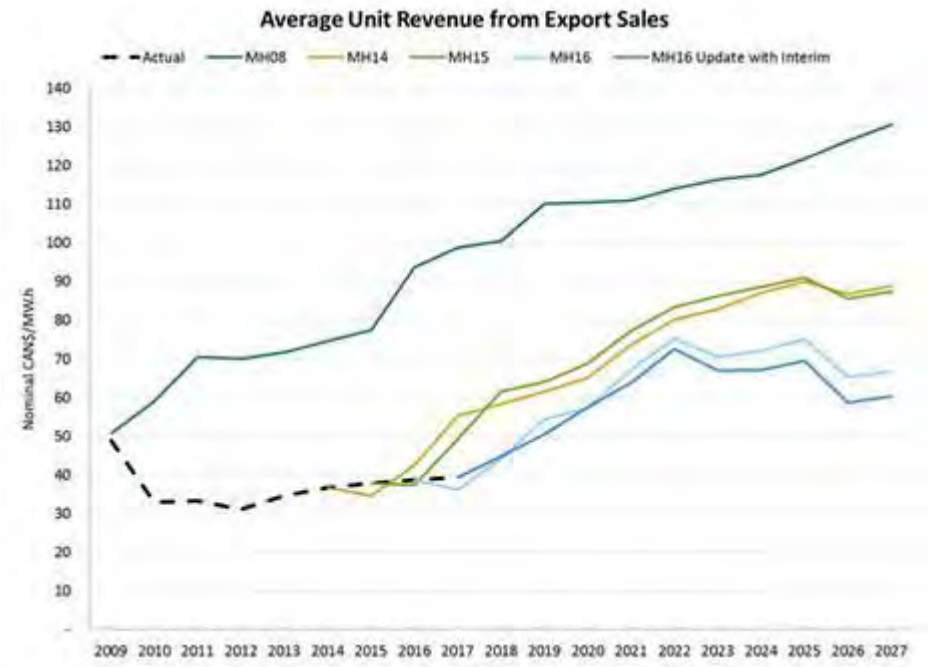
Intervener experts have asserted that there has been no deterioration in Manitoba Hydro's business such that the evidence advanced by the Corporation does not support the 7.9% rate increase trajectory included in Manitoba Hydro's current financial forecast. This is a significant assertion to Interveners as it is the fundamental underpinning of the belief that the 3.95% rate path put forward at NFAT and in the 2015 GRA (IFF14) remains viable (Section 5.0 of the Pre-Filed Testimony of Patrick Bowman, filed on behalf of the Manitoba Industrial Power Users Group, Exhibit MIPUG-13 and Section 3 of William Harper, Econalysis Consulting Services Evidence, filed on behalf of the Consumers Coalition, Exhibit CC-20).

Manitoba Hydro submits that the conclusions advanced by such experts do not consider all of the facts that are underpinning Manitoba Hydro's current outlook and which are summarized below:

4.1 Export Revenues Are Materially Lower

Since IFF14, the Corporation's outlook for opportunity export prices, which is based on third party forecasters, has decreased significantly (see chart below drawn from slide 39 from Manitoba Hydro's Policy Panel Presentation, Exhibit MH-64). As shown in the updated Schedule 10 provided in response to MH/Coalition (Harper)–5, forecast export revenues in the 2018-2027 period have declined from $8.0 billion under MH14 to $6.4 billion under MH16 Update with Interim meaning $1.6 billion of revenue has evaporated from Manitoba Hydro's expectations over the next 10 years.

Figure 4.1



Source: Exhibit MH-64, Slide 39

4.2 Domestic Load Growth and Revenues are Materially Lower

Manitoba Hydro's outlook for domestic load growth has also declined sharply as seen in the figure below (reproduced from slide 38 of Exhibit MH-64). As shown in the updated Schedule 10 provided in response to MH/Coalition (Harper) – 5, forecast domestic revenues in the 2018-2027 period have declined from $20.6 billion under MH14 to $19.3 billion under MH16 Update with Interim (at MH15 rates) meaning $1.3 billion of revenue has eroded from Manitoba Hydro's expectations over the next 10 years.

Figure 4.2



Source: Exhibit MH-64, Slide 38

Since MH14 and MH15, the capital costs for the major projects currently underway have increased significantly. The Bipole III reliability project budget has increased from $4.6 billion to $5.0 billion while the Keeyask Generating Station budget has increased from $6.5 billion to $8.7 billion. These two projects combined represent a 23% increase in capital costs in MH16 Update with Interim as compared to prior forecasts which, in turn, significantly increases the revenue requirement in the updated forecast.

4.3 Debt Has Gone Up

Since NFAT, Manitoba Hydro's outlook for peak net debt level has climbed by over 15% or $3.4 billion dollars (Manitoba Hydro Follow-up to Undertakings 7 & 8, Exhibit MH-93, Page 14).

Combined with the above noted deterioration in load growth since 2014, the debt load on customers is rising to more than four times the relative debt levels after Limestone went into service as demonstrated at Figure 1.16 of Manitoba Hydro's Written Rebuttal Evidence (Exhibit MH-52). As explained by Mr. McCallum in his direct evidence (Transcript Page 134):

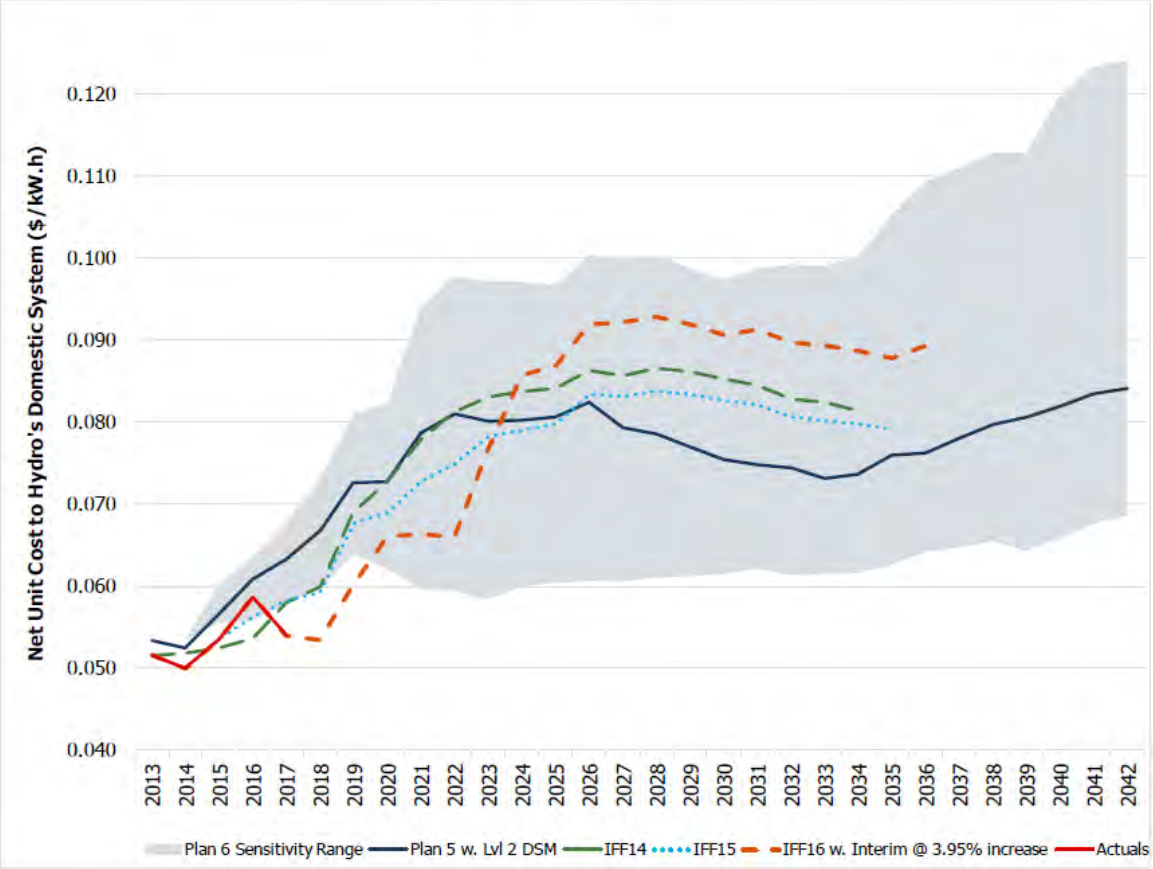
> *"The debt we will inescapably build over the next several years is, simply put, unsustainable. The only -- the old way of thinking about how to fix Manitoba*

Hydro's finances, and how long to take to do it will simply not work. The old plans have clearly already failed. We cannot put this off any longer. Action to address today's immediate situation is required if we are to protect all stakeholders' long term best interests".

In PUB/MIPUG-1, Mr. Bowman provides a corrected chart (reproduced below) comparing net unit costs under NFAT Plan 5, IFF14, IFF15 and IFF16 Update with Interim (at MH15 Rates). While Manitoba Hydro takes issue with these calculations being done with an "at generation" domestic load, as seen in the chart below, under MH16 Update with Interim, net unit costs are now forecast to be significantly higher than under any of the prior forecasts.

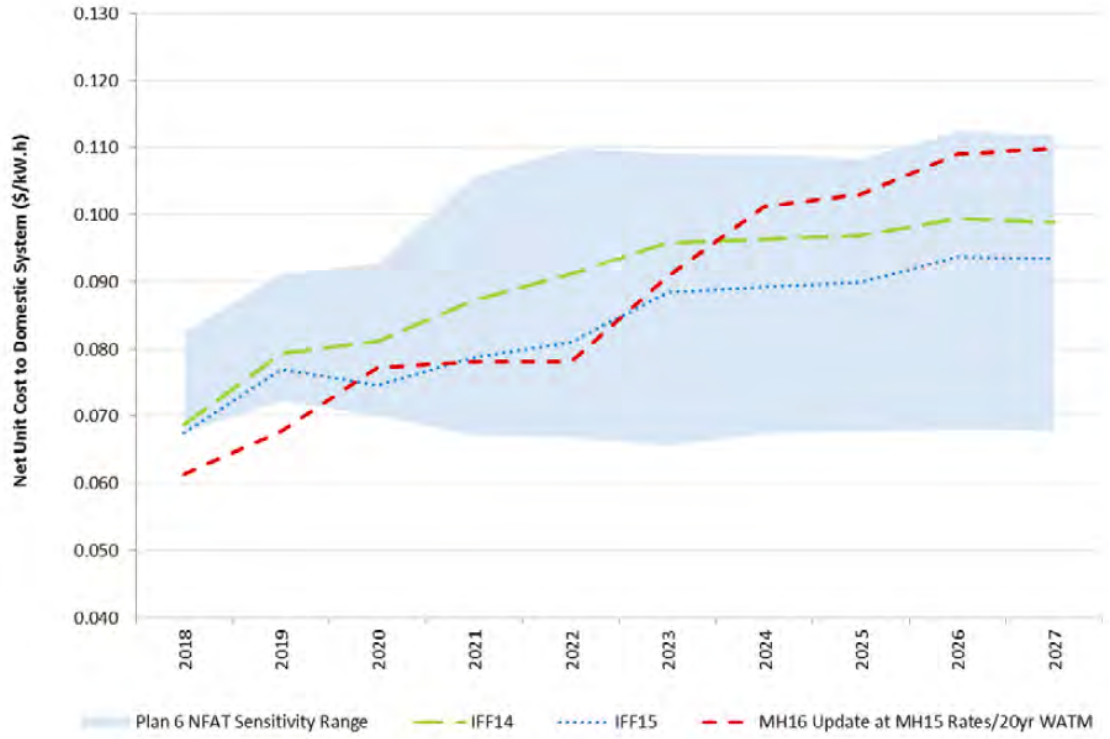
Figure 4.3

Figure 5-1: Net Unit Cost of Hydro's Domestic System (before reserves) Under NFAT Plan 5/6 versus IFF16 (assuming 3.95% increase scenario) – Updated for Load Forecast 2017 (PUB-MFR-65)



Manitoba Hydro reproduced at page 3 of Exhibit MH-52 the above chart using domestic load "at meter", which is the relevant metric given it is "at meter" by which Manitoba Hydro bills its customers. As can be seen, net unit costs are pushing right to the top of the range from NFAT.

Figure 4.4 Net Unit Cost to Domestic Sales ($/kWh)



Finally, in Figure 1.1 of Exhibit MH-52 Manitoba Hydro provided the following table:

Figure 4.5 Comparison of MH16 Update with Interim (at MH15 Rate Increases and 20 Year WATM) with MH15

	MH16	MH15	Difference	% Difference
2017-2027 Domestic Revenue	$20,865	$22,265	($1,400)	-6.3%
2017-2027 Export & OtherRevenue	$7,193	$8,746	($1,553)	-17.8%
2017-2027 Net Income	($325)	$607	($932)	-153.5%
Adjusted for Current 2017/18 and 2018/19 Outlook*	($78)		($78)	
Adjusted for Keeyask In-Service delayed 21 months**	($750)		($750)	
Proforma 2017-2027 Net Income Comparison	($1,153)	$607	($1,760)	-290.0%
2024 Net Income	($222)	$56	($278)	-496.4%
2024 Net Debt	$24,811	$22,449	$2,362	10.5%
2024 Equity Ratio	12%	12%	-	
2027 Net Income	($160)	$232	($392)	-169.0%
2027 Net Debt	$25,060	$21,838	$3,222	14.8%
2027 Equity Ratio	10%	14%	-4.0%	
2024 Net Cost per GWh***	$0.1000	$0.0900	$0.0100	11.1%
Increase from 2017/18 Net Cost per GWh	65.0%	32.0%	33.0%	
Cumulative Rate Increase after 2017/18	30.0%	30.0%	0.0%	

This table reveals in comparison to MH15 a 500% decline in forecast net income for 2023/24, a 170% decline in forecast net income for 2026/27 and an 11% increase in net unit costs. More urgently, this table shows that MH16 Update with Interim (at MH15 rates) projects a 65% increase in net unit costs per GWh between 2017/18 and 2023/24 wherein Keeyask is fully in service. Under MH15 the increase in net unit costs over that time frame was forecast at 32%. Cumulative rate increases of 3.95% from 2017/18 would result in a 30% cumulative rate increase which Manitoba Hydro submits is wholly insufficient in the face of unit cost escalation of 65%.

In Manitoba Hydro's view, there can simply be no basis for interveners to suggest there has not been any deterioration in Manitoba Hydro's financial outlook.

Manitoba Hydro takes issue with the fact that not one intervener has brought forward an expert with any experience in operating a business, especially not one the size and complexity of an integrated utility like Manitoba Hydro. Not one intervener has brought forward an expert with any experience managing the risks associated with a multi-billion dollar balance sheet and debt portfolio. And not one intervener has brought forward an expert with any credible experience working in the capital markets and dealing with investors. Manitoba Hydro has this expertise and therefore can assert that growth and

the continued expectation of growth are fundamental in order to relieve financial distress when it presents. Without growth, a business has lost the most vital tool a business has to get itself out of trouble, which in Manitoba Hydro's case means too much debt. The very best way to get out of this trouble is through growth; however, as explained in the application materials, in direct evidence throughout the hearing, and as summarized above, Manitoba Hydro cannot expect to do that anymore. As a result, the business, as compared to its prior forecast, has deteriorated.

Between 2017 and 2027, aggregate net income has gone from a positive $600 million to, on a like basis, a loss of almost $1.16 billion (not including any adjustment for the delay in Keeyask planned in-service). Mr. Harper understood this in his evidence; it is irrefutable (Transcript Pages 5406 to 5408).

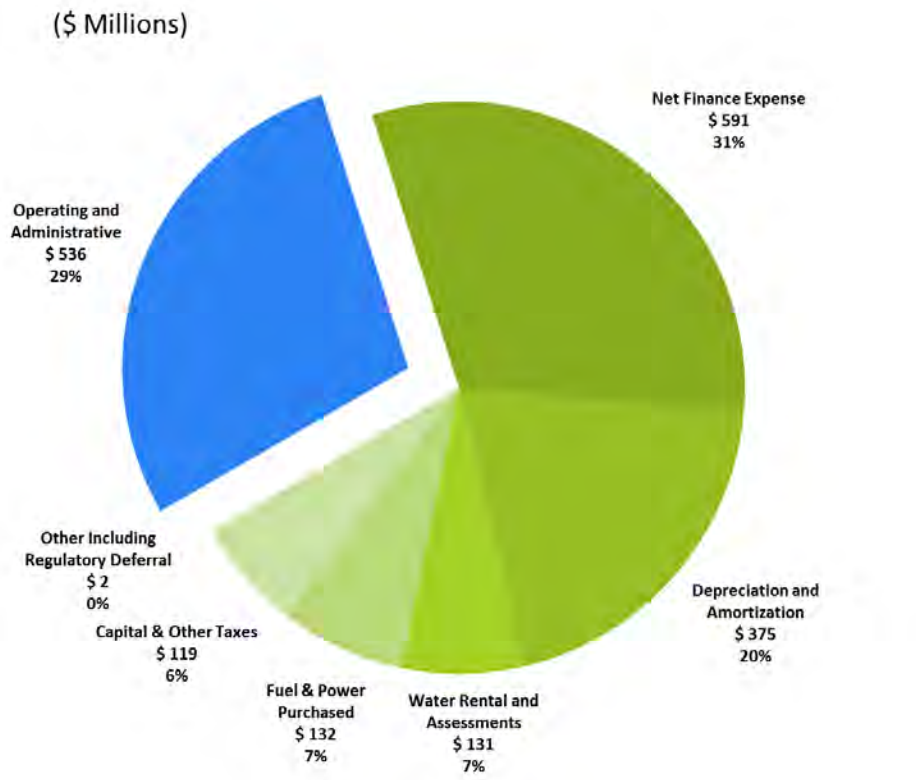
Manitoba Hydro feels it is important to remind the PUB that there was no commitment at NFAT that if Manitoba Hydro got off track (with lower load growth, lower export price appreciation, higher capital costs, drought or other events) that the proposed rate path would remain at 3.95%. The 27 sensitivity scenarios reviewed at NFAT included compensatory rate increases to deal with downside scenarios. As noted in the footnote on page 5-3 of Exhibit MIPUG-13, Mr. Bowman's worst case scenarios included an assumption of 5.48% rate increases until 2032 to offset the hypothetical downside erosion that is now present in immediate effect. In other words, all of the analysis of NFAT said Manitoba Hydro was going to need to act if things do not go to plan. As demonstrated in MH16 Update with Interim, and throughout the GRA proceeding, things are not going as planned and, to reiterate Mr. McCallum's testimony cited above, Manitoba Hydro and the PUB must take action now.

5 WITHOUT HIGHER RATE INCREASES MANITOBA HYDRO CANNOT SUPPORT ITS DEBT

5.1 Cost of Debt Financing is Manitoba Hydro's Largest Expense

As a capital intensive organization, Manitoba Hydro's assets drive its costs. Interest expense, incurred as a result of borrowing to fund asset investment, depreciation of assets and capital taxes drives over 60% of the current corporate cost structure. Slide 10 from Manitoba Hydro's Policy Panel Presentation, Exhibit MH-64, below, demonstrates the breakdown of the expenses on the income statement for the 2016/17 fiscal year.

Figure 5.1 Breakdown of Expenses



Source: Slide 10 of Exhibit MH-64

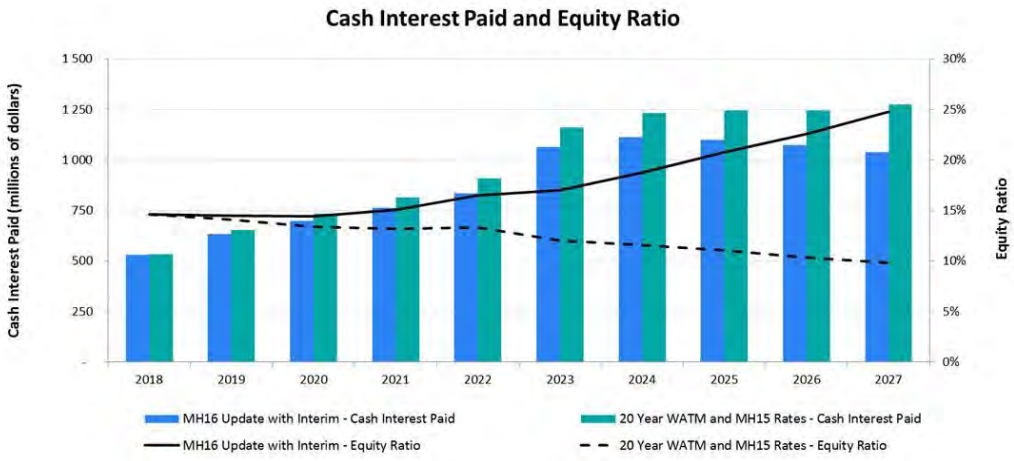
These costs will increase upon the completion of Bipole III and Keeyask adding nearly another $1 billion of annual depreciation and interest expense into Manitoba Hydro's revenue requirement once Keeyask is in service (PUB MFR 20).

Interest payments are, and will continue to be, Manitoba Hydro's largest requirement for cash outlays. As long as there are annual cash flow deficiencies, additional debt will be needed to fund the business and cash interest paid will increase. This connection

between cash flow and capital structure supports the need for a deliberate and sustained effort to restore the equity ratio (by lowering debt) in order to reduce the need for cash (and rate revenue) to fund interest costs. The amount of debt is the most significant driver of cash flow and financial health.

It is informative to consider the significant improvement to the Corporation's equity ratio, and cost-savings available to ratepayers resulting from the reduction in total interest by following the 7.9% rate path, rather than the 3.95% rate path, demonstrated by Figure 1.11 from Manitoba Hydro's Written Rebuttal Evidence, Exhibit MH-52.

Figure 5.2



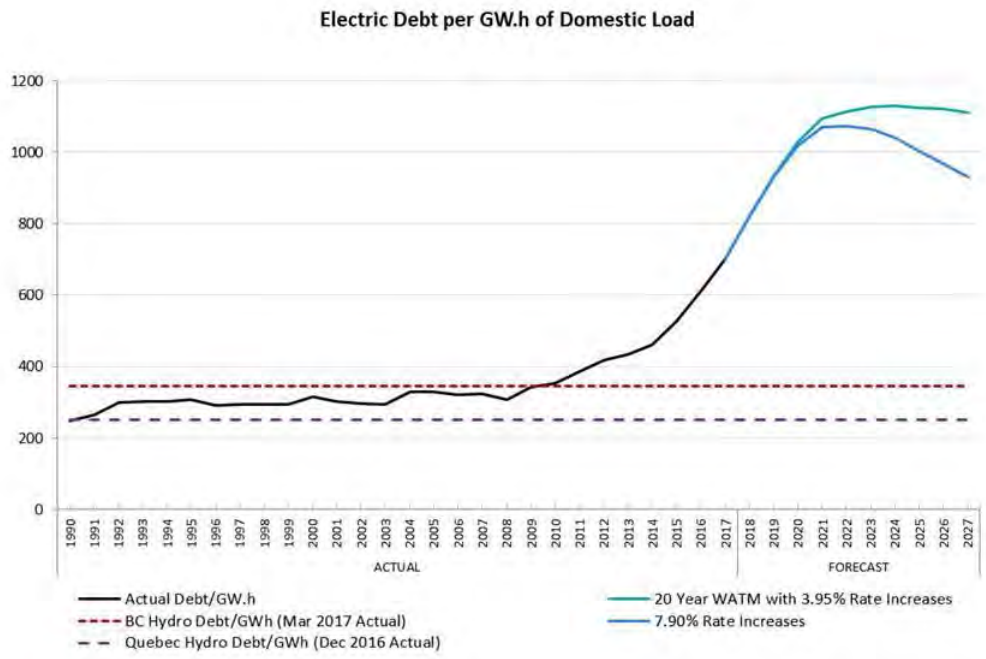
Source: Exhibit MH-52, Page 16

The negative net income and persistent annual cash flow deficiency under the 3.95% rate path contributes to an equity ratio decline of 5% (from 15% down to 10%) over the 10-year forecast period. In contrast, the 7.9% rate path generates surplus cash beginning in fiscal 2021, the cumulative cash flow deficiency is eliminated by fiscal 2022, the equity ratio begins to improve, and cash interest paid is lower in each year of the forecast and declines beginning in fiscal 2025.

5.2 No Precedent for Pending Level of Debt Burden on Domestic Customers

Manitoba Hydro's debt is growing out of all historical proportion to the size of the business. Manitoba Hydro's debt per gigawatt hour of domestic load or consumption has increased dramatically since 1990 as seen in Figure 1.16 of Exhibit MH-52.

Figure 5.3



Source: Exhibit MH-52, Page 25

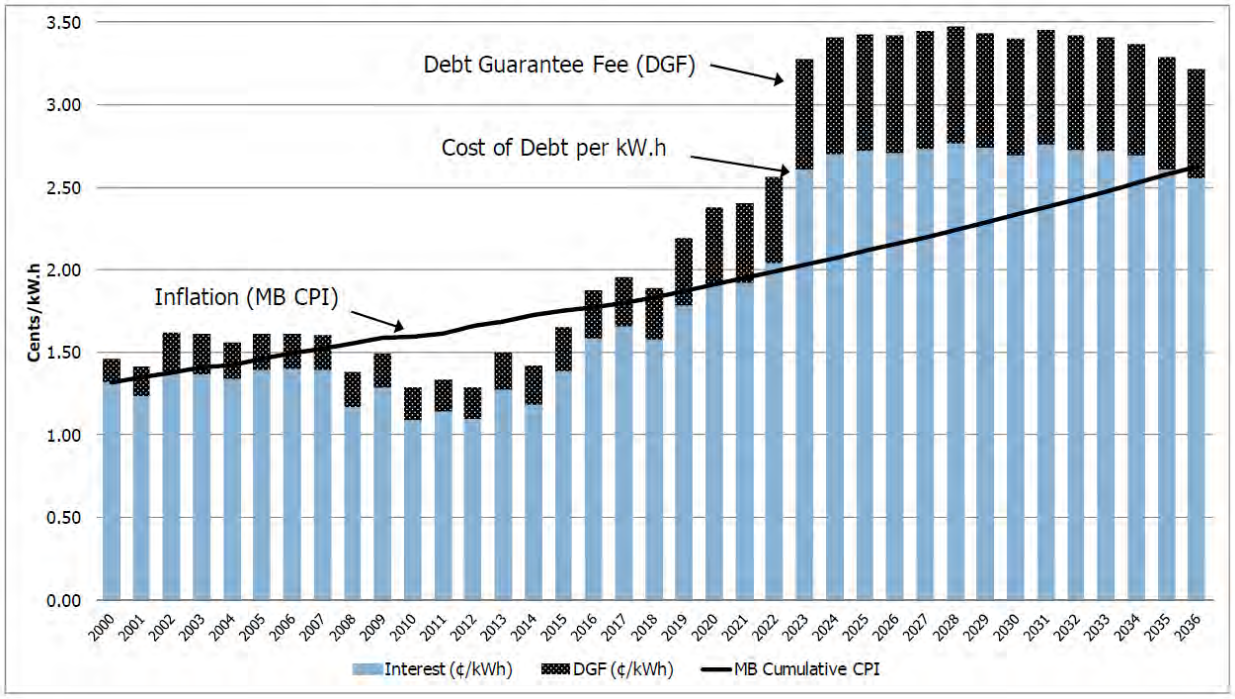
As shown on slide 20 of Exhibit MH-64, in 1990 Manitoba Hydro had almost $250,000 of debt per gigawatt hour of annual domestic load. As borrowing increases for Keeyask and Bipole III, the debt per gigawatt hour of annual domestic load increases dramatically, and under a 3.95% rate plan this metric eventually climbs to over $1.1 million per gigawatt hour and remains at that level. Relative to the size of Manitoba Hydro's business, the Corporation is building to being roughly four times as indebted as it was immediately after the construction of Limestone. As compared to BC Hydro and Hydro Quebec, Manitoba Hydro is already much higher and will be multiples of their levels of relative indebtedness in the future. Domestic load is an appropriate measure by which to evaluate debt levels because it is a proxy for how much debt service will need to be carried by each kW.h of domestic sales. It is the domestic ratepayers that are responsible for this risk. If interest rates increase, every dollar of additional interest rate expense will need to be recovered from the domestic ratepayer. Understanding the degree of leverage which is placed upon domestic ratepayers is vital to appreciating the vulnerability of the situation. The MH16 Update with Interim rate path, beginning with the approval of the requested rate increases in this Application will begin to reduce the risk facing the Corporation and its ratepayers, but even this will not restore debt to the

relative levels consistent with past practice, or to the levels consistent with its peers, BC Hydro or Hydro Quebec.

Figure 2 in the response to MH-MIPUG (Bowman) 23 illustrates the pressure debt is going to put on domestic ratepayers (reproduced below).

Figure 5.4

Figure 1: Manitoba Hydro Cost of Debt (Interest Payments & Debt Guarantee Fee) Comparison to MB CPI (cents/kW.h) MH16 w. Interim Update and MH15 Rate Increases – 2000 to 2036



Source: MH-MIPUG (Bowman) 23, Page 2

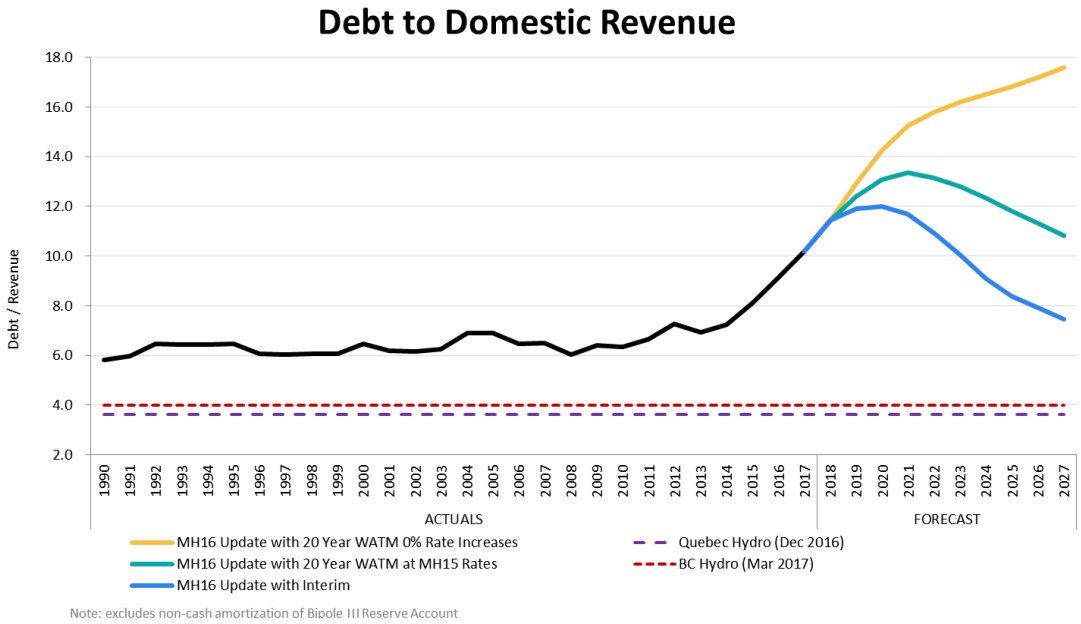
As can be seen from the chart above, the growth in the amount of interest expense per kW.h is dramatically outpacing inflation, notwithstanding declining interest rates from 2010 to 2017. This chart is prepared based on hydraulic generation. This chart is showing that the interest expense to be borne by each kW.h of generation will increase by more than 100% between 2018 and 2024. Were it to be done on domestic load at meter (which is the appropriate standard given where the liability for interest rate volatility resides), the pace of escalation would be even more dramatic. As shown in PUB MFR 18, cash interest paid in 2017/18 is approximately $900 million which would represent almost 60% of domestic revenue (including revenue allocated to the Bipole III

reserve). Therefore debt per kW.h is at least doubling for an annual cash burden that is already 60% of domestic rate revenue.

Manitoba Hydro has provided evidence demonstrating the interest costs as a share of domestic revenue. Once the major projects conclude and all of the interest flows through to the income statement, over 60% of each domestic revenue dollar is going to pay interest (Exhibit MH-64, Slide 21). There is not much revenue left with which to run the business and maintain assets. Should interest rates increase more than anticipated, this situation will only worsen, as shown in the Key Variable Sensitivity Impacts provided in the response to PUB/MH I-45.

The following chart from Exhibit MH-64 compares debt to domestic revenue.

Figure 5.5



Source: Exhibit MH-64, Slide 28

Similarly, the relationship of debt to domestic activity is critical as it is domestic customers who absorb 100% of the volatility that comes from any of the risks that face Manitoba Hydro's business including interest rates, water conditions and export prices. Since the in-service of Wuskwatim, debt has grown out of all proportion to Manitoba Hydro's business activities. This metric is now double historic norms for Manitoba Hydro and triple that of two of Manitoba Hydro's Canadian peers. MH16 Update with

Interim is more aggressive in bringing this relationship back toward pre-build norms however at the end of 2027 Manitoba Hydro still forecasts debt levels, on a relative basis, which are 30% above levels seen between 1990 and 2010. The 3.95% path does not make much progress on improving this metric. While domestic revenue goes up with the cumulative 47% rate increases over a decade, the lack of income and cash flow do not allow for debt retirement.

5.3 Debt Management Can't Mitigate Longer Term Risk

Manitoba Hydro must manage interest rate risk in order to control finance expense. In the short term this can be accomplished by managing refinancing risk through prudent debt management strategies. However, in the intermediate and longer term interest rate risk and finance expense can only be managed by reducing the total amount of debt. Manitoba Hydro's volume of debt is dependent upon the growth of the investment in assets. This growth must be funded by cash from operations or debt financing. The additional revenue generated by the requested 7.9% rate increase is a first step on a ten year path that, in the words of Mr. McCallum (Transcript Page 184), is "about getting our debt under some control to take some of the risk out of a perilous and unprecedented financial situation".

Manitoba Hydro will need to go to the markets to borrow between $19 and $23 billion over the coming decade which will increase the Corporation's exposure to interest rate risk. The table below illustrates borrowing requirements under two rate increase paths and is drawn from Exhibit MH-64, slide 36. Over the period, virtually all of Manitoba Hydro's debt will need to be initially borrowed and/or refinanced. This exposes ratepayers to risks from increases to interest rates. Should those interest rates increase unexpectedly, even in the order of 1%, this will have dire consequences for ratepayers.

Figure 5.6

In Billions of Dollars	MH Plan	3.95% / 12 Year WATM
2017/18 - 2021/22 Borrowing	$13.5	$14.1
2022/23 - 2026/27 Borrowing	$8.8	$9.7
2022/23 - 2026/27 Cash Flow	($3.1)	($0.4)
Total 10-Year Borrowing	$19.2	$23.4

Source: Exhibit MH-64, Slide 36

In the 2023-2027 timeframe, the higher cash flows from the 7.9% rate path limit new borrowing requirements by approximately $1 billion and create surplus cash of $3.1 billion that can be used to pay down debt as it comes due instead of refinancing debt. In contrast, there is virtually no debt retirement under the 3.95% rate path. As a result, all of this debt will be exposed to refinancing risk as it comes due. This was acknowledged by Morrison Park Advisors ("MPA") during cross-examination when Mr. Colaiacovo stated, *"Anything that is being refinanced within a period is subject interest rate risk within that period"* (Transcript Pages 5130 to 5131). Interest rate exposure will be lessened with a 7.9% rate path by removing $4 billion of debt from the balance sheet.

5.4 Debt to EBITDA is a Troubling Metric

Debt to EBITDA provides another way of understanding how much debt a corporation's cash flow is expected to service. Ratios of 6 and 7x are often considered highly leveraged. During cross-examination, MPA was referred the ratings methodology of Fitch Ratings (MPA Evidence filed on behalf of the Consumer's Coalition, Exhibit CC-17, Page 116) which describes Debt to EBITDA ratios of greater than 8x as *"Weaker"* and indicative of an insufficient rate structure. MPA acknowledged that Fitch Ratings would be looking for a suitable rationale for a corporation with a ratio of eight times, including perhaps investment in a major capital program, and admitted that if the ratio were in the order of 12 times, and projected to worsen to 13 times that they would expect after completion of the capital program that it would start to improve. (Transcript Page 5059).

"MR. MATTHEW GHIKAS: Okay. And if we go to the weaker row, then, under that column, we see greater than eight (8) times debt with a suitable rationale can indicate deficient rate structure.

MR. PELINO COLAIACOVO: I -- I think you meant without a suitable --

MR. MATTHEW GHIKAS: Sorry, without a suitable rationale [can] indicate deficient rate structure?

MR. PELINO COLAIACOVO: Correct. And

MR. MATTHEW GHIKAS: Right. So – so you would expect that Fitch would be looking for a suitable rationale, for example, they had already been over eight (8) times for six (6) years.

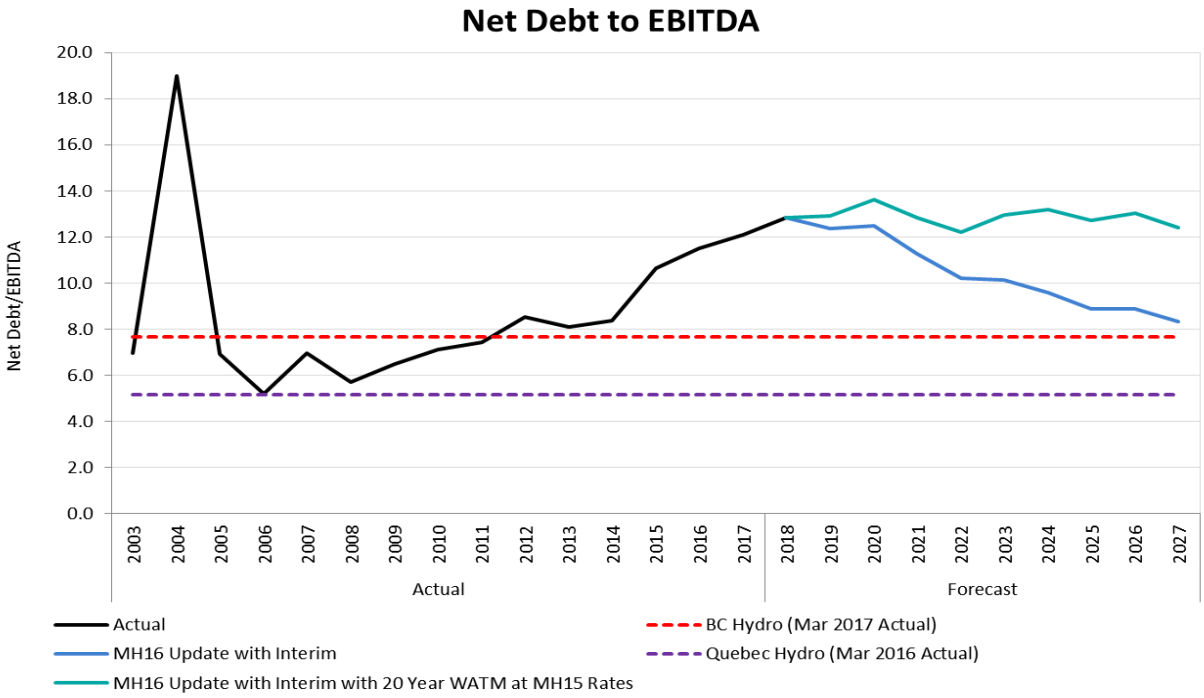
MR. PELINO COLAIACOVO: And I think a suitable rationale is investment in a major capital program, and -- and that's what that is actually about.

MR. MATTHEW GHIKAS: And they would be looking for a rationale. Would you put it as the capital thing if the -- today it was a twelve (12) times and was going to get worse to thirteen (13) times?

MR. PELINO COLAIACOVO: Yeah, and --but they would expect that after the completion of the major capital expenditures, ***that would start to improve****."* (Emphasis Added)

The following graph from Exhibit MH-64 shows that Manitoba Hydro's debt to EBITDA has been steadily climbing even since before the start of the major build program.

Figure 5.7



Source: Exhibit MH-64, Slide 56

With a 3.95% rate path, this metric is forecast to reach nearly 14x before declining to the 13x range where it stays through 2027. This stands in stark contrast to what Mr. Colaiacovo asserts would be the expectation of ratings agencies who would expect to see recovery in the post-construction phase.

In 2003/04, when Manitoba Hydro lost over $400 million during a drought, the Debt to EBITDA ratio spiked to over 18x before returning to historic levels on the back of lofty export revenues. It should be very concerning to the PUB that under a 3.95% rate path, Manitoba Hydro will be building debt to a level directionally consistent with the temporary level reached during a terrible drought – a time when the PUB was so concerned about Manitoba Hydro's financial condition that it awarded the corporation a higher rate increase than requested (Order 101/04).

Mr. Colaiacovo spoke of the 2003/04 shock to cash flow in his testimony at Transcript Page 5053:

"MR. MATTHEW GHIKAS: And in your – in your testimony yesterday, in response to a question from member Kapitany …you referred back to the early 2000s. 2003, you believed went -- that was an extremely short, sharp shock in that period in the second lowest water year ever. Do you recall that generally?

MR. PELINO COLAIACOVO: Yes.

MR. MATTHEW GHIKAS: Okay. And you indicated that Manitoba -- Manitoba Hydro's cash flow plummeted through the floor?

MR. PELINO COLAIACOVO: That's correct.

MR. MATTHEW GHIKAS: And were you aware that during that period, this metric was only at nineteen (19) times?

MR. PELINO COLAIACOVO: That may well-- very well be the case."

MPA reports that the credit rating agency S&P regards Debt to EBITDA as one of two primary metrics that it focuses on with respect to cash flow (Exhibit CC-17, Page 33). MH16 Update with Interim takes action on this metric although by the end of 2027, it remains elevated from historic norms for Manitoba Hydro, above peers' current metrics and above levels categorized as evidence of rate inadequacy by Fitch Ratings.

5.5 Capital Markets Are Concerned with Rate Inadequacy

Manitoba Hydro's financial health and deteriorating financial metrics due to the imbalance between the growth of debt and lack of revenues have been of concern to its credit rating agencies.

In Moody's November 28, 2017 Report on the Manitoba Hydro Electric Board filed as Exhibit MH-61 in confidence, the rating agency states:

"While rates increases are nominally set on a cost-of service basis rate increases in recent years have clearly not kept up with costs as evidenced by ongoing weak financial metrics."

Additionally:

"As part of its debt management strategy, Manitoba Hydro targets certain financial metrics such as an interest coverage ratio greater than 1.8x and equity-

to-capitalization greater than 25%. However, both targets are not expected to be met for an extended period of time due to the large generation and transmission projects currently underway such as Keeyask and Bipole III and limited rate increases. For example on a last twelve month basis Moody's adjusted EBITDA to interest expense was 1.3x and debt to book capitalization was 88%. These financial metrics are among the weakest, if not the weakest, of any of Manitoba Hydro's peers, including vertically integrated provincially owned crown corporations in Canada."

In Exhibit MH-71 (DBRS Provincial Outlook Report November 28, 2017) it is reported that Manitoba Hydro's debt as a percentage of GDP is larger than its Canadian peers. In fact, by adding the Manitoba Hydro-Electric Board self-supported debt of 28.8% at March 31, 2017 (Exhibit MH-71, Page 95), to the Manitoba debt percentage of approximately 45% (Manitoba Hydro letter dated May 5, 2017, Exhibit MH-4, Page 6), Manitoba rivals Newfoundland for the highest debt burden as a percentage of GDP.

Rating agencies and investors clearly understand that elevated debt leaves an issuer much more susceptible to risks, particularly adverse interest rate movements. As noted in the response to PUB/MH I-45, Figure 4.4 - Key Variable Sensitivity Impacts to Retained Earnings filed in Tab 4 of the Application, has been updated based on MH16 Update with Interim Rate. The projected impact of a + 1% increase in Interest rates results in a cumulative decrease to retained earnings of $885 million to 2027/28. This results in the equity target not being reached until fiscal 2029 despite 7.9% rate increases for six years. MH16 Update with MH15 rate increases, with a greater debt burden, is prone to a greater degree of interest rate risk than MH16 Update with Interim. Given the 25% equity target is not reached until fiscal 2034 with the base case MH15 rate increases, a + 1% increase in interest rates would further pressure Manitoba Hydro's poor financial metrics.

5.6 Financial Targets Are Not Met Without Higher Rate Increases

On page 43 of their report (Exhibit CC-17), MPA makes a number of assertions about the sufficiency of various rate paths including the statement that:

"the 3.95% rate path is reasonably robust from a cash flow perspective for the first 10 years of the modeling period. After 2030, however, reducing the rate path down to 2% increase exposes the corporation to too much risk."

MPA goes on to states "It is not clear why annual rate increases were not kept at 3.95% for additional years beyond 2028/29 but based on this modeling, it would definitely be necessary." MPA points to sensitivity analysis drawn from PUB/MH II-41 and points out, in support of the need for the 3.95% rate increases to continue beyond 2028/29, that "net income actually becomes negative at the P20 position for more than half of the years of the model" (line 17-18, page 43).

The following table, sourced from PUB/MH II-41, sets out annual net income and EBITDA to Interest ratio (both under the MH15 rate path) at the P20 level for the years from 2028/29 to 2035/36 when the target equity ratio of 25% is nearly met (at the P50 level).

Figure 5.8

	MH16 Update with Interim at MH15 Rates							
	2029	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
P20 Net Income	($130)	($73)	($53)	$16	$67	$137	$217	$216
P20 EBITDA to Interest	1.58x	1.64x	1.64x	1.70x	1.75x	1.83x	1.91x	1.93x

Source: PUB/MH II-41

The next table, sourced from Appendix 1.3 to Exhibit MH-52 lays out net income and the EBITDA to Interest ratio but instead at the P50 (i.e. reference) level. This scenario is MH16 Update with Interim with MH15 Rates and 20 Year WATM.

Figure 5.9

	Exhibit MH-52 (Rebuttal), Appendix 1.3							
	2024	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
P50 Net Income	($222)	($176)	($226)	($160)	($91)	$17	$100	$182
P50 EBITDA to Interest	1.47x	1.52x	1.49x	1.54x	1.60x	1.69x	1.78x	1.87x

Source: Exhibit MH-52, Appendix 1.3

In comparing the two tables Manitoba Hydro notes a paradox in MPA's assertions on rate inadequacy. The *"reasonably robust"* rate path for the first 10 years produces large losses in the reference case for many years along with, for the most part, the EBITDA to Interest minimum target of 1.80x not being met. These losses are well in excess of the P20 level losses Morrison Park cites in support of it being *"too much risk to the corporation"* to reduce the rate path to 2% beyond 2028/29. Likewise the EBITDA to interest ratio is considerably lower. It is especially noteworthy that the income levels and EBITDA to Interest ratios cited as being *"too much risk"* occur at the P20 level meaning there is only a 20% chance (according to this analysis) that net losses would be worse. Meanwhile at the P50 level in the comparison, net losses are substantial larger and the interest coverage levels lower while having a 50% chance of being even worse and yet are *"reasonably robust"*. Manitoba Hydro is unable to reconcile how a forecast of comparatively modest losses and stronger interest coverage ratios with relatively lower likelihood can be deemed *"too much risk"* and yet larger losses that have a higher level of certainty of occurring are deemed *"reasonably robust"*. Manitoba Hydro is unable to reconcile how relatively stronger results much further in the future are a cause for concern while even larger losses and weaker metrics 5-10 years from now are *"reasonably robust"*. This is particularly confusing given the increases in potential variance are further into the future. For example, under the MH15 rate path, P50 net income for 2034 is estimated to be $530 million but with a range of a $207 million loss (P05) to $1.6 billion of net income (P95).

5.6.1 EBITDA to Interest

EBITDA is a very commonly used proxy for cash flow before any interest payments or capital expenditures. MPA describes it this way at page 8 of their report (Exhibit CC-17):

> *"The Interest Coverage Ratio…is often considered an important metric when assessing the credit-worthiness of an enterprise, because it provides information about the sufficiency of cash flow to cover interest cost….while this ratio serves as an <u>indicator</u> of the sufficiency of cash flow, it is an "accounting" measure and not a true "cash flow" measure of the results of the period for which the calculation is being made".* (Emphasis by MPA)

Manitoba Hydro concurs with the above statement. However, at page 42 to 43 of Exhibit CC-17, MPA states:

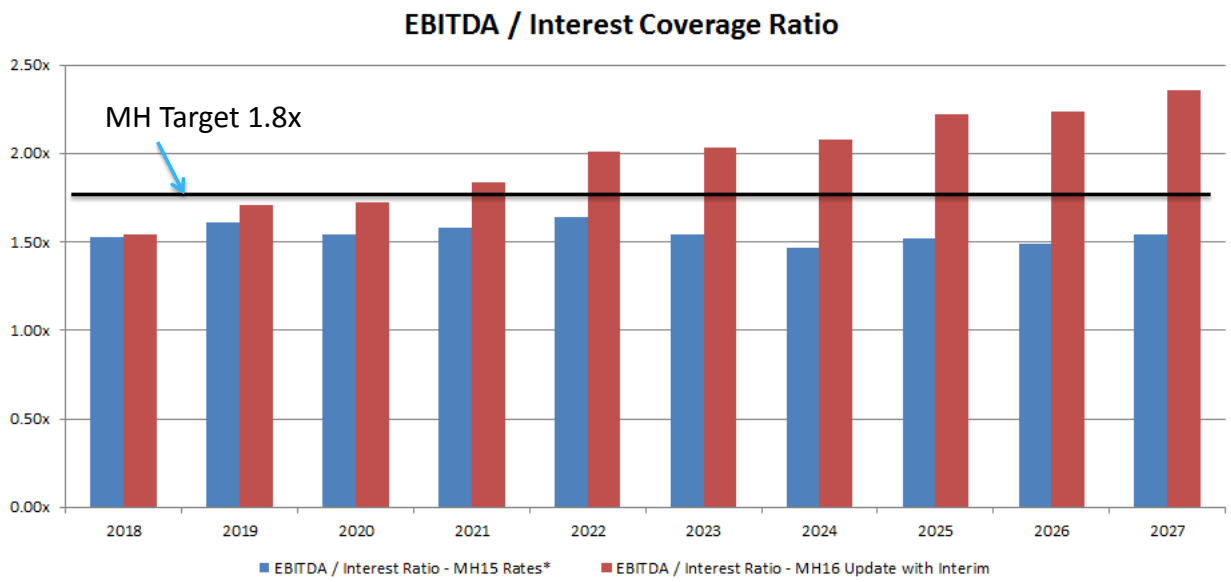
At the P01 position of the EBITDA to Interest plot on the 3.95% rate path, the ratio is never below 1. It should be noted that a ratio of 1 means that operating income is just sufficient to cover finance expense costs. In the parlance of the Moody's and DBRS, as long as Manitoba Hydro is able to continue to cover all of its costs – including operating costs and interest – it will continue to be regarded as "self-supporting", and not a burden to the Province"

MPA's use of the EBITDA to Interest coverage ratio in support of assertions regarding Manitoba Hydro's self-supporting status and overall rate adequacy is significantly flawed. An EBITDA to Interest coverage ratio of 1.0x on a sustained basis necessitates significant borrowing of new debt every year to meet sustainment capital needs and ongoing obligations. There is no argument that this is a financially prudent path or one that would be endorsed by capital markets participants as evidence of being self-supporting. Manitoba Hydro cannot continue to operate and generate EBITDA in the first instance without replenishing its assets. Manitoba Hydro cannot sell from inventory like another business can when its plant fails. Manitoba Hydro requires its assets to be in-service in order to generate revenue. During his testimony, Mr. Colaiacovo acknowledged that at an EBITDA to Interest level of 1.0x, no cash would remain, after meeting interest payments, to be used for any of capital expenditures, debt reduction, mitigation or City of Winnipeg liabilities (Transcript Pages 5068 to 5071). Exhibit MH-52, Figure 1.12 (reproduced in sub-section EBITDA to Cash Burdens below), demonstrates that the annual capital expenditures and other cash burdens on Manitoba Hydro are in a narrow range between $723 million and $822 million annually over the next 10 years. At an EBITDA to Interest level of 1.0x this would reflect, dollar for dollar, the incremental debt Manitoba Hydro would need to borrow to maintain its operations and meet its mandate.

Without an EBITDA to Interest ratio significantly above 1.0x, Manitoba Hydro is deficit funding its ongoing operations which, if sustained, is the very definition of not being self-supporting.

The following chart compares Manitoba Hydro's EBITDA to Interest ratio under MH16 Update with Interim and the same scenario with MH15 rates and 20 Year WATM (Exhibit MH-52, Appendix 1.3):

Figure 5.10



Source: Exhibit MH-52, Appendix 1.3

As can be seen from the above, under the 3.95% rate plan, Manitoba Hydro never reaches its minimum target and in fact barely crosses 1.50x throughout the period and with no pattern of improvement particularly after the in-service of Keeyask. Manitoba Hydro expects this would be deeply concerning to bond investors who watch trends carefully.

The table is a reproduction of Figure 1.10 from Exhibit MH-52, page 15. It sets out Manitoba Hydro's cash flows under the MH15 rate plan (Exhibit MH-52, Appendix 1.3):

Figure 5.11

millions of dollars

	Actual		Forecast									
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Receipts from Customers	1 907	1 997	2 152	2 170	2 173	2 371	2 577	2 734	2 821	2 931	2 897	3 011
Payments to Suppliers and Employees	(736)	(933)	(892)	(843)	(870)	(885)	(894)	(903)	(935)	(953)	(952)	(966)
Interest Paid (Net of All Capitalized Interest)	(520)	(536)	(528)	(641)	(711)	(789)	(889)	(1 155)	(1 227)	(1 239)	(1 241)	(1 266)
Bipole III and Other Business Operations Capitalized Interest*	(107)	(141)	(197)	(93)	(21)	(18)	(16)	(19)	(19)	(19)	(18)	(20)
Business Operations and Deferred Capital Expenditures:												
Business Operations Capital Expenditures**	(616)	(578)	(586)	(566)	(554)	(544)	(525)	(532)	(544)	(601)	(627)	(646)
Demand Side Management	(54)	(50)	(55)	(97)	(92)	(87)	(85)	(64)	(58)	(60)	(64)	(68)
Mitigation and Other Deferred Expenditures	(22)	(5)	(27)	(26)	(23)	(23)	(22)	(22)	(21)	(22)	(21)	(22)
Ineligible Overhead	(20)	(20)	(20)	(20)	(20)	(20)	(20)	(20)	-	-	-	-
Cash From Operations Less Capex	**(167)**	**(267)**	**(153)**	**(116)**	**(119)**	**5**	**126**	**19**	**16**	**38**	**(26)**	**24**
Mitigation, Major Development & Other Liability Payments	(26)	(13)	(59)	(46)	(36)	(79)	(98)	(88)	(84)	(84)	(71)	(70)
City of Winnipeg Payments	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)
Cash Flow (Deficiency)/Surplus	**(209)**	**(296)**	**(228)**	**(178)**	**(170)**	**(89)**	**12**	**(85)**	**(84)**	**(62)**	**(113)**	**(62)**
Cumulative Cash Flow (Deficiency)/Surplus			**(228)**	**(406)**	**(576)**	**(665)**	**(653)**	**(739)**	**(823)**	**(884)**	**(998)**	**(1 060)**

*Bipole III and Other Sustaining Capitalized Interest does not include any capitalized interest associated with Keeyask, MMTP or GNTL.
**Represents Business Operations Capital Expenditures and MNG&T Capital Expenditures of a sustaining nature (excluding Bipole III costs).

Source: Exhibit MH-52, Appendix 1.3

As can be seen, and comparing with the EBITDA to Interest graph above, an interest coverage ratio in the order of 1.50x following the 3.95% rate path translates to significant, repetitive cash flow deficiency. Over the 10 year horizon, the ongoing operations of Manitoba Hydro require $1.1 billion of additional borrowing over and on top of the borrowing necessary to complete the major capital projects. In only one year (2021/22 at $12 million) does Manitoba Hydro generate any positive cash flow from its operations.

EBITDA to Interest Coverage is often regarded as a solvency metric in that it indicates a company's ability to service its interest costs out of operating earnings (before non-cash depreciation expense). However, as a test of financial durability and cash flow sufficiency, the metric has important shortcomings. It presumes that the cash interest requirements of the business can assert primacy over all the other cash burdens on the company such as capital reinvestment or payment of other contractual liabilities. In actual fact, EBITDA Interest Coverage does not consider that, other than under very short time frames, Manitoba Hydro must fund both its interest costs and its capital and other requirements. As Mr. McCallum noted (Transcript Page 225) *"When elements of the system wear out and fail, which happens every day, we have to replace them or we are not meeting our commitments to Manitobans."* If Manitoba Hydro does not have sufficient cash flow after interest payments to fund its ongoing capital and other cash

needs then it cannot support its revenue and meet its mandate without borrowing money.

Mr. Colaiacovo, at Transcript Page 4944, describes Manitoba Hydro's EBITDA to Interest target of 1.8x as *"reasonable because it's consistent with targets that public power utilities in the United States use, and one point five (1.5) to two (2) times, as Moody's recognizes is a reasonable target for a – a public power utility."* Likewise, at slide 33 of MPA's direct evidence (Exhibit CC-45), MPA asserts that *"1.8x is a "healthy" margin that gives comfort that under "normal" conditions, Manitoba Hydro will have* ***plenty of cashflow to satisfy obligations****"* (Emphasis Added). MPA further states that *"for Public Power Utilities 1.5x to 2.0x interest coverage is consistent with an "A" rating"* by Moody's. This stands in direct contrast to page 9 of Exhibit CC-17 wherein at line 13-15 wherein it is stated *"This measure alone does not clarify whether the company's debt is increasing, since there is no information captured in this metric about the size of capital expenditures".*

Manitoba Hydro asserts that the Moody's test is not EBITDA to interest but rather debt service coverage given that is how it clearly labeled in the referenced Moody's report. Mr. Colaiacovo acknowledged this at transcript page 5072. During cross-examination, Manitoba Hydro questioned Mr. Colaiacovo as to whether adjusted debt service coverage included principal payments:

> *"MR. PELINO COLAIACOVO: Not always. It actually just depends on the arrangements of the Utility.*
> *MR. MATTHEW GHIKAS: In common financial discourse debt service generally includes interest and principal, doesn't it?*
> *MR. PELINO COLAIACOVO: So it depends on your financial arrangements. Debt service coverage ratio is a typical term but in some instances debt service coverage ratio refers only to interest and some instances it refers interest and principal"* (Transcript Page 5072).

Manitoba Hydro submits that the evidence in this respect is unclear as to whether Moody's debt service coverage test would be applied to Manitoba Hydro using a calculation of interest or interest and principal payments. Nonetheless, even by the less stringent measure, Manitoba Hydro does not sustain itself at even the bottom end of

Moody's standard on a sustained basis and in fact does not meet its own internal target of 1.8x until 2030/31.

5.6.2 EBIT to Interest

The following table shows Manitoba Hydro's key financial metrics as well as other informative metrics.

Figure 5.12

Financial Ratios:	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27
Equity Ratio (Target > 25%)										
MH16 Update with Interim	15%	14%	14%	15%	17%	17%	19%	21%	23%	25%
MH15 Rates	15%	14%	13%	13%	13%	12%	12%	11%	10%	10%
Capital Coverage Ratio (Target > 1.20x)										
MH16 Update with Interim	1.40 x	1.48 x	1.47 x	1.88 x	2.34 x	2.25 x	2.37 x	2.34 x	2.20 x	2.29 x
MH15 Rates	1.39 x	1.33 x	1.15 x	1.36 x	1.59 x	1.30 x	1.21 x	1.20 x	1.10 x	1.18 x
EBITDA Interest Coverage Ratio (Target > 1.80x)										
MH16 Update with Interim	1.54 x	1.71 x	1.72 x	1.84 x	2.01 x	2.03 x	2.08 x	2.22 x	2.24 x	2.36 x
MH15 Rates	1.53 x	1.61 x	1.54 x	1.58 x	1.64 x	1.54 x	1.47 x	1.52 x	1.49 x	1.54 x

Other Metrics:	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27
EBIT Interest Coverage Ratio (Target > 1.20x)										
MH16 Update with Interim	1.10 x	1.21 x	1.20 x	1.31 x	1.45 x	1.38 x	1.36 x	1.47 x	1.45 x	1.54 x
MH15 Rates	1.10 x	1.13 x	1.03 x	1.07 x	1.12 x	0.95 x	0.83 x	0.86 x	0.82 x	0.88 x
Net Debt										
MH16 Update with Interim	$ 18 473	$ 20 743	$ 22 407	$ 23 296	$ 23 609	$ 23 388	$ 22 831	$ 22 201	$ 21 613	$ 20 947
MH15 Rates	$ 18 474	$ 20 825	$ 22 657	$ 23 809	$ 24 496	$ 24 761	$ 24 811	$ 24 877	$ 24 994	$ 25 060

Source: Exhibit MH-64, Slide 53

Mr. Bowman points to the EBIT / Interest ratio as:

> *"the normal regulatory basis for determining an annual Revenue Requirement. The best metric used by Manitoba Hydro to measure this is the previous EBIT Interest Coverage ratio. Achieving an EBIT Interest Coverage ratio above 1.0x means that debt costs for the year can be funded from revenues for the year. The previous EBIT Interest Coverage ratio targeted 1.2 or better, reflecting a cushion above break even"* (MH-MIPUG (BOWMAN)-12).

The preceding table demonstrates that the 3.95% rate plan which Mr. Bowman advocates grossly fails his preferred test. Under the MH15 rate plan, Manitoba Hydro's EBIT to Interest ratio declines below 1.0 indicating, according to Mr. Bowman, that debt costs are not being funded by revenues.

More importantly, as Ms. Stephen testified (Transcript Page 953), Moody's has expressed concern to Manitoba Hydro with respect to the EBIT ratio falling below 1 for several years under a 3.95% rate plan. Ms. Stephen also testified that Moody's cautioned that if Manitoba Hydro is viewed as being unable to service its debt, and no steps are taken to mitigate the circumstances, the rating agency may change the self-supporting status of Manitoba Hydro's debt.

5.6.3 Capital Coverage Ratio

Mr. Bowman asserts that because the Capital Coverage Ratio is greater than 1.2x under the MH15 rate plan that Manitoba Hydro is attaining its goal to *"meet all financial obligations including debt service and capital reinvestment out of the revenues of the Corporation"*. However, as noted in its evidence, there are shortcomings in Manitoba Hydro's capital coverage ratio which must be recognized in order to properly determine the ratio.

Firstly, certain projects are included in *"Major New Generation and Transmission"* by virtue of their individual size resulting in the true sustainment capital needs of Manitoba Hydro's operations being understated. The exclusion of other non-discretionary cash payments such as mitigation, development and other liability payments and the annual payment to the City of Winnipeg compounds the understatement.

Secondly, without making any adjustment for capitalized interest on funds borrowed to finance reliability and sustainment projects like Bipole III, cash flow from operations (the numerator in the formula) essentially excludes the interest paid which is an immediate and ongoing cash outlay by the Corporation. Mr. Bowman's conclusion that the capital coverage ratio is maintained at or above target (1.2x) for the entire 20 year forecast under the 3.95% rate path (Pre-Filed Testimony of Patrick Bowman, on behalf of the Manitoba Industrial Power Users Group, Exhibit MIPUG-13, Page 5-10) fails to make the adjustments noted above or to acknowledge the declining trend line over the forecast period. Mr. Bowman asserts at lines 24-26, page 4-5 of MIPUG-13 that after 2022/23 Manitoba Hydro would be *"rapidly retiring debt"* in the absence of Major New Generation and Transmission investments. In fact, as demonstrated in the table above (Exhibit MH-64, Slide 53), Manitoba Hydro's net debt actually grows by $300 million

between 2022/23 and 2026/27 under the MH15 rate plan disproving Mr. Bowman's assertion that a sufficient capital coverage ratio is indicative of *"rapidly retiring debt"*.

5.6.4 EBITDA to Cash Burdens

Manitoba Hydro's ongoing, repetitive capital and other cash obligation needs in its core operations are anticipated to range between $700 million and $800 million per year as noted in the line *"Capital and Other Needs"* from the table below. This table reproduces Figure 1.12 of Exhibit MH-52 wherein the EBITDA interest coverage ratio is adjusted to include all the fixed burdens on Manitoba Hydro under the MH15 rate path. As can be seen, and consistent with its evidence that it is and will be *"deficit funding"* its core operations, other than in 2021/22 Manitoba Hydro never reaches parity or 1.0x wherein it has sufficient EBITDA to meet all of its cash obligations.

Figure 5.13

millions of dollars

	Forecast									
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Net Income	90	128	33	80	141	(66)	(222)	(176)	(226)	(160)
Net Finance Expense	573	677	753	839	925	1 179	1 251	1 263	1 263	1 283
Capitalized Interest	359	320	318	333	290	55	19	19	18	20
Depreciation and Amortization*	408	482	548	596	643	735	823	840	856	870
Corporate Allocation	8	8	8	8	7	7	7	7	7	7
EBITDA Numerator	**1 439**	**1 614**	**1 661**	**1 856**	**2 006**	**1 911**	**1 880**	**1 953**	**1 918**	**2 019**
Interest	939	1 003	1 078	1 178	1 221	1 241	1 277	1 288	1 287	1 309
Capital and Other Cash Needs	763	772	740	769	766	742	723	783	799	822
Cash Burdens (Denominator)	**1 703**	**1 775**	**1 819**	**1 947**	**1 987**	**1 983**	**2 000**	**2 071**	**2 087**	**2 131**
EBITDA / Ongoing Cash Burdens	**0.85**	**0.91**	**0.91**	**0.95**	**1.01**	**0.96**	**0.94**	**0.94**	**0.92**	**0.95**
Equity Ratio	**15%**	**14%**	**13%**	**13%**	**13%**	**12%**	**12%**	**11%**	**10%**	**10%**

*Including related items in Net Movement.

Source: Exhibit MH-52, Page 19

Under the MH15 rate plan, Manitoba Hydro never reaches parity or 1.0x wherein it has sufficient EBITDA to meet all of its cash obligations.

At page 54 of Exhibit MH-64, Manitoba Hydro also presented this illustrative ratio under the MH16 Update with Interim rate path wherein by 2019/20 Manitoba Hydro is

essentially cash flow break-even and by later in the forecast has an adequate cushion which can be used to deleverage and de-risk unsustainable debt loads.

Figure 5.14

(In Millions of Dollars)	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27
MH16 Update with Interim:										
EBITDA (Numerator)	**1439**	**1676**	**1795**	**2068**	**2307**	**2308**	**2384**	**2495**	**2435**	**2508**
Interest	936	982	1041	1121	1145	1138	1148	1125	1089	1060
Capital and Other Cash Needs	763	772	740	769	766	742	723	783	799	822
Cash Burdens (Denominator)	**1700**	**1754**	**1782**	**1890**	**1911**	**1880**	**1871**	**1908**	**1888**	**1882**
EBITDA / Ongoing Cash Burdens	**0.85 x**	**0.96 x**	**1.01 x**	**1.09 x**	**1.21 x**	**1.23 x**	**1.27 x**	**1.31 x**	**1.29 x**	**1.33 x**
Equity Ratio	**15%**	**14%**	**14%**	**15%**	**17%**	**17%**	**19%**	**21%**	**23%**	**25%**
At MH15 Rates:										
EBITDA / Ongoing Cash Burdens	**0.85 x**	**0.91 x**	**0.91 x**	**0.95 x**	**1.01 x**	**0.96 x**	**0.94 x**	**0.94 x**	**0.92 x**	**0.95 x**
Equity Ratio	**15%**	**14%**	**13%**	**13%**	**13%**	**12%**	**12%**	**11%**	**10%**	**10%**

Source: Exhibit MH-64, Page 54

5.7 Past Leverage Levels of No Current Relevance

Mr. Osler provided testimony attempting to put Manitoba Hydro's current circumstance in historical context. A large basis of the comparison was to the post-Limestone period (early 1990s onward) wherein Manitoba Hydro emerged from a period of major investment with an extremely low debt:equity ratio. Mr. Osler explains how this made sense in customary regulatory practice and should serve as a guide for the patient restoration of Manitoba Hydro's financial health in the current period.

The circumstances of the Limestone-era are vastly different from the scale of issues facing Manitoba Hydro at present. Mr. McCallum outlined these at Transcript Pages 184 to 186:

> *"After Limestone, we had $4 1/2 billion of debt. That was about ten thousand dollars ($10,000) of debt per customer. Today we have thirty- five thousand dollars ($35,000) of debt per customer. We're heading to about forty-two thousand dollars ($42,000) of debt per customer, four (4) times higher…*
>
> *In the ten (10) years after Limestone, we had net income of almost $1 billion. Those are in then dollars, not even adjusting for inflation over twenty (20) years. That was earning -- earned operating a business that averaged about $5 billion*

of net plant in service over that decade. It was earned operating a business in a significantly higher rate interest environment, three (3) to four (4) times higher, and in a decade where we enjoyed above-average water conditions in two (2) of the ten (10) years.

Let's turn to the 3.95 percent plan… our business is five (5) times larger. Our relative debt levels are four (4) times greater… instead of making the… 1 billion we did in the decade after Limestone, instead, if things go well, lose 400 million. The suggestion we were in the same place as we have been before is preposterous."

The addition of the Limestone generating station, for $1.43 billion (Manitoba Hydro's Written Rebuttal Evidence on the MGF Report, Exhibit 117, Appendix A), reflected roughly a 40% increase[6] to the plant in service of the Corporation. The additions of Keeyask, Bipole III and MMTP reflect a $14.2 billion combined investment (Appendix 3.1 of the Application, page 51) which more than doubles the in service asset base of today.

In summary, the scale of assets and debt being added to Manitoba Hydro relative to its pre-existing operations is entirely different. In every respect, the financial impact of Manitoba Hydro's development plan dwarfs that of Limestone and comes on the heels of a prolonged period of insufficient rates. Therefore the financial plan necessary to absorb this growth in the business must be dramatically different.

[6] Transcript page 185 notes an average $5 billion net plant in service in the decade after Limestone.

6 FINANCIAL TARGETS AND THE ROLE OF RESERVES IN MANAGING FINANCIAL HEALTH

6.1 Overview of Financial Targets

As discussed in Tab 4 of the Application, Manitoba Hydro has revised its primary financial targets following internal review and an external review by KPMG in May, 2015. These targets are described below.

6.1.1 Equity Ratio:

The debt:equity ratio measures the relationship of long-term and short-term debt to equity. Effectively, Manitoba Hydro's calculation of its debt:equity ratio compares net debt to total capital (calculated as net debt plus equity). This ratio identifies the capital structure of the Corporation and assesses the overall financial risk to Manitoba Hydro.

As indicated in Appendix 4.1 of the Application on page 16, the capital structure as measured through the debt:equity (or debt to capital) ratio is universally accepted by the capital markets and financial and investment industry as one of the primary measures of financial strength.

Manitoba Hydro's objective is to maintain the appropriate balance between debt and equity. An adequate level of retained earnings is required to withstand the financial impacts of risks faced by Manitoba Hydro, including but not limited to drought and water flow, and is an important consideration in credit ratings and financing costs.

Manitoba Hydro's current debt:equity target of 75/25 is a reasonable long-term target. KPMG did note that a target of 70/30 would provide additional financial strength to address the utility's unique financial challenges and risks and recommended that the debt:equity ratio should fall within the range of 75/25 to 70/30. Following an internal review in 2016, the Manitoba Hydro Electric Board and senior management team determined that the target should remain at 75/25, and that the Corporation should target attainment of the 25% equity in a period not longer than 10 years in order to reduce the financial risks to the Corporation (Tab 4, page 7).

6.1.2 Interest Coverage Ratio:

The Interest Coverage Ratio assesses the degree to which Manitoba Hydro can meet its interest obligations with the operating income generated annually. An EBITDA-based metric includes the cash flows associated with the accounting of depreciation and

amortization expense in the numerator of the interest coverage calculation. As these cash flows can be used to make interest payments, this indicator uses an approach for calculating coverage that is more cash-flow based than that using EBIT.

EBITDA, however, is not an exact measure of cash flow since it does not incorporate capital expenditure requirements or working capital adjustments. Nevertheless, it is closer to a cash-flow metric than EBIT.

KPMG recommended a minimum EBITDA interest coverage ratio at a target level of 1.8 or greater. Previously, Manitoba Hydro had maintained a minimum target for the EBIT interest coverage ratio of 1.2. The KPMG recommendation for an EBITDA interest coverage ratio with a minimum target of 1.8 was adopted by the Manitoba Hydro Board in December, 2015.

6.1.3 Capital Coverage Ratio:

The Capital Coverage Ratio measures Manitoba Hydro's ability to fund its sustaining capital expenditure (e.g. ongoing maintenance and replacement capital expenditure "capex"), excluding Major New Generation and Transmission, from its current cash flow from operations. KPMG found that the current target of 1.2 or greater for the capital coverage ratio is reasonable, and the Manitoba Hydro-Electric Board endorsed the ratio and target in December 2015. An inherent limitation of this ratio is that it does not reflect the financial challenges associated with major expansion programs. Hence it may be misunderstood or misinterpreted by stakeholders.

6.2 Financial Targets are a Measure of Financial Health

Achieving and maintaining financial targets is important for the financial health of the utility, supporting the interest of domestic ratepayers who ultimately bear the cost of operating, maintaining and renewing the system. Given the credit support provided to Manitoba Hydro by the Province of Manitoba, it is also fundamental that Manitoba Hydro be self-supporting in the eyes of credit rating agencies and lenders to avoid the unacceptable risk of having the Province's cost of borrowing impaired and implicitly or explicitly having to subsidize the continued financial viability of the electricity system. Presently, Manitoba Hydro enjoys a cost of financing that is significantly lower than what it could obtain without the Provincial Guarantee, while the quantum of borrowing required would likely be unattainable given the Corporation's current credit profile.

The equity ratio along with an EBITDA coverage ratio and a Capital Coverage ratio are conventional measures of financial health and credit-worthiness. Positive cash flow from operations inclusive of servicing debt is also relevant to a determination of self-supporting status.

As indicated in the response to PUB/MH I-42, Manitoba Hydro's financial targets are set in the context of being a government-owned entity with a modified cost of service rate regime. As such, targets are set based on a minimum level of financial strength that reasonably minimizes the risk of any contagion impact of the Corporation's financial profile on the credit rating and/or borrowing costs of the Province of Manitoba as well as ensuring Manitoba Hydro has the wherewithal to absorb adverse conditions such as below average water conditions or rising interest rates, or event risks such as asset failures, without having to look to ratepayers for emergency relief.

Such wherewithal stems from appropriate levels of income, cash flow and reserves. Manitoba Hydro's equity position can only be enhanced through net income and, as such, building an adequate equity position over a reasonable planning horizon. This is particularly critical in the early years of the current financial plan where the capacity to absorb risk is low due to current deficiencies in income and equity levels along with an unavoidable escalation in debt and operating costs as two major new projects are completed and commissioned. Attainment and maintenance of a 75/25 debt equity ratio also positions Manitoba Hydro to manage its unique set of risks including hydrology risk, export market risk, interest rate risk and its limited financial flexibility.

6.3 There is No Need to Adjust Targets for Purposes of Ratemaking

At Transcript Page 4938, Mr. Colaiacovo of Morrison Park Advisors ("MPA") states:

> *"And I would suggest that having a rule of some kind would help guide rate-making and allow you to make the kind of determination that I think you would like me to offer."*

Manitoba Hydro has established financial targets for the purposes of guiding, managing and reporting on its financial health. The financial targets used by Manitoba Hydro were established with the assistance of recommendations from two leading, globally

recognized experts (RBC Dominion Securities in 1995, KPMG in 2015). MPA asserts that some new vaguely defined *"rule"* is now required to address an unsupported argument of deficiency in Manitoba Hydro's current practices.

The PUB has acknowledged the importance of Manitoba Hydro having a sound plan to return to financial strength, and endorsed the 75/25 debt:equity ratio. For example, in Order 101/04, the PUB provided the following comments on Manitoba's Hydro's debt to equity financial target:

> *"Achieving a debt:equity ratio of 75:25 would provide increased rate stability benefits, and hold down financial charges. The 75:25 benchmark represents a modest target, one comparable with the current debt:equity ratios of similar Crown hydroelectric utilities in other Canadian provinces (BC Hydro and Hydro-Quebec). In summary, meeting this target within a reasonable period of time would reduce long-term pressure on domestic electricity rates, better assure bondholders and thus constrain financial charges and provide a hedge against a future drought"* (Page 31 of PUB Order 101/04).

The PUB also commented on the importance of Manitoba Hydro's financial strength in Order 116/08:

> *"It is the Board's [PUB] understanding that rating agencies look prominently at MH's financial strength in assessing the credit rating of the Province. A weakening of the financial strength of MH would not be viewed favourably by those credit agencies and may have implications impacting the credit rating of the Province, making provincial borrowing more expensive. Such a development would not be in the public interest"* (Page 130 of Order 116/08).

The PUB reiterated the importance of Manitoba Hydro's Financial Strength in Order 43/13:

> *"The Board is concerned that, by moving towards a 90:10 debt-to-equity ratio by the end of the decade, there will be an insufficient retained earnings*

reserve to deal with droughts and other risks such as infrastructure failure or rising interest rates….

The Board notes that Manitoba Hydro shares the benefit of the flow-through credit rating of the Province, which affords it preferential interest rates on its debt and access to funds to meet its major capital spending program. However, as its debt grows, there is a potential for Manitoba Hydro's financial condition to affect the credit rating of the Province. It is important that Manitoba Hydro remains a financially strong and viable organization" (Page 23 of Order 43/13).

6.4 The Role of Reserves in Managing Manitoba Hydro's Risks

At numerous points in the evidence, Manitoba Hydro as well as a number of intervenors acknowledged that reserves are essential to the corporation and in fact required by Section 40 of the *Manitoba Hydro Act*. Mr. Bowman acknowledged that operating with little or no equity is not a good idea and that it is clear that Manitoba Hydro requires substantial reserves:

"MR. MATTHEW GHIKAS: Right. Now, in terms of your reference to the many Crown utilities, both electrical and other, that have operated for long periods with little or no equity, first of all, irrespective of whether there have been other entities operating with little or no equity over time, doesn't necessarily mean that's a good idea when it comes to Manitoba Hydro, does it?

MR. PATRICK BOWMAN: I'm not suggesting this statement is -- is setting out that it's a good idea. I'm suggesting this statement is setting out the fact that -- that it's possible. And, as matter of fact, the very next line says ***it is clear Manitoba Hydro requires relatively substantial reserves"*** (Emphasis Added) (Transcript Page 6279).

Mr. Coloaiacovo of MPA stated:

"So, you know, you always want to make sure that in a challenging scenario, you have enough reserves" (Transcript Page 4942)

And later

"There's no question that Manitoba Hydro requires reserves. The only thing that we're debating is what the size of those reserves should be" (Transcript Page 5138).

As Manitoba Hydro's cash deficit evidence has amply demonstrated, current rates are not adequately funding maintaining operations and reinvesting in the utility (see Section 2.1.2 for further information regarding cash deficits).

MPA has asserted that reserves are important and that the 3.95% rate path appears *"reasonably robust"*. Manitoba Hydro notes that the trajectory of net income under the 3.95% rate path forecast over the next 10 years is worse than the net income actually earned by Manitoba Hydro over the prior 10 years. As such Manitoba Hydro sought to at least have MPA defend the conclusion that historic cash flows and income levels created or maintained sufficient financial reserves as a precursor to evaluating the sufficiency of the forward projection. At MH/Coalition (MPA) – 16, MPA responds:

> *"MPA does not assert that historic cash flows and income levels created "sufficient" financial reserves, merely that any reserves (or "equity") that are in place were the result of ratepayer contributions".*

As demonstrated at slide 66 of Manitoba Hydro's Policy Panel Presentation, Exhibit MH-64, Manitoba Hydro's net income has been dropping precipitously in the last 10 years notwithstanding above average water conditions, declining interest rates and a growing asset base. This is evidence that no contribution to reserves is being made in rates charged to current ratepayers. Moreover, the analysis Manitoba Hydro provided in response to new evidence introduced in the hearing by MPA reinforces the erosion of reserves over the last 5 years. Ignoring the impacts of the major capital projects, rate inadequacy has led to debt increasing 20% while equity <u>decreased</u> 10% resulting in a 5.4% decline in Manitoba Hydro's equity to debt ratio just as a result of core operations.

Figure 6.1 Deterioration in Capital Structure

	Net Equity	Net Debt	Equity Ratio	Debt Ratio	Accounting Standard
2017 Capital Structure per MPA Adjusted Analysis	$3,289	$8,961	26.8%	73.2%	Adjusted
Conawapa Construction Work in Progress	$0	($379)			
Bipole III Deferred Revenues [1]	($196)	$196			
Wind Farm Loan Repayment [2]	$0	$250			
Bipole III Interest Capitalized [3]	($55)	$55			
Export Revenues Attributable to Above Average Water [3]	($219)	$219			
Non-Recurring Gain [4]	($20)	$20			
Adjustments	**($490)**	**$361**			
2017 Capital Strucutre per MPA Adjusted for Above (A)	**$2,799**	**$9,322**	23.1%	76.9%	Adjusted
2012 Capital Structure - excluding Bipole III, Conawapa and Keeyask (B)	$3,102	$7,788	28.5%	71.5%	CGAAP
Deterioration in Capital Structure (A - B)	**($303)**	**$1,535**	**-5.4%**	**5.4%**	
Change from 2012	**-10%**	**20%**			

[1] The Manitoba Hydro-Electric Board 65th Annual Report, Note 26, p.84

[2] Appendix 6.1, The Manitoba Hydro-Electric Board 64th Annual Report, Note 21, p.83

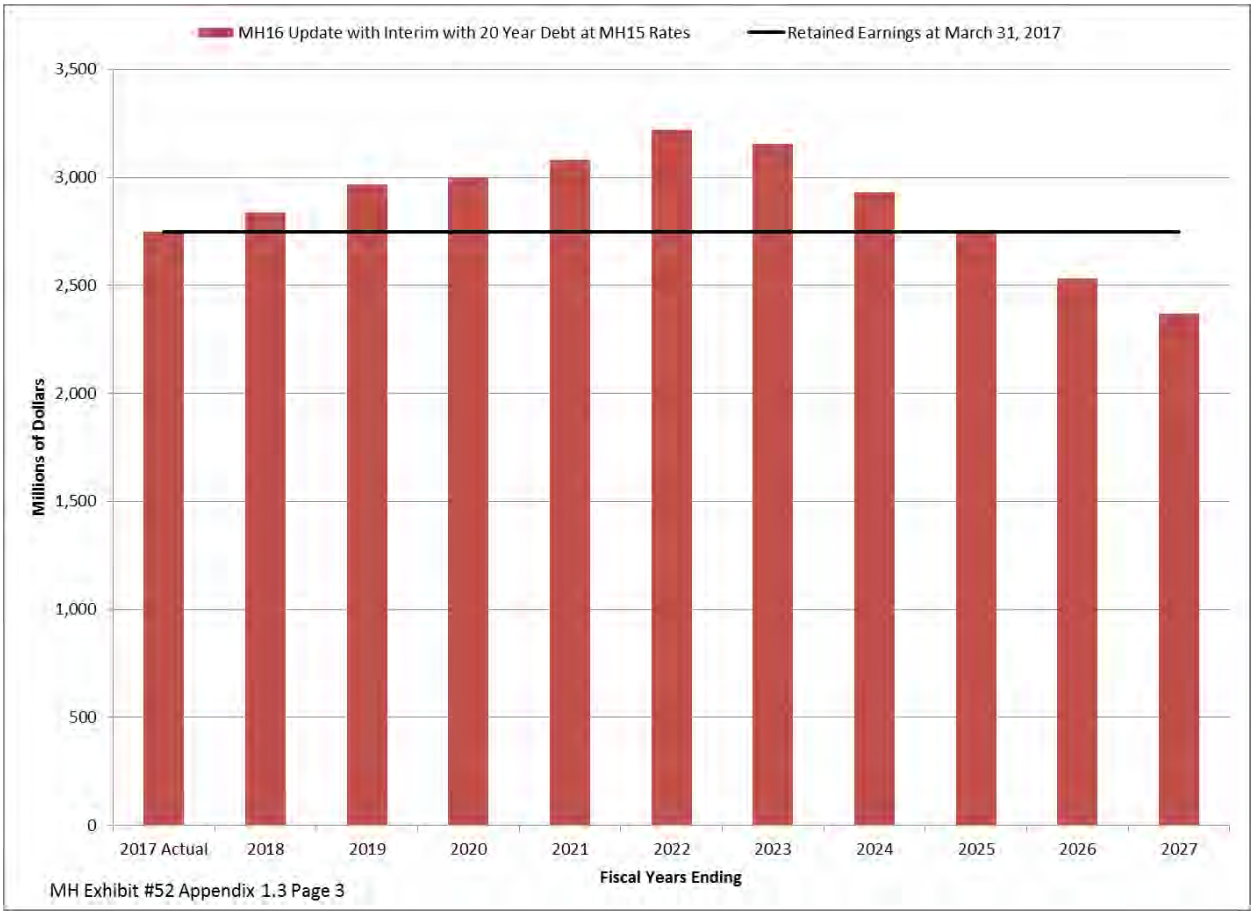
[3] Manitoba Hydro Exhibit #64, slide 44

[4] The Manitoba Hydro-Electric Board 65th Annual Report, Note 26, p.84

Source: Exhibit MH-135, page 6

Looking forward, the following **Figure 6.2** compares Manitoba Hydro's retained earnings from the MH16 Update with Interim scenario which assumed 20 year debt and the previous plan's 3.95% rate increases (MH Exhibit #52, Appendix 1.3, page 3) to the retained earnings as at March 31, 2017. **Figure 6.2** shows that customer revenues are just sufficient to make modest annual contributions to retained earnings until 2022, but that following Keeyask in-service, financial losses deplete retained earnings to a level below the current $2.7 billion at March 31, 2017.

Figure 6.2 Manitoba Hydro Retained Earnings at 3.95% Rate Increases



Depletion of retained earnings is evidence customer revenues are not sufficient to cover the operating and carrying costs of assets. Manitoba Hydro must borrow to cover these costs on top of the increased leverage resulting from the investments in Bipole III and Keeyask.

At MH/Coalition (MPA)–16(c), Manitoba Hydro asked how MPA concluded that the 3.95% rate plan effectively contributes to financial reserves to manage unforeseen risks or rate stabilization and received the following response:

"MPA does not make that conclusion…."

Rates must be set inclusive of proper reserve contributions. This comes in the form of a rate path that is expected to generate positive net income in normal water flow years.

At Transcript page 4941, Mr. Colaiacovo appears to agree that the forecast ought to include the assumption of progress on financial targets in normal water years:

> *"And if the rates are high enough, well, then, that helps guide you to a- -- a decision that those rates are sufficient. Then, you would also ask yourself, if water was at more typical levels over that period, over that five (5) or seven (7) year period, what would be the effect? Would it be -- would we be making progress on our financial targets more broadly? Would be -- we be repaying capital?"*

That reserves come in the form of ongoing expectations of net income (and cash flow) is critical given, as demonstrated above and confirmed by Intervener witnesses, retained earnings is non-cash and powerless to abate debt growth in the face of financial distress, poor hydrology or forecast error.

During NFAT, MPA (then as IEC to the PUB) made this statement at page 38, lines 15-18 of its January 2014 report (included as Tab 8 of Manitoba Hydro's Book of Documents #1, Exhibit MH-116-1):

> *"Retained earnings are driven in part by the rates approved by the PUB for electricity in Manitoba, which nominally should include a "return on equity" component in order to ensure that Manitoba Hydro actual (sic) earns net income that can be retained."*

Likewise at NFAT, in the response to PUB/MPA 1-030 (a) (included as Tab 3 of Exhibit MH-116-1) as follows:

> *"Since Manitoba Hydro's cash flows fluctuate dramatically with hydrology and export prices, and* ***Manitoba Hydro's target equity ratio is a comparatively thin 25%****, the use of an equity risk premium as low as 4.5% is notable. On the other hand, Manitoba Hydro is governed by "cost of service" legislation, which nominally requires Manitoba ratepayers to bear all of Manitoba Hydro's costs, and Manitoba Hydro benefits from a Province of Manitoba guarantee of substantially all of its debt. Assuming the legislation is accepted at face value and domestic rates could rise to whatever level were required at any given time to*

> *maintain Manitoba Hydro solvency, under any circumstances, then a legitimate question is whether an "equity risk premium" is applicable? On its face, the legislation coupled with the provincial debt guarantee suggests that there is no risk to equity, and hence the premium should be 0%.* ***In reality, however, rates do not rise and fall annually, but are smoothed over time. This suggests that equity returns should be built into rate structures to provide a cushion for inevitable swings in cash flow that derive from non-controllable events, such as hydrology and export prices. Moreover, the possibility of prolonged financial distress also suggests that equity premiums (and a healthy equity ratio target) are required."*** (Emphasis Added))

Manitoba Hydro was perplexed by the new assertion MPA makes in these proceedings, as an Intervener expert witness, that now reserves ought to only be maintained for hydrology risks (Transcript Page 4911). MPA takes the position that it is not appropriate to address interest rate risk or export price risk through reserves on the basis that because interest rates change slowly, Manitoba Hydro does not have large quantums of debt subject to interest rate risk in any one period, and that export prices cannot be forecast in the longer term due to unidentifiable technology change. As a result, MPA concludes (Transcript Page 4913) that the financial impacts of these risks cannot be smoothed over the longer term. Of interest, at Transcript Page 5011 Mr. Colaiacovo confirms that export prices and interest rates are *"noncontrollable"* which would be precisely the argument he makes at NFAT (per above quote) as necessitating a rate structure that contributes to reserves such that rates can be *"smoothed over time"*.

In Manitoba Hydro's view, neither the current rate increase request nor the Corporation's longer term financial plan are intended to shield customers from legitimate and enduring changes in cost drivers over the long term by absorbing them into reserves. Manitoba Hydro's objective in this Application has been quite the opposite – the request to advance rate increases from 3.95% to 7.90% is specifically intended to address the reductions in revenues attributable to reduced expectations for domestic load growth and export prices. As Mr. Shepherd indicated *"…[Manitoba Hydro] missed a great opportunity to add to our reserves and avoid more debt by taking advantage of many, many years of excellent water conditions which should have been used to boost net income."* (Transcript Page 243).

MPA's conclusion that *"…the amount of [Manitoba Hydro's] debt that is exposed to interest rates in any one (1) year is a relatively small portion; notwithstanding the fact that they're in the midst of issuing a lot of debt."* (Transcript Page 4911) is incorrect. Slide 62 of Exhibit MH-68 and pages 12-13 of Manitoba Hydro's Written Rebuttal Evidence (Exhibit MH-52) indicate that assuming adoption of a 7.9% rate path, between 2018 and 2022, Manitoba Hydro is projected to borrow $13.5 billion This means that a moderate 100 basis point (1%) increase in interest rates over that forecast in MH16 Update with Interim will result in an increase to finance charges of $130 million annually (not including the compounding effects over multiple years) or an equivalent one-time rate increase of 8%. Under a 3.95% rate path, the amount of new borrowing and refinancing risk exposure over the first five years of the forecast increases to over $20 billion. In Manitoba Hydro's respectful submission, $13 billion of new borrowing and refinancing over the next five years is not a *"small portion"* of Manitoba Hydro's net debt (forecast to end 2017/18 at $18.5 billion per Appendix 3.8) and should be considered in addition to the risk of drought in setting an appropriate level of reserves.

Manitoba Hydro noted with great interest MPA's disagreement in this proceeding with Manitoba Hydro's view that when managing distress caused by events such as drought, the critical issue is the magnitude of the outstanding debt on the balance sheet, not the size of the retained earnings:

> *MR. MATTHEW GHIKAS: Okay. Now, I'd suggest to you that when it comes to managing distress that comes with an event such as drought, the critical issue is the magnitude of the outstanding debt on the balance sheet, not the size of the retained earnings.*
> *MR. PELINO COLAIACOVO: I don't think I would necessarily agree with you.* ***I don't think magnitude of debt in isolation has any relevance.*** *Debt in relation to assets so, you know, if your assets are highly leveraged it wouldn't matter but if you have $50 billion of assets and $25 billion of debt is 25 billion an important number? I don't actually think so. So the magnitude of the debt in isolation is just a fact.* (Emphasis Added) (Transcript Page 4991)

MPA's evidence in this regard once again directly contradicts its response provided to its current client (Consumers Association of Canada) during the NFAT proceeding when, acting in the capacity of PUB Independent Expert Consultant it stated:

> ***"The critical issue is the magnitude of outstanding debt on the balance sheet, not the size of the retained earnings.*** *In the event of a persistent revenue shortfall caused by prolonged drought, for example, interest charges related to a large outstanding debt represent a real call on cash flow. A large pool of retained earnings in this environment would be beneficial in that the company balance sheet potentially could sustain a series of annual losses, but balance sheet retained earnings bear little relationship to the availability of cash resources"* (NFAT IR CAC/MPA-13 reviewed during cross-examination by Mr. Ghikas, (Emphasis Added) (Transcript Page 4992).

Upon being presented with this contradictory statement during cross-examination by Mr. Ghikas (Transcript Page 4992), while no explanation was provided for this dramatic about-face, MPA did acknowledge that retained earnings are not cash and that cash flow is the issue:

> *"The magnitude of the outstanding debt tells you how much interest, as it says here, the interest charge is related to the large outstanding debt represent a real call on cash flow because cash flow is the issue. And so if drought causes your cash flow to fall, you have a problem that you have to manage"* (Transcript Page 4993).

Presumably the *"[cash flow] problem that you have to manage"* is an issue regardless of whether it is caused by drought, interest rates increasing, export prices being non-responsive or capital costs going up. This position is consistent with the evidence of Manitoba Hydro's President, Mr. Kelvin Shepherd, regarding the role of reserves relative to the need for cash flow:

> *"Equity in and of itself does nothing for you. This is particularly the case when almost all of our equities is derived from cumulative earnings generated more than ten (10) years ago. Even more recently, the entirety of the growth in our equity has been a byproduct of unexpected profits owing to near record water conditions over the last several years.*

> *Equity is not cash. This is essential to understand. Equity is not a store of cash that we can use to mitigate rate increases when bad things happen. The only cushion to absorb unforeseen events and risk without having to raise rates even more and/or borrow yet more money is having rates at sufficient levels where your generating income and cash flow. And as we make clear, the old plan with its 3.95 percent rate path comes nowhere near close to doing this for us. Without this cushion when adverse events occur, the only choices available are to increase rates, potentially a lot, or borrow more money. We should not and cannot as a planning matter knowingly put ourselves in that position"* (Transcript Page 240).

Depleting Manitoba Hydro's reserves over a period of years under average water flow conditions and expected assumptions in the previous 3.95% rate plan as shown in **Figure 6.2** is neither sustainable nor prudent. As noted by Mr. McCallum,

> *"…as a planning matter, we don't believe you can target nil or breakeven net income for a businesses as large, complex, asset intensive, volatile, and indebted as ours. We have to plan, inclusive of in our rate strategy, for a cushion that allows for a margin of error and to create reserves in the form of paying down debt when things go right"* (Transcript Page 154).

It is interesting to note that despite Intervenors acknowledgement of the need to maintain adequate reserves, none presented evidence of a plan which in anyway served to contribute to and rebuild reserves.

It is of critical importance to move off the rate path of 3.95% to build reserves annually. As Ms. Carriere correctly observed *"…there is simply no additional capacity for the 3.95 percent rate plan to absorb any further increases in costs or deterioration in financial position [and]…the level of debt has grown out of proportion with our assets and the current level of revenues*" (Transcript Page 720). It should be noted that in the event Manitoba Hydro's forecasts of load and export revenues prove conservative and actual results turn out more favourably, customer contributions to reserves do not *"leak out"* as dividends as they would in a typical investor-owned utility. Customer contributions stay within Manitoba Hydro and under cost of service regulation, the PUB has an opportunity in future proceedings to adjust customer rates accordingly.

6.5 Debt Markets Care about Debt:Equity Ratio

On Pages 34 to 35 of MPA's Evidence filed on behalf of the Consumer's Coalition, Exhibit CC-17, MPA suggested that analysts serving the capital markets appear to place a higher priority on cash flow metrics and the ability to adjust rates as required to match operational requirements. It noted that, *"Certainly, the capital structure of a utility is important, and all analysts do recognize that, but few if any appear to make capital structure a centerpiece of their analysis in the way Manitoba Hydro does."*

The suggestion advanced by MPA that debt markets do not prioritize the strength of the equity ratio is not correct. Equity ratio is a good proxy for overall debt levels and investors care very much about that. Markets and rating agencies understand the intrinsic relationship between equity ratio and cash flow and all of the other financial metrics that analysts take into consideration.

Nonetheless, Section 2.2 of Manitoba Hydro's Application along with slide 46 of Exhibit MH-64 emphasize just how concerned the Corporation is with the level of forecasted cash flow and its ability to meet critical ongoing business requirements.

Manitoba Hydro presented a cash flow analysis *"Cash Flow from Operations to Capital Expenditures"* in Section 2.2 of the Application to better represent its capacity to meet its core obligations under different rate paths. Without the proposed rate increases, this metric demonstrates how cash flows will not be sufficient to cover the projected increase to interest payments associated with the unprecedented investment in major projects and the unavoidable capital requirements related to system renewal and expansion. This is consistent with what MPA suggests is a higher priority for analysts serving the capital markets.

In the August 2017 Supplementary Update to Manitoba Hydro's Financial Target Review, KPMG commented that, *"We note that Manitoba Hydro has developed an additional metric that examines adjusted cash flow to adjusted capital expenditures. This metric is intended to reflect overall cash flow impacts and related challenges in a more complete way during periods of major capital investment."* (Appendix 4.5 of the Application, page 11)

Manitoba Hydro's rate proposal was established to provide increased cash flow to meet two key objectives: (i) avoid deficit funding the ongoing business over the next five years and (ii) partially abate the increase in debt as the major capital projects are concluding and then begin retiring debt following Keeyask's in-service so as to mitigate future rate increases that may be required should interest rates rise. As such, Manitoba Hydro's plan to restore financial strength is centered on generating positive cash flow and managing the absolute level of debt.

6.6 The Importance of Manitoba Hydro Being Viewed as Self-Supporting

The key to preserving the credit of the province is for Manitoba Hydro to be viewed as self-supporting. MPA notes agreement with this concept and the importance of messaging to the markets:

> *"… I do think that managing the message to the capital markets is, indeed, important and in their application, Manitoba Hydro has talked about credit quality and the impact on credit ratings and the treatment of Manitoba Hydro in the province of Manitoba by the markets. And the very fact that Manitoba Hydro has made this application and has requested a series of 7.9 percent increases is in itself a message to the markets; a partial message, an initial message but nonetheless a message. And so, the Board's response to that application is also a message and I think the crafting of those messages is-- is important and has to be taken into account"* (Transcript Pages 4850 to 4851).

Credit rating agencies have indicated that they will continue to monitor the progress on the capital projects, rate increases, Manitoba Hydro's financial metrics and the financial outlook. Credit rating agencies monitor a variety of financial metrics as evidenced in this quote from DBRS on page of its credit rating report on the Manitoba Hydro-Electric Board from November 26, 2015 (Appendix 4.4 of the Application):

> *"The Utility has forecast leverage (81.0% as at March 31, 2015) to increase to around 88% during this period of high capex. Additionally, due to the significant lag before electricity rates fully reflect the cost of the ongoing major projects, Manitoba Hydro has forecast weaker earnings, including two years of negative net income, and significant free cash flow deficits for*

the medium term in its 2015 Integrated Financial Forecast. This will result in further pressure on the Utility's key financial metrics, which could be exacerbated in the event of an adverse circumstance (i.e., severe drought)."

MPA asserts at page 3 and 4 of Exhibit CC-17 that "*While the capital structure of a prospective borrower like Manitoba Hydro is important, it appears to be a secondary issue for the capital markets."* Yet in MPA's own evidence on page 33 MPA identifies seven metrics tracked by S&P in assessing financial risk and identifies that the two primary metrics are both associated with relative debt levels (not cash flow sufficiency alone). This is discussed at Transcript Pages 5043 to 5044:

"MR. MATTHEW GHIKAS: Now, you go on to line 21 there, where you say: "S&P further defined seven (7) -- seven (7) metrics that it focuses on with respect to cash flow. Note the first two (2) are the primary metrics, and the other five (5) are secondary, the sheer number of which provides an illustration of the level of focus on cash flow in S&P's typical financial risk analysis. These are..." And then you set them out?

MR. PELINO COLAIACOVO: Yes.

MR. MATTHEW GHIKAS: So the first two (2) are the primary ones, right?

MR. PELINO COLAIACOVO: Yes.

MR. MATTHEW GHIKAS: And both of those metrics are a function of debt?

MR. PELINO COLAIACOVO: They are."

Furthermore, notwithstanding MPA's assertions as to the primacy of cash flow, in their own report (Exhibit CC-17) at page 101, credit rating agency Fitch states:

"Fitch's analysis of financial metrics focuses principally on three core areas: cash flow, liquidity and capital structure. ***No single financial ratio stands apart from the rest.*** *On the contrary, the ratios are examined together,*

providing a context for a utility's financial position that informs a complete analysis."

Finally, on page 103 of Exhibit CC-17, Fitch indicates:

A rising equity ratio is viewed favorably, as it typically suggests ***adequate cost recovery in rates, load growth and a component of internal funding of capital investments****."*

Manitoba Hydro would observe that the 3.95% rate plan endorsed as *"reasonably robust"* by MPA results in the exact opposite which is to say an equity ratio that continue to decline following the in-service of Keeyask and thus, per Fitch, suggesting continued inadequacy of cost recovery in rates.

The financial viability and creditworthiness of the Corporation is assessed by credit rating agencies using debt:equity and interest coverage ratios as well as other relevant financial and risk profile information. The debt:equity and interest coverage ratios indicate the Corporation's ability to provide an *"equity cushion"* for possible losses and the Corporation's ability to meet all of its financial obligations when due. These ratios are used to assess whether the Corporation is financially self-supporting and capable of absorbing a variety of financial risks.

The overall debt level is inextricably linked to the cash flow of the corporation. Interest expense will be, by far, the largest cash flow burden on Manitoba Hydro's revenues. The pursuit of a 25% equity ratio target within a 10-year planning horizon triangulates with and reinforces generating the net income and cash flow sufficiency that lead to creation of necessary reserves against unforeseen events and contribute to overall debt reduction and support more stable and ultimately lower rates in the long-run than if the 3.95% rate path is pursued. Equity is not cash or a cash reserve that can be used to mitigate rate increases to address adverse / unforeseen events. The equity ratio can also be thought of as the Debt Ratio; the goal of the equity target is to get absolute levels of debt down. The equity ratio is the best indicator of progress on rate adequacy, sustainability and risk.

On cross-examination (Transcript Page 5010), MPA acknowledged his comment from the NFAT hearing that rate smoothing: *"… suggests that equity returns should be built into rate structures to provide a cushion for inevitable swings in cash flows that derive from noncontrollable events such as hydrology and export prices. Moreover, the possibility of prolonged financial distress also suggests that equity premiums and a healthy equity ratio target are required.*" In addition, on page 5006 of the transcript, MPA states that: *"…in a company like Manitoba Hydro where revenues go up and down with exports and with water, you can't actually predict these things perfectly in advance. It makes sense to have some cushion, to have some equity in the Company and to adjust your rates accordingly over time."*

In addition at Transcript Pages 5006 and 5007, MPA agreed that over time a healthy business should generate sufficient cash flows to pay for its capital expenditures and necessary interest and returns on equity associated with that capital, and that a sign that a business has been retaining net income over time is that the equity portion of the capital structure is increasing.

Manitoba Hydro agrees with MPA's comments that stipulate a healthy business should generate sufficient cash flows to generate net income and that net income is effectively a contribution to retained earnings.

MPA also discussed the importance of the Corporation's ability to maintain its self-sufficiency during an extended drought. *"…So, if there's a drought and the drought results in a Company having to issue lots more debt and rates do not go up in concert with the drought conditions, then the debt will continue to accumulate and, eventually, that will, you know, bring into question the Company's self-supporting status if it didn't have enough reserves to begin with."* (Transcript Page 5137). Mr. Colaiacovo went on to confirm that, consistent with his evidence during the NFAT, credit rating agencies which currently do not include Manitoba Hydro debt as an obligation of the province of Manitoba may reconsider that position, at least for a portion of Manitoba Hydro's debt, which could have a significant implications for the government.

Manitoba Hydro believes this commentary underscores the value of an appropriate level of equity for Manitoba Hydro as well as the Province of Manitoba.

6.7 What a Supportive Regulatory Regime Really Means

The Pre-Filed Testimony of Patrick Bowman, on behalf of the Manitoba Industrial Power Users Group, Exhibit MIPUG-13, states on page 4-7,

> *"… all indications are that there is no need to move to a 7.9%/year annual rate increase regime to achieve a utility that is self-supporting. If anything, a key conclusion… is the lack of need for a 7.9%/year rate increase today, but instead a significant requirement to communicate regulatory support and a reliable regulatory regime to lenders and credit rating agencies."*

The argument that showing a reliable and predictable regulatory regime to rating agencies and investors means maintaining a 3.95% rate increase regime is specious. A regulatory regime which is not responsive to changing business conditions under the guise of *"predictability"* would send the message to rating agencies and investors that Manitoba Hydro's financial health is not a high priority to the regulator. By not acting to address obvious financial health issues, Manitoba Hydro risks making its financial results and future rate increases even more unpredictable.

As indicated in the response to MIPUG/MH I-8, S&P's criteria indicate that the regulatory advantage assessment is MHEB's largest business risk component, at 60% weighting. The response quotes directly from S&P's Criteria| Corporates| Utilities: Key Credit Factors For the Regulated Utilities Industry (attached to the response) as follows:

> *When assessing regulatory advantage, we first consider four pillars and sub-factors that we believe are key for a utility to recover all its costs, on time and in full, and earn a return on its capital employed:*
>
> *Regulatory stability:*
> *• Transparency of the key components of the rate setting and how these are assessed*
> *• Predictability that lowers uncertainty for the utility and its stakeholders*
> *• Consistency in the regulatory framework over time*
>
> *Tariff-setting procedures and design:*
> *• Recoverability of all operating and capital costs in full*

• Balance of the interests and concerns of all stakeholders affected
• Incentives that are achievable and contained

Financial stability:
• Timeliness of cost recovery to avoid cash flow volatility
• Flexibility to allow for recovery of unexpected costs if they arise
• Attractiveness of the framework to attract long-term capital
• Capital support during construction to alleviate funding and cash flow pressure during periods of heavy investments

Regulatory independence and insulation:
• Market framework and energy policies that support long-term financeability of the utilities and that is clearly enshrined in law and separates the regulator's powers
• Risks of political intervention is absent so that the regulator can efficiently protect the utility's credit profile even during a stressful event

Mr. Bowman focuses on just two pillars to the exclusion of the remaining two. Financial stability to permit the timely recovery of costs and capital support during construction to avoid cash flow pressure, and the ability to recover all costs cannot be ignored. In Manitoba Hydro's case where the utility has been operating with insufficient cash flow for cost recovery for several years, regulatory support through the approval of required rates is especially critical for the utility to be self-supporting.

It is a fallacy to suggest that credit rating agencies will take comfort in the utility being permitted a rate increase insufficient to meet its needs simply because is it *"predictable"*. *"Predictable"* in this context must be understood to mean rate increases, the need for which have been communicated to ratepayers (as has been the case since May, 2017 when Manitoba Hydro first sought a 7.9% rate increase)[7], approved by a regulator who has demonstrated the willingness to respond to events as they unfold, having been satisfied that the request is supported by the weight of the evidence.

[7] See also the evidence of Dr. Yatchew at Transcript Page 4458

7 MYTH OF THE 3.95% RATE PROMISE

In the opening comments made by Consumers Coalition, Dr. Williams opined that, *"…[rate] promises that were made during the NFAT process have been broken by Manitoba Hydro"* (Transcript Page 81).

Similarly, Manitoba Keewatinowi Okimakanak ("MKO") stated in its opening comments at Transcript Page 115:

> *The MKO First Nations took an active role in the in the NFAT hearings on the understanding that if rate increases were necessary, they would be looked at, they would be examined, they would be made appropriate. And that's what was done, and the rate increases approved at that time were substantially lower than was being done right now* (Emphasis Added)

In MKO's cross-examination of Mr. Shepherd and Mr. McCallum, Manitoba Hydro legal counsel clarified for the record that the Needs For And Alternatives To ("NFAT") was not a rate hearing and the NFAT did not seek approval of any rate increases. The Chairperson affirmed the panel's understanding of the purpose of the NFAT and 2015/16 & 2016/17 General Rate Application ("GRA") as it related to rate increases:

> *NFAT dealt with a number of issues that -- as I understand it, the 3.95 arose in the GRA that was following NFAT in the 2015 hearing, which was a rate-setting hearing, and that one (1) did not relate to the other* (Transcript Page 603).

In the presentation by Manitoba Hydro's Revenue Requirement Panel (Exhibit MH-68), Ms. Carriere addressed the myth of the NFAT and 2015/16 & 2016/17 GRA rate promise:

> *With respect to the rate projections for each of the development plans, Manitoba Hydro was explicit in stating that the rate plans presented were developed for the purposes of comparing development plans* (Transcript Page 714);

> *Manitoba Hydro emphatically stated that minimum rate increases were necessary under all plans…* (Transcript Page 715); and
>
> *Importantly, Manitoba Hydro cautioned the NFAT panel that the rate projections set forth for each of the development plans were not applicable for rate-setting purposes* (Transcript Page 716).

At no point has Manitoba Hydro ever made rate promises based on its long term forecasts and has always been careful to distinguish between proposed and indicative rate increase projections – a distinction which the Chairperson and panel have also been acutely cognizant of through the course of this proceeding:

> *Notwithstanding the indicative information in the IFFs, the only rate approval requests by Manitoba Hydro before this Board at this time are the confirmation of the two (2) existing interim 3.36 rate increases, as well as the request to grant a 7.9 percent rate increase effective April 1st, 2018 from Manitoba Hydro's 2018/'19 fiscal year* (Transcript Page 4120)

In reality, forecasting is inherently unreliable. The further out the forecast goes, the less likely it is to be accurate. This view is confirmed by Daymark Energy Advisors.

> *…the use of [a forecast] is really in -- in understanding and preparing yourself for change. Forecasts are inherently wrong* (Transcript Page 3879).

As noted in Section 3.4.3 Manitoba Hydro believes limited value should be ascribed to forecasts a decade or more in the future. While the mid to latter years of forecasts provide important information on directional trends of financial results, they should not be relied upon for rate-setting purposes in specific test years. Forecasts are updated at least annually and future rate decisions are better made based on forecasted information available at that time.

Ms. Carriere reminded the panel that, at NFAT, Manitoba Hydro was careful to advise:

> *"…that due to the uncertainty of forecasting, the rate increases are indicative and are showing general directional trends in -- in rates. Actual rate increases will vary from those, and will depend on many other factors and not just the choice of development plan but due to changing water flows, weather and costs to maintain the system and economic variables"* (Transcript Page 715 to 716).

Historically in past orders, the Public Utilities Board of Manitoba ("PUB") has acknowledged and accepted that there is risk of forecast uncertainty and no "promise" in the rate increases in Manitoba Hydro's applications, and in certain circumstances, even in the rate increases approved by the PUB. In January 2004 in the midst of one of the lowest water flow conditions on record, Manitoba Hydro sought PUB approval for a 3% rate increase for April 1, 2004 and 2.5% for April 1, 2005 to recover reserves following the extreme financial loss of 2003/04, on the heels of other significant events such as the acquisitions of Centra Gas and Winnipeg Hydro and the special payment to the province, all of which contributed to the depletion of reserves. Prior to the 2004 application, Manitoba Hydro had last appeared before the PUB in 1996, where average increases of 1.5% effective April 1, 1996 and a further 1.3% effective April 1, 1997 were approved, and in the 2002 Status Update Filing, where the corporation sought no rate adjustment but the PUB directed rate reductions to the General Service Large and Small classes.

In the Order arising from the 2004 filing, the PUB approved more than Manitoba Hydro requested; 5% for August 1, 2004 and two conditional rate increases of 2.25% for April 1, 2005 and October 1, 2005. In granting the two conditional rate increases, the reasons cited by the PUB at the time are remarkably familiar:

> *In making the last two increases conditional, the Board provides a level of protection for the long-term interests of ratepayers. At the same time, these conditional increases provide reasonable assurance to MH that its revenue base will be strengthened if the need is present. In particular, conditional increases recognize the uncertainties present with respect to forecasting export sales and net income. These uncertainties are related to water levels and storage issues, export demand, pricing and other related matters* (Order 101/04, Pages 23 to 24).

Both conditional rate increases were subsequently approved as final.

The PUB further demonstrated an absence of rate "promises" in Orders 90/08 and 32/09. In Order 90/08, the PUB granted Manitoba Hydro a 5% rate increase for July 1, 2008 and a further 4% conditional rate increase for April 1, 2009. Manitoba Hydro had only sought 2.9% for each of 2008/09 and 2009/10; however, the PUB expressed a lack of confidence that the requested 2.9% were sufficient.

The PUB subsequently varied and approved a final rate increase in Order 32/09:

> *After a thorough and intense consideration of the evidence, and considerable contemplation, the Board will approve rate increases as of April 1, 2009 but will vary the level of the increases to 2.9%, to apply to all classes excepting for the Area and Roadway Lighting class.*
>
> …
>
> *By so doing, the Board balances MH's evidence of recent improvements in the Utility's financial situation and the pressures on its customers due to the recession with the Board's ongoing concern respecting the many risks faced by MH* (PUB Order 32/09, Page 1).

8 PROJECTED REVENUES ARE DOWN

8.1 Overview

Manitoba Hydro's projected revenues are down, primarily as a result of the combined effect of a flattening of the domestic load forecast, export prices not rebounding as previously expected and increased capital costs associated with the major projects, Keeyask and Bipole 3.

- Manitoba load growth has not materialized as previously forecasted and the Corporation is now faced with 10 years or more of no net load growth (Slide 38 of Manitoba Hydro's Policy Panel Presentation, Exhibit MH-64);
- The forecast of export prices continues on a downward trend since MH15 (Slide 39 of Exhibit MH-64);
- The Keeyask control budget has increased by $2.2B to $8.7B and there has been a 21 month delay to the in-service date (Slide 40 of Exhibit MH-64).

The impacts of these risks have been somewhat offset by the following:

- Interest rates have remained at record low levels;
- Manitoba Hydro has enjoyed 14 consecutive years of greater than average system inflows (Slide 33 of Exhibit MH-64).

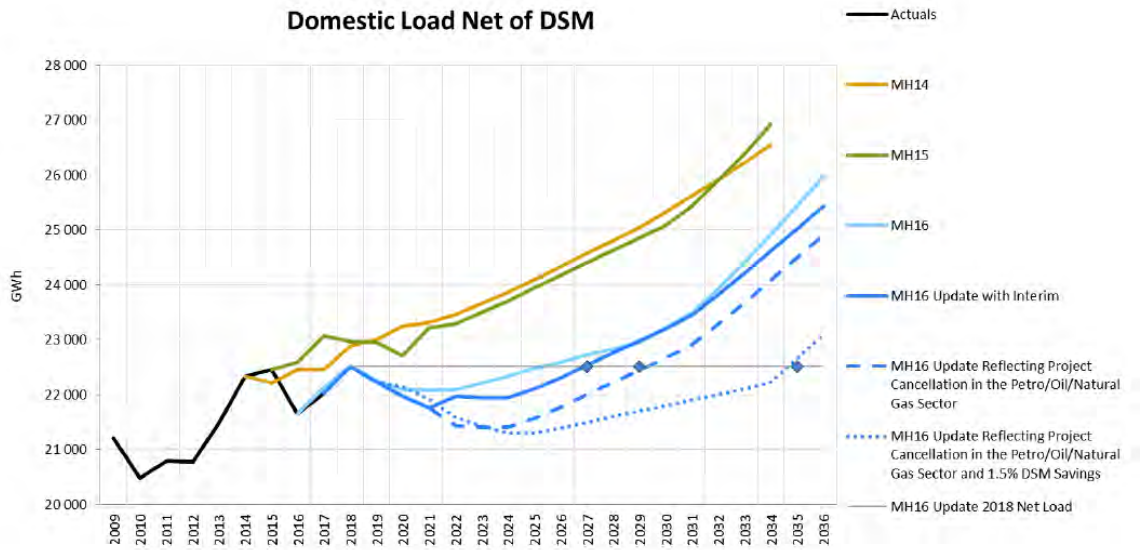
To assess the reasonableness of Manitoba Hydro's revenue projections, the Public Utilities Board of Manitoba ("PUB") retained Daymark Energy Advisors to review the corporation's Load Forecast, Export Price Forecast and Export Revenue Forecast. Daymark was provided unfettered access to Manitoba Hydro's information, including commercially sensitive information not available on the public record. In addition, Dr. Adonis Yatchew reviewed the price elasticity values incorporated in Manitoba Hydro's load forecast. While areas for enhancement were identified, no issues were reported that materially impacted forecast results or revenue projections.

8.2 Load Forecast

8.2.1 Future Manitoba Load Forecast is Trending Down

Manitoba's future domestic load requirements and domestic revenue expectations have deteriorated compared to previous load forecasts and including the impact of future demand side management ("DSM") programs are expected to exhibit no net load growth for the next 10 years as indicated in Manitoba Hydro's direct evidence (Exhibit MH-64).

Figure 8.1 Domestic Load Net of DSM

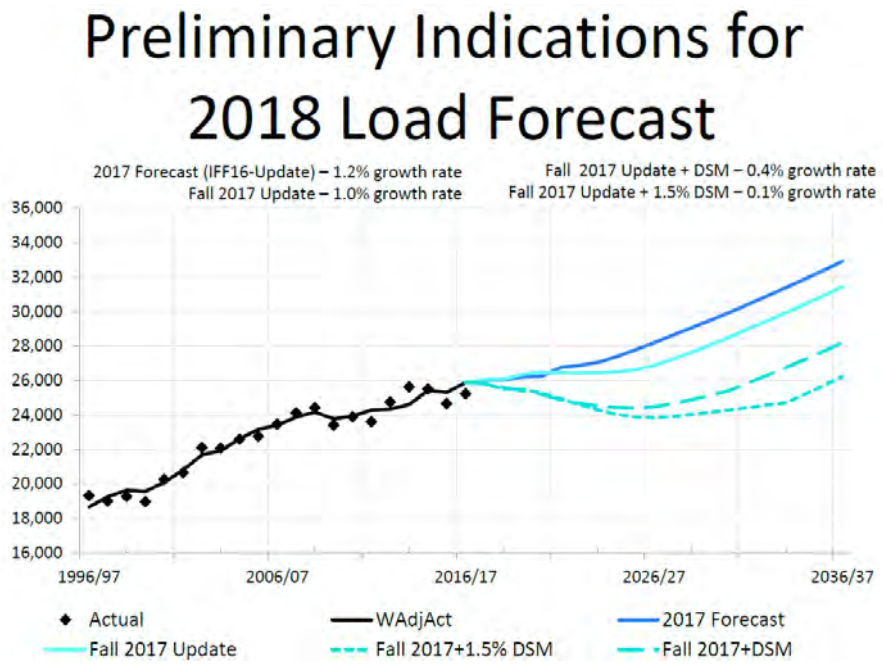


Source: Slide 40 of Exhibit MH-64

Ms. Morrison in her testimony provided preliminary indications as to where the 2017 Fall Update Load Forecast is compared directionally to the 2017 Forecast (Transcript Page 647). Manitoba Hydro has been forthcoming on the reasoning underlying the reduction in domestic load. Ms. Morrison advised that a large project in the petrol, oil and natural gas sector was recently cancelled which results in a reduction of approximately 530 GWh (Transcript Page 1126) to the 2017 Load Forecast (PUB MFR 65 Attachment 1).

Slide 20 of the Revenue Requirement Panel Presentation, Exhibit MH-68, compares the 2017 Electric Load Forecast with the preliminary 2017 Fall Update Forecast including the future DSM programs currently forecast in Manitoba Hydro's Power Smart Plan. It is noteworthy that Efficiency Manitoba has a mandate in the Efficiency Manitoba Act of achieving 22.5% over 15 years of overall energy savings targets as compared to Manitoba Hydro's current 2016/17 15-Year DSM plan, which has a cumulative target of 17.3% over a 15 year period. (Transcript Pages 646 to 647). Also presented below in Figure 8.2 is a representation of the 2017 Fall Update Forecast including Efficiency Manitoba's mandated efficiency target of 1.5% of load.

Figure 8.2 Preliminary Indications for 2018 Load Forecast



Source: Slide 20 of Exhibit MH-68

Further discussion on DSM programming and Efficiency Manitoba is contained in Section 8.2.7 of Manitoba Hydro's written final argument.

8.2.2 Load Forecast Methodology is Reasonable

Manitoba Hydro respectfully submits that its 2017 Load Forecast (PUB MFR 65, Attachment 1, page 1) and the supporting methodologies underpinning this Application are reasonable and are a reliable estimate of future energy requirements.

Manitoba Hydro's the load forecast is updated annually to include current information about Manitoba Hydro customer groups in order to produce a reasonable estimate of future load requirements. Key changes incorporated since the 2014 load forecast include updates to the economic inputs such as the forecasts of electricity and natural gas prices, population, GDP and income, and a change for potential long term growth in the Top Consumers sector (Transcript Pages 641 to 643). As Ms. Morrison stated at Transcript Page 641, *"some model enhancements were pursued with the change to the top consumers having a notable impact upon the long-term forecast. This enhancement was explored specifically to address past PUB concerns regarding the potential inappropriate upward adjustment in the forecasting for this sector"*.

As noted above, Daymark was contracted to review the reasonableness of Manitoba Hydro's Load Forecast and its supporting methodologies. In summarizing the overall findings of the Daymark Energy Advisors review of Manitoba Hydro's load forecasting methodologies, Ms. Kelly concluded:

> *"Manitoba Hydro's forecast methodologies are reflective -- fully reflective of industry practice. I've seen exactly what they're doing in other places before, and other - - most utilities are relying on similar tools and technologies to do their forecasts"* (Transcript Page 3895)

Daymark identified the following key findings regarding Manitoba Hydro's base forecast for consideration:

- The Top Consumers projected long term growth was considered conservative in comparison to the method utilized in previous forecasts;
- The population forecast may be under-forecasting based on the historical evaluation of previous population forecasts;
- Electricity price elasticity values may be incorrectly estimated based on the evaluation of the econometric models currently in use by Manitoba Hydro;
- The possibility of fuel switching/substitution to an alternative fuel type or fuel source due to the increase in electricity prices in all sectors.

(Page 5 of Daymark Energy Advisors Report - Forecast Revised, Exhibit DEA-2-1)

Although Daymark Energy Advisors identified key findings and possible enhancements regarding several elements of the load forecast and indicated that the load forecast may directionally be conservative, Ms. Kelly acknowledged during her testimony that Manitoba Hydro regression equations of each sector is appropriate in total based on the statistics of the regressions evaluated (Transcript Pages 3993 to 3994).

Daymark also identified a number of enhancements for consideration by Manitoba Hydro in development and reporting of future Load Forecasts (Page 64 of Exhibit DEA-2-1):

- Consider scenario analyses by developing alternative load forecast to complement the base forecast and evaluate uncertainty utilizing stochastic risk assessments;

- Incorporate additional years of data in the development of the weather-normalization methodology;
- Move to a shorter period in the definition of defining the weather normal year from the existing 25 year period;
- Provide greater transparency in the review and testing of econometric models underlying the electric load forecast.

As noted in Manitoba Hydro's Written Rebuttal Evidence on Daymark, Exhibit MH-83, a number of these proposed enhancements have already been considered and some reviewed by the PUB, such as the use of 25 years for determining Weather Normal. (Page 13 of Exhibit MH-83).

8.2.3 Top Consumers and Potential Large Industrial Load ("PLIL")

As discussed at page 21 of PUB MFR 65 Attachment 1, Manitoba Hydro's Top Consumers segment is comprised of a limited number of customers spread across a broad grouping of differing industry sectors. The number of customers within each sector is relatively small with no one sector having an overwhelmingly larger concentration of customers than other sectors. Variables related to facility age and technologies employed within industrial facilities located in Manitoba reflect different levels of competitiveness within a global industrial landscape.

Daymark's Ms. Kelly acknowledged, as a former forecaster, that preparing a forecast of the Top Consumers sector is challenging:

> *"It's -- it's a very difficult job to predict, as pointed out earlier in some of the work that the Consumer Coalition was -- was showing us. They are very large consumers. They are very lumpy. They have their own business plans and they -- they are driven by their own business indices. It's very difficult to forecast."* (Transcript Page 4036)

Manitoba Hydro recently changed its approach in forecasting Top Consumers where the threshold to be considered a Top Consumers changed from a load of approximately 6 MW to 25 MW in the 2017 Load Forecast (Page 2 of Exhibit MH-83). The PLIL methodology change made in the 2017 Load Forecast was undertaken in response to recommendations and concerns expressed by the PUB following the Needs For and

Alternatives To ("NFAT") and 2015/16 & 2016/17 General Rate Application ("GRA") proceedings. For example, the PUB in Order 73/15 found that:

> *"There is evidence that Manitoba Hydro consistently over-estimates the Top Consumers load growth. The first year of each load forecast for the past five years over-estimated the Top Consumers load in the greater-than-100 kV sub-class. The PLIL does not recognize the last test years of near-zero load growth in the Top Consumers sector, or than using PLIL in addition to large pipeline load additions overlaps in some years and may be double-counting. The Board sees Manitoba Hydro's PLIL as an in appropriate upward adjustment that does not reflect the recent Top Consumers load growth history. The Board recommends that Manitoba Hydro take a more rigorous approach to forecasting the Top Consumers load."* (Page 78 of PUB Order 73/15)

Daymark's Scope of Work directed it to review Manitoba Hydro's 2017 Load Forecast and assess the changes with respect to the 2014 Load Forecast (DEA Exhibit-2-1, Appendix A, Item #8). Daymark noted that the more conservative PLIL method used in 2017 forecasted 523 GWh less load than using the 2014 method and 2017 data over the 20-year forecast period. This result is not unexpected and was implemented to address the concerns expressed by the PUB. The change in forecasting methodology for PLIL better represents the expected growth in this sector (Page 2 of Exhibit MH-83).

8.2.4 Population Forecast

In its initial report, Daymark identified a possible area for improvement with respect to Manitoba Hydro's treatment of population forecast within the Load Forecast. Recognizing that Manitoba Hydro utilizes external agencies for Manitoba's population forecast, Daymark's concern was driven by its evaluation of previous population forecasts, which on average were under-forecasting population trends.

Manitoba Hydro addressed the Population forecast accuracy regarding the impact of the Provincial Nominee Program when comparing to population forecasts prior to the announcement of the Provincial Nominee Program in 1999 (Exhibit MH-83). When evaluating recent forecasts since the inception of the Provincial Nominee Program, Daymark confirmed in response to Coalition/IEC Daymark Load 7(b) and further

confirmed in Undertaking 45, Exhibit DEA-12 that Manitoba Hydro's more recent population forecasts have not been under-forecast.

8.2.5 Price Elasticity well within Literature Review

Manitoba Hydro currently utilizes econometric models incorporating the impacts of electric price elasticity. Future forecasted price increases are included as part of the analysis to capture the reduction in electrical consumption by customers as a response to increasing electric prices.

Although Dr. Yatchew's review of Manitoba Hydro's electricity price elasticities initially suggested that Manitoba Hydro electric price elasticities are somewhat lower than those suggested by his research, he acknowledged that Manitoba Hydro's price elasticities are well within the range of price elasticities identified by the literature referenced within his expert testimony (MH/Yatchew I-1(b)).

While studies from other jurisdictions may be useful in providing certain insights, they should be used with caution as the production of price elasticities values are not necessarily applicable to Manitoba, and it is not prudent to simply adopt a price elasticity found in any specific study without understanding the conditions and drivers underpinning that value. Differences between Manitoba and other jurisdictions that should be taken into consideration include starting price, rate structure, and average versus marginal pricing and cross price effect with other fuels. All non-price effects must be accounted for in order to minimize the potential for double counting, such as double counting the effects of an economic downturn, codes and standards, conservation rate programs and DSM programming. Dr. Yatchew identifies that Manitoba Hydro electric prices are low by national standards and it is possible that the response to price increases could be attenuated until the price crosses a certain threshold (Page 32 of Dr. Adonis Yatchew Report, Exhibit AY-1). Although Dr. Yatchew acknowledges the difficulty in assessing the threshold in his response to MH/Yatchew I-5, it is certainly plausible for Manitoba to have slightly lower price response than jurisdictions with higher electricity prices.

8.2.6 Evidence presented during public presentations

Dr. Garland Laliberte's submitted both a paper and PowerPoint presentation presenting his view of Manitoba Hydro's Load Forecast and Load Forecasting in general. Manitoba

Hydro must address a few of the assertions and recommendations presented by Dr. Laliberte, which demonstrates that Dr. Laliberte misinterpreted the data, and thus made erroneous conclusions regarding Manitoba Hydro's Electric Load Forecast.

Dr. Laliberte discussed during the presentation that Manitoba Hydro's annual load growth of 1.2% is higher than projections in other areas within North America, which are forecasting load growth from about a .5% to 1% (Transcript Page 3567). While other jurisdictions are predicting on average less than 1 percent, those growth rates include the impacts of energy efficiency initiatives in other jurisdictions whereas the 1.2% load growth for Manitoba Hydro referenced by Dr. Laliberte does not include future program based DSM. In the 2017 Load Forecast (Page 58 of PUB MFR 65 – Attachment 1), Manitoba's expected annual load growth including the impacts of program-based DSM initiatives is forecast to be 0.7%, well within the range of annual growth rates currently forecast in other jurisdictions.

Dr. Laliberte also presented financial impacts on domestic revenue from calculations based on a simple 10-year linear extrapolation in comparison to Manitoba Hydro's electric load forecast. During cross examination by the Consumer Coalition, Dr. Laliberte admitted that a simple linear regression for the purpose of Load Forecasting is not what he is suggesting Manitoba Hydro undertake as a methodology enhancement. When asked about the technique utilized by Dr. Laliberte, Ms. Kelly of Daymark Energy Advisors stated:

> *"this…approach of… using just a simple trend line, …as Suman pointed out, misses a lot of underlying explanatory variables and relationships that -- that change the forecast from time to time. Back in the '50s and '60s, before I went into forecasting, there was the better opportunity to use this kind of approach, because they were building like crazy, everybody was growing. It was -- it was postwar make-up. For a lot of time, that wasn't happening. And I remember talking to my mentors and trainers who talked about the days when they just took a log-linear, a piece of paper, and drew a line, and that was forecast, and it was going to be right, which is not something that you can see today. And simp -- making this simple is crazy."* (Transcripts Page 4100, lines 1-15)

Manitoba Hydro submits that no weight should be placed on Dr. Laliberte's assessment of Manitoba Hydro's forecast, its methodologies or potential financial impacts resulting from his analysis.

8.2.7 Demand Side Management and Efficiency Manitoba

Manitoba Hydro's DSM plans have played a key role in meeting energy needs in a sustainable manner and assisting customers in reducing their energy bills. The most current 2017/18 DSM Plan was filed in response to PUB MFR 61.

There has been much discussion during this hearing about what level of DSM should be included in Manitoba Hydro's long term financial projections. Mr. Bowman testified that Manitoba Hydro's baseline IFF includes DSM activities that *"are benchmarked too high, given the facts facing us"*. (Transcript Page 6079)

The 2016/17 DSM Plan – 15 Year Supplemental Report, filed as Appendix 7.2 of the Application outlines the corporation's current DSM plan over the next 15 years, and includes the best projections available at this time. As Ms. Morrison has testified, it would be inappropriate for Manitoba Hydro to propose a different plan on behalf of Efficiency Manitoba. As Ms. Morrison testified:

> *"The reason we did not -- we did not include this table in the 2017/'18 one year DSM plan is that we did not undertake a 15 year analysis or plan for '17/'18. This is because we were aware that the Efficiency Manitoba legislation was being tabled and in our discussions with the provincial government, we were basically holding constant on the programs we had in place. And so we went and undertook in our consultations to develop a one year plan, as we have in the past, and that one year plan then became the new plan and we are simply carrying forward the -- what was developed under the 2016/'17 15 year plan until Efficiency Manitoba can come forward with a revised, updated long-term plan."* (Transcript Page 1569)

Ms. Morrison further clarified this position during cross examination by PUB Counsel, *"That mandate is moving over to Efficiency Manitoba. We are not making any changes until that has successfully transferred. That will then be the direction of Efficiency Manitoba."* (Transcript Page 2622)

The 2016/17 DSM Plan – 15 Year Supplemental Report projects average annual DSM savings of 1.2% of load which, although lower than the 1.5% targets identified in the Efficiency Manitoba Act, are at least in the range of the legislated targets and therefore appropriate for the review of this Application. These savings are certainly not greater than those mandated by the Efficiency Manitoba Act and as such cannot be said to be benchmarked too high as suggested by Mr. Bowman.

8.2.8 Forecast Conclusion

Manitoba Hydro respectfully submits that the evidence in this proceeding supports its position that the Load Forecast methodologies underpinning this application are reasonable and are a reliable estimate of future energy requirements.

8.3 Export Revenue Projections are Reasonable

8.3.1 Consensus Price Forecast Process is Reasonable

For the MH16 Update, Manitoba Hydro prepared a Reference Case long-term export price forecast in spring 2017, using the consensus of four external price forecast services. In simple terms, the *"consensus"* is a simple average of the price forecast consultant forecasts. In connection with the review of Manitoba Hydro's Export Price Forecast, Daymark was provided individual price forecaster data in electronic format in confidence for their review.

In its Export Pricing and Revenues Review report, Daymark confirmed this approach stating:

> *"MH received electronic information from each vendor, which represented the entirety of the information available for reviewing and characterizing the forecast received. For all four vendors that information was provided via one or more spreadsheets. All four vendors provided annual energy and capacity prices. Some provided monthly energy prices as well. MH used a consensus approach, taking the average of the annual energy and capacity prices to create a single forecast, which MH called their reference energy price forecast"* (Page 36 of Daymark Energy Advisors Report – Export, Exhibit DEA-1).

Manitoba Hydro's consensus approach to long term price forecasting has been externally reviewed a number of times, including during the NFAT and the 2010 Risk Review/ KPMG External Quality Review. It is the accepted approach.

On Slide 22 of Daymark Energy Advisors Export CSI Presentation, Exhibit DEA-9 CSI and Transcript Pages 4348 to 4350, Daymark makes comparisons to other forecasts, including information from the U.S. Energy Information Administration. Comparisons of the Reference Price forecast with other older price forecasts or other unidentified price, natural gas or carbon forecasts are not meaningful or useful. Manitoba Hydro incorporated the current price forecast information from its independent price forecast consultants regarding natural gas and carbon into its forecast at the time MH16 Update was prepared. The price forecast represented the best independent estimates available to Manitoba Hydro at that time.

Daymark provided in Exhibit DEA-9 CSI the identities of each individual consultant, the individual price forecast detail, and the consensus price forecast. Daymark did not raise any objections to the consensus price forecast process, finding that *"MH used the average of the four forecasts as its reference case"* (Page 50 of Exhibit DEA-1).

8.3.2 Other Export Revenue Projections are Reasonable

The export revenue projections in the MH16 Update also incorporate information including revenues sourced from contracted energy and capacity sales (Page 60 of Exhibit DEA-1) and the exportable energy and capacity volumes (Page 52 of Exhibit DEA-1).

Daymark noted that Manitoba Hydro's firm contract revenue forecast is a contract-by-contract analysis of the terms of each contract (Slide 34 of Daymark Energy Advisors Export Presentation, Exhibit DEA-7). With regard to the contracted energy and capacity sales (firm contracts revenues), Daymark found that

- *"Manitoba Hydro's revenues forecast from existing export contracts is reasonable"*
- *"The treatment of those contracts is consistent with the analysis of those contracts in NFAT"*
- *"The treatment of the new contracts is consistent and the resultant revenues forecast is reasonable"*

(Slide 35 of Exhibit DEA-7)

Daymark also reviewed the forecasting methodology used by Manitoba Hydro to determine the exportable energy and capacity volumes, considering the flow and inflow conditions, reservoir levels, as well as other hydrologic inputs that are applied to the computer modeling of the hydro system. Daymark found *"that the methodology used by MH for both the short-term and the long-term periods appeared to be reasonable."* (Page 52 of Exhibit DEA-1). With regard to the forecast surplus capacity and energy volumes, Daymark found that:

- *"MH's forecasting methods are consistent with past practices"*
- *"The forecast reasonably represents the average supply considering the range of hydrologic uncertainty."*

(Slide 38 of Exhibit DEA-7)

These findings are significant. The export revenue projections also depend on the surplus volume estimates and the firm contract revenue estimates, and Daymark found these key components to be reasonable and appropriate.

8.3.3 Manitoba Hydro Uses Multiple Sources in its Short-Term Export Price Forecast

Manitoba Hydro has used a total of four vendor forecasts along with Intercontinental Exchange ("ICE") forward power prices and recent historic prices experienced in the market in preparing the short term forecast of export revenues for IFF16 and IFF16 Update. Manitoba Hydro notes that Daymark's evidence (Transcript Page 4362) in this respect is incorrect, and that it appears that Daymark did not apprehend the multiple sources used in the development of the short-term export price forecast used in operations and in projecting export revenues in the early years of its Integrated Financial Forecast.

Manitoba Hydro's use of multiple forecast sources for the first two years of the IFF is a more thorough approach than what Daymark understood to be the process. Daymark concluded based on its review and understanding of the data and methodology that it was reasonable (Page 35 of Exhibit DEA-1). Manitoba Hydro submits that this conclusion remains valid, and, if anything, is strengthened by the use of additional forecast sources.

8.3.4 Review of SaskPower Sale and Transmission Construction Deemed Beneficial

Mr. Cormie provided an overview of the 100 MW SaskPower sale starting at Transcript Page 663 and Slide 30 of Exhibit MH-68. Daymark reviewed the economic justification for the sale and associated transmission project and found *"The transaction, including the transmission project, remains in the best interest of Manitoba Hydro and its ratepayers"* (Slide 18 of Daymark Energy Advisors - Saskpower Presentation, Exhibit DEA-10). The revenues and costs associated with this sale were included in Manitoba Hydro's financial forecast MH 16 with Update.

8.3.5 No Additional Capacity Resources Required in MISO Until 2023 Time Frame

Midcontinent Independent System Operator ("MISO")'s conclusion in its MISO Transmission Expansion Plan ("MTEP") 2017 regarding the need date for additional capacity resources in its market region was *"Beginning in 2023 MISO capacity is projected to fall below the PRMR [Planning Reserve Margin Requirement] and remain there for the rest of the assessment period (Table 6.2-1)"* (MH/DAYMARK (EXPORTS) I – 1). MISO's conclusion is significant, as if there is no demand for additional capacity, there can be no value for generation capacity and in turn no premium in Manitoba Hydro's revenue projections until 2023. At page 72 of Exhibit DEA-1, Daymark agreed with MISO's conclusion in stating *"that it is likely that MISO will be short capacity within the next ten years, possibly as soon as 2025"*. In their Direct Evidence Daymark changed their position somewhat, stating in various places that *"2022 MISO predicted need for new capacity"* with a reference MISO MTEP Table 6.2-1 (Slide 53 of Exhibit DEA-7), and a *"2023/2024 Year of Need"* (Slide 23 of Exhibit DEA-7) assuming new resources but not new, low certainty resources currently under development are completed.

Manitoba Hydro accepts MISO's projection of the summer of 2023 as the need date for additional capacity resources. MISO's finding is consistent with NERC which stated in its 2017 Long Term Reliability Assessment (Page 42 of the NERC - Long Term Reliability Assessment, Exhibit CC-39) that *"The Anticipated Reserve Margin remains above the Reference Margin Level of 15.8 percent through the summer of 2022"*. As noted on Page 30 of Exhibit MH-83, this need date is subject to uncertainty, and has been deferred over the last five MISO MTEP assessments.

8.3.6 Long Term Dependable Product Premium No Longer Exists

In Tab 3 of the Application at page 14, Manitoba Hydro states, *"… the premium that has historically been applied to the long-term dependable forecast prices has been removed as the achievability of this premium has reduced significantly in the MISO market"*. Historically, the Long Term Dependable Product Premium was applied by Manitoba Hydro based on its ability to leverage what was once an almost unique fixed price carbon free product in the MISO market.

As outlined on Page 25 of Exhibit MH-83, the premium was reviewed during the NFAT and Manitoba Hydro notes that both the PUB and Daymark were previously skeptical of the premium. Daymark (then LaCapra) stated, *"MH provides little justification for the amount of the premium"* (Page 6-61 of Appendix 6 in Manitoba Hydro's NFAT Submission). In their current report, Daymark now advocates for the inclusion of the premium stating, at Page 61 of Exhibit DAE-1, *"The elimination of the premium in the longer term is not consistent with the longer-term outlook for energy, capacity and clean energy requirements in the Northern MISO region"*. On page 115 in the June 2014 PUB NFAT report, the PUB itself expressed its skepticism of the premium stating, *"The Panel is concerned with the risk that future export contracts may not attract the premium pricing that Manitoba Hydro assumes"*.

Subsequent to the NFAT, Manitoba Hydro made the decision documented in the 2016 Energy Price Forecast, that the addition of the Long Term Dependable Product Premium was no longer appropriate as a result of five changes/ concerns in the export market. Details of the five concerns were included as CSI on Page 59 of Exhibit DEA-1, which was reviewed at Transcript Page 4359.

Manitoba Hydro agrees with Daymark's finding *"The elimination of the premium appears reasonable for the near term"* (Page 61 of Exhibit DEA-1). However, Manitoba Hydro does not see the return of the Long Term Dependable Product Premium in the longer term, in 2023 and beyond, when new capacity resources may be needed in MISO. As noted on page 27 of Exhibit MH-83, wind generation and more recently solar generation have increased significantly in the MISO market, with the four states in Manitoba Hydro's immediate market already generating from 17 to 36% of their own supply from wind generation in 2016. Accordingly, Manitoba Hydro is no longer the only renewable option for potential customers seeking a carbon free renewable product

at a fixed price. Competition from low cost renewables does not support a premium for long-term dependable products at this time, and Manitoba Hydro expects the situation is unlike to improve in the future as wind and solar costs are falling, even as subsidies for wind generation are being phased out.

8.3.7 Value of Generation Capacity in the Future is Uncertain

Potential capacity revenue is a significant uncertainty in the projections of future export revenue. In times of oversupply, the value of generation capacity can be very low. This uncertainty was recognized by the PUB in its NFAT report when it stated on page 108 *"However, it has not been conclusively demonstrated that all of this surplus dependable energy will achieve capacity revenues in addition to energy revenues".*

Given MISO and NERC findings that MISO's regional surpluses and potential resources are sufficient to meet requirements in the 2019 - 2022 timeframe, it follows that there is expected to be little or no demand for additional capacity resources in the MISO market through the end of 2022. In times of capacity surplus, as in the current situation, the capacity price is likely to be close to zero. For 2023 and beyond, if MISO load forecasts prove to be correct, there is the potential for a need for new capacity, and in turn a potential for some yet to be determined value for generation capacity at that time.

In determining the export revenue forecast, and in consideration of significant uncertainty associated with the value of generation capacity in the long term, a policy decision has been made by Manitoba Hydro to remove the potential capacity revenue associated with unsold capacity and dependable energy from the revenue forecast. This policy decision reflects the uncertainties and delay in the need for additional capacity resources in MISO (described as the Receding Horizon for the Capacity Need Date in MISO) (Page 30 of Exhibit MH-83). The continued delay in the need for additional capacity resources in MISO is a result of:

- Load growth, which for the US as a whole, and for MISO in particular, is low by historical standards, and has been trending even lower for 20 years. MISO's most recent projections of load growth are in the 0.3% (MH/DAYMARK (EXPORTS) I-1 Attachment 1) to 0.5% (Page 31 of Exhibit MH-83) range.
- Increasing wind and solar renewables, which MISO considers as providing some capacity to meeting regional peak load requirements in their supply and demand

analysis. In MTEP 17, MISO allocated wind generation a 15.6% capacity credit and solar generation a 50% capacity credit (MH/DAYMARK (EXPORTS) I-1 Attachment 1), as a portion of the installed or gross capacity rating, to meet peak load in their supply and demand analysis. This generation capacity from wind and solar reduces the need for generation capacity from other resource types.

- The deferral of emissions requirements in the US resulting from the Trump administration's rollback of environmental regulations, the lack of pending carbon legislation, and the pending plans to terminate the Clean Power Plan have (PUB MFR 79U) allowed existing thermal power plants, which may have been forced to close due to environmental regulations, to stay open, deferring the need for new capacity resources.
- Resource planners and generation developers within MISO already have under development significant generation with which to replace any expected generation retirements within MISO. As stated in MTEP 2017 *"MISO's West Region alone faces more than 22 GW of generation under study"* (MH/DAYMARK (EXPORTS) I-1 Attachment 1).

8.3.8 Export Prices are Continuing to Fall

Electricity prices in MISO have been on a general downward trend since 2008 driven in large part by falling natural gas prices. The August 2017 Staff Report to the Secretary on Electricity Markets and Reliability prepared by the US Department of Energy (DOE Staff Report) has an entire section titled *"Falling Natural Gas Prices"* (MH/DAYMARK (EXPORTS) I-1 Attachment 1). In discussing falling natural gas prices, the DOE Staff Report notes at page 36 that *"natural gas plants and gas prices have been the largest single driver of spot electricity prices"*. The DOE Staff report also states:

> *"Shale gas development has significantly expanded the availability of natural gas and lowered its cost across the United States and the world. Before the widespread use of horizontal drilling techniques in the past decade, U.S. natural gas prices averaged more than $7 per million British thermal unit (MMBtu) between 2003 and 2008, and approached $14/MMBtu in several short periods (including in 2005 after Hurricanes Katrina and Rita reduced production and delivery from Gulf of Mexico sources). Hydraulic fracturing practices spread and made previously inaccessible gas sources economic, causing natural gas prices to*

fall, averaging less than $3.20/MMBtu between 2012 and 2016" (MH/DAYMARK (EXPORTS) I-1 Attachment 1).

As indicated in the November 16, 2017 letter from Manitoba Hydro to the PUB which provided the Quarterly Report for the six months ended September 30, 2017,

> *"As of September 30, 2017, on peak opportunity prices were 22% below the target in MH16 Update with Interim while off peak prices were 6% below target. This represents a further deterioration compared to the quarter ended June 30, 2017 where on-peak prices and off peak prices were 16% and 4% below target."*

The current export market conditions are challenging and very competitive.

Dr. Yatchew summarized the market challenges very well:

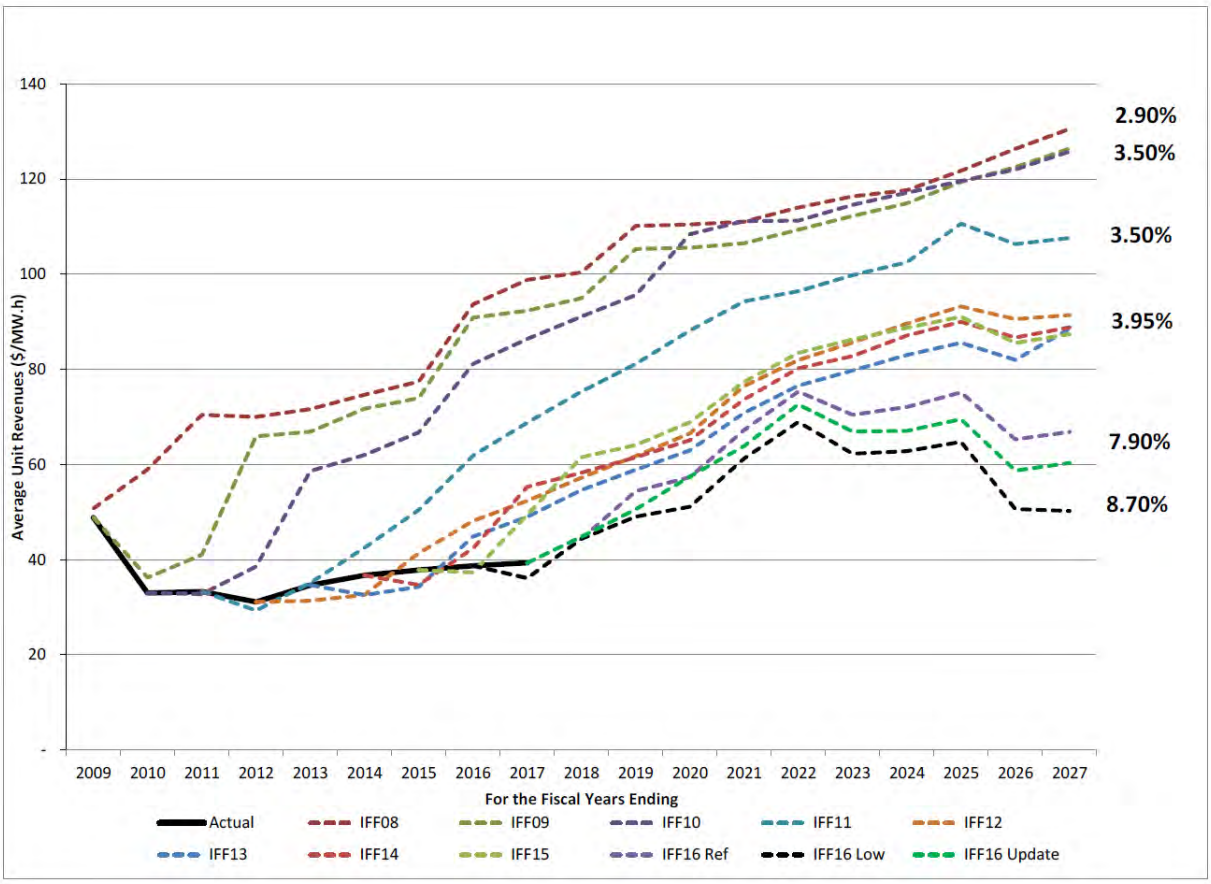
> *"In any discussion of Canada's economic circumstances, consideration of the effects of the current U.S. administration cannot be ignored. The North American Free Trade Agreement is being re-negotiated at the initiative of the U.S. At a minimum, this injects considerable uncertainty into trade relations with our largest trading partner. The U.S. administration has also altered direction on its decarbonization policies, disengaging from the Paris Agreement and making efforts to revive the coal industry. Together, these factors are likely to have a dampening effect on investment, and weaken prospects for long-term power sales agreements that are premised on clean hydro-electric power"* (Page vii of Exhibit of AY-1).

8.3.9 Manitoba Hydro's Unit Export Revenue has Historically Been Overestimated

Manitoba Hydro's average unit export revenue is calculated as total export revenue divided by total export volume. Future projections of the export revenue reflect actual firm contract revenues, as well as revenue for expected future sales based on the electricity export price forecast. As export prices have fallen since 2008, so too has Manitoba Hydro's average unit export revenue. The history of Manitoba Hydro actual average unit export revenue compared to forecasts from previous IFFs was provided in response to PUB/MH I-153(b) and is reproduced below in Figure 8.3.

Figure 8.3 Progression of Average Export Unit Revenues Graph

Figure 3.7 Progression of Forecast Average Unit Revenues Compared to Actual Average Prices



Source: PUB/MH I-153(b)

When MH08 was prepared, the expectation for average unit export revenue for 2017 was in the order of $100/ MWh. In recent years, the actual average unit export revenue has been just under $40/ MWh. As near-term actual export prices have fallen, so too have the long term electricity price forecasts.

Average unit export revenues in MH16 Update over the forecast horizon have dropped nearly 50% from MH08 and over 20% compared to MH15. The decline in actual and projected average export unit revenues primarily reflects the previously noted steep declines in natural gas prices, with declines in carbon pricing outlook and increasing amounts of wind and solar generation also contributing. As can be seen in Progression

of Average Export Unit Revenues graph, each of the nine Integrated Financial Forecasts in the 2008 thru 2015 period have significantly overestimated the current actual average export unit revenue. This is not a result of any bias of Manitoba Hydro but rather reflects a decade long decline in natural gas and electricity market prices in the independent price forecasts Manitoba Hydro utilizes to form its consensus price forecast.

A review of the Progression of Average Export Unit Revenues graph shows that for the IFF16 Update, the average export unit revenue is projected to increase from around $40 today to around $70/ MWh in 2022. Given the history of underperformance of the unit export revenue projections over the last nine year due to declining price forecast, there is reason for concern as to whether the export revenue will increase to the degree anticipated. Daymark asserted that *"the reference case energy market price forecast and the resultant energy revenues are susceptible to be biased low"* (Page 1 of Exhibit DEA-1) suggesting that the forecast is too low and actual results will be higher. Actual experience over the last nine years has been the opposite.

There is much uncertainty as to what will happen five years in the future, in the 2023 time period, when MISO may need new capacity resources. As Mr. Shepherd noted,

> *"…one (1) of the key adjustments we've made is to reduce the expectation that we are going to be able to achieve premiums in export pricing associated with a firm or capacity demands and – and that's based upon a view that those are very uncertain at this stage that we will be able to actually achieve that level of pricing premium. So we've been more conservative in our export pricing forecast, and I think given our track record of it seems like regularly overestimating export pricing, being a little bit more conservative is the prudent thing to do"* (Transcript Page 296).

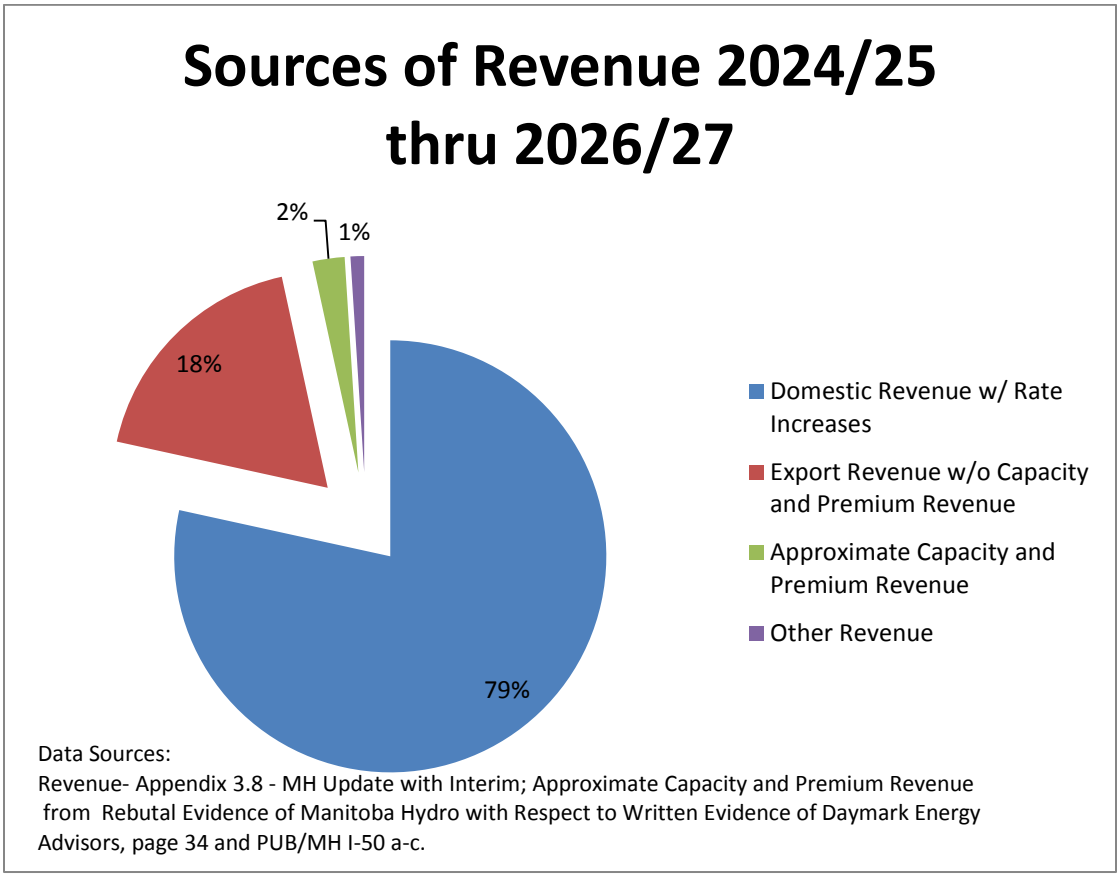
8.3.10 Impact of Potential Longer Term Premium and Generation Capacity Revenue Doesn't Change Current Rate Needs

Manitoba Hydro does not believe there is any realistic potential for the Long Term Dependable Product Premium to return for the MISO market, given competition from other renewables, on any time horizon. For 2023 and beyond, if MISO load forecasts prove to be correct, there is the potential for a need for new capacity, and in turn a

potential for some yet to be determined value for generation capacity at that time. Should additional capacity sales be contracted, the associated forecast revenues can be added into the IFF at the specific contract prices. There is likely to be two further General Rate Applications between now and 2023 to make this adjustment. However, for the purposes of the 2017/18 and 2018/19 test years, Manitoba Hydro's assumptions are reasonable and prudent in the circumstances.

As noted in Manitoba Hydro's Rebuttal Evidence, even if one were to include the Long Term Dependable Product Premium and the value of generation capacity after 2024/25 as suggested by Daymark, the impact on net export revenues for the period2024/25 to 2026/27 would be in the order of $200 to $300 million (PUB/MH I-50a-c CONFIDENTIAL). Manitoba Hydro's projected total revenue for this three year period, based on MH16 Update with Interim (Appendix 3.8 Revised) is in the order of $3.5 billion per year and about $10.4 billion for the three year period. Accordingly, the estimate of $200 to $300 million represents a very small portion of total revenue requirement some 7 to 10 years into the future, as shown in Figure 8.4 below.

Figure 8.4 Sources of Revenue 2024/25 – 2026/27



Data Sources:
Revenue- Appendix 3.8 - MH Update with Interim; Approximate Capacity and Premium Revenue from Rebutal Evidence of Manitoba Hydro with Respect to Written Evidence of Daymark Energy Advisors, page 34 and PUB/MH I-50 a-c.

The uncertainty of the potential premium and generation capacity revenue in the 2023 time period and beyond is well within the range of forecast uncertainty, and could be accounted for in future financial forecasts, should it materialize. The potential for such premium and capacity value in the 2023 and beyond timeframe does not have any impact on the current rate requests before the PUB.

8.3.11 Current Water Conditions Have Not Changed Significantly from IFF16 Forecast and Are Less Favourable Than IFF16 Update.

Mr. Cormie provided an update of water conditions in his direct testimony (Transcript Pages 657 to 659). With reference to slides 24 through 26 of Exhibit MH-68, he explained how inflow conditions declined from flood conditions in the early summer of 2017 (when MH16-Update was prepared) to close to average by late summer, and were close to average as of December 2017.

River flows and storage remain close to average and cumulative winter precipitation (November 1st through February 1st) is slightly below average. Carry forward storage into 2018/19 is similar to what was projected in MH16. Conditions continue to be such that Manitoba Hydro cannot confidently rule out the occurrence of flood or drought in 2018/19. The range of uncertainty in flow related revenues is approximately $500 million - between $100 million favourable and $400 million unfavourable (Slide 35 of Exhibit MH-64).

8.4 Interest Rate Outlook

Continuation/reliance on rates not seen since Depression era extremely risky strategy – reasons outlined in detail in next section

Interest rate risk is the risk that future cash flows will fluctuate due to changes in market interest rates. There are a number of forms of interest rate risk affecting the existing debt portfolio. Floating or variable rate debt is subject to interest rate reset risk during the life of the debt as the interest rate becomes adjusted at the periodic reset dates. Refinancing risk pertains to the interest rate exposure that exists upon refinancing a short or long term debt issue at its maturity. On a prospective basis, there is also interest rate risk on borrowings for new cash requirements.

Given the significant level of upcoming debt financings, the corporation's sensitivity to interest rate changes will be elevated during the next few years. Financial market conditions and the corporation's risk mitigation activities will be especially important during this timeframe.

Actual interest rates in the Canadian capital markets have generally been on a downward trajectory over the past two decades but since July 2017, the Bank of Canada has raised the overnight rate 75 basis points. The July 2017 interest rate hike was the first increase in this rate in seven years. Interest rates across the yield curve are projected to continue rising in the next few years.

Manitoba Hydro has been fortunate that the interest rate environment has remained low throughout the beginning of the intensive capital investment period. However, to continue to rely upon historically low interest rates as a means to buffering financial forecasts to reduce revenue requirement is an extremely risky strategy.

In PUB/MH I-31a (Revised) Manitoba Hydro updated the short and long-term rates based on September 2017 forecast information.

PUB/MH I-31(a) compared the short and long-term interest rates based on the September 2017 forecast and March 2017 forecast (used in MH16 Update with Interim). Manitoba Hydro's September forecast of Canadian long-term interest rates based on a 12 year WATM is 10 to 30 basis points higher than IFF16 Update with Interim until 2021 and then is lower thereafter by up to 25 basis points compared to the March forecast. For Manitoba Hydro's forecast Canadian short-term interest rates, the September forecast is up to 70 basis points higher to 2022 and then up to 20 basis points lower thereafter.

Over the forecast 2018 to 2027, the total impact to finance expense under the September 2017 forecast of interest rates is an increase of approximately $180 million net of a $13 million increase in capitalized interest related to Keeyask compared to the March interest rate forecast. Inclusive of modest increases in finance income on cash balances, the higher net finance expense resulting from the higher forecast near term interest rates results in net debt that is approximately $150 million higher and lower equity of approximately $150 million by 2026/27. This results in the target 25% equity ratio not being reached until during the 2027/28 fiscal year (PUB/MH I-31a).

Manitoba Hydro will amend its debt management strategy including the WATM of new debt issuance based on changing conditions. These amendments and associated interest impacts will be reflected in the forecast of the day.

9 SUSTAINING CAPITAL

9.1 All Business Operations Capital investments in the test year are required for the sustainable, safe and reliable operations to the benefit of Manitoba Hydro's customers.

Electricity is essential to public safety. The system is expected to function reliably 365 days a year, 7 days a week and 24 hours a day. Manitoba Hydro is responsible for managing that system and investing as required to assure the safe, reliable and sustainable operation of the electrical system, while achieving a balance of cost, performance and risk for the customer.

All of the capital investments planned for the test years in this Application are required for the sustainable, safe and reliable operation of the electrical system in Manitoba. This is supported by the extensive record of evidence on this subject matter in this proceeding.

Business Operations Capital investments are required to sustain electricity service through the replacement of aging or obsolete assets, capacity enhancements, and expansion due to load growth (Transcript Page 686). Growth and expansion investments are required to connect new customers and meet growing regional demand. In its Direct Evidence (Transcript Page 687), Mr. Wortley notes that Manitoba Hydro is required to be responsive to customer needs and therefore the timing of these investments is out of Manitoba Hydro's control.

System renewal accounts for the majority of the sustainment investment, either to replace failed assets or to proactively intervene to address asset deterioration ahead of failure (Transcript Page 688). This was the focus of METSCO's evidence (METSCO Report prepared on behalf of the Consumers Coalition, Page v, filed as Exhibit CC-19).

After reviewing all of the evidence on the record of this proceeding with respect to sustaining capital planned for the test years of the Application, it is clear that METSCO does not identify nor make a specific recommendation for even one program or project warranting reduction, deferral or any other form of modification. Instead, METSCO, without providing any specific facts or analysis, baldly asserted that there was insufficient justification for the sustainment renewal funding for the test years (Exhibit CC-19, page 45). This conclusion is specious.

All of the proactive interventions planned by Manitoba Hydro in the test years are justified by risk assessments performed by experienced operators and subject matter experts with professional expertise based on asset condition and criticality, with appropriate management oversight and approval. As observed by the UMS Group in their Asset Management Gap Assessment, *"Hydro is using risk to support its asset management decisions, mainly with regard to Capital Planning"* (Appendix 5.1 of the Application, page 16). As noted by Mr. Wortley at Transcript Page 689,

> *"We've got a high level of confidence that this is the right work at the right time… it is based on the actual condition of the asset or its performance. It's a risk assessment made by experienced operators and subject matter experts reviewed and approved by line management."*

Nothing in the evidence would suggest otherwise. These decisions are made by professionals with many years of collective technical experience and expertise with the sole purpose of achieving what is in the best interest of the customers of Manitoba Hydro. As Mr. Hjartarson, the CEO of METSCO confirmed in cross-examination *"I worked with many professionals from Manitoba Hydro, and -- and they are very knowledgeable in their field. So that's – we absolutely did not contest that."* (Transcript Page 7006).

System renewal investments in the test years benefit customers by improving safety and reliability and managing costs. For example:

- Streetlight replacements and grounding improvements to mitigate safety risks (Manitoba Hydro Rebuttal, page 41, lines 14-17, filed as Exhibit MH-52);
- Deteriorated pole and cable replacements serve to maintain customer service levels (Exhibit MH-52, Page 41, lines 17-20);
- Deteriorated apparatus replacements avoid damage to customer and Manitoba Hydro equipment (Exhibit MH-52, page 42, lines 7-15);
- Upgrades to the spacer-dampers on Bipole I and Bipole II to arrest conductor damage and avoid the costs of much larger future repairs (Exhibit MH-52, page 42, lines 17-27);
- Life extension works such as pole treatments and cable injection to delay future replacement costs (Exhibit MH-52, page 42, lines 1-2);

- Remediation of a deteriorated concrete dam to mitigate the risk of dam breach and generation reliability risk at a fraction of the cost of replacing the structure (Exhibit MH-52, page 42, line 29 to Page 43, line 2); and
- Upgrading obsolete generator control equipment to assure the reliability of Manitoba Hydro's largest generating station (Exhibit MH-52, page 43, lines 1-10).

Delaying sustainment investments in deteriorated assets will result in:

- Direct and collateral equipment damage due to in-service failure;
- Higher costs due to emergency replacement of failed assets being more costly than planned replacement;
- Jeopardizing employee and public safety;
- Harmful environmental impacts;
- Lost export revenue which increases costs to Manitobans; and
- Most significantly, customers service interruption.

Moreover, prolonged under-investment can result in a backlog of deteriorated assets which can threaten the sustainability of operations. METSCO stated in reference to sustainment funding during cross-examination (Transcript Page 7089) *"You cannot really just skip it for some time. Your assets do age and you'll have – you'll be in real problem."*

As noted by Mr. Wortley Transcript Pages 2187 to 2188,

> *"It's the customer, ultimately, who is subject to that balance of cost -- cost performance and risk, and essentially, the – the safe, reliable operation of the system is deemed to be what's best for the customer. And so these are the dollars are required to protect that safe and reliable operation and make sure that the customer -- we're there when the customer needs us."*

To conclude, all test year Business Operations Capital investments are required for sustainable, safe and reliable operations to the benefit of Manitoba Hydro's customers which Manitoba Hydro serves by striking a reasonable balance of cost, performance and risk.

9.2 Forecasts of future expenditures will be tested in future General Rate Applications

The Business Operations Capital targets beyond the test years are currently budgeted based on the extrapolation of past asset investment requirements, shaped by the best available information of future trends (see Exhibit MH-52, page 49 and Mr. Wortley's direct evidence at Transcript Page 689). Manitoba Hydro is working towards establishing a budget model for future operations capital in which these budgets will be more closely aligned with quantitative assessments of future risks based on forecasts of asset degradation. This is consistent with UMS' recommendations to close asset management gaps (Appendix 5.1, UMS Report, pages 34-36) and METSCO's recommendation for future work (see Transcript Page 7091, lines 11-19).

However, planned improvements to the budgeting process does not impact or change the fact that all of the capital investments planned for the test years in this Application are required for the sustainable, safe and reliable operation of the electrical system in Manitoba. The appropriate time for the Public Utilities Board of Manitoba ("PUB") to consider and review the merits of capital budgets beyond the test years in this Application is when the budget years in question are included as test years in future General Rate Applications as filed by Manitoba Hydro.

There are some indications of growing demand in sustainment investment levels, most significantly in the potential for coincident waves of similarly aged assets coming to end of life and exceeding historic replacement rates (Mr. Wortley's direct evidence at Transcript Page 690). The Boston Consulting Group also found *"Currently good reliability, but ageing assets a looming issue"* (PUB MFR 72 Attachment, Page 340) and *"System renewal capital investment insufficient to replace aging assets"* (PUB MFR 72 Attachment, page 342). Similar trends are being experienced in the industry as noted by METSCO *"…they're probably not spending enough on system renewal … Assets are aging at Manitoba Hydro as – as in other places. I – I would not be surprised if that was the story"* (Transcript Pages 7096 to 7098).

While these are indications of potential upward pressure on capital budgets, the demand for capital beyond the test years remains uncertain. This uncertainty is one of the drivers to implementing the tools and processes to enable the forecasting of investment requirements based on further and more refined predictions of asset

degradation. As noted in Tab 5 of the Application, three to five years are expected to be required to fully implement and mature these tools and processes.

9.3 Asset Management Practices are being Enhanced

Manitoba Hydro is committed to improving its asset management maturity and is proceeding purposely but cautiously to avoid costly missteps (see Transcript Page 693). Manitoba Hydro commissioned an asset management maturity gap assessment by UMS Group (see Appendix 5.1 of the Application). As anticipated, UMS identified gaps that would need to be closed in order for Manitoba Hydro to achieve best practice while also concluding that Manitoba Hydro's asset management maturity compared favourably to North American industry.

Plans to close these gaps are under development with significant progress anticipated in 2018. Advancing asset management maturity in a large organization like Manitoba Hydro is a complicated endeavour to be accomplished over several years. As described throughout these proceedings (e.g. in Tab 5 of the Application, during the Technical Conference on Asset Management conducted on June 20, 2017, a number of Information Requests, including PUB/MH I-71a-c, and several times in oral testimony including at Transcript Pages 693 and 1419), Manitoba Hydro has a number of initiatives underway to improve capital planning and portfolio management and is proceeding with its Corporate Asset Management Initiative. As Mr. Wortley testified in cross examination (Transcript Page 1421), Phase 2 – the development of asset management policies and strategies – will begin in early 2018 with a detailed roadmap for implementation to follow as Phase 3.

Also, as described in Section 9.3, Manitoba Hydro is undertaking a number of asset management process improvements in order to achieve its objectives of optimizing the timing of investments to maximize value and forecasting long-term capital requirements of the corporation, which are expected to take three to five years to come to full maturity. This timeline was confirmed to be reasonable by METSCO in their testimony at Transcript Page 6992,

> *"…we do acknowledge and commend Manitoba Hydro for the complex path of implementing and entrenching the new asset management tools and the experts*

that preceded us, the Manitoba Hydro's expert put the timeline at about three (3) to five (5) years of doing this work. To us, this timeline is not unreasonable."

METSCO also confirmed in cross examination that achieving a broader asset management maturity is a larger endeavour and *"it's really a never-ending journey"* (Transcript Page 7058).

In summary, Manitoba Hydro will continue to focus its efforts on closing the gaps identified by the UMS Group in the immediate and near term while in the midst of the corporate restructuring initiative.

9.4 METSCO's Recommendations for Additional Regulatory Oversight Must Be Reviewed According to the PUB's Regulatory Mandate and the Incremental Cost of Reporting

In Section 4.0 of their report (Exhibit CC-19), METSCO provided a list of potential accountability tools for consideration by the PUB in establishing additional regulatory oversight and incentive mechanisms for Manitoba Hydro.

METSCO does not appear to fully understand or appreciate how their suggested recommendations would be consistent with Manitoba Hydro's current regulatory construct. For example, METSCO mistakenly believed that the PUB was responsible for approving Manitoba Hydro's capital expenditures forecast (Transcript Page 7018). Such a misconception has now been recognized by METSCO.

Additionally, METSCO did not provide any evidence as to the ongoing costs of additional staffing to prepare reports and for the PUB to review and assess the information, both of which add to the cost of compliance ultimately born by the customer.

For example, at page 46 of its report (Exhibit CC-19), METSCO recommends *"…that the PUB establish a range of potential incentive mechanisms to ensure that the applicant progresses along its path of continuous improvement in asset management capabilities, while exercising increasing cost discipline".*

Regulatory incentive mechanisms are employed with investor-owned utilities to provide sufficient financial reward for shareholders to influence the utility to pursue a

given set of activities. However, Manitoba Hydro does not have a "shareholder" and therefore incentive based mechanisms are not necessarily appropriate in Manitoba. Manitoba's cost of service regulatory model sets customer rates according to the revenue required for sustainable operation of the utility for the customer. Moreover, incentives are not required as Manitoba Hydro is committed to continuing its asset management journey, as described in Section 9.3 above.

METSCO also recommended that the PUB consider an extensive array of new key performance, capital planning, portfolio management and project-specific reporting requirements to be provided to the PUB on a routine basis. A significant effort would be required to create these reports for the PUB with a costly ongoing effort to regularly refresh and publish them.

Furthermore, such reporting would require additional time and resources on behalf of the PUB and potential costs to engage external technical experts to review and assess the contents of such reports. It is also necessary to consider what the PUB would practically do with such technical information as it will not provide the PUB with information it can utilize in determining rates.

Manitoba Hydro reiterates that oversight and accountability for managing the Corporation, including implementation of the Corporation's asset management initiatives, properly rests with the Manitoba Hydro-Electric Board and the Executive and Management teams of Manitoba Hydro. Further, under the existing regulatory framework, there is opportunity for the PUB to review Manitoba Hydro's progress and results with respect to its asset management initiatives as part of the rate-setting process without the requirement for any additional reporting or monitoring as recommended by METSCO. Additional oversight and reporting will ultimately result in Management's efforts being diverted toward responding to these additional compliance requirements rather than working toward implementation of the improvement initiatives.

Manitoba Hydro submits that the current regulatory framework already provides opportunity for the PUB to review the Corporation's progress toward the implementation of its asset management framework. As part of this GRA, Manitoba Hydro has provided a status update with respect to the corporation's plans to

implement an overall asset management framework. In future GRA filings, Manitoba Hydro will provide updates on its progress with respect to the implementation of its asset management initiatives.

10 MAJOR CAPITAL PROJECTS

10.1 Overview

The Public Utilities Board of Manitoba ("PUB"), and the ratepayers of Manitoba, should be reassured by the detailed review of the construction and management of Manitoba Hydro's major capital projects that took place during the course of this General Rate Application.

By way of background, by virtue of Manitoba Order In Council 00092 / 2017 issued April 5, 2017, the PUB was assigned the duty of considering capital expenditures by Manitoba Hydro, in its next review, as a factor in reaching a decision regarding rates for services, in order to support setting rates for services in a manner that balances the interests of ratepayers and the financial health of the Manitoba Hydro.

In its Application filed on May 12, 2017, Manitoba Hydro provided a brief description of its Bipole III Reliability Project ("Bipole III"), its Keeyask Generating Station Project ("Keeyask"), and the U.S. Tie-Line Project made up of the Manitoba-Minnesota Transmission Project in Manitoba ("MMTP") and the Great Northern Transmission Line in Minnesota ("GNTL"). CEF16 also described the Manitoba-Saskatchewan Transmission Project. Included in those descriptions were the budget estimates in place as at that time, and the projected In-Service Dates for each as of May, 2017. The Application also made reference to the review of those projects by the Boston Consulting Group in 2016.

With respect to other review and regulation of the above projects, Bipole III underwent a 37 day hearing before the Manitoba Clean Environment Commission in the fall of 2012 and the spring of 2013. During that lengthy hearing, system risks and reliability, as well as the Corporation's requirement for this HVDC transmission line, were reviewed. Issues such as the proximity of transmission lines to each other, and weather risks such as tornadoes and wind events, were discussed. The Manitoba Clean Environment Commission then recommended this project to the Province of Manitoba and a licence was issued in 2013.

In 2014, the Needs For and Alternatives To ("NFAT") hearing was held before the PUB, and it included a review of both Keeyask and MMTP.

With respect to the Keeyask Project, starting at pages 122 of the PUB's decision dated June 20, 2014, there is a detailed description of the review done by Knight Piésold, an independent expert retained by PUB. It is stated:

> *"In its scope of work, Knight Piésold was asked to review the cost estimates, contracting practices, and the contract provisions. They undertook to determine the extent practices were appropriate, costs were reasonable, and measures were in effect to address changes or increases in construction costs. The Panel focused on Keeyask-related contracting given the immediate nature of decisions on whether to proceed with construction in July 2014, and the fact that Conawapa construction contracts had not yet been entered into.*
>
> *Knight Piésold assessed Manitoba Hydro's costs estimates and contracts. They discussed questions about documentation and procedures with Manitoba Hydro staff. They then used their experience and past work to assess these practices against industry best practices and similar hydropower construction projects. Knight Piésold reported to the Panel that many of Manitoba Hydro's practices and procedures were reasonable and appropriate, relative to industry best practice. Knight Piésold supported Manitoba Hydro using an Early Contractor Involvement process to obtain input from the chosen contractor in order to refine the design, construction techniques, schedule, and risk sharing. Knight Piésold told the Panel that Manitoba Hydro had made the appropriate choices in the various Keeyask Project contracting efforts. The contracting choices were designed to secure the most cost effective contracts."*

It is also clear that the PUB had the opportunity, at the NFAT hearing, to consider the appropriateness of the General Civil Contract in place with BBE. The following is an excerpt from page 123:

> *"The Keeyask general civil contract is a cost-reimbursable contract, not a fixed price contract. This leaves the contract vulnerable to cost escalations as a result of: quantity risk, especially in areas where quantities may have been underestimated; escalation to the contractor's cost factors due to labour productivity or labour costs; escalation in the cost of supply and equipment; and challenges related to adverse weather conditions."*

While there was much discussion about the GCC during the 2017/2018 GRA, virtually all of these issues have already been considered by a previous panel of the PUB and a decision made, based upon that analysis on the information available at that time, for the Keeyask Project to proceed. Having reviewed the nature of contract, as outlined above, the PUB concluded (page 34):

> *"There are good reasons to proceed with the Keeyask Project at this time in light of the need for new resources, construction expenditures undertaken to date, the socio-economic and environmental benefits of the project and the important commercial relations that Manitoba Hydro has established both with First Nations and through its export contracts. Moreover, there are associated reliability benefits with the 750 MW Transmission Interconnection Project." [MMTP]*

With respect to the new US Tie Line [MMTP], there is a detailed description of the review that was done by the PUB. It stated:

> *"With respect to Manitoba Hydro's construction cost estimates for transmission facilities, the Panel concludes that such estimates are reasonable and recommends that Manitoba Hydro be given approval to proceed with the construction of a 750 MW transmission interconnection to the United States for a 2020 in-service date. This interconnection provides increased firm transmission access extending into Minnesota, provides important, increased reliability, and supports import and export of electricity."*

The Province of Manitoba went on to accept the PUB's recommendations with respect to construction of both Keeyask and MMTP.

Keeyask and MMTP also underwent rigorous environmental review at hearings before the Manitoba Clean Environment Commission in 2013/14 and 2017 respectively. In both cases, the Commission recommended the projects to the Province of Manitoba. The Province issued a licence for Keeyask in 2014. The Province's decision with respect to MMTP is pending. MMTP will undergo further scrutiny at the upcoming hearing this spring before the National Energy Board.

The GNTL underwent regulatory review in the United States and received a Certificate of Need and A Route Permit from the Minnesota Public Utilities Commission, a Presidential Permit from the US Department of Energy and a Section 404 Wetlands Permit from the U.S. Army Corps of Engineers allowing its construction to proceed.

In addition to review through this current GRA process, the Manitoba-Saskatchewan Transmission Project is regulated under The Environment Act of Manitoba, though due to its size, a hearing will not be required. It is worthy to note that an independent review of this project was conducted by Daymark Energy Advisors for the PUB and it determined that it was in the best interests of Manitoba's ratepayers to proceed with the project. (Transcript Page 5979)

Although the Intervenors may wish to revisit many of the issues and considerations already reviewed at other regulatory proceedings, the PUB's task and focus is to now consider the Corporation's expenditures to date on these projects in its rate setting decision making process, as well as the budgets going forward.

Manitoba Hydro provided thousands upon thousands of documents, and responded to dozens of requests for information from MGF Project Services Inc. ("MGF"), an entity retained by the PUB to review Manitoba Hydro's capital expenditure program in relation to the above projects and to provide its opinion on Manitoba Hydro's updated costs for each. Although there are recommendations going forward, some of which may be implemented by Manitoba Hydro where feasible, practical and of value, it is notable that MGF made the following comments in its Report (Redacted MGF Report, Exhibit MGF–2R):

> "*Manitoba Hydro staff are competent and professional*". (Page 1)
>
> "*The Manitoba Hydro teams on all projects are very capable and dedicated*." (Page 2)
>
> "*In general Manitoba Hydro is very strong in capturing and reporting costs and has a very capable group*." (Page 35)

"*The team is comprised of a very knowledgeable and capable group*". (Page 99)

Further, Manitoba Hydro established a Major Projects Executive Committee that meets twice monthly to review the Corporation's major projects. (Transcript Page 5543) The Executive report regularly to the Board of Manitoba Hydro to keep it apprised of developments, and quarterly reports are provided to the PUB (Response to Directive 13 of PUB Order 73/15). Collectively, these steps should give the PUB and ratepayers comfort, going forward, that project execution is in good hands.

In terms of the impact on rates, with Bipole III coming into service this year, the finance expense, depreciation, and operating expense associated with it will be reflected on Manitoba Hydro's income statement and revenue requirement. The Keeyask Project and MMTP/GNTL are net income negative upon entering service and remain net income burdens for a 30 year period. Manitoba Hydro's financial position now must recognize the new reality of the carrying cost of these significant assets coming into service in the near future (Tab 2 of this Application on Page 48). Specifically with respect to GNTL, as it is not a Manitoba Hydro project, the construction cost contributions payable are not in Manitoba Hydro's capital expenditure forecast. However, they are included in the IFF. (Transcript Page 5067)

Below is Manitoba Hydro's position with respect to the issues discussed in relation to each of the major projects discussed at the hearing. The Manitoba-Saskatchewan Transmission Project is discussed in Section 10.4 below.

10.2 Keeyask Generating Station Project

As described on page 42 of Tab 2 of the Application, the Keeyask Generating Station is a 7 unit 695-megawatt hydroelectric generating station situated at Gull Rapids on the lower Nelson River in northern Manitoba and is owned by a partnership between Manitoba Hydro and four Manitoba First Nations, known as the Keeyask Hydropower Limited Partnership ("KHLP"). Manitoba Hydro has been tasked with the responsibility of managing the construction of the Keeyask Project and the operation of the facility when it enters into service on behalf of the KHLP. The Keeyask Transmission Project will transfer the power produced at Keeyask onto the Manitoba Hydro system when the generating station enters into service, currently projected to be in 2021. (Transcript Page 5562).

10.2.1 Complex project

The complexity of the Keeyask Project cannot be understated, as it is distinct from Manitoba Hydro's other major projects, and unique from many other projects across North America, as noted on Slide 24 of the Capital Panel presentation (Manitoba Hydro's Major Capital Panel Presentation, Exhibit MH-120). It takes many years to build and, unlike many other projects that are built near major centres, it is in a remote location requiring a camp that can accommodate a workforce of 2,400 people. Due to its northern location, there are seasonal constraints on construction. There will be limited warm weather construction time, and extreme cold may also hamper construction. There are numerous environmental and regulatory requirements necessary to protect and preserve the environment, as outlined in the Project's various licenses and permits. For example, the Project requires diverting a river over a kilometer wide and has extensive diking. Significant structures are required to protect the work area and the natural topography presents challenges as subsurface conditions underlying the river only become evident once cofferdams are constructed and the river bed is exposed. (Transcript Page 5547 and 5552 to 5553) Accordingly, forecasting of both the budget and schedule is challenging, particularly at the early stages of the Project.

10.2.2 Economics

In 2016, the Boston Consulting Group did an analysis and concluded that Keeyask should proceed as the Net Present Value was favorable when compared to the gas option. (PUB MFR 72) In 2017, Manitoba Hydro reviewed the economics once again and, though they have deteriorated to some degree since the 2014 NFAT, the corporation determined that it was still appropriate to continue construction to completion. (Transcript Page 451 and Tab 2 of the Application on Page 48) Cancellation would have increased aggregate revenue requirements in the billions through to 2026/27. (Transcript Page 451 and Tab 2 of the Application on Page 48) As such, its focus is to now deliver this Project on time at the new projected In Service Date ("ISD") and on budget consistent with the control budget of $8.7 billion. Manitoba Hydro has put forward a strong plan to do so and is working cooperatively with its General Civil Contractor ("GCC") to do just that.

When Keeyask comes online in 2021, the station will provide clean, renewable energy to Manitobans for generations. The energy generated by Keeyask will support export contracts until it is required to fulfill domestic load requirements.

10.2.3 Awarding of the General Civil Contract

Manitoba Hydro's decision to select BBE Hydro Constructors LP ("BBE") for the GCC was reviewed extensively again at this hearing. Hindsight being perfect, others may decide that the selection made several years ago was not the best one when considering the cost-reimbursable target price contract structure for the GCC. However, at the time, and with the full knowledge of the Manitoba Hydro-Electric Board, the selection was made. It is also important to note that the contract model is not determinative of success on a project. Both Muskrat Falls and Site C have contract models different from this GCC. However, both have experienced serious, if not more significant challenges in their projects, and both projects are behind schedule and over budget (Transcript Pages 7305 to 7312).

While it seems fruitless now to re-visit this decision, one that cannot be reversed, Manitoba Hydro will briefly summarize the history and the reasonableness of its past actions.

The GCC is the largest contract on the Keeyask Project and includes river management structures, rock excavation, concrete and earth structures, and electrical and mechanical work. (Transcript Page 5557) The form of contract entered into is a target price contract where the contractor is reimbursed for actual costs. The contractor is incentivized to perform and minimize cost and schedule as their profit and General Administration and Overhead ("GA&O") are at risk if they exceed their target price (Transcript Page 5560 and 5576).

The decision to proceed under the cost reimbursable target price contract model was made in 2012 and was part of a larger Project Delivery Strategy for the Keeyask Project. This decision was informed by a number of factors including lessons learned on the recently completed Wuskwatim Generating Station Project, completeness of the design, and allocation of risk and prevailing market conditions at the time (Page 5 of Manitoba Hydro's Written Rebuttal on the MGF Report, Exhibit 117).

In 2012, as Manitoba Hydro was evaluating various project delivery options, the North American major capital project market was extremely competitive. In this environment, megaproject contractors were not accepting hard money contracts, where risks such as labour availability and productivity would pass on to contractors without substantial and cost prohibitive premiums. This caused owners to proceed with alternative forms of contract, sharing risk where possible, and retaining risks that could not be cost effectively passed on to contractors. (Transcript Page 5558) As acknowledged by Mr. Campbell, contractors had many projects to choose from (Transcript Pages 7303 to 7305).

As described in the hearing, Manitoba Hydro experienced this reality on the Wuskwatim Project when it attempted to tender the GCC as a unit price contract. (Transcript Pages 5558 to 5559) A second lengthy procurement process was necessary which exposed the project to greater risk and required a much shorter ramp up schedule for the eventual GCC. These were factors in increasing the cost and lengthening the schedule for Wuskwatim.

In 2012, when Manitoba Hydro began to evaluate procurement options for the Keeyask GCC, the economic environment was similar to when the Wuskwatim GCC was procured. Having experienced the cost and schedule consequences of attempting to tender a contract model not reflective of the prevailing market conditions, Manitoba Hydro prudently undertook a three stage procurement process, beginning in 2012, that began with an appropriate market sounding exercise to better gauge the market conditions. The result of that sounding exercise was confirmation that it was best for Manitoba Hydro to proceed with a cost reimbursable target price model in order to secure the most competitive pricing considering the major project environment at the time. The process advanced on that basis and culminated in four prequalified proponents bidding on the work in a competitive environment. Manitoba Hydro prepared an internal engineering estimate and also engaged a third party to provide a reference proposal for comparison of the bids. The pricing proposed by the third party was generally in line with the Engineer's Estimate and was within the range of bids received from the four Proponents. (Page 10 of Exhibit MH-117) However, Manitoba Hydro still did an analysis to review BBE's bid, as it was lower, prior to awarding it in March of 2014, and carried a significant labour reserve to deal with potential productivity issues. Again, with the benefit of hindsight, the labour reserve should have

been higher to offset the issues experienced with the contractor (Transcript Pages 5677 to 5680).

The PUB and Knight Piésold ("KP"), the independent expert consultant retained by the PUB during the NFAT in 2014, were aware of the contracting methodology of the GCC, having received procurement and contract documents and summaries of the proponent's bids. On Executive Summary page II of IV of KP's report dated January 23, 2014, in reference to construction management, schedule and contracting plans (rebuttal page 4), KP stated that:

> *"The overall approach follows well documented internal standards developed by Hydro's NGCD [New Generation Construction Division]. The contracting method varies by project component but the principal civil works contracting strategy is an Early Contractor Involvement (ECI) Project Delivery Strategy. Overall the project delivery strategy has been to transfer risk away from Contractors and to Hydro in order to better understand and share the risks and obtain a better contract price as a result."* [Acronym explanation added]

10.2.4 2016 Issues and Recovery Plan

At the beginning of the 2016 construction season, the Project was generally on track and the project team was forecasting that the control budget of $6.5B and the schedule with a November 2019 unit 1 ISD would be achieved (Page 15 of Exhibit MH-117). Prior to the start of the concrete work in 2016, a senior off-site review team, comprised of former Manitoba Hydro and BBE senior staff not directly involved in the day-to day activities, was assembled to provide an objective review of the work falling under the GCC to ensure Manitoba Hydro and BBE were doing everything possible to be successful. Although this team identified areas of potential opportunity, the team did not predict the soon-to-be-realized underperformance (Transcript Pages 5569 to 5570).

In early June 2016, approximately 6 weeks into concrete activities, it was evident that BBE's actual volume of concrete completed to date was significantly less than planned. Manitoba Hydro immediately took action and took a number of steps that were both timely, and as KCB agreed, appropriate (Transcript Pages 7315 to 7320).

On June 19, 2016, Manitoba Hydro formally requested that BBE develop a recovery plan to increase its hiring rate to get more workers on site and to increase concrete production in order to bring production back in line with the 2016 plan. Manitoba Hydro staff continued to monitor the progress carefully during this time (Transcript Page 5570).

By July 2016, it was apparent that the initial recovery efforts by BBE were not going to be impactful enough to recover to the original plan. As well, both BBE and Manitoba Hydro were becoming aware that the work could not be built as it was originally planned, and re-sequencing efforts were undertaken (Transcript Page 5571).

By the end of the 2016 season, BBE had achieved only 41% of the concrete plan and 65% of the earthworks plan. Manitoba Hydro then implemented a formal Recovery Plan in September 2016 (Transcript Pages 5571 to 5572), which included:

- A call to action for BBE's project team, Executive Sponsors and CEOs;
- Developing a plan for the continuation of concrete through the severe winter months, which had not been planned previously;
- Identifying root causes that were impacting performance;
- Initiating activities to reforecast the cost and schedule for the Project;
- Undertaking analysis around contractor's claims; and
- Supplementing the commercial expertise of the team.

A separate task force was set up to understand the source of the underperformance and to understand the root causes. Multiple root causes were identified and mitigation measures began to be developed (Transcript Pages 5572 to 5573). More specifically, it was determined that the main contributing factors for this underperformance included:

- aggressive concrete production assumptions from BBE's bid that could not be achieved in the current marketplace;
- slower than planned progress during the ramp-up; and
- geotechnical and geological conditions, discoverable only upon the commencement of actual construction, which were more challenging than planned and impacted both concrete and earthworks.

In addition to these root causes, it was evident that the six month advancement opportunity that existed coming into the 2016 construction season had been lost and the Keeyask Project was facing a potential delay of two to three years or more (Transcript Pages 5572 to 5573). The large variance between actual and planned production also resulted in BBE having no opportunity to earn profit for the remainder of the Project under the existing contract structure. The erosion of profit potential created a risk of worsening performance for the remainder of the project if not addressed.

Between the Fall of 2016 and Spring of 2017, Manitoba Hydro's Keeyask team worked with BBE to implement the Recovery Plan to improve performance. There were meetings and negotiations between Manitoba Hydro and BBE resulting in a reworked schedule and cost forecast for the civil works and the entire Project. In addition, Manitoba Hydro reviewed its options on how to proceed for the balance of the Project. (Slide 7 of Manitoba Hydro's Major Capital Panel CSI Presentation, Exhibit MH–121) In consultation with legal and technical advisors, and with the approval of the Manitoba Hydro-Electric Board, the decision was made that the least cost option was to continue with BBE and to negotiate an amended contract (Slides 9 to 11 of Exhibit MH–121). Other options would have resulted in a substantial cost increase and significant time added to the schedule, as well as introduced significant risk to the delivery of the Project. (Transcript Page 5574, PUB/MH I-6a-b-CONFIDENTIAL Attachment 1, and CSI Transcript January 23, 2018, Page 23)

Further, Manitoba Hydro and BBE conducted a joint review of the schedule and saved the Project over one additional year in the schedule. (Transcript Page 5575) Such joint and collaborative efforts will continue throughout the life of the Project.

10.2.5 Amending Agreement #7 - Key aspects

Manitoba Hydro could not unilaterally change the terms of the agreement without being in breach of contract. The negotiation included *"gives and gets"* from both parties and, ultimately, an amended agreement was reached (CSI Transcript January 23, 2018, Page 27 and Slide 14 of Exhibit MH–121). The terms in Amending Agreement #7 lowered the overall costs and schedule risk for Manitoba Hydro and re-established a reasonable profit that BBE could earn back based on its future performance.

Foundational to the agreement was alignment of both parties' interest to deliver at the lowest cost and shortest schedule (Transcript Page 5575). The key features of the amendment are:

- Schedule and cost incentive pool provides incentive for BBE to earn profit and Manitoba Hydro to minimize Project cost and schedule;
- GA&O capped at 1.0x the target price; previously capped at 1.3x the target price;
- Contractor claims *"wiped clean"*, reducing Hydro's potential liability and overall cost;
- Narrowed ability for future claims so the contractor's focus would, instead, be on getting the work done;
- Liquidated damages for late delivery were established; the original contract had no damages for late delivery beyond the limitation of the profit pool; (Transcript Page 5576)
- Additional requirements such as a commitment to improve performance, focusing on efficiencies in indirect costs, more controls around cost and schedule, and training requirements were also part of the amended contract.

(CSI Transcripts Pages 26 to 36, Slide 63 of Exhibit MH-120, and Slides 17 to 19 of Exhibit MH–121)

10.2.6 2017 Outcomes

The revised control budget for Keeyask is $8.7B (at a P50 contingency level) with a first unit ISD of August 2021 (Slide 65 of Exhibit MH-120). The Project team considered the status of the Project, and the key risks remaining, and determined that this estimate balances the remaining risks and challenges the team to execute to that budget (Transcript Page 5577).

In the 2017 construction season, the first year of construction after the implementation of the Recovery Plan, significant improvements in both concrete and earthworks production were achieved. Despite the greater complexity of the concrete work in 2017 as a result of more curved formwork and work at higher elevations, there was a 12% increase in the concrete volume and a 90% increase in earthworks between 2016 and 2017. In 2017, three milestones were achieved which allowed the Project to protect an advanced schedule that could see the units come online earlier than the revised control schedule of August 2021. These milestones include completion of the spillway concrete, installation of the Powerhouse crane and enclosure of the Service Bay and Powerhouse unit 1.

Despite achieving these key milestones, concrete and earthworks production targets were not fully achieved. There was a deficit of approximately 20% of concrete and 25% earthworks (Transcript Pages 5557 to 5558).

Manitoba Hydro and BBE have worked to address this issue in 2018. BBE's updated forecast schedule from December 2017 recovers the delay to the GCC work as a result of last year's performance shortfall by extending the concreting season within the enclosure throughout the coldest winter months and adjusts monthly production targets to reflect actual quantities achieved in 2016 and 2017 by the Contractor. The GCC forecast schedule demonstrates that the Service Bay and Powerhouse Unit 1 enclosure was achieved on schedule in December 2017, and enclosure of units 2 and 3 were achieved in late January 2018 - on or ahead of schedule. The draft tube liner installation by the Turbine and Generator contractor began on schedule in late January 2018. The Project is also on track to achieve the diversion milestone where the South Channel of the river will be diverted through the Spillway in late August 2018. (Manitoba Hydro Undertaking 55, Exhibit MH–131 and Confidential Attachment)

To further improve production in the future and remove inefficiencies, Manitoba Hydro, working together with BBE has (Tab 2 of the Application on Page 46):

- Developed and deployed an issue management system;
- Developed refined processes, systems and tools based upon the root cause analysis;
- Implemented a change management program to enable a culture shift within the Project team; and
- Developed key performance indicators to report on all deliverables.

Manitoba Hydro has also taken a more active role in its management of BBE, embedding and integrating its team at the Project site (120 – 150 Hydro employees now working at site beginning in 2016) and introducing *"cold eyes"* reviews by experienced retired contractor employees (CSI Transcript January 23, 2018, Pages 47 to 49).

Most recently, discussions have just successfully concluded with the Allied Hydro Council and it is expected that the changes to the BNA will bring improvements to productivity and production (CSI Transcript, January 23, 2018, Pages 26 to 36).

10.2.7 Current Forecast at Completion

Manitoba Hydro is currently forecasting a final cost of Keeyask on or below the control budget of $8.7 B with all units completed ahead of the control schedule (Slide 74 of Exhibit MH-120). Meeting the control budget will require an achievable performance improvement of a further 10% by the GCC and no major risks to materialize (Transcript Page 5725). Manitoba Hydro is committed, despite the skepticism expressed by MGF, that with the improvements made in 2017, and the additional management and review tools and processes in place, we can achieve the necessary productivity increase in 2018. Manitoba Hydro and BBE's interventions are intended to create positive change, and efficiencies gained through completing repetitive work on the seven units.

With four years remaining, construction on Keeyask is approximately half complete. Significant risks remain that have the potential to jeopardize meeting the control budget and schedule, including:

- Execution/productivity rates of the GCC;
- Unexpected geotechnical/geological conditions at the South Dam/Dyke;
- Unseasonable weather (Slide 73 of Exhibit MH-120)
- Loss of site access/work stoppages;

However, as stated by the MGF team, there is still four years to run on the Project and still much opportunity to get the contractor to perform better in the future (Transcript Page 7191). Manitoba Hydro is continuously evaluating risks and developing mitigation plans to manage the risks when they materialize. The issues with respect to cost and schedule are also not unique.

Unlike Manitoba Hydro's rigorous budgeting process, and risk-based probability analysis done by John Hollmann of Validation Estimating, MGF provided a loosely estimated cost of $9.857B that cannot be relied upon. By its own admission, it was not precise, and was only an order of magnitude figure. It could go up, or it could go down (Transcript Page 7185). This value was also developed without a detailed probabilistic risk analysis, or any Monte Carlo analysis, to provide a more realistic range of outcomes and to verify its legitimacy (Transcript Page 7357). MGF also included a 10% contingency, or almost $900 million, on top of their forecasted cost increases due to BBE performance not meeting the plan. Further, it did not factor in any of the mitigation activities being

undertaken by both Manitoba Hydro and BBE (MGF Presentation (Keeyask -MGF Estimated Project Value), Exhibit MGF-4–1 and CSI Transcript, January 31, 2018, Pages 39 - 40).

10.2.8 2018 Plan and key upcoming activities

To improve outcomes in 2018 and beyond, Manitoba Hydro is working in close collaboration with BBE on execution planning, and is exerting greater oversight of BBE's construction management to improve BBE's performance. This initiative will continue to be a focus in 2018 and for the remainder of the civil contract. Manitoba Hydro has increased the pressure on the GCC to perform, and has collaborated wherever possible to stimulate greater productivity and production (Transcript Pages 5579 to 5582). Some of these areas include:

- Contractor's management of the trades;
- Travel logistics for the contractor's workforce;
- Site wide respectful workplace campaign;
- Contractor's revised organizational structure and increased supervision capacity and experience;
- The development of an effective monitoring and control system to provide daily feedback to contractor workforce;
- Combining and streamlining BBE's and Manitoba Hydro's quality control and assurance teams and processes;
- Establishment of single mission and team ethics for the Manitoba Hydro and BBE teams.

Manitoba Hydro has also been leading efforts to gain efficiencies, improve methods/processes and achieve cost and schedule savings. A few examples of key initiatives where Manitoba Hydro spearheaded efforts that led to significant cost and/or schedule benefits:

- The decision to procure a new draft tube formwork system to utilize on the remaining 5 units (Page 20 of Exhibit MH–117). This decision shortened the schedule to install the bottom portion of the water passage referred to as the draft tube and improved overall cost and schedule performance.

- The decision to utilize column extenders in the Powerhouse and Intake allowed for structural steel to be installed in the concrete structures at lower elevations. This installation provided an opportunity to enclose the Powerhouse and Service Bay earlier resulting in a schedule savings of over 1 year (Transcript Page 5656).
- Advancement of the south dyke in 2018 and supporting design changes (Page 20 of Exhibit MH–117). The advancement of the start of work on the south dyke will allow for additional quantities to be placed during the winter 2018 and reduce risk to the project schedule. (Pages 22 to 23 of Exhibit MH–117)

The 2018 plan, as noted on slide 72 of Exhibit MH-120, lists initiatives Manitoba Hydro and BBE are undertaking to drive further improvement. One example is strategic winter work being undertaken to allow for greater progress during the 2018 summer months including advancing the South Dyke, and winter concrete work for the Powerhouse now that it is enclosed (Exhibit MH-131 and Confidential Attachment).

10.2.9 Summary on the Keeyask Project

Manitoba Hydro is confident that the improvements from 2017 can continue and that further improvement will take place in 2018. Manitoba Hydro has engaged external experts to test Manitoba Hydro's and BBE's plans for 2018 to ensure everything is being done to deliver the project at lowest cost and the shortest schedule (Transcript Page 5580).

10.3 Bipole III Transmission Reliability Project

The Bipole III Transmission Reliability Project is critical to increasing the reliability of the HVDC system in Manitoba. Currently, approximately 70% of the Province's power is generated in northern Manitoba and is delivered to southern Manitoba by the Bipole I and Bipole II transmission lines which rest in the same right-of-way corridor and both terminate at the Dorsey Converter Station. Bipole III will provide a separate transmission corridor and termination point for the HVDC system

The Bipole III Transmission Reliability Project continues to be on schedule for a July 2018 in-service date and is on target to be completed within the $5.04 Billion control budget (Transcript Page 5595). As outlined by the PUB's Independent Expert Consultant MGF Project Services, the Bipole III HVDC Converter Stations are well managed by Manitoba

Hydro and the potential for cost over-runs is low (Page 1 of Exhibit MGF-2R and Slide 28 of MGF's Presentation, Exhibit MGF–4).

Similarly, the Bipole III Transmission Line is well organized and efficiently managed. The Project overall has used contracting strategies that were commercially astute and allocated risk appropriately (Page 2 of Exhibit MGF–2R).

With approximately 6 months remaining until the in-service date, the remaining risks on the Bipole III Transmission Reliability Project relate primarily to schedule. Performance issues with one of the Transmission Line contractors have presented risks to the on-time completion of the Transmission Line. However, Manitoba Hydro took *"immediate action"* to mitigate this risk by removing scope from the under-performing contractor and continues to closely monitor and manage schedule risks to ensure the July 2018 in-service date is achieved. This was the right course of action, as attested to by MGF (Transcript Pages 7202 to 7203).

10.4 Manitoba-Minnesota Transmission Project

The new 500 kV interconnection between Manitoba and Minnesota is a crucial part of Manitoba Hydro's development plan to meet the future electricity needs of the Province. The plan, at its core, includes the construction of the Keeyask Project, the new interconnection, and several long-term firm export sales to the US and Canadian utilities which will support the plan, and improve the economics, reliability and robustness (Transcript Page 5604).

The Manitoba portion of the new interconnection is currently on schedule for an In-Service Date of June 2020 and has a budget of $453 million (Transcript Pages 5611 and 5619, and Page 2 of Exhibit MGF–2R). MMTP has had the benefit of using recent costing and scheduling information from Bipole III and other smaller transmission line projects in its scheduling, forecasting and budgeting processes, allowing it to provide a current estimate at the P75 level (Transcript Page 5614).

Manitoba Hydro continues to manage the project appropriately and is committed to continuing efforts to secure the June 2020 ISD (Transcript Page 5809). Further, the Transmission Projects group is continually improving and adjusting how they perform (Transcript Page 5614).

Manitoba Hydro's use of Primavera P6 for its scheduling activities is appropriate and proven to be successful on several of its transmission line projects (Pages 52 to 54 of Exhibit MH–117). Further, Manitoba Hydro's approach to tower design is appropriate and cost effective (Pages 58 to 59 of Exhibit MH–117).

Manitoba Hydro's estimating methodology is consistent with industry standard (Page 2 of Exhibit MGF–2R). Manitoba Hydro will be updating the project estimate to include awarded contracted values instead of estimates when those contract values become available (Page 58 of Exhibit MH–117). While there are risks to both cost and schedule as the Project is still at the pre-construction stage awaiting licensing and regulatory conditions, the risks are being appropriately managed.

10.5 Great Northern Transmission Line Project

The U.S. portion of the new 500 kV interconnection between Manitoba and Minnesota is on schedule for in-service on June 1, 2020. To date, the project is on budget with approximately 10 percent of the funds spent. Manitoba has the expectation that the Project will be under budget given the conservative nature of the Minnesota Power's budgeting process (Transcript Page 5610).

The PUB's Independent Expert Consultant, MGF, reviewed the GNTL project. MGF concluded (Page 163 of Exhibit MGF–2R):

> *"The project is progressing, with Rights of Way being cleared, amongst other activities. The Construction Management Agreement is well considered commercially and serves to protect the interests of Manitoba Hydro. When benchmarked with other similar projects, its cost estimate is considered high and this should be reviewed in due course."*

Manitoba Hydro maintains that its estimates of costs included in the IFF associated with GNTL are appropriate. Specific terrain conditions and weather dependency do impact construction costs for the GNTL Project. As a large portion of the Right of Way is through very remote and wet terrain, the Project is dependent on favourable winter construction weather to minimize access costs. As a result, the Project has built an extra

year into the schedule to provide for the option of delaying work if a mild winter occurs (Transcript Pages 5609 to 5610).

Further, as Minnesota Power has yet to finalize some of its contract costs, once those contract costs are finalized, the budget will be updated to reflect market prices.

Given the challenging terrain conditions and the access related risk and associated dependency on favourable weather conditions for construction and finally the fact that construction is in its early stages with contracts remaining to be let, Manitoba Hydro argues that the GNTL related costs that are included in its IFF are appropriate. Consistent with MGF's recommendation, Manitoba Hydro will update the cost assumptions in due course and those assumptions will be updated in future IFFs.

11 12-YEAR VERSUS 20-YEAR DEBT TERMING STRATEGY

As outlined in Manitoba Hydro's Debt Management Strategy, filed as Appendix 3.5 to the Application:

> *Manitoba Hydro's fundamental debt management objective is to provide low cost, stable funding to meet the financial obligations and liquidity needs of the Corporation, while maintaining risk at prudent levels and reserving sufficient flexibility to adapt to changing circumstances.*

The potential cash flow stemming from cost reductions and the proposed rate increases assumed in MH16 Update with Interim (filed as Appendix 3.8) provided an opportunity for Manitoba Hydro to use the increase in forecasted cash flows to permanently retire debt in the early 2020s when cash flow from operations is projected to exceed cash required for investing activities. With the new forecast assumptions, there was an opportunity for Manitoba Hydro to consider shortening the term to maturity of new debt issuance, timing the maturity of new debt terms to coincide with periods in which Manitoba Hydro would have cash available for debt repayment.

Historically, Manitoba Hydro's interest rate forecast for Canadian borrowing has been the average of 10 and 30 year Manitoba cost of borrowing, which Manitoba Hydro called the 10 Yr+ rate. In the past, for forecasting purposes, Manitoba Hydro had assumed a 20 year term to maturity for new Canadian dollar borrowing.

MH16 Update with Interim modeled a reduction of the Weighted Average Term to Maturity ("WATM") for new borrowing from 20 to 12 years. Using this assumption, the forecast shifted approximately 30% of new debt issuance from the 30 year+ maturity bracket to the under 10 year maturity bracket. The increased weighting was predominantly in the 5 year term.

Matching expected surplus cash flows with maturing debt creates opportunity to avoid refinancing risk by permanently reducing debt. Manitoba Hydro can capture interest rate savings by borrowing more debt in the 5 year term as it is typically less costly than 30 year debt.

At the time of filing this General Rate Application ("GRA"), the new forecast modeled approximately $500 million interest savings in the decade out to 2027. Providing all forecast assumptions held, including forecast rate increases, the planned level of interest rate risk would be kept at a manageable level. This would have permitted Manitoba Hydro to reduce the net 10 year borrowings to 2027 by $4.2 billion. The following table (reproduced from Figure 1.9 of Manitoba Hydro's Rebuttal Evidence, Exhibit MH-52) shows the total planned borrowing for the next decade comparing the scenario of Manitoba Hydro's requested rate increases in MH16 Update with Interim with a 3.95% rate path.

Figure 11.1 MH16 Update with Interim under different rate increase scenarios

In Billions of Dollars

	IFF16U 7.9%	IFF16U 3.95%
2018-2022 Borrowing	$ 13.5	$ 14.1
2023-2027 Borrowing	$ 8.8	$ 9.7
2023-2027 Debt Retirement	$ (3.1)	$ (0.4)
Total 10 Year Borrowing	$ 19.2	$ 23.4

With higher rate increases, the MH16 Update with Interim generates more cash flow than under a 3.95% rate path. In the first five years of the forecast (2018-2022), this serves to modestly temper debt growth and borrowing needs as Manitoba Hydro borrows to complete Keeyask, Bipole III, GNTL and MMTP. In the second five years (2023 – 2027), the higher cash flows both limit new borrowing requirements and create surplus cash that can be used to pay down debt as it comes due instead of needing to refinance. Under the MH16 Update with Interim following the 7.9% rate path, Manitoba Hydro will borrow $8.8 billion in the 2023-2027 timeframe, and therefore face refinancing risk on those borrowings. However, the plan assumes $3.1 billion of cash flow that can be used to retire debt in that timeframe, leaving a net exposure of $5.7 billion. Should the $3.1 billion of cash flow not materialize as planned, the refinancing risk would increase. Even with the assumption of the 7.9% rate increases, a drought during this period could add $1.5 billion to refinancing risk. Rising interest rates, depressed export prices, and/or a decrease in domestic load could impact cash flow, thereby further increasing refinancing risk. Increased capital costs and delays in the in-service date of Keeyask could add new debt borrowings into this timeframe further increasing interest rate risk.

The rate increase and debt management strategy proposed by Mr. Bowman in his evidence would require the Corporation to borrow $14.1 billion between 2018 and 2023 followed by an additional $9.7 billion between 2023 and 2027. Prospective cash flow would offer almost no relief to the borrowing need in the 2023 to 2027 period.

Placing over $9 billion of refinancing risk into the 2023-2027 timeframe in the absence of any prospective cash flow is, in Manitoba Hydro's informed judgement, too risky. Even without adverse events or forecast error, it would increase the debt exposed to refinancing risk by over 60% ($5.7 billion vs. $9.3 billion) in the period immediately after Keeyask enters service, and results in effectively 100% of Manitoba Hydro's debt being exposed to interest rate risk in the next decade. This strategy is inconsistent with past debt strategies with the 3.95% rate path. Both NFAT scenario 5/6 and IFF15 had much lower levels of refinancing risk immediately following the in-service of Keeyask. If Manitoba Hydro has no reasonable prospect of cash flow and de-leveraging, prudence dictates that it must shift its debt strategy toward longer dated maturities in order to protect its ratepayers from unexpected interest rate movements for longer.

MH16 Update with Interim showed savings of approximately $500 million due to lowering the WATM of new debt issuance from 20 years to 12 years. However, this was predicated on an interest rate forecast which had an upward sloping yield curve with approximately 160 basis points between the all-in borrowing cost for a 5 year Province of Manitoba bond and a 30 year Province of Manitoba bond. However, as noted by Ms Stephen (Transcript Pages 1025 - 1026) Manitoba Hydro will adjust its debt management strategy based on changing market conditions. This is inclusive of the yield curve flattening as has been the case since the Bank of Canada began raising interest rates in July 2017. As at the beginning of December 2017, the yield curve had flattened such that there were approximately 90 basis points between the all-in borrowing cost for a 5 year Province of Manitoba bond and a 30 year Province of Manitoba bond. Based on that differential, the savings over the next 10 years under MH16 Update with Interim erode to under $250 million from adjusting the WATM for new debt issuance from 20 to 12 years.

Currently, the yield curve has flattened even further thus reducing the savings even further. This is a market risk similar to rising interest rates. Interest rates are still at historical lows, however, the Bank of Canada has raised interest rates three times since

July 2017 and will likely raise rates again in 2018. The current all-in borrowing cost for a 5 year Province of Manitoba bond is already exceeding the interest rate forecast used in MH16 Update with Interim. If interest rates increase 1% over Manitoba Hydro's forecast levels, the additional $4 billion of exposed debt under the 3.95% rate path (Transcript Page 703) would cost the Corporation an additional $40 million per year. There is potential over the 10 year period for the cost due to the rise in interest rates to exceed the savings from adjusting the terming from 20 to 12 years. Without the ability to generate sufficient cash to retire debt in the next 10 years, as would be the case under a 3.95% rate path, it would be imprudent to reduce the WATM to 12 years. Manitoba Hydro will monitor the spread between 5 and 30 year debt and the available cash to retire debt to determine and capitalize on any potential benefits available to ratepayers in adjusting the WATM of new debt issuance.

12 NO SAVINGS TO BE FOUND IN OPERATING AND MAINTENANCE EXPENSE

Manitoba Hydro has implemented effective cost reduction measures including an accelerated cost reduction plan to minimize growth in Operating & Administrative costs ("O&A"). These measures have resulted in a growth in O&A costs at or below inflation since 2009/10. As demonstrated on page 35 of Manitoba Hydro's Rebuttal Evidence (Exhibit MH-52), the corporation will achieve a 1.8% annual decrease in O&A over the 5 year period from 2014/15 to 2018/19, well below Manitoba CPI. To achieve this level of savings, Manitoba Hydro has eliminated over 400 operating positions between 2014/15 and 2016/17 and will be further streamlining its workforce by eliminating 900 staff of which approximately 700 are anticipated to be operational in nature. The 900 person staff reduction will be achieved primarily through the implementation of a Voluntary Departure Program ("VDP") which was launched in April 2017 in addition to a 30% reduction in Executive as well as a 40% reduction in senior management. The following table (**Figure 12.1**) summarizes the staffing reductions achieved since 2014/15 including the results of the VDP by each Corporate/Operating group.

Figure 12.1 Workforce Reduction Plan

	Workforce Reduction Plan		
	Achieved 2014/15 - 2016/17	**Current Committed Reductions**	**Total Reductions**
President & CEO	4	1	5
General Counsel & Corporate Secretary	2	5	7
Human Resources & Corporate Services	77	147	224
Indigenous Relations	10	9	19
Finance & Strategy	13	33	46
Generation & Wholesale	105	157	262
Transmission	115	198	313
Marketing & Customer Service	103	267	370
Total	429	817	1 246

Source: Page 35 of Exhibit MH-68

In addition to position reductions, Manitoba Hydro has committed to achieve procurement savings through supply chain management initiatives (as outlined in the response to Coalition/MH I-108b). As indicated in the response to Coalition/MH I-107b, to date Manitoba Hydro has achieved savings of approximately $8 million with estimated future annual cost savings between $20 and $50 million over the 5 year

period 2017/18 through 2021/22 (approximately 70% related to capital and the remaining 30% to operational savings).

Mr. Bowman's evidence (Exhibit MIPUG-13) on page 6-5 on lines 27 to 29 states "…*the utility has not even achieved a level of O&A that is as low as simple inflation since the 2011/12 year*." The O&A figures used as the basis for Figure 6-2 on page 6-4 of Mr. Bowman's evidence were provided in the response to MH-MIPUG (BOWMAN)-18, and do not take into consideration the impact of significant accounting changes that were implemented over the period 2009/10 to 2013/14 in support of the Corporation's transition to IFRS.

As shown in **Figure 12.2** below, Manitoba Hydro recognized approximately $37 million of accounting changes in 2011/12 which increased to $91 million by 2013/14. The majority of the changes were a result of aligning the corporation's capitalization polices with other Canadian utilities and are not indicative of a change in the costs to operate the corporation; rather they are a change in the accounting treatment of such costs and should be excluded from any analysis of year over year growth in O&A expenditures.

Figure 12.2 Summary of Accounting Changes Under CGAAP

Summary of Accounting Changes Under CGAAP
(in thousands of dollars)

	2009/10	2010/11	2011/12	2012/13	2013/14
Reduction to Overhead Costs Capitalized	9 100	28 727	29 302	60 180	61 384
Intangbile Assets - Costs Ineligible for Capitalization	4 080	4 162	4 245	4 330	4 416
Pension & Benefits - Discount Rate changes	0	0	3 032	13 835	25 355
Total	13 180	32 889	36 579	78 345	91 155

Source: Page 36 of Exhibit MH-52

On page 52 of its evidence (Exhibit GSS/GSM-9), London Economics International ("LEI") recommends that Manitoba Hydro's request for a rate increase should be held in abeyance until several analysis is performed. Manitoba Hydro is concerned by such a recommendation given that in LEI's response to MH/LEI 1-11b, they confirm their analysis was only illustrative in nature and "*… that more detailed evidence on Manitoba Hydro relative productivity would be an important consideration in determining the appropriateness of Manitoba Hydro's operating costs*." This point is further confirmed in LEI's oral testimony (Transcript pages 6820 and 6821):

Ms. Patti Ramage: But—okay. The metrics you've provided in your report are not the type of metrics that would tell us whether Manitoba Hydro is achieving operating efficiencies, correct? We would have to do more than your report?

Mr. A. J. Goulding: I—I believe that we've acknowledged that in our report, that—that more would need to be done.

As stated on page 37 of Manitoba Hydro's Rebuttal Evidence (Exhibit MH-52):

Manitoba Hydro is also concerned with the key performance indicators ("KPI") used by LEI (page 45) in their comparison of the Corporation's operational efficiency with other utilities. Each of the KPIs measure the output per employee; however there is no information as to whether the utilities' employee bases are comparable in nature to Manitoba Hydro.

In addition, several of the metrics selected by LEI will improve instantaneously the moment Keeyask comes in-service (Transcript page 6819) which demonstrates the hazards of making conclusions based on arbitrarily selected metrics when dealing with a complex business such as that of Manitoba Hydro and the need to approach such analysis with caution. Manitoba Hydro notes that vertically integrated utilities are large complex organizations whose operations are influenced by a myriad of factors including political (provincial, federal and international) and regulatory influences, landscape, weather, provincial economics (employment levels, labour rates, inflation, etc.), financial markets, age of assets, type of supply (hydro vs. coal), location of supply, technology, etc. Because of the extensive number influences over the operations of a utility, comparisons (e.g. KPIs) amongst utilities are often limited to providing a surface analysis at best as the underlying reasons for differences are typically comprised of a number of different factors where the impact of any one factor is not specifically measurable. The complexity associated with comparing utilities to one another is discussed by Mr. Yatchew on Transcript pages 4475 and 4476 of his testimony as he states:

I mean for Manitoba Hydro to actually try to compare itself to other utilities, not on the outcomes, but really on the cost side, is a fairly-its-it's a-it's a fairly

challenging exercise because of its unique characteristics. That falls under the rubric of benchmarking, and benchmarking is a complicated process, and its always an evolving process.

The metrics presented by LEI in no way assist in assessing whether the Corporation is achieving operational efficiencies and does not provide any conclusive evidence to justify the abeyance of the requested rate increase. Further, the analysis does not provide justification that a more in-depth analysis/comparison of Manitoba Hydro's operations is required. Based on the actual and projected reductions to operating costs, Manitoba Hydro can demonstrate that the Corporation has taken aggressive cost reduction measures. The end stage of a Voluntary Departure Program involving the elimination of roughly 900 positions, where functions have been eliminated, jobs combined, departments dismantled and redistributed and operating costs have been reduced significantly is not the time to embark on a time consuming and costly benchmarking exercise. A more detailed review will only result in an increase in consulting costs to be borne by the ratepayer while providing limited value in terms of assessing the efficiency of Manitoba Hydro in comparison to other utilities.

13 IMPACT ON MANITOBA ECONOMY

13.1 Job Creation

Dr. Janice Compton and Dr. Wayne Simpson are correct in concluding that where the additional revenues received by Manitoba Hydro through a rate increase are all sent, in turn, by Manitoba Hydro to creditors outside Manitoba to pay interest and principal on debt, a consequence will likely be that fewer jobs will be created in Manitoba. There will be less money circulating in the Manitoba economy (Page 3 of Dr. Janice Compton and Dr. Wayne Simpson's Evidence filed on behalf of the Consumer's Coalition, Exhibit Consumer's Coalition CC-18). London Economics International ("LEI") gave the same conclusion, though its employees used a different model than did Drs. Compton and Simpson.

The precise impact on job creation, however, of a rate increase of 7.9% for one year commencing on April 1, 2018 is debateable. Drs. Compton and Simpson used a simple model to estimate the impact of the rate increase and acknowledged that their model did not take into account that as some firms choose not to hire, or to decrease their labour force, in response to a price increase in electricity, the supply of labour in the market place will increase (Transcript Pages 4650 to 4655). Other firms will react to an increase in the supply of labour, and the corresponding downward pressure on wages, to hire more labour. This, in turn, will modify the negative impact on job creation of an increase in the price of electricity where one assumes that the entire revenue raised from the price increase leaves the Province. Further, Drs. Compton and Simpson acknowledged that their model did not take into account that to the extent that there is an increase in the number of unemployed persons as some firms cut back their labour force, there is an increase in money coming into the Province in the form of Employment Income payments from the federal government. This increase in funds flowing into Manitoba will offset to an extent the flow of funds being sent out of Manitoba by Manitoba Hydro to pay its debt.

In their initial work, Drs. Compton and Simpson also ignored that some residential customers, as many as 70 per cent of Manitoba's residential customers, have the option of reducing the amount they save each year in order to pay for an increase in their electricity bills as opposed to cutting back their spending on other goods and services (Transcript Page 4795). Similarly, some businesses have the option of paying for an increase in their electricity bills by drawing on their tax deferral accounts, as opposed to passing on such increase in their prices, reducing their profits or reducing their purchases of other commodities used in their businesses. These facts will also modify the impact to Manitoba's economy of an

increase in electricity rates because they result in a more modest reduction to the overall amount of money circulating in the Province.

LEI's effort to "illustrate" the impact of an increase in the price of electricity on hog, dairy and potato farms, convenience stores and hotels was undermined by its misuse of Manitoba agricultural data that was itself imprecise and intended only as an "illustrative" guide to farmers for budgeting purposes and by a puzzling decision to rely upon American data for convenience stores and hotels in that country (Transcripts Pages 6828 to 6838 and 6856 to 6857). Dr. Adonis Yatchew, like Drs. Compton and Simpson, relied upon Canadian sources, primarily Statistics Canada, and Appendix 4 of Dr. Adonis Yatchew Report, filed on behalf of the Public Utilities Board of Manitoba, Exhibit AY-1, sets out over some three pages the proportion that electricity bears in the costs of the industries and business in Manitoba's economy. With the exception of six industries, electricity is less than five per cent, in many cases less than one percent, of the cost of doing business. An increase in the price of electricity of 7.9% on April 1, 2018 will have a far more modest impact on these businesses than an increase in price in a host of other commodities that they buy, a change in the exchange rate or, most significantly, an increase in interest rates. Indeed, Dr. Yatchew observed on slide 53 of Dr. Adonis Yatchew Presentation, Exhibit AY-2, "about 60% of Manitoba energy is from hydrocarbons". Although this compares very favourably with the rest of Canada, it nonetheless reveals that Manitoba's economy continues to be far more vulnerable to the impacts of an increase in the price of hydrocarbons that it is to the impact of an increase in the price of electricity.

One must also avoid confusing slower job creation following an increase in the price of electricity where, to repeat, one assumes that all of the revenue raised through the price increase leaves the Province, with a decline in the growth of Manitoba's economy. Since 2009, the price of electricity in Ontario has grown by 50 per cent (Slide 43 of Exhibit AY-2), well in excess of the proposed rate increase of 7.9% to commence April 1, 2018. Notwithstanding a much larger increase, Ontario's economy has continued to grow.

At worst, an increase in the price of electricity of 7.9% on April 1, 2018 might lead to something less than 80 fewer jobs than there otherwise might be (Undertaking 51, Exhibit CC-51)

The evidence presented on job creation is helpful in understanding the impact to Manitoba's economy that ultimately follows from the borrowing of many billions of dollars. Drs. Comptom and Simpson, to repeat, concluded as the basis of their analysis that money that leaves Manitoba to pay debt is taken out of circulation and this has a negative impact on the Province's economy, in particular on job creation (Transcript Pages 4650 to 4655). The more money that Manitoba Hydro is compelled to borrow to meet its day to day operating costs, estimated to be another one billion dollars in the absence of rate increases, will lead to more money leaving Manitoba in the future. If one wants to give priority to job creation, as is done by governments in the face of serious recessions, and accepts that it is necessary to borrow billions of dollars to facilitate job creation, such borrowing is best done by government. Government can best allocate such borrowing directly to businesses and jobs that will at least create infrastructure to improve the lives of the taxpayers who, in due course, will have to pay the cost of the borrowing. Leaving Manitoba Hydro in a position where it must borrow another billion dollars in order to operate, as distinct from creating new infrastructure, because it will avoid in the near term a negative influence on job creation is a clumsy and inappropriate use of a utility's ability to borrow. And, such borrowing effectively leaves the utility's rate payers, in the long term, with no discernable benefit, other than the knowledge that generally, with no rate increase, there was no negative impact on job creation that can be attributed to electricity rates. And leaving Manitoba Hydro in a position where it is compelled to borrow large sums just to operate is particularly ill-advised when such a course of action increases the risk of a down-grade in the credit rating of the Province of Manitoba (and of Manitoba Hydro). This immediately results in even more dollars being removed from circulation within Manitoba and being sent to creditors outside the Province with the same negative consequences to job creation and Manitoba's economy identified by Drs. Compton and Simpson and the employees of LEI.

Manitoba Hydro has created and is creating thousands of jobs through the borrowing it has and is doing to create new infrastructure, namely the Keeyask Project and Bipole Ill. Leaving it to borrow more in the near term so that jobs, in theory, may be created in other sectors of the economy, or not be lost, is ill- advised. Better to avoid such borrowing, pay back as quickly as feasible what has been borrowed and look at a future in which increases in electricity rate can match the rate of inflation and, in the long term less money will leave the Province through the payment of debt and remain to create jobs.

13.2 City of Winnipeg

The City of Winnipeg's Economist Tyler Markowsky attempted to quantify the increased direct and indirect electric utility cost to the City of Winnipeg over the next 20 years, assuming all rate increases in MH16 Update were approved. This evidence has demonstrated a series of unrealistic and oversimplified assumptions. Manitoba Hydro therefore submits that the PUB should give little weight to the conclusions advanced by the City of Winnipeg in this evidence.

Section 5 of Manitoba Hydro's Written Rebuttal Evidence, Exhibit MH-52, outlines several serious flaws in the financial analysis offered by the City of Winnipeg. Further, Mr. Markowsky admitted that the analysis includes not only the proposed rate increases which form the subject of this Application, but all indicative rate increases in MH16 Update (Transcript Page 6490); assumed no price elasticity (Transcript Page 6520); did not consider rate class, demand charges, or basic monthly charges (Transcript Page 6522); was not weather-adjusted (Transcript Page 6527); and that Mr. Markowsky had not made enquiries to ensure that the charges which formed the basis of his calculations did not include unrelated fees for licenses or miscellaneous billings (Transcript Pages 6525 to 6526).

Mr. Markowsky's decision to exclude the effects of price elasticity or the effects of energy conservation in extrapolating growth in consumption is an unrealistic assumption that results in a potentially significant overestimate of future costs to be borne by the City of Winnipeg. Manitoba Hydro has provided technical and financial assistance to the City of Winnipeg for in the order of 150 Power Smart projects, many of which are still in progress. Furthermore, Manitoba Hydro has embarked on a program to replace all streetlights with new high efficiency LED luminaires. Power Smart projects, the replacement and retrofitting of aging building stock and replacement of existing street lamps with high efficiency LED luminaires are factors which impact consumption and consumption patterns (Exhibit MH-52). It is therefore not reasonable to disregard the effects of energy conservation on electricity costs over the period of 2017 to 2037. Even by Mr. Markowsky's own admission, "it's not a – a perfectly precise analysis" (Transcript Page 6523).

In considering the impact of the Application presently before the PUB, Mr. Markowsky calculated the impact to the City of Winnipeg for 2019 to be $721,000. While this figure suffers from the imprecision noted above, it is worthy to note that this amount represents only 0.06% of the City of Winnipeg's projected budget expenditures for the same year

(Transcript Page 6535). Manitoba Hydro does not dispute that the City of Winnipeg's finances may be impacted by an increase in electricity rates, but submits that the City of Winnipeg is in a better position than most ratepayers recognizing that they receive Electricity Tax revenue calculated as a percentage of Winnipeg residents total electricity bills, and are able to recover net cost increases by increasing revenues through taxes, fees and other charges imposed by the City of Winnipeg. Given the significant flaws inherent in his analysis, Manitoba Hydro submits that the conclusions of Mr. Markowsky's analysis should be afforded very little, if any, weight in considering the impact of the requested rate increase on the City of Winnipeg.

14 MANITOBA HYDRO IS COMMITTED TO WORK WITH STAKEHOLDERS TO DEVELOP APPROPRIATE AND COST EFFECTIVE SOLUTIONS THAT WILL ADDRESS CHALLENGES OF LOW INCOME AND AFFORDABILITY

14.1 Income Sufficiency and Energy Poverty are Complex Issues

Manitoba Hydro is of the view that the issue of affordability of energy, like any other essential items such as food and housing, extends beyond considerations associated with electricity price increases.

Issues of poverty and distributional effects are complex and ought to be addressed through the setting of social policy which is within the purview of government. As such, Manitoba Hydro is of the view that of the provision of social assistance programs directed to low income customers is appropriately reserved for the Province of Manitoba.

As discussed in Tab 7 of the Application, Manitoba Hydro offers programs to assist customers in managing their energy consumption through the implementation of energy efficiency opportunities in their homes and businesses. Moreover, to assist low-income customers, Manitoba Hydro continues to provide targeted and enhanced support through its Affordable Energy Program, to improve the energy efficiency of their homes resulting in lower energy bills and increased comfort.

Manitoba Hydro actively participated in the Bill Affordability Stakeholder Engagement Process undertaken in 2016 to review existing initiatives and explore potential alternatives to further address bill affordability for Manitobans. Manitoba Hydro's existing suite of bill affordability initiatives includes the Affordable Energy Program, Neighbours Helping Neighbours Program and Bill Accommodation practices. These initiatives were reviewed by stakeholders in the collaborative process and enhancements were suggested to further increase assistance to lower income customers. Manitoba Hydro will enhance, where appropriate, its programs and processes to assist low-income customers.

The work of Bill Affordability Collaborative Group shed light on how difficult it can be at first instance to even define energy poverty and how complex it can be to administer an income based program.

Two of the key findings from the Bill Affordability Collaborative Process is that energy poverty is not a prime cause of arrears (Transcript Page 2326) which indicates those experiencing energy poverty may not necessarily struggle with their energy bills and the relationship between consumption and income is very low (Transcript Page 2328).

Manitoba Hydro's administration of the Affordable Energy Program, which is income based, is no stranger to the challenges of obtaining income information (Transcript Pages 2512 to 2513). As noted by Dr. Mason in his testimony, *"…there's a certain number of people who will not actually reveal their income…"* (Transcript Page 2325).

At Transcript Pages 2526 and 2527, Dr. Mason was asked about overcoming the issues identified with implementing a low income rate, and in his reply, he suggests that existing government social programs should be modified to address the issue:

> *"I think in my view, which is looking at how the – the resources that would be needed to do this, my view is that much closer cooperation with the provincial government and the existing programs, rent assist, social assistance or income assistance would be the smart way to go.*
>
> *I think if the Board were to kind of direct or sort of suggest that these programs be adjusted and accommodate energy increases in the same way they accommodate inflationary increases that would be, I think, the most direct way and cost efficient way to actually provide assistance."*

Dr. Mason raises another point for consideration in his discussion with Board Member Grant at Transcript Pages 2545 to 2550, regarding the complications in targeting recipients on the basis of low income, when they may not necessarily be low net worth individuals:

> *"We all talk about income, but we don't talk about wealth, and we have a lot of wealthy poor people in the country, and they're called seniors. They have assets, but they have low income, and that's very common.*
>
> *"So throughout our lifespan, our income and our wealth fluctuate upon which stage of our life cycle we're at. And so designing policies that apply to people at*

various stages of their income and wealth life cycle is very tricky. But you know, I think most Canadians would accept the fact that an income-tested program that referenced income tax data is probably still the best way to go, but we're going to always have to deal with these anomalies where we fund people under these programs who happen to be living in a household of relatively well-off people. So, I mean, targeting is always going to be a problem."

"And that's why I come back is that we have specialists in our society that do that. They're called income assistance people who work for the provincial government. Building a separate expertise in Manitoba Hydro is going to be quite complex, and you're just never going to get it right."

These findings and difficulties with the administration, implementation and on-going operation of a rate assistance program pose significant challenges in identifying which customers truly require assistance and point to the need for further exploration to ensure any assistance mechanism best addresses the intended need.

Dr. Mason summarizes this in his testimony at Transcript Page 2335 by stating,

"…running an income assistance program is extremely complicated and it's high cost and it requires a whole range of expertise that is typically not embedded within Hydro. It's typically embedded within the income assistance programs of the province, which have better access to information. So, the whole caution that I want to encourage, the Board needs to be careful in directing Manitoba Hydro to apply rate relief based upon an income test. The argument here is that Manitoba Hydro does not have nor is it likely to obtain critical information that will allows it to target rate support programs accurately. Manitoba Hydro is not currently equipped and is unlikely to run income tested program effectively."

Manitoba Hydro does not have the resources to administer a new income-based program nor does it have access to pertinent data, such as income of its customers, to successfully implement such a program. The Provincial Government of Manitoba already administers income based programs, has the resources and provides these programs through a variety of existing mechanisms noted in the report of the Bill Affordability Collaborative Process.

Manitoba Hydro's position has and continues to be any deviation from standard rate setting such as a special rate design for a specific customer rate class is a social policy issue to be funded by Government. Mr. Raphals agrees with this principal as noted on page 10 of his evidence on behalf of the Assemble of Manitoba Chiefs, Exhibit AMC-7-1,

> *"Since the affordability program should be designed to ensure energy security for those unable to cope with rising energy costs, however, funding from all taxpayers rather than simply higher income ratepayers or dedicated fees seems most appropriate, much as other income security programs such as Manitoba's Employment and Income Assistance are financed from general revenues."*

14.2 Manitoba Hydro's Role in Addressing Affordability Issues

Mr. Shepherd testified in his direct evidence presentation (Exhibit MH-64) on the perspectives of Manitoba Hydro on broader societal issues of energy poverty and economic competitiveness. At Transcript Pages 135 to 137, he states:

> *"Questions of income and energy poverty and economic competitiveness are certainly important and ones we have considered to the degree we can. But these are really issues of broad public policy and cannot easily be resolved through a rate-setting process. The responsibilities and tools for such matters do not rest with Manitoba Hydro or the Public Utilities Board.*
>
> *Manitoba Hydro has always worked and will continue to work with all stakeholders on these kinds of issues, and will seek to play a positive role in solutions that improve the economic conditions for all Manitobans. But income adequacy and economic development issues are mostly beyond Manitoba Hydro's mandate or control. We cannot and should need not use this rate-setting hearing to do the work of developing and implementing public social policies. We are not well-equipped to handle these issues and the potential consequence of trying to do so is compromising both the financial integrity of the utility and ultimately making decisions that result in the transfer of costs from some groups of customers to other customers.*

I believe these issues are best left to government, who are responsible for establishing the appropriate policy framework and directives for both Manitoba Hydro and this Board to follow."

14.3 Legal Issues to be Considered

Manitoba Hydro is aware that in Public Utilities Board of Manitoba ("PUB") Order 73/15, the PUB noted on page 28 that the PUB remained of the view, consistent with the findings in Order 116/08, that it had the jurisdiction to order the implementation of a bill affordability program. Manitoba Hydro's legal position on the issue has not changed since the last GRA. In our respectful view, there is a serious jurisdictional question, and concern that the PUB's conclusion in Order 73/15 cannot be reconciled with the current statutes in Manitoba. This jurisdictional issue remains untested in the court in Manitoba.

Manitoba Hydro submits that the PUB, ought to reconsider the issue and as such has set forth its legal position on the matter below. It is noteworthy that while the Nova Scotia Court of Appeal decision was raised in argument during the 2014/15 GRA, the PUB declined to provide reasons in Order 73/15 as to why this decision was not considered or applied. Furthermore, this issue has been considered in two additional Canadian jurisdictions, British Columbia and Alberta. Manitoba Hydro submits that the decisions of these two regulatory authorities are persuasive and ought to be considered.

As an administrative tribunal, the PUB is not bound by the concept of stare decisis - it is not obliged to follow its own previous decisions on similar issues. An administrative decision maker has the capacity to determine the scope of his or her own jurisdiction. The determination of an administrative tribunal's jurisdiction is a question of statutory interpretation.[8] The object of statutory interpretation is to *"seek the intent of Parliament by reading the words of the provision in their entire context and according to their grammatical and ordinary sense, harmoniously with the scheme and object of the Act and the intention of the legislature"*.[9] While the jurisprudence is clear that a broad, liberal and purposive approach should be taken to statutory interpretation, Canadian courts have repeatedly cautioned that *"a liberal and purposive interpretation cannot*

[8] *Canada (Canadian Human Rights Commission) v. Canada (Attorney General)*, 2011 SCC 53 at paragraph 33.
[9] *Canada (Canadian Human Rights Commission) v. Canada (Attorney General)*, 2011 SCC 53 at paragraph 33.

supplant a textual and contextual analysis simply in order to give effect to a policy decision different from the one made by Parliament."[10]

The PUB derives its jurisdiction to review Manitoba Hydro rates from section 25(1) of *The Crown Corporations Governance and Accountability Act* which provides as follows:

> 25(1) Despite any other Act or law, rates for services provided by Manitoba Hydro and the Manitoba Public Insurance Corporation shall be reviewed by The Public Utilities Board under The Public Utilities Board Act and no change in rates for services shall be made and no new rates for services shall be introduced without the approval of The Public Utilities Board.

Section 25(4) of *The Crown Corporations Governance and Accountability Act* contains a list of factors which the PUB may consider in a rate review application. None of those factors expressly permit the PUB to consider affordability or customers' ability to pay. It is worth noting that of the nine factors set out in section 25(4)(a), seven relate to Manitoba Hydro's fiscal needs. The remaining two factors permit the PUB to consider any *"compelling policy consideration"* or *"any other factor"* that the PUB may consider relevant to the rate for services application before it. When read in isolation paragraphs 25(4)(a)(viii) and (ix) are vague and expansive. However, the PUB does not have limitless discretion to consider any factor it chooses. The grant of discretion must be interpreted within the context of Part IV of *The Crown Corporations Governance and Accountability Act* and the entire statutory scheme rating to the price for supply of power, and the PUB's primarily role to set just and reasonable rates.[11]

Subsection 39 of *The Manitoba Hydro Act* is germane to the issue. The Act states:

> Price of power sold by corporation

[10] *Canada (Canadian Human Rights Commission) v. Canada (Attorney General)*, 2011 SCC 53 at paragraph 62; also see *Gould v. Yukon Order of Pioneers*, [1996] 1 S.C.R. 571 at paragraph 50 per Forest, J concurring; *Placer Dome Canada Ltd. v. Ontario (Minister of Finance)*, 2006 SCC 20 at paragraph 23.

[11] See *ATCO Gas & Pipelines Ltd. v. Alberta (Energy & Utilities Board)*, 2006 SCC 4 at paragraph 47 wherein the Supreme Court of Canada considered the jurisdiction of a utilities regulator to impose any condition in an order that was necessary for the public interest. The Court held "These provision on their own are vague and open-ended. It would be absurd to allow the Board an unfettered discretion to attach any condition it wishes to an order it makes. Furthermore, the concept of "public interest" found in s. 15(3) is very wide and elastic; the Board cannot be given total discretion over its limitations".

39(1) The prices payable for power supplied by the corporation shall be such as to return to it in full the cost to the corporation, of supplying the power, including

(a) the necessary operating expenses of the corporation, including the cost of generating, purchasing, distributing, and supplying power and of operating, maintaining, repairing, and insuring the property and works of the corporation, and its costs of administration;

(b) all interest and debt service charges payable by the corporation upon, or in respect of, money advanced to or borrowed by, and all obligations assumed by, or the responsibility for the performance or implementation of which is an obligation of the corporation and used in or for the construction, purchase, acquisition, or operation, of the property and works of the corporation, including its working capital, less however the amount of any interest that it may collect on moneys owing to it;

(c) the sum that, in the opinion of the board, should be provided in each year for the reserves or funds to be established and maintained pursuant to subsection 40(1).

Fixing of price by corporation

39(2) Subject to Part 4 of *The Crown Corporations Governance and Accountability Act* and to subsection (2.1), the corporation may fix the prices to be charged for power supplied by the corporation.

Equalization of rates

39(2.1) The rates charged for power supplied to a class of grid customers within the province shall be the same throughout the province.

Interpretation

39(2.2) For the purpose of subsection (2.1),

(a) grid customers are those who obtain power from the corporation's main interconnected system for transmitting and distributing power in Manitoba; and

(b) customers shall not be classified based solely on the region of the province in which they are located or on the population density of the area in which they are located.

Simply put, the price charged for power must allow the Corporation to recover its costs of supplying such power inclusive of certain specified business expenses. The rates charged for power supplied to a class of grid customers must be the same throughout the province, and customers must not be classified solely on their location or on the population density of the area in which they are located.

Subsections 39(2.1) and (2.2) were enacted by *The Manitoba Hydro Amendment Act*, SM 2001, c 23. The purpose of this amendment was to ensure Manitoba Hydro charged a consistent rate for all customers regardless of point of delivery. The amendment was characterized as one of *"fundamental fairness"* with the aim to make *"uniform electricity rates a reality in Manitoba and put everybody on an equal footing when it comes to the rates charged for basic services."*[12] The purpose of section 39(2.1) and (2.2) was to create a *"single rate for residential hydro users"*.[13]

It is expected that parties to this proceeding may ask the PUB to implement a low income program targeting First Nations living on reserves. Such a program would necessarily classify customers based upon their geographic location within the Province of Manitoba. Manitoba Hydro submits that a First Nations living on reserve class would violate the express prohibition contained within subsection 39(2.2) of *The Manitoba Hydro Act*.

The PUB's rate setting function must also be interpreted having regard to Manitoba Hydro's mandate. Section 2 of *The Manitoba Hydro Act* provides that the purpose and object of the Corporation is to provide for the supply of power adequate to meet the province's needs and to promote economy and efficiency in all matters related to the generation, transmission, distribution and use of power. Subsection 43(3) states the Corporation's funds shall not be employed for the purposes of the government or any government agency. Accordingly, the only appropriate use for Manitoba Hydro funds are the legitimate purposes set out in section 2.

[12] Legislative Assembly of Manitoba, Debates and Proceedings, 2nd Session 37th Legislature, May 30, 2001 at page 2505 (Hon. Greg Selinger). Found as **Appendix 14.1** to this Section.
[13] Legislative Assembly of Manitoba, Debates and Proceedings, 2nd Session 37th Legislature, May 30, 2001 at page 2505 (Hon. Greg Selinger).

Manitoba Hydro does not have a mandate, either express or implied, to engage in social programming. The bill affordability programs discussed by some Interveners during the evidentiary portion of the hearing aim to mitigate existing social inequities through rate setting. While such a goal is laudable, it falls outside Manitoba Hydro's stated mandate. Manitoba Hydro respectfully submits that absent express language to the contrary, the PUB cannot, through its rate setting function, expand the mandate and purpose of Manitoba Hydro.

The PUB's jurisdiction is expressly limited to the approval of rates which appropriately balance the interests of ratepayers and the financial health of the utility.[14] *The Public Utilities Board Act* applies to Manitoba Hydro only to the degree necessary to fulfill the function set out in Part IV of *The Crown Corporations Governance and Accountability Act*.

In Manitoba Hydro's respectful submission, the text, context and purpose of *The Crown Corporations Governance and Accountability Act*, *The Manitoba Hydro Act* and *The Public Utilities Board Act* clearly demonstrate that the PUB does not have the jurisdiction to order the implementation of low income rates or other bill affordability programs.

The Supreme Court of Canada held that only after a textual, contextual and purposive approach reveals a genuine ambiguity, should a court resort to any subsidiary principles of statutory interpretation, including consideration of constitutional values and other external aids.[15] Where there are two equally plausible interpretations, the interpretation that complies with constitutional values will generally be preferred. However, reliance upon the *Charter* as an interpretive aid cannot be used to defeat clear legislative intent.[16]

[14] *Manitoba Keewatinowi Okimakanak Inc. v. Manitoba Hydro-Electric Board*, 1992 CarswellMan 373 at paragraph 9 and *Consumers' Assn. of Canada (Manitoba) Inc. v. Manitoba Hydro Electric Board*, 2005 MBCA 55 at paragraphs 64-65.

[15] *Bell ExpressVu Limited Partnership v. Rex*, 2002 SCC 42 at paragraphs 28 and 55.

[16] Ruth Sullivan, *Sullivan and Driedger on the Construction of Statutes*, 4 ed (Markham: LexisNexis, 2002) at page 369.

While it may be appropriate for the PUB to consider relevant constitutional values in the exercise of its discretion,[17] reliance upon constitutional values in the determination of its jurisdiction is unnecessary absent a genuine ambiguity. The interpretation of the PUB's statutory grant of authority is not ambiguous when the modern principles of statutory interpretation are applied. As such, resort to constitutional principles is unnecessary, and could be considered improper.

Any efforts to rely upon constitutional values and *The Path to Reconciliation Act* is an attempt to broaden the purpose of the PUB's rate review function to achieve a policy objective not contemplated in the legislation. If permitted, this would result in an unreasonable expansion of the PUB's jurisdiction beyond what was contemplated by the Legislature.

While not binding upon the PUB in this matter, it is persuasive to consider parallel legislation in other Canadian jurisdictions.[18] Public utilities regulators in Ontario, Nova Scotia, New Brunswick, Alberta and British Columbia have considered whether their governing legislation grant jurisdiction to consider ability to pay in the exercise of its rate setting function.

The Ontario Energy Board, pursuant to section 36(3) of the *Ontario Energy Board Act, 1998*, SO 1998, c. 15, has the jurisdiction to adopt any method or technique that it considers appropriate in fixing just and reasonable rates.[19] This provision has been interpreted to allow the regulator to employ specific methods or techniques that it considers appropriate to further its statutory objectives of energy conservation and the protection of customer interests with respect to prices.[20] A majority of the Ontario Superior Court of Justice held that, while cost of service and cost causality are the root principles underlying the determination of rates by the Ontario Energy Board, subsection 36(3) of the *Ontario Energy Board Act* permits deviation from those principles and allows for the consideration of income level.[21]

---

[17] *Doré v Barreau du Québec*, 2012 SCC 12.
[18] *Canada (Canadian Human Rights Commission) v. Canada (Attorney General)*, 2011 SCC 53 at paragraphs 57 – 58.
[19] *Advocacy Centre for Tenants-Ontario v. Ontario Energy Board*, 2008 CanLII 23487 (Ont Sup Ct J). Found as **Appendix 14.2** to this Section.
[20] *Advocacy Centre for Tenants-Ontario v. Ontario Energy Board*, 2008 CanLII 23487 at paragraph 55 (Ont Sup Ct J).
[21] *Advocacy Centre for Tenants-Ontario v. Ontario Energy Board*, 2008 CanLII 23487 at paragraphs 52-53 (Ont Sup Ct J).

In Manitoba, there is no equivalent provision to subsection 36(3) of the *Ontario Energy Board Act*. The majority of the Ontario superior Court of Justice found subsection 36(3) to be the primary source of the Ontario Energy Board's jurisdiction to order low income rates. In the absence of similar statutory language in Manitoba, the Ontario jurisprudence is of limited assistance to the PUB. In addition, it is noteworthy that the dissenting opinion of the Ontario Superior Court of Justice commented *"Were the board to assume jurisdiction to order a rate affordability assistance program, it would be taking on a significant new role as a regulator of social policy. Given the dramatic change in the role that it has historically played, as well as a departure from common law principles, it would require express language from the Legislature to confer such jurisdiction."*[22]

The Nova Scotia Utility and Review Board does not have jurisdiction to implement a rate assistance program for low income customers. The Board's governing legislation, the *Public Utilities Act,* requires all uniform rates be charged to customers in substantially similar circumstances in respect of service of the same description:

> 67(1) All tolls, rates and charges shall always, under substantially similar circumstances and conditions in respect of service of the same description, be charged equally to all persons and at the same rate, and the Board may by regulation declare what shall constitute substantially similar circumstances and conditions. [23]

The Nova Scotia Court of Appeal upheld the utility board's finding that low income residential customers receive substantially the same level of service as all other residential customers and as such, subsection 67(1) of the *Public Utilities Act*, R.S.N.S. 1989, c. 380 prohibited differential rates based upon the customer's income.[24]

---

[22] *Advocacy Centre for Tenants-Ontario v. Ontario Energy Board*, 2008 CanLII 23487 at paragraph 106 (Ont Sup Ct J).
[23] *Public Utilities Act*, RSNS 1989, c. 380, subsection 67(1).
[24] *Dalhousie Legal Aid Service v. Nova Scotia Power Inc.*, 2006 NSCA 74 at paragraph 24, leave to appeal to SCC refused 31627 (January 18, 2007) . Found as **Appendix 14.3** to this Section.

The Court of Appeal went on to confirm that *"[t]he Board's regulatory power is a proxy for competition, not an instrument of social policy."*[25] Implementation of a rate assistance program was found to be a public policy initiative properly within the purview of the legislature, not the regulator.[26]

Finally, the Court of Appeal considered the appellant's argument the *Public Utilities Act* ought to be interpreted in a manner that is consistent with the *Charter*. The Appellant submitted that poverty is an analogous category under section 15 and as such the Court could direct the institution of an ameliorative program. The Court of Appeal declined to apply the *Charter* as an interpretative aid, on the grounds that there was no ambiguity in the statute and the statutory language could not accommodate the construction suggested by the Intervener.[27]

In Manitoba Hydro's respectful submission, section 67 of the Nova Scotia *Public Utilities Act* is similar to section 39(2.1) of *The Manitoba Hydro Act.* Both provisions require equal rates be charged to customers receiving substantially similar levels of service.[28]

The New Brunswick Board of Commissioner of Public Utilities also declined to order relief for low income customers, including the lowering or elimination of service charges, as such programming would necessarily result in some customers paying more for the same service.[29] The Board found that it has no legislative authority to establish rates that discriminate between similarly situated customers on the basis of income.

There are a number of parallels between the New Brunswick *Electricity Act*, S.N.B. 2013, c.7 and *The Crown Corporations Governance and Accountability Act*. Both statutes set out a number of factors for the regulator to consider in approving rates for services

[25] *Dalhousie Legal Aid Service v. Nova Scotia Power Inc.*, 2006 NSCA 74 at paragraph 33.
[26] *Nova Scotia Power Inc., Re*, 2005 NSUARB 27 (CanLII) at paragraph 256.
[27] *Dalhousie Legal Aid Service v. Nova Scotia Power Inc.*, 2006 NSCA 74 at paragraph 36-39.
[28] In PUB Order164/16, Order in Respect of a Review of Manitoba Hydro's Cost of Service Study Methodology, December 20, 2016 at page 5, the PUB stated "customers are grouped into customer classes according to their similar characteristics in terms of their electricity consumption and service requirements.
[29] *Review of New Brunswick Power Distribution and Customer Service Corporation's Customer Care Policies*, 29 January 2007 at pages 12-13.

which include *"any other factors that the Board considers relevant."*[30] Manitoba Hydro respectfully submits that the PUB can be guided by the New Brunswick jurisprudence.

The Alberta Energy and Utilities Board also held that it does not have the jurisdiction to order reduced rates for certain groups of individuals based upon the social principle of a customer's ability to pay[31], referred to as *"lifeline rates"*. That Board found that tariff applications were an unsuitable forum to address social issues such as lifeline rates. It further held that in the absence of express statutory authority, differential rates based upon a customer's ability to pay may contravene the statutory requirement that rates not be unduly preferential, arbitrary or unjustly discriminatory.[32]

Most recently, the British Columbia Utilities Commission found that it has the jurisdiction to approve a low-income rate if there is an economic or cost of service reason to do so.[33] The Commission concluded that a low-income rate in the absence of an economic or cost of service justification is necessarily unduly discriminatory because it differentiates between customers on the grounds of personal characteristics as opposed to energy consumption.[34] The Commission concluded that *"affordability is not a regulatory justification"* for the proposed low income rate.[35] Leave to appeal the Commission's decision was refused on the grounds that there was no reasonable prospect for success.[36]

Subsection 59(2) of the British Columbia *Utilities Commission Act,* R.S.B.C. 1996, c. 473 is akin to section 39(2.1) of *The Manitoba Hydro Act.* Subsection 59(2) provides:

> 59(2) A public utility must not

[30] *Electricity Act,* S.N.B. 2013, c.7, s.103(8)(e) and *The Crown Corporations Governance and Accountability Act,* C.C.S.M. c. C336, s 25(4)(a)(ix)
[31] Enmax Power Corporation, 2004 Distribution Tariff Application, Decision 2004-066, August 13, 2004 at page 160-161.
[32] Enmax Power Corporation, 2004 Distribution Tariff Application, Decision 2004-066, August 13, 2004 at page 161.
[33] British Columbia Utilities Commission Decision and Order G-5-7, in the Matter of British Columbia Hydro and Power Authority 2015 Rate Design Application, January 20, 2017 at page 80.
[34] British Columbia Utilities Commission Decision and Order G-5-7, in the Matter of British Columbia Hydro and Power Authority 2015 Rate Design Application, January 20, 2017 at page 59.
[35] British Columbia Utilities Commission Decision and Order G-5-7, in the Matter of British Columbia Hydro and Power Authority 2015 Rate Design Application, January 20, 2017 at page 93.
[36] *British Columbia Old Age Pensioners' Organization v. British Columbia Utilities Commission*, 2017 BCCA 400. Found in **Appendix 14.4** to this Section.

a) As to rate or service, subject any person or locality, or a particular description of traffic, to an undue prejudice or disadvantage, or
b) Extend to any person a form of agreement, a rule or a facility or privilege, unless the agreement, rule, facility, or privilege is regularly and uniformly extended to all persons under substantially similar circumstances and conditions for service of the same description.

Regulators in most other Canadian jurisdictions recognize the departure from non-discriminatory rates is a significant matter, and one which ought not be undertaken without express statutory authority. While recognizing that these decisions are not binding on the PUB, the regulatory schemes in Nova Scotia, New Brunswick, Alberta and British Columbia are sufficiently similar to that in Manitoba, and the PUB may reasonably draw upon the principles set out in the above decisions.

The Appellate Court in Nova Scotia has upheld this determination, clearly articulating the distinction between social policy and rate-setting. The subsidization between customers on the basis of income is a policy decision that ought to be considered by the Legislature. To the extent that the decision of the Ontario Energy Board departs from this principal, Manitoba Hydro submits that its authority to do so is contemplated by the statutory framework in Ontario, and that neither *The Crown Corporations Governance and Accountability Act* nor *The Manitoba Hydro Act* grant the PUB similar discretion to implement *"any method or technique to set rates"*.

14.4 Bill Affordability Collaborative Process

As directed by the PUB in Order 73/15 Manitoba Hydro led a collaborative process in 2016 to examine bill affordability issues. The collective effort of the participants assisted in shaping the research questions and methods to be utilized to help discover and build knowledge of these issues within a Manitoba context.

The Working Group members collaborated to hire a third party facilitator and research firm to guide the process in the defined time period imposed by the Public Utilities Board of Manitoba ("PUB"). All decisions made through the Collaborative Process were done by consensus. A significant amount of work was undertaken by all actively engaged working group members, with over 30 meetings (working group and

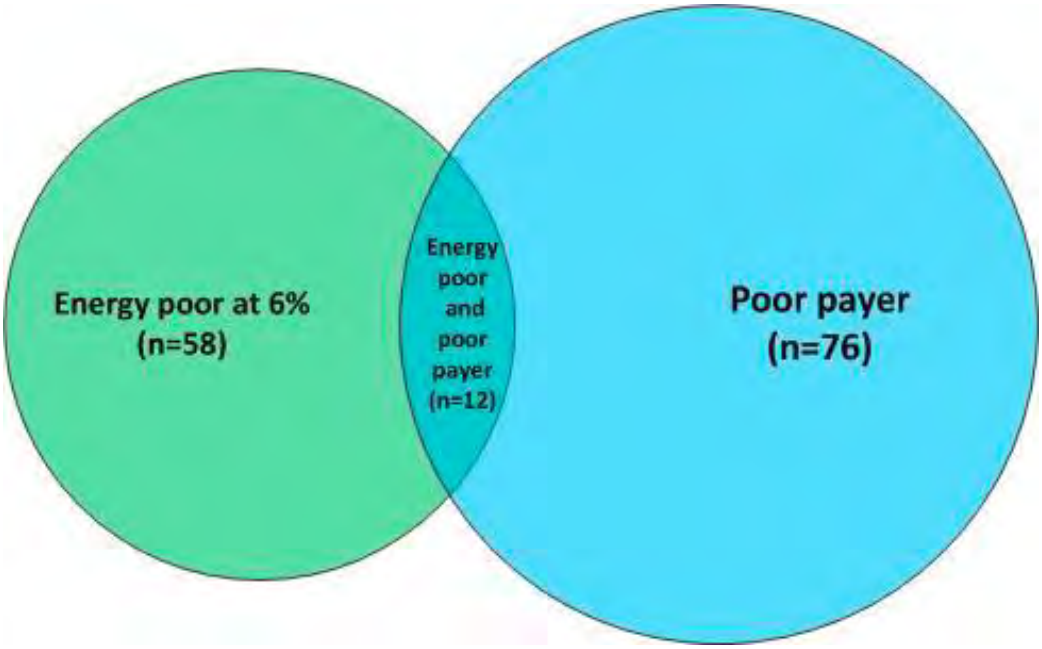
subcommittee) plus additional work completed outside of these meetings, until the final report was filed in January 2017. The cost of the Collaborative Process was approximately half a million dollars. Working group members felt the process would have been further enhanced with the participation of the Assembly of Manitoba Chiefs and Indigenous and Northern Affairs Canada, who were both invited but declined to participate (Transcript Pages 2312 to 2314).

The Working Group undertook the first of its kind study of energy poverty in Manitoba with the assistance of Prairie Research Associates. The research work followed a defined research framework which the working group agreed to and included a literature review, definition of energy poverty, key interviews, a consumer telephone survey of Manitoba Hydro customers, analysis of Manitoba Hydro administrative data linked with survey responses, quantitative modelling of rate options and projections of potential rate increases with the associated impact to customer's energy burdens (Bill Affordability Working Group Report , Appendix 10.5 of the Application, page 45 of 242).

Some of the key findings were a surprise to the Working Group based on preconceived assumptions as few customers are poor payers and energy poor, energy poverty is not a prime cause of arrears and there was little correlation between electricity consumption and income (Manitoba Hydro Cost of Service, Rate Design and Bill Affordability Panel Presentation, Exhibit MH-88).

The consumer research revealed the link between arrears and energy poverty is relatively weak. The research showed that between 14% of customers who experienced arrears would be classified as energy poor using a 6% of income threshold, while just under 10% of the overall customer base would be classified as energy poor using the same threshold (Appendix 10.5 of the Application, page 18 or 242). While this demonstrates customers who are classified as energy poor are somewhat more likely to experience arrears, the vast majority of customers experiencing arrears cannot be considered energy poor.

Figure 14.1 Energy Poor and Poor Payer Households – General Sample



Source: Figure 3, PRA – Bill Affordability Research Services Final Report – January 9, 2017 (Appendix 10.5 of the Application, page 77 of 242)

This finding had significant implications for the research and the understanding of the issue. It also has significant implications for Manitoba Hydro in terms of how it can address these issues from a business perspective. The research showed that 86% of customers who experience arrears are not considered energy poor using a 6% energy burden threshold (Appendix 10.5 of the Application, page 77 of 242). This means that even a program that perfectly targeted customers classified as energy poor would be poorly targeted when the benchmark is Utility revenues and costs. On the other hand, an arrears forgiveness program would need to be extremely well targeted to benefit customers who are considered energy poor while not providing benefits to customers who fall outside that definition.

The working group also reviewed Manitoba Hydro's existing programs and initiatives which assist those struggling with energy bills. Ultimately, the working group did not include a recommendation to implement a subsidized rate design as the cost to Manitoba Hydro and therefore ratepayers was too significant to offset any reduction in Manitoba Hydro's collection costs.

Of the recommendations made by the working group, many were for Manitoba Hydro to continue its offerings and where practical, seek to further enhance them.

New program offerings are being implemented or piloted at Manitoba Hydro as a result of this collaborative work such as Energy Instalment Affordability Program and an arrears management initiative (Transcript Page 2289 and 2507 to 2508). Manitoba Hydro has also enhanced its Affordable Energy Program to increase the number of LED bulbs provided to 10 (Transcript Page 2489).

Manitoba Hydro has continued to work to address issues of energy poverty stemming from the collaborative process by undertaking an additional survey of Indigenous consumers with respect to Bill Affordability to gain further insight (AMC/MH I-4). Manitoba Hydro also convened its Bill Affordability Advisory Committee (formerly known as the Affordable Energy Advisory Committee) and invited all of the working group members on June 22, 2017. The meeting provided an update of Manitoba Hydro's efforts since January 2017 and sought feedback from those three members who attended (Transcript Page 2505). Moving forward, Manitoba Hydro believes all parties need to be fully engaged and participate in further exploring issues of energy poverty.

Manitoba Hydro is of the view that this stakeholder engagement was a valuable step forward in building understanding on the issue. Given that the outcomes of some of the research were contrary to assumptions held by many parties at the outset, the report of the Working Group forms a base of understanding for addressing these issues going forward.

14.5 Manitoba Hydro's Affordability Programs

Manitoba Hydro maintains a suite of initiatives aimed at enhancing the affordability of its service for customers with high energy usage, low incomes, or a combination of the two.

14.5.1 Bill Management Activities

As discussed in Appendix 10.8 of the Application, Slides 23 and 25 of Exhibit MH-88, and by Mr. Paul Chard at Transcript Pages 2286 to 2287, Manitoba Hydro undertakes a number of activities to assist customers in managing their electric and natural gas bills. Many of these activities have evolved over time to respond to changing conditions or

requirements. One of the longest standing and most popular programs in this area is the Equal Payment Plan which helps customers smooth their payments throughout the course of the year despite periods of high consumption (in winter months) and low consumption (in summer months) within the year. More than one-quarter of Manitoba Hydro's electric customers use this program. As discussed in the Transcript Page 2287, customers who require additional assistance in budgeting or managing their bill payments, are offered customized due dates and flexible payment arrangements from Manitoba Hydro. Payment arrangements allow for payment of bills in a series of smaller installments over time. When such payments plans are required for reasons of insufficient income, late payment charges are waived to ensure the customers financial concerns are not compounded. Manitoba Hydro also works with Income Assistance administrators in First Nation communities and with the provincial Employment and Income Assistance program to ensure that appropriate social assistance payments are applied to accounts. As noted by Mr. Chard on Transcript Page 2287, an enhancement to the Equal Payment Plan will be introduced in 2018 entitled the Energy Affordability Instalment Plan. This program came about as a result of the recommendations of the bill affordability collaborative process. The program will take a customer's arrears balance and spread it out over a longer period. Those repayment amounts will then be integrated with an equal payment plan amount into a single payment for the customer to manage.

14.5.2 Neighbours Helping Neighbours

As discussed during the course of the hearing and outlined at Transcript Page 2293, Manitoba Hydro offers the Neighbours Helping Neighbours program which provides a one-time financial grant to those facing a financial crisis. The program is offered in partnership with the Salvation Army, who administers the program, and since 2004, there have been approximately 8,000 financial grants offered to customers requiring assistance for a total of $2,665,337 (Slide 27 of Exhibit MH-88). In addition, the Salvation Army provides additional support services such as counselling, budget skills, job training and food assistance according to the unique needs of each customer and Manitoba Hydro provides access to a specialist in its credit recovery services department who works with customers and connects them with additional community support where they can obtain additional assistance.

As noted further in its oral direct testimony at Transcript Pages 2293 to 2294, Manitoba Hydro covers all of the Salvation Army's administration expenses along with matching customer donations dollar for dollar. In terms of the donations to the program, as can be seen on slide 27 of Exhibit MH-88, customers have donated $465,360. Not only has Manitoba Hydro matched donations dollar for dollar, Manitoba Hydro has also provided funds for the shortfall of donations that is required to meet the needs of the program. Manitoba Hydro's funding has been approximately $2.2 million, which translates to approximately 88% of all expenses for the Neighbours Helping Neighbours program being covered by Manitoba Hydro. With respect to the administrative expenses, Manitoba Hydro has covered over $1 million dollars related to the administrative expenses of the Salvation Army, which does not include administrative expenses related to Manitoba Hydro's efforts related to the program.

14.5.3 Affordable Energy Program ("AEP")

As explained in Manitoba Hydro's Annual Affordable Energy Program Report at Appendix 10.8 of the Application, page 2, Manitoba Hydro's Affordable Energy Program assists lower income customers with energy efficiency upgrades through a turnkey approach where customers receive a free in-home energy review, free basic energy saving measures, free insulation including installation and the provision for a low cost high efficient natural gas furnace when converting from a standard efficient natural gas furnace for only $9.50/month over five years interest free. As discussed in Transcript Pages 2489 to 2490 and 2511 to 2515, Manitoba Hydro has implemented improvements to its AEP, including increasing the offering of four LED bulbs to ten LED bulbs, and accepting alternative forms of income tax verification. An online application was also created in July 2015 to provide a more efficient option for an application system, and approximately 40% of AEP applications are now received through the online application form (as noted in response to PUB-MH-I-126 b-e).

Manitoba Hydro also continues to address barriers to participation in the AEP. As discussed in PUB/MH I-126 b-e, customers do not tend to experience a sense of urgency to acquire a new furnace or insulation except in the case of malfunction. Manitoba Hydro addresses this by forming strategic relationships with community groups (e.g. North End Community Renewal Corporation, Brandon Neighbourhood Renewal Corporation, Selkirk Community Renewal Corporation, Dakota Ojibway Tribal Council, and Manitoba Metis Federation) whereby Energy Advocates from these organizations

attend community events and canvass neighborhoods to directly explain the benefits and bill savings associated with the eligible energy efficiency upgrades. Continuous mass media and targeted marketing throughout the year along with internal promotion by Manitoba Hydro staff (Contact Center and Credit & Recovery Services departments) is also utilized to ensure that the AEP is top of mind whenever customers are looking to lower their energy bills, or upgrade their furnace and insulation. Targeted marketing efforts include autodialed calls to customers in arrears and direct mail letters and brochures to areas in Winnipeg and rural towns with higher incidences of low income populations. Promotional materials such as brochures, magnets and bookmarks are also distributed to local community centers and libraries across the province.

As further noted in response to PUB/MH I-126 b-e), Manitoba Hydro also specifically targets customers with higher than average energy consumption offering a free Home Energy Assessment (same offer as the in-home review provided under AEP) via mail and direct call campaigns. Customers are subsequently encouraged to apply to the AEP or any other Power Smart programs. Dedicated customer service portals such as a direct phone line, toll free phone number and email inbox also provide customers easy access to knowledgeable staff in order to complete the required eligibility and subsequent upgrade forms required to participate in the program. A video that will explain the steps of participation in the AEP is also currently in development. The first part of the video which gives an overview of the AEP is currently available on the Manitoba Hydro website (Transcript Page 2301). As discussed in Manitoba Hydro's Written Rebuttal Evidence, Exhibit MH-52, these continued efforts have attributed to the success of Manitoba Hydro providing over 20,000 lower income customers with energy efficient upgrades.

There have been some criticisms levied at Manitoba Hydro's Affordable Energy Program based on cursory reviews of the AEP. Dr. Simpson provides general comments regarding the AEP being a modest starting point, that significant barriers to participation exist, that better coordination is required between the AEP and other bill assistance programs. These comments understate the achievements of the program to date. While programs expand and evolve and there are always opportunities to improve programs, Manitoba Hydro aggressively markets its Affordable Energy Program to educate customers on the benefits of the program with mass media efforts as noted above, a video tailored to the target market and through customized outreach within the

community as discussed in Manitoba Hydro's Annual Affordable Energy Program Report at Appendix 10.8 of the Application, page 5 of 21.

The Bill Affordability Working Group identified key strengths of the Affordable Energy Program including, participation and savings with retrofits made to almost 18,000 homes, accessibility by addressing the unique barriers low income customer face by minimizing the financial burdens associated with upgrades; addressing eligibility by targeting gas and electric savings measures to low-income customers; a reflection of savings demonstrating estimated annual bill reductions per customer from anywhere between $37 (as a result of basic measures) and $556 (for insulation in electric heated homes); and outreach to customers by delivering and expanding awareness of the value and benefits of the AEP program (Appendix 10.5 of the Application, page 23). In addition, the conclusions of the Bill Affordability Working Group Report, at page 22, "Throughout the collaborative process, the AEP was shown to be well-managed and achieving solid results to date." and at page 24, *"Recent evaluations and studies conducted by other researchers generally reflect positively on the design of the AEP and the results it has achieved to date."* As further noted in the findings of an independent, external review of the Affordable Energy Program by Dunsky Energy Consulting , provided as an attachment to AMC/MH I-37, page 67, "Results in terms of participation rates, install rates and savings are strong".

With respect to the coordination of the AEP with other bill assistance programs, according to an independent review of The Affordable Energy Program by Dunsky Energy Consulting which also included a review of Customer Billing Assistance Initiatives , provided as an attachment to AMC/MH I-37, page 54, *"There is significant coordination between the Affordable Energy Program and Bill Assistance program…"* . Since the Dunsky review, as noted in Ms. Galbraith's direct testimony at Transcript Page 2296, Manitoba Hydro has further enhanced the coordination between programs. In March 2017, to ensure increased participation, a mandatory joint application form for both the Affordable Energy Program and Neighbours Helping Neighbours was created. In addition, at Transcript Page 2298, Ms. Galbraith discussed the new approach to landlord and tenant situations and how Manitoba Hydro is continually following up with landlords on behalf of their tenants to encourage the landlords to participate in the Affordable Energy Program for their revenue properties. As noted by Ms. Galbraith, Manitoba Hydro has noticed an increased number of customers participating in both the

Neighbors Helping Neighbors and the Affordable Energy Program; an increase from 14% to 28%.

Manitoba Hydro continually looks to increase participation for lower income customers who are struggling with payment of their energy bill such as increased awareness through various media, bill inserts, canvassing, energy advocates, community groups and centres, tradeshows, targeted calling of customers in arrears by the Affordable Energy Program and frontline staff in the Contact Centre and Credit department promoting the AEP.

14.5.4 Indigenous Power Smart Program

As shown in slides 34 to 36 of Exhibit MH-88 and as further discussed on Transcript Pages 2301 to 2306, Manitoba Hydro is taking a comprehensive approach with respect to Indigenous Demand Side Management. Manitoba Hydro's Indigenous Power Smart Program is customized to meet the unique needs of Indigenous communities. As indicated in PUB-MH-I-126 b-e, all homes located on First Nations reserves are eligible to participate regardless of income level. A dedicated Indigenous Energy Advisor works with each Indigenous community's Band Housing Manager (Transcript Pages 2301 to 2302) or housing designate (Transcript Page 3339) to identify qualifying homes and recommends energy efficient measures. While there has been some question with respect to Manitoba Hydro's use of one dedicated Indigenous Energy Advisor responsible for serving all 63 First Nations (Page 27 of Exhibit AMC-7-1), it is through this one point person that has led to the success of the program. The Indigenous Energy Advisor works directly with band housing managers to confirm with his feet on the ground as to what homes would still be eligible for installation upgrades (Transcript Page 2656) Ms. Galbraith explained at Transcript Page 2301 that this band housing manager has the intimate knowledge of the housing stock in communities and is the liaison with any federal government housing programs.

As noted at Transcript Page 2302, as part of the Indigenous Power Smart Program, Manitoba Hydro also provides the training and funding for the local residents to complete the installations of both the insulation and basic measures which create employment for members of the community. There is no cost to the indigenous community to participate. With over 5,000 homes having received retrofits through the

program, the equivalent of 22 full time jobs of Indigenous employment has been generated (PUB-MH I-126 b-e).

As further noted in PUB-MH-I-126 b-e, energy saving seminars are also available to provide community members with information and tips on what they can do to make their communities more energy efficient. In addition, a customized Heat Recovery Ventilation ("HRV") video explaining how to operate and maintain the unit was created to assist the Band Housing Managers. The video is currently available in three languages: English, Ojibway and Cree, and Dene (Transcript Page 2300). As further described in response to PUB/MH I-126 b-e, the video was distributed to all applicable First Nation Band Housing Managers and is also posted on the Manitoba Hydro's website. In addition, a customized Indigenous Energy Savings Tips publication was also created for use at events and it is distributed to each home as they participate through the direct install channel.

Upon reviewing the data provided by Manitoba Hydro in response to AMC/MH II-5 a-g that almost one-third of all First Nation on-reserve dwellings have participated in Indigenous Power Smart and 18.7% have received insulation retrofits, Mr. Raphals commented as follows, *"While there is clearly a long way to go, these results testify to a serious effort on the part of Manitoba Hydro to reach First Nations communities"*. (Page 27 of Exhibit AMC-7-1).

As noted at slide 35 of Exhibit MH-88, the total estimated Indigenous insulation target market is 3,778 homes. Manitoba Hydro has made significant achievements in terms of insulation efforts under the Indigenous Power Smart Program where 3,254 homes have received insulation upgrades as of October 31, 2017 which represents 86% of the estimated insulation market (Transcript Page 2303). In addition to these insulation upgrades, in approximately three years, over 5,000 homes have received basic measures which represents approximately one third of the overall Indigenous market (Transcript Page 2305). As shown in Exhibit MH-52, since its inception, the Indigenous Power Smart Program has achieved 1% to 16% participation annually. In its review of the Affordable Energy Program Report at page 21, Dunsky Energy Consulting noted that in his review of leading programs, the best programs achieve participation rates of 1% to 4% annually (AMC/MH I-37- Attachment 1).

In terms of the Manitoba Keewatinowi Okimakanak ("MKO") communities, as shown on slide 37 of Exhibit MH-88 and discussed at Transcript Pages 2305 to 2306, as of October 31, 2017 1,320 homes of an estimated 1,468 in the MKO communities have received insulation upgrades through the Indigenous Power Smart Program. This represents a 90% completion rate. Additionally, 1,790 homes of the estimated 7,375 have received the basic measures, representing approximately 24% of the market.

14.6 Demand Side Management Programming and Efficiency Manitoba

While the preceding section discussed programs that are specifically targeted at lower income customers, Demand Side Management programs have been and continue to be a key strategy for assisting all customers in managing their energy use, making energy more affordable. Manitoba Hydro currently offers a wide and comprehensive suite of programs as outlined in the 2017/18 Demand Side Management Plan (PUB MFR 61 - Attachment 1).

At Tab 7 of the Application, Manitoba Hydro has highlighted the DSM initiatives that have been implemented in the last couple of years since the last GRA. These include new DSM initiatives and enhancements to existing initiatives that have been introduced to assists all customers in managing energy bills. As shown on slide 38 of Exhibit MH-88, Manitoba Hydro has a variety of programs continuing to support all customer classes. New programs which have been introduced in the last couple of years include the Solar Energy Program, Power Smart Shops Program, Condensing Commercial Water Heater Program, Commercial HRV Program, Parking Lot Controller Program, New Homes Program, Residential Instant Rebates & Bill Credits Program, and Residential HRV Controls Program. In addition, a number of enhancements to existing Power Smart programs were introduced, such as increased incentives, new measures, and enhanced sales and technical support which are further outlined in Tab 7 of the Application.

In addition to the significant efforts achieved through the Indigenous Power Smart Program, First Nation Communities, benefit from other customized DSM initiatives. At Transcript Page 2310, Ms. Lois Morrison highlighted the Community Geothermal Program. Under the program, Manitoba Hydro worked with Aki Energy, a non-profit indigenous social enterprise funded by Manitoba Hydro, in order to install geothermal heat pump systems in residential homes. As of July 2017, Manitoba Hydro has had upgrades installed in 340 homes since the program began in April 2013. In addition to

this, Ms. Morrison discussed at Transcript Page 2311 that Manitoba Hydro provides technical guidance and financing through its PAYS Program to cover the up-front cost of the installations. For homes where the energy savings do not offset the financing costs of the geothermal systems, Manitoba Hydro will provide additional financial support. As further noted, the community invests in training local members to install the systems with 45 band members to date being trained and nine accredited as installers.

Ms. Morrison also highlighted the community energy profiles as another Manitoba Hydro offering. At the community's request, Manitoba Hydro will provide a report outlining the historical energy use trends by residential customers in their communities, and for the individual band-owned buildings in the community. (Transcript Page 2311) As noted by Ms. Morrison, we continue to be in discussions with communities and pursue these opportunities as they arise.

The 2016/17 DSM Plan – 15 Year Supplemental Report (Appendix 7.2 of the Application) projects average annual DSM savings of 1.2% of load which, although lower than the 1.5% targets identified in the Efficiency Manitoba Act. Mr. Bowman argues that Manitoba Hydro's forecasts for DSM spending are substantial and well beyond what can be justified on economic and cost effectiveness grounds. Mr. Bowman suggests that Manitoba Hydro should assume a substantially lower DSM investment and projected energy savings in its Application and determination of future revenue requirements when he states that *"it is appropriate to consider the likelihood that Efficiency Manitoba, its Minister, or the PUB will make a finding that continuing large-scale DSM is not cost effective for at least the next 5 – 7 or so years. Hydro should take this likelihood into account in its planning and budgeting"* (Patrick Bowman Pre-Filed Testimony, filed on behalf of the Manitoba Industrial Power Users Group, MIPUG-13, Page 6-25).

The Efficiency Manitoba Act received royal assent in June, 2017 and was proclaimed on January 24, 2017. There has been no evidence to suggest that the new entity or its planned activities will differ from those established in The Efficiency Manitoba Act or the 2016/17 DSM Plan. The Efficiency Manitoba Act requires a cumulative 22.5% energy savings over 15 years; it does not mandate specific year over year savings. To arbitrarily reduce forecasted DSM in the face of a legislative mandate that exceeds Manitoba Hydro's current plan, which outlines 17.3% energy savings over 15 years, is poor planning practice and there is absolutely no basis for considering such a suggestion.

In terms of next steps, as Ms. Morrison discussed at Transcript Page 646, , the responsibility for the planning, design and implementation of Demand Side Management programs will transition to the new Crown Corporation, Efficiency Manitoba. As Ms. Morrison testified:

> *"Now, the challenge that we are facing is, as I mentioned during my testimony at the revenue requirement panel, we're in a holding pattern on pursuing new opportunities or expanding our DSM offerings until we pass the torch effectively over to Man -- Efficiency Manitoba"* (Transcript page 2608).

In addition, The Efficiency Manitoba Act outlines a continuing key role for the PUB in the review of Demand Side Management activities in Manitoba as outlined under section 8.2.7.

15 COST OF SERVICE AND RATE DESIGN

15.1 Rate Setting Process

Manitoba Hydro provided the PUB panel with an overview of the rate setting process in its direct evidence presentation on December 19, 2017. As discussed on Transcript Pages 2258 to 2261, there are three sequential steps to the setting of electricity rates.

In the first step, the overall level of the revenue requirement is determined. After the total amount of the revenue requirement is finalized and confirmed, the Cost of Service Study is used to apportion the total revenue requirement to each customer class. The Cost of Service Study evaluates the allocated revenue requirement against the revenues expected to be generated by rates, and determines the Revenue to Cost Coverage ("RCC") ratio for each customer class.

Should the PUB determine that an adjustment to class revenues is needed to address any specific class RCC's that may lie outside of a zone of reasonableness, that decision must be explicit and determined prior to designing rates. Class revenues should be confirmed and then rates can be designed to recover the finalized level of revenues for each customer class, on a forecast (weather normal) basis.

In its direct evidence presentation, Manitoba Hydro noted its primary rate design objective, and how it related to one of Bonbright's *"Criteria of a Sound Rate Structure"*. Manitoba Hydro views its primary rate making objective as stated on page 2 of Tab 9 of this Application:

"Recovery of Revenue Requirement – Rates must provide the Corporation the opportunity to fully recover its allowed revenue requirement."

Similarly, Professor James Bonbright states that a sound rate structure should have:

"Effectiveness in yielding total revenue requirement under the fair-return standard without any socially undesirable expansion of the rate base or socially undesirable level of product quality and safety" (Page 30 of Manitoba Hydro's Book of Documents No. 2, Exhibit MH-116-2).

Both of these objectives reinforce the desirability of rates being designed to recover, to the fullest extent possible, the amount of revenue requirement identified as being the responsibility of each individual customer class.

Therefore, in the event that the PUB determines that revenues must be shifted between classes to achieve a change in RCC, that direction should be made prior to the calculation of rates for final approval. In that way, Manitoba Hydro will be able to design rates to accomplish the desired shift of RCC's while maintaining overall the ability to fully recover its allowed revenue requirement.

15.2 COST OF SERVICE

15.2.1 Intervenors Have Endorsed the PCOSS18 Implementation of the Directives from Order 164/16

Manitoba Hydro has provided a cost of service study in this Application that it views as essentially fully compliant with the methodology directed in Order 164/16. Intervenors who offered comments on the cost of service methodology appeared to share the view that changes made for Prospective Cost of Service Study 18 ("PCOSS18") were consistent with the Public Utilities Board of Manitoba ("PUB") direction in Order 164/16, and further that any outstanding matters were relatively minor.

Mr. Bowman provided his endorsement of the Corporation's implementation of the directives:

"Reviewing the filing, my conclusion was of the cost of service study as filed largely follows Order 164/16. It's refreshing to have a cost of service study that aligns with and an order and that needs at most some – some small outstanding directives dealt with" (Transcript Page 6101).

Mr. Harper echoed this view during his direct presentation:

"So if we're on slide 26, in terms of Manitoba Hydro's implementation of Order 164/16, their pers -- perspective cost of service study for 2018 generally follows the methodology set out in the Board's Order. There are a few areas of departure. However, in my view, these are based on either a lack of data, or simplifying assumptions" (Transcript Page 5229).

Finally, Mr. Chernick offered, on page 44 of his Direct Testimony, on behalf of the Green Action Centre, Exhibit GAC-11, that he had

"not identified any problems with the Company's revisions to its cost- of-service study methodology to reflect the Board's Order 164-16".

Manitoba Hydro acknowledges there are two outstanding directives in PUB Order 164-16 that remain to be addressed in the next cost of service study, specifically Directive 1(v) to update the weighted allocator for service drops, and Directive 1(gg) to study the allocation of common costs. Manitoba Hydro does not expect that the final outcome of these two remaining directives would materially impact the RCC outcomes of the next cost of service study, as discussed below.

The annual revenue requirement associated with Service Drops represents only one tenth of one percent of the total revenue requirement (Schedule 4.1 of Appendix 8.1 of this Application). Even with some unforeseen dramatic change in the class weighting factors or allocation method, the minimal dollars at stake simply cannot result in any significant changes to the level of allocated costs by class.

With regard to the treatment of common costs, while the quantum of common costs is greater, Manitoba Hydro does not anticipate any significant changes in the methodology used to functionalize these costs or in their ultimate allocation to customer classes. During the Hearing Mr. Barnlund shared the corporation's view that the current approach is reasonable and that parties should temper any expectations that there may still be large impacts to come from the upcoming review of common costs.

> *"And so while the Board had encouraged us to look to see if there's other methods which conceivably could be more cost causal, our current view is that the interim approach that we are us -- that we are using, and I would say this is the approach that we've been using for twenty (20) years. So, you know, it's not like this is something that we have -- have not used in the past. We have used this all the time.*

And -- and it's a reasonable way of allocating common costs. Your activities relate to a function, right. And so you can use that as being the driver to be able to drive common costs, and that's what we currently do.

Now, which isn't to say that we're not going to take a look at this from that perspective because the Board has asked us to look at it and we will do that. But, you know, I -- I don't want to leave this discussion with the impression that the way of allocating common costs is -- is lacking something. No, it's a valid allocator and it's an allocator that's been in use for over twenty (20) years here with Manitoba Hydro" (Transcript Page 2574).

Manitoba Hydro also notes that the examination of the treatment of common costs in the Cost of Service Methodology Review did not generate controversy. The PUB itself noted in Order 164/16 at the bottom of page 90, that:

"The issue of the allocation of common costs was not contentious in this proceeding and the interveners did not put positions forward."

15.2.2 Eliminating Non Cost Casual Factors from PCOSS Requires a Revision to the Zone of Reasonableness

In Order 164/16, the PUB provided clear direction on the methodology to be used in the preparation of future cost of service studies, as well as its view that cost causation should be the primary objective of a cost of service study and that other ratemaking principles should be considered at the rate setting stage after the cost of service results are known[37]. Manitoba Hydro has proposed in this Application that the PUB could consider expanding the zone of reasonableness from the current 95% to 105% band to a broader 90% to 110% range in response to this updated view on the role of cost of service in rate making.

[37] Order 164/16, page 27 – Board Findings "The Board finds that Manitoba Hydro's ratemaking principles and goals of rate stability and gradualism, fairness and equity, efficiency, simplicity, and competitiveness of rates should be considered in a General Rate Application ("GRA") and not in the cost of service methodology. While ratemaking principles are important in the overall process of setting rates, these concepts are issues for rate design and should therefore not be considered at the COSS stage. Likewise, consideration of RCC ratios is a rate design matter that should be addressed in the rate-setting phase of the GRA."

A broadening of the Zone of Reasonableness ("ZOR") is justified to accommodate the pre-existing fairness and equity matters that were considered at the time of the 2016 Cost of Service Methodology Review. For example, the elimination of the uniform rates adjustment from the study has reduced the revenues attributed to the Residential class by $21 million dollars (Coalition/MH II -85) in the 2018 study. If the use of the Uniform Rate Adjustment had been maintained, the RCC of the Residential class would have been approximately 1.6% higher at 96.4%, which would fall within the current ZOR (Transcript Page 3017).

The use of a widened zone of reasonableness also appears to be supported by practice in other Canadian jurisdictions. An informal survey conducted by Mr. Harper indicated that most two common ranges used in Canada are 95-105 and 90-110, and that even wider ranges are applied on a class by class basis by the OEB (Page 29 of William Harper, Econalysis Consulting Services Evidence filed on behalf of the Consumer's Coalition, Exhibit CC-20).

15.2.3 Revising the Method of Calculating RCC Would Require an Expansion to the Zone of Reasonableness

Manitoba Hydro traditionally calculates the RCC ratio by adding class revenues to the classes' share of Net Export Revenues, and then dividing those combined revenues by the allocated cost for the class. The existing RCC methodology has been utilized by Manitoba Hydro in each of its cost of service studies since 1979 (GSS-GSM/MH I-9). The calculation was used in this form when the ZOR was initially established; as we well as in 1996 when the zone was reviewed and reduced to the current 95-105% range as noted in PUB Order 51/96.

Mr. Bowman proposes modifying the long standing calculation to use export revenues as a reduction to cost in the denominator of the ratio, rather than as part of the calculation of total revenue in the numerator. He suggests this approach would provide results that are more relevant to customers (Transcript Page 6102), although he provides no evidence as to why a customer would prefer one methodology over another.

Manitoba Hydro has acknowledged this alternative approach is simply a re-ordering of the algebra in the equation, however, Manitoba Hydro cautions that this alternative

approach generates results with a much broader set of RCC outcomes (93.5 to 115.7) for PCOSS18 when compared to the current method (94.8 to 112.5) as shown in response to GSS-GSM/MH I-9. As further noted by Manitoba Hydro, the difference between the two methods will decrease as the revenue cost coverage ratios approach unity.

For classes outside the ZOR the differences can be significant. Using the traditional formula indicates that the GSL >100kV class is 3.6% above the 105% upper bound of the zone of reasonableness. Under the modified calculation proposed by Mr. Bowman, the variation from the upper bound doubles to 7.3% This alternate representation of the very same set of costs and revenues suggests a much more dramatic and immediate rate adjustment may be required than using the metrics as normally employed.

Changing the calculation of RCC should not be done in isolation, and must be accompanied with a reexamination of the appropriate ZOR.

Switching to the modified calculation of the RCC ratio should not be considered as this approach would represent a significant departure from the traditional RCC calculation that has been used to report PCOSS outcomes since the adoption of a ZOR. If the RCC formula is changed, it will not produce results that are directly comparable to those historically reported. Furthermore, a change in the RCC formula should then be accompanied by adopting a wider zone of reasonableness.

15.2.4 Outcomes of PCOSS18

Based on Manitoba Hydro's proposed expansion of the zone of reasonableness to 90% to 110%, all but one class would be captured within the revised zone of reasonableness.

Figure 15.1 PCOSS18 Results Compared to Zone of Reasonableness

Customer Class	PCOSS18 RCC[38]	Compared to 95-105% ZOR	Compared to 90-110% ZOR
Residential	94.8%	-0.2%	In ZOR
GSS Non Demand	112.5%	+7.5%	+2.5%
GSS Demand	101.0%	IN ZOR	IN ZOR
GSM	98.3%	IN ZOR	IN ZOR
GSL 0-30 kV	99.1%	IN ZOR	IN ZOR
GSL 30-100 kV	109.3%	+4.3%	IN ZOR
GSL >100 kV	108.6%	+3.6%	IN ZOR
Area & Roadway Lighting	100.3%	In ZOR	IN ZOR

While Manitoba Hydro is not proposing to shift revenues between customer classes to adjust RCC's, it recognizes that the PUB may determine to do so. If downward adjustment is made to one customer class, it should be recognized that the adjustment will require an upward adjustment to the other customer classes in order to maintain revenue neutrality and to afford Manitoba Hydro the opportunity to recover its full revenue requirement.

In the event that the PUB direct revenue changes by customer class, Manitoba Hydro requests that this matter be addressed explicitly and transparently in its rate Order for this GRA. Manitoba Hydro would request that the PUB provide clear direction as to how much revenue is to be shifted away from any given customer class and provide direction as to which customer classes would be responsible for those revenues, so as to keep Manitoba Hydro whole for its total approved revenue requirement.

15.2.5 RCC Evaluation Should Not Ignore Impact of Bipole III Coming in Service

BPIII is currently under construction and not yet in-service, and is therefore not reflected in the revenue requirement used for PCOSS18. However, the project will be part of the next cost of service study to be reviewed by this Board and it is appropriate

[38] Appendix 8.1, Schedule 1.1

to consider the results of PCOSS18 in conjunction with the directional changes expected in the next study.

The additional revenue requirement related to this massive Generation-functionalized asset will result in significant and predictable changes to class cost responsibility in future cost of service studies. In this application Manitoba Hydro has provided an alternate version of the cost of service study that includes an estimate of the revenue requirement for 2019/20 to illustrate the changes that are expected due to the addition of Bipole III.

The RCC for the smaller distribution level customers are expected to increase by up to two or three percentage points, with a more dramatic six or seven percent decrease expected to the RCC of the industrial classes.

Figure 15.2

Customer Class	PCOSS18 RCC[39]	Estimated 2020 RCC with BPIII In Service[40]	Estimated RCC Change
Residential	94.8%	96.7%	1.90%
GSS Non Demand	112.5%	115.3%	2.80%
GSS Demand	101.0%	101.3%	0.30%
GSM	98.3%	97.4%	-0.90%
GSL 0-30 kV	99.1%	96.5%	-2.60%
GSL 30-100 kV	109.3%	103.5%	-5.80%
GSL >100 kV	108.6%	101.5%	-7.10%
Area & Roadway Lighting	100.3%	118.2%	17.90%

These impacts by class are predictable based on each class' relative usage of the bulk power system, as well as the change in cost structure due to the significant, lumpy

[39] Appendix 8.1, Schedule 1.1
[40] MIPUG/MH I 23a-b

increase in the amount of Generation-related revenue requirement included in the study. The expected change in costs is sufficient to move the RCCs for both the Residential and Industrial customers to within the zone of reasonableness as soon as Bipole III comes into service without the need for any additional rate differentiation.

These results have been generally accepted by Mr. Bowman:

"I think Bipole III will likely have the type of effect people are showing. In other words, if you -- it will have a tendency to put a larger cost in percentage terms on people who make more use of the bulk power system. I think that's a given, the way it's classified. So in cents per kilowatt hour basis, it'll cost a little more for residentials than industrials. But overall, people will tend to pay the same cents per kilowatt hour for Bipole. And as a result, the RCC ratios will pull in somewhat, but I don't -- it won't address the greater than 10 percent that we're facing" (Transcript Pages 6103 to 6104).

Manitoba Hydro notes that Mr. Bowman cites a greater than 10 percent variance based on his alternative approach to calculating class RCC, while the traditional calculation results in an 8.6% variance for GSL > 100 kV and a 9.3% percent variance for the GSL 30 – 100 kV class. This alternate calculation has not been endorsed by this Board. It has not been used in PCOSS18 or any other study, and is not the standard measure used in reference to class RCCs. Manitoba Hydro has cautioned elsewhere in this argument that this revised measure of RCC cannot be used without reevaluation of the zone of reasonableness.

While acknowledging the reasonableness of Manitoba Hydro's evidence, Mr. Bowman remains unconvinced that Bipole III alone will move his clients sufficiently close to unity, suggesting in his direct testimony that previously the "same claims made about Wuskwatim and that did not occur". (Page 45 of Patrick Bowman Pre-filed Testimony on behalf of the Manitoba Industrial Power Users Group, Exhibit MIPUG-13).

Manitoba Hydro submits that there is no evidence on the record that isolates the impacts of Wuskwatim on class RCC that would confirm Mr. Bowman's assertion. Mr. Bowman is also neglecting to recognize the significant difference in the scale of Bipole III compared to the much smaller Wuskwatim project. The expected impact of a $5 billion asset (Tab 5 of the Application, Page 19) with no associated incremental revenue can

reasonably be assumed to be more consequential than that of a $ 1.4 billion (Tab 5 of the Application, Page 22) asset which is able to produce offsetting revenues.

Mr. William Harper also acknowledges and appears to accept the validity of the directional changes expected once Bipole III comes into service in his exchange at Transcript Page 5473.

The cross examination of Mr. Barnlund at Transcript Pages 2369 to 2370 identifies one further key consideration. The impact of Bipole is significant and immediate, but will be followed by directional consistent impacts in the longer term as Keeyask comes into service.

15.2.6 Cost of Service Treatment of Bipole III Reserve Account Revenues

As a percentage of revenue, all customer classes have contributed equally to establishing the Bipole III reserve account. With the upcoming in-service of Bipole III, these funds will be transferred out of the account and the additional revenues will be recognized in the next Cost of Service Study. It is Manitoba Hydro's intention to return the revenue to domestic classes on the same basis by which the revenues were accumulated in the fund - that is equally on an across-the-board basis. It is Manitoba Hydro's view that this approach most fairly apportions the reserve account to each class.

The alternative treatment of applying the revenues from the reserve account directly against the cost of the Bipole III asset will disproportionately benefit those classes that make relatively greater use of the Generation facilities, notwithstanding that each class has contributed equally to the reserve account.

Manitoba Hydro has demonstrated the impact of this disproportionate allocation, which would increase the revenue cost coverage ratio of the GSL>100 kV class by one percent (MIPUG/MH-I-23b and MIPUG/MH II-18a-b). For this reason, Manitoba Hydro does not view this as a reasonable alternative for purposes of Cost of Service.

Manitoba Hydro requests that the PUB provide direction confirming the proposed cost of service treatment of the amortization of the Bipole III Reserve Account in future studies.

15.3 Rate Design

15.3.1 Residential Rate Design

Manitoba Hydro has applied for rates in this General Rate Application based on its standard rate design. Manitoba Hydro's Residential rate design is a two-part rate, with a fixed basic charge per month and a single energy charge for all energy consumed in the billing period.

On September 12, 2017, Manitoba Hydro filed *"A Report on Rate Design for the Residential Class"* which included an illustrative residential rate design scenario. The rate design scenario was a residential electric heating rate which would shield electric heating customers from a portion of the proposed rate increase and would require non-heating customers to bear the additional revenue responsibility in order to be revenue neutral within the entire Residential Class. The rate design scenario in that report has not been approved by the Manitoba Hydro-Electric Board, and Manitoba Hydro is not seeking regulatory approval to implement that rate design.

<u>Rate Design Issues and Policy Considerations</u>

In Manitoba Hydro's view, any modification to the rate design needs to be examined to ensure it is undertaken with full regard and consideration for long standing rate making principles.

There was much discussion in this proceeding regarding inverted block rates (also referred to as *"inclining block rates"* or *"conservation rates"*). GAC's expert, Mr. Chernick, provided evidence as to potential inverted block rate designs to be considered for the Residential Class, which included tail block rates priced at approximately 9 cents per kWh.

However, setting electricity prices at this level for the run-off rate is considerably in excess of the levelized marginal value of electricity of 5.75 cents[41] and would send an inappropriate price signal to customers.

[41] On December 18th, Manitoba Hydro filed an update to PUB/MH II – 57 with the calculation of the levelized marginal values based upon the 2017 Load Forecast and the 2017 Energy Price Forecast and an updated value of generation marginal value. The 2017/18 levelized Marginal Value is approximately 28% lower than the 2015/16 Marginal Value, declining from 7.94 cents (in 2017$) to 5.75 cents.

Simply implementing inverted block rates or conservation rates needs to be assessed against the future conditions that may be experienced when Keeyask comes into service. The significant change in marginal value from 7.9 cents to 5.7 cents should be heeded.

Mr. Barnlund discussed this point with Mr. Gange at Transcript Pages 3063 and 3064:

> *"I think we need to look at the question of rate design and considering some of the issues we've got with electric heat customers, with low income customer with the potential photovoltaics coming out of the system, and I would add to that the information we talked about this morning where the marginal value of energy, if we – if we strictly look at which is being – being calculated, suggests that you would be looking to a declining block rate and not an inclining block rate."*
>
> *"So, I think that with all due respect, Mr. Gange, we find ourselves in far different circumstances today than we did in 2003, or 2008, 2009, and I think that we have to be alive to that change in circumstances, and we have to be intelligent terms of how we proceed with this."*
>
> *"We should be looking at the conditions of the present and the conditions of the future in terms of how we proceed."*

<u>Mr. Chernick's Rate Proposal Has Serious Shortcomings</u>

In Exhibit GAC-11, GAC's expert Mr. Chernick provided a rate design proposal which comprised four separate residential rate designs, including a LICO-125 electric heating rate, a LICO-125 non-heating rate, a non-LICO 125 conservation rate and non-LICO 125 electric heating rate. Each rate design had the size of the first block differentiated by four seasons (summer, fall, winter, spring). The LICO-125 rates also included the elimination of the monthly basic charge and the inclusion of a sharp price discount for the initial block of usage.

Manitoba Hydro requested that Mr. Chernick provide Proof of Revenue Statements for all of his proposed rate designs (MH/Chernick I – 10) in order for Manitoba Hydro to assess whether the proposed combination of basic charges, waivers of basic charges,

discounts to first block usage, seasonal block size variations and the recovery rate from non-LICO 125 customers would produce the required revenues as sought by Manitoba Hydro from the Residential Class in this Application. Unfortunately, Mr. Chernick did not conduct this analysis, as noted in his response to that Information Request. Furthermore, under cross examination from PUB Counsel at Transcript Oage 3836, Mr. Chernick stated:

"I don't believe that I – I've located the necessary data, and I wasn't able to provide the analysis."

Manitoba Hydro provides a Proof of Revenue Statement in each rate application to verify that the combination of rates and charges when applied to the test year load forecast, generates the expected level of revenue by customer class. As Mr. Chernick has not undertaken such an analysis, it is impossible to test his rate design proposal to ensure it produces the appropriate level of revenue, and therefore no weight can be given to his propose rate designs.

15.3.2 Rate Design for General Service Large Customer Classes

Time of Use Proposal

In his pre-filed evidence at pages 7-14 to 7-16, Mr. Patrick Bowman for MIPUG discusses the RCC outcomes for the GSL>100 class and proposes that Manitoba Hydro implement a time of use rate structure on an *"optional"* basis for that customer class.

His optional time of use rate design references the illustrative Time of Use ("TOU") rate scenarios previously prepared by Manitoba Hydro which were based upon revenues and billing determinants for August 1, 2016 rates. Under Mr. Bowman's proposal, both standard and TOU rates would be designed for the GSL>100 class and each of the 14 customers in the class would have the option to choose from either the standard rate design or the TOU rate design.

In his direct evidence testimony at Transcript Page 6106, Mr. Bowman states that time of use rates help make the rates within a class fairer, even if customers don't shift load. The *"fairness"* of a time of use rate design within a given customer class is an appropriate point to make when considering the reduction of cross subsidy between customers within any given class. For customers within the GSL > 100 kV class, the

degree of cross subsidy between customers depends upon their individual usage characteristics.

Based on each GSL > 100 kV customers actual usage characteristics, the annual bill impact to each of those customers was shown in the response to MIPUG/MH I-5c and on Page 71 of Manitoba Hydro's Written Rebuttal Evidence, Exhibit MH-52, which is provided below.

Figure 15.3

	Bill Impact of TOU vs Standard GSL > 100 Rate Design ($)	Customer under TOU rate design
Customer 1	900,200	Higher bill
Customer 2	438,500	Higher bill
Customer 3	140,300	Higher bill
Customer 4	114,700	Higher bill
Customer 5	39,500	Higher bill
Customer 6	36,800	Higher bill
Customer 7	400	Higher bill
Customer 8	(29,700)	Lower bill
Customer 9	(70,800)	Lower bill
Customer 10	(96,900)	Lower bill
Customer 11	(103,800)	Lower bill
Customer 12	(221,500)	Lower bill
Customer 13	(294,400)	Lower bill
Customer 14	(711,000)	Lower bill
7 customers	$ (1,528,100)	Lower revenues - TOU
7 customers	$ 1,670,400	Higher revenues - TOU

Mr. Bowman states that a time of use rate design has better fairness attributes than the existing rate design. The data in the above table compares annual bills under both a time of use and the standard rate design. This analysis demonstrates that customers 1 through 7 are not fully covering the cost to serve them under the standard GSL > 100 kV rate design, as they would be paying higher bills under the time of use rate design. Therefore, as Mr. Bowman observes, a time of use rate design would *"make the rates within a class fairer"*, indicating that Customers 1 through Customer 7 are currently being cross subsidized by Customers 8 through Customer 14 in the GSL > 100 kV class.

Manitoba Hydro's concerns with providing a standard rate design and an optional time of use rate centres on the issue of total revenue collection, in the event that only half of the customers opt for the time of use rate, leaving the higher cost customers on the standard rate design. This situation opens the door to self-selection by customers, based solely on their potential to benefit from one rate design or the other.

The result of the potential self-selection by GSL > 100 customers is that only customers whose bills could be lower under the time of use option would switch rates and therefore Manitoba Hydro would see a revenue shortfall of approximately $1.5 million for the GSL > 100 class as shown in the table above.

Mr. Bowman acknowledges the revenue losses of approximately $1.5 million on Page 7-15 of Exhibit MIPUG-13.

On page 7-16 of Exhibit MIPUG-13, Mr. Bowman suggests that the current RCCs of the GSL>100 kV class could drop with the implementation of optional TOU rates and no further recovery of the lost revenues.

The appropriate level of revenues should be explicitly dealt with by viewing the class by class RCC outcomes of PCOSS18 and determining whether there should be any deliberate shift in revenue responsibility between rate classes, prior to designing tariffs at the rate design stage.

In other words, if the likely outcome of an optional TOU rate offering is a net reduction of revenues of $1.5 million, that revenue must be made up either from other non-participating GSL>100 kV customers, by increasing the level of the standard rate, or it must be made up from customers in other rate classes.

In cross-examination by PUB Counsel on January 25, at Transcript Pages 6457 to 6459, Mr. Bowman discusses his recommendation on the matter of a Time-of-Use rate design. In his exchange, beginning on Transcript Page 6458, Mr. Bowman states:

"My – my suggestion to the Board is that it – t indicate to Hydro that – that work should be done on an – creating a new rate schedule available to at least the largest two (2) classes of customers. And that that rate schedule should be one (1) that customers can

opt into, but need not be required to move into. That rate schedule would not change the fact that they're in the overall class for the purposes of setting RCCs, so if there is less revenue it would affect the – it would affect the class in the cost of service study."

Mr. Bowman's recommendation suggests that Manitoba Hydro should not be compensated for any revenue loss caused by the self-selection of customers under an optional rate offering scheme. This recommendation violates Manitoba Hydro's rate making objective of full recovery of the revenue requirement, and furthermore violates Bonbright's criteria of *"effectiveness of yielding total revenue requirements"*.

15.3.3 The Relevance of Demand Charges in Rate Design

Mr. Chernick, at pages 39 to 42 of Exhibit GAC-11, advises the PUB to consider reducing or eliminating demand charges in the design of rates for general service customers.

Contrary to Mr. Chernick's opinion, demand charges provide a meaningful price signal to general service customers, in that electricity service consists of both the supply of energy and the provision of capacity to meet those customers' peak load requirements. Distribution feeders, substations, sub-transmission and transmission facilities are designed to accommodate the planned peak loads on the system, and the Corporation is contractually obligated to serve customers to the level of their required peak demand.

In addition, demand charges also provide the Corporation with a greater degree of revenue stability, which is also an important rate making consideration.

Demand charges give customers a price signal as to the cost of the capacity requirements that they impose on the system, the information to make better decisions around the management of peak demand, and an incentive to manage these peak demands. Without such an incentive, customers may place greater demand on the system than they would otherwise, which can result in increased capacity requirements on the system and increased costs to be borne by all customers.

On pages 42 and 43 of Exhibit GAC-13, Mr. Chernick expresses his view that Manitoba Hydro should eliminate demand ratchets or minimum billing demand provisions from its GSM and GSL tariffs.

The monthly billing demand for General Service Medium (over 200 kVA) and General Service Large customers is the greater of either (Appendix 9.3 (Updated) of the Application, Page 10-11):

1. measured demand; or
2. 25% of the contract demand; or
3. 25% of the highest measured demand in the previous 12 months.

Mr. Chernick has several criticisms of demand charges on page 43 of his evidence. He suggests that demand ratchets and contract demand provisions provide no incentive to reduce energy usage in low demand months (under 25% of the highest measured demand in the previous 12 months) and excessively penalize customers for marginal usage in the highest demand months, which in his view provides confusing and misleading price signals.

However, minimum billing demand and contract demand provisions reinforce the price signal to customers of the cost of demand that they impose on the Manitoba Hydro system. The cost of capacity and energy are shown separately on bills and customers can assess these costs in making their electricity usage decisions. In addition, contract demand provisions also encourage customers to more carefully assess their capacity requirements when adding load to the system. Without contract demand provisions, customers may contract for excess capacity on the possibility that it may be needed in the future. This capacity must then be constructed and reserved for that customer, and a contract demand provision provides for some level of ongoing revenue recovery for that additional capacity.

Lastly, Mr. Chernick suggests that demand bill impacts may arise for customers who unintentionally establish a new maximum contract demand. Manitoba Hydro notes that customers that inadvertently set a new maximum demand level may contact a customer representative to explain their specific circumstances and potentially have their billing demand level reviewed and adjusted, and therefore may not pose the bill impacts to customers as Mr. Chernick has suggested.

16 RATE SHOCK

16.1 Manitoba Hydro's Rate Request Does Not Represent Rate Shock

As noted by Mr. Barnlund on Transcript pages 2386 and 2387, Manitoba Hydro has, in fact, mitigated the level of rate increases that would otherwise be caused by the in-service of the Bipole III Reliability Project, the Keeyask Generating Station and the U.S. Interconnections comprised of the Manitoba-Minnesota Transmission Project and the Great Northern Transmission Line. In Order 73/15, the Public Utilities Board of Manitoba ("PUB") provided a table on page 7, reproduced below, which indicated the impact to revenue requirements of these new facilities entering service.

Figure 16.1. Revenue Requirement Impact (from Order 73/15)

The following table illustrates Manitoba Hydro's new revenue requirements attributable to new major projects, starting in 2019:

Revenue Requirement Impacts ($ Million)

Year Ending March 31	2019	2020	2021	2022
Bipole III Transmission Reliability Project	234	384	382	377
Keeyask Generating Station	28	80	316	462
Manitoba/Minnesota Transmission Project / Great Northern Transmission Line	1	5	85	115
Conawapa Sunk Costs	35	34	34	33
Additional Annual Revenue Required for New Projects	298	503	817	987
Cumulative Indicative-Only Annual Rate Increase Required to Pay New Costs	20%	34%	54%	65%

Sources: Application Appendix 11.15, Exhibit MH-118

Source: Page 7 of PUB Order 73/15

The increases in revenue requirement due to incremental depreciation, finance expense, capital tax and Operations & Maintenance associated with new major projects entering service would result in unmitigated rate increases of 20% in 2019, 34% in 2020, 54% in 2021 and 65% in 2022, if those costs were passed directly through to customers as that plant became used and useful. Unlike most other utilities that are regulated on a rate-base, rate-of-return basis, Manitoba Hydro is regulated under a cost of service approach that facilitates a more gradual smoothing into customer's rates of these lumpy increases in revenue requirement.

Given the extent of the unmitigated rate increases that would otherwise be necessary given the significant costs incurred with the in-service of these major projects, Manitoba Hydro's request of a 7.9% increase on April 1, 2018 demonstrates the significant rate impact mitigation that Manitoba Hydro is affording its customers through this time period.

The Consumer Coalition, MIPUG and the GSS/GSM-KAP representatives have characterized the rates requested in this General Rate Application as constituting "rate shock". Manitoba Hydro does not agree with this characterization, as discussed by Mr. Barnlund at Transcript Page 1469:

> *"MR. GREG BARNLUND: … We would not consider 7.9 percent rate increases to be -- meeting a threshold of rate shock.*
>
> *Typically utilities and utility boards consider a threshold of 10 percent. In 2004 this utilities board looked at Manitoba Hydro's application for August 1 rates and they considered a definition of rate shock or discussion of rate shock at that particular hearing. And they found that as long as the increases were no more than 8 or 9 percent that they would not be considering those as rate shock.*
> *…*
>
> *MR. GREG BARNLUND: While it's a difficult increase it's not rate shock because rate shock also infers a sudden surprise on customers and Manitoba Hydro has been very clear in terms of its communication of its financial situation, and indicating that there would be a need for continual rate increases of this order of magnitude."*

The reference to 2004 in the excerpt above is in respect of Manitoba Hydro's rate application filed on January 29, 2004. In that application, Manitoba Hydro applied for general rate increases of 3.0% to be effective April 1, 2004 and 2.5% to be effective on April 1, 2005.

The subject of rate shock was examined by the PUB in its review of that rate application which resulted in the PUB issuing Order 101/04 on July 28, 2004. The PUB granted

Manitoba Hydro a 5.0% increase (a full 2.0 % greater than requested by the corporation in its initial filing) for August 1, 2004 and a further 2.25% on a conditional basis for April 1, 2005 and 2.25% on a conditional basis for October 1, 2005.

In that Order, on page 27, the PUB noted:

> *In coming to a decision on the rate increases, firm and conditional, the Board considered the issue of rate shock, and opines that the rate increases for most customers will be within the thresholds put forth by the Intervenors (i.e. no more than 8-9% for any customers for the August 1, 2004 increase, and much less for most).*

Mr. Barnlund also raised the matter of the increases previously granted to Centra Gas Manitoba Inc. by the PUB in regards to natural gas rates. In Transcripts pages 2013 and 2014, in response to questions by Mr. Monnin on behalf of GSS/GSM-KAP, Mr. Barnlund testified:

> *I might, I guess, draw your attention though to some of the decisions that this Board has made with respect to the natural gas utility, Centra Gas Manitoba Inc., which of course deals with a much more volatile cost structure due to the fact that a great deal of the cost as passed on to customers is a cost of gas that's procured in the wholesale market.*
>
> *And there's been ten (10) at least – or ten (10) occasions where this Utilities Board has approved increases to natural gas customers in excess of 10 percent. And a situation in 1999 and 2000 when wholesale commodity prices really increased at a – at a very fast pace, the Utility Board passed through an increase of upwards of 25 percent on one (1) occasion.*

Mr. Barnlund further testified at Transcript pages 2014 and 2015, in response to questions from Mr. Monnin:

> *And – and you were asking me about the surprise to customers. And certainly some of the gas rate increases that have been approved by this*

Board were driven by some surprising changes in the wholesale market where there is relatively little notice that was provided to customers of those changes. And that was more of an issue of rate shock to be contended with than what we are certainly referring to here in this General Rate Application, sir

Regulators in Ontario and Alberta have identified a threshold of 10 percent as being an indication of rate shock or a level of rate increase that may require the utility to provide a rate mitigation plan to accompany its rate filing as discussed by Mr. Barnlund at lines 1 through 7 on Transcript page 2108.

Manitoba Hydro's proposed rate increase for 2018/19 of 7.9% is less than the 10% threshold identified in other jurisdictions, is less than the 8% - 9% threshold mentioned by the PUB in Order 101/04, and is far less than the unmitigated impact to revenue requirement that would otherwise be experienced as Major New Generation and Transmission projects come into service over the coming years.

17 REGULATORY DEFERRAL ACCOUNTS AND INTERIM APPROVALS

17.1 Regulatory Deferral Accounts

Under International Financial Reporting Standards ("IFRS"), financial statements must reflect the impacts of regulatory decisions with respect to timing differences for the recognition of revenue/expenses for rate setting purposes as compared to financial reporting purposes (e.g. $20 million of overhead expensed for financial reporting and deferred for rate setting). When performing the audit of Manitoba Hydro's financial statements, Manitoba Hydro's external auditor will review the content found in Public Utilities Board of Manitoba ("PUB") Orders to validate the accounting for regulatory deferrals as presented in the Corporation's financial statements.

Manitoba Hydro is seeking PUB endorsement of the following, pertaining to various deferral accounts:

- The proposed deferral and subsequent amortization for the costs incurred with respect to the Conawapa Generating Station as discussed in Tab 3 (page 18) of this Application;
- The proposed amortization period for the disposition of the regulatory deferral account established to capture the annual difference ($20 million) between overhead costs expensed for financial reporting purposes based on IFRS and overhead costs expensed for rate setting purposes reflecting Order PUB 73/15;
- The proposed amortization period for the disposition of the regulatory deferral account established to defer gains and losses on the disposition of assets; and
- The proposed time frame for the recognition into revenue of the Bipole III deferral account.

Manitoba Hydro's preference is to have a single basis of depreciation for both financial reporting and rate setting purposes thereby eliminating the need for a deferral account. This would address Manitoba Hydro's concerns with respect to the excessive growth in the deferral account balance, as well as reduce the ongoing administrative cost and effort to maintain the deferral indefinitely as the calculation of the deferral will become more complex over time.

However, Manitoba Hydro recognizes that for a single basis of depreciation to apply, the PUB's directives from Order 43/13 must be addressed. Given the specialized and technical nature of this subject matter, Manitoba Hydro is supportive of finding an

alternate process where the requirements of the depreciation directives can be discussed and resolution of this issue can be achieved. Manitoba Hydro is also supportive of finding an alternate process where the issue of the indefinite deferral of ineligible overhead can be discussed in more detail.

17.1.1 Conawapa Generating Station

Manitoba Hydro has incurred approximately $380 million in costs pertaining to the construction of the Conawapa Generating Station (Exhibit MH-127). A decision has been made to discontinue any further development of the station at this time. As a result, the Corporation is anticipating to write-down these costs to net income in 2017/18 as per Ms. Bauerlein's oral testimony on Transcript Page 765:

> *Things have changed. We will have to have discussions with our auditor this upcoming March 2018 to assess whether or not that this asset will be viewed as what we call a stranded asset, and would therefore have to be written off. Based on things that happened over the last several months, we believe that is a strong possibility.*

Manitoba Hydro is seeking the PUB's endorsement of its proposal to record the costs pertaining to the construction of the Conawapa Generating Station in a regulatory deferral account effective March 2018 and commence amortization of the costs to income on a straight line basis over a period of 30 years beginning April 1, 2018, in order to minimize the impact on customers.

At pages 49-50 of Mr. Harper's Evidence, filed as Consumers Coalition Exhibit CC-20, Mr. Harper provides endorsement of Manitoba Hydro's proposed accounting treatment with respect to Conawapa construction costs, stating that "*Since the decision dealt with the most appropriate way to meet Manitoba Hydro's energy needs over a long-term planning horizon, the write-off can be viewed as part of the overall cost of implementing the Board's decision. Overall, the 20 year period is reasonable.*"

It is noted that in oral testimony (Transcript Page 5186 and 5187), Mr. Harper corrected his written evidence referencing the 20 year amortization period to a 30 year amortization period consistent with Manitoba Hydro's proposal.

17.1.2 Depreciation Methodology

Manitoba Hydro adopted the Equal Life Group ("ELG") method of depreciation to be compliant with the financial reporting requirements of IFRS. This change resulted in an initial annual increase in depreciation expense of approximately $30 million compared to the CGAAP Average Service Life ("ASL") method of depreciation used by Manitoba Hydro prior to IFRS. Notably, over the service life of an asset, the total depreciation will be the same under either method.

In Order 43/13, the PUB directed Manitoba to perform the following:

> *8. That Manitoba Hydro file updated depreciation rates and schedules based on an International Financial Reporting Standards-compliant Average Service Life methodology with the next General Rate Application.*
>
> *9. That Manitoba Hydro file with the Board, with the next General Rate Application, a chart showing a comparison of the impact on its Integrated Financial Forecast (i.e. 'Budget') of asset depreciation pursuant to the Average Service Life methodology (without net salvage) and the Equal Life Group methodology (without net salvage), applying both methodologies to all planned major capital additions.*

In Directive 10 of Order 73/15, the PUB further directed Manitoba Hydro to continue to use the CGAAP-ASL method of depreciation for rate setting purposes until the PUB is satisfied that a change in depreciation methodology is warranted.

As indicated in Tab 10 of the GRA, Manitoba Hydro has addressed the requirements of Directive 10 of Order 73/15 by deferring the difference between depreciation expense calculated for financial reporting purposes (based on IFRS-compliant ELG depreciation rates) and depreciation expense calculated for rate-setting purposes (using CGAAP-compliant ASL depreciation rates) in a regulatory deferral account. As required by IFRS 14, Manitoba Hydro is also making a corresponding adjustment through the net movement in regulatory balances account such that for rate setting purposes, Manitoba Hydro's revenue requirement for the test years continues to reflect depreciation expense based on CGAAP-compliant ASL depreciation rates. Although a deferral account

has been established, Manitoba Hydro is not seeking approval of the amortization period for the differences in the depreciation methodology at this time.

Manitoba Hydro notes that a change in methodology was required in order to be compliant with IFRS and it is expected that an increase in depreciation expense would have occurred regardless of whether Manitoba Hydro used IFRS compliant ELG or ASL depreciation rates.

As an initial means to offset the impact of the change to the ELG method, Manitoba Hydro eliminated the recognition of negative salvage in depreciation rates which reduced depreciation expense by approximately $50 million per annum. This change more than offset the $30 million annual increase that resulted from the change to the ELG method.

Manitoba Hydro's preference is to have a single basis of depreciation for both rate setting and financial reporting purposes. A single basis of depreciation would have the benefit of eliminating the need for a deferral account and address Manitoba Hydro's concerns with respect to the excessive growth in deferral account balances ($1.9 billion by 2035), as evidenced in the response to PUB/MH I-1b. The corporation is concerned that such balances will need to be absorbed by future rate payers in addition to other risks (e.g. drought, reduced export prices) that may also arise. A single basis of depreciation will also reduce the ongoing administrative cost and effort to maintain the deferral indefinitely as the calculation of the deferral will become more complex over time as Manitoba Hydro continues to add and replace assets.

However, Manitoba Hydro recognizes that for a single basis of depreciation to apply, the PUB's directives from Order 43/13 must be addressed. Manitoba Hydro is supportive of finding an alternate process where the requirements outlined in the depreciation directives issued by the PUB can be discussed in more detail and a resolution of this issue can be achieved. Having an alternative process would allow Manitoba Hydro to provide the PUB with the information necessary to move forward with respect to the depreciation methodology issues. This is aligned with the recommendations of Mr. Harper's oral testimony at Transcript Pages 5219 to 5220 where he states:

The Board's directive also called for Manitoba Hydro to return with the necessary information to permit it to make a determination as to which depreciation -- while -- methodology should be used for rate -- rate setting. Assuming Manitoba Hydro intends to comply with the directive in a timely fashion, there is no need, in my view, to either, 1) amortize the current balance, or -- or establish a date after which the cost differences between the two (2) will no longer be deferred. These matters can better be addressed by the Board after it has determined what is the appropriate depreciation methodology for rate-setting purposes.

As noted above, Manitoba Hydro has established a deferral account to capture the difference between depreciation expense calculated based on IFRS-compliant ELG depreciation rates and CGAAP-ASL rates. While an assumption has been included in the current integrated financial forecast to amortize the deferral balance for rate setting purposes over a period of 20 years beginning in 2019/20, Manitoba Hydro believes that a more appropriate course of action would be to convene a process to review and consider the depreciation directives outside of a GRA process and before 2019/20.

17.1.3 Ineligible Overhead

Upon its transition to IFRS, Manitoba Hydro reduced the extent of overhead costs capitalized in property, plant and equipment to bring its capitalization policies in line with other Canadian utilities and to comply with the financial reporting requirements of IFRS. In the PUB findings on page 35 of Order 73/15, the PUB did not accept for rate setting purposes expensing an additional $20 million in annual overhead costs that were deemed ineligible for capitalization under IFRS and found instead that these additional overhead costs should continue to be capitalized, consistent with the practices used by Manitoba Hydro prior to its transition to IFRS.

As outlined in Tab 3 of the Application, Manitoba Hydro has established a regulatory deferral account to capture the $20 million in annual overhead costs that are ineligible for capitalization under IFRS. This deferral facilitates compliance with the PUB's direction in Order 73/15. As shown in MH16 Update with Interim, the balance in this deferral account grows to approximately $160 million by 2022/23.

Manitoba Hydro is seeking PUB endorsement of its proposal, as outlined in Tab 3, to amortize the balance in this deferral account over a 20 year period, beginning in 2017/18.

Intervenors to this application, specifically Mr. Bowman and Mr. Harper, have argued that the amortization period for the ineligible overhead costs should be extended to a 30 year period. As discussed by Manitoba Hydro on page 38 of Exhibit MH-52, while extending the amortization period for regulatory deferrals will result in a reduction to amortization expense and a subsequent increase to net income and retained earnings, such increases are based on a reduction to a non-cash related expense (i.e. amortization expense). The scenario provided by Manitoba Hydro in Appendix 3.1 of Exhibit MH-52 incorporates the recommendations of Mr. Bowman including: i) continuation of both the overhead and ELG/ASL deferrals through the forecast period; ii) extension to the amortization period of the overhead deferral to 30 years; and iii) no amortization of the ELG/ASL depreciation deferral.

The results of this analysis indicate that requested rate increases would marginally decrease by 0.26% from the 7.9% requested to 7.64% per year over the 6 year period from 2018/19 through to 2023/24. This marginal decrease is due to the fact that reductions to non-cash expenses have no impact on cash flows and as a result, do little to reduce debt levels. This fact is acknowledged by Mr. Bowman on page 6-10 (lines 17-18) in Exhibit MIPUG-13 as he states, "*The adjustment will not directly improve nor harm Hydro's cash flows, as deferral and amortization is a non-cash adjustment."* Consistent with Manitoba Hydro's responses to MIPUG MFR 5, PUB/MH I-1b and PUB/MH II-2a-c, the analysis demonstrates that 7.9% rate increases are required as a result of growing debt levels and a deterioration in cash flows and are not resolved through accounting changes related to the amortization periods of regulatory deferral accounts.

Manitoba Hydro notes that in Order 73/15, the PUB did not provide any direction with respect to how long Manitoba Hydro should continue to capitalize the additional overhead costs. Manitoba Hydro is concerned that an indefinite deferral is not appropriate given that there is no impact to net income by the end of the amortization period. As such, it is not clear what the benefit to the ratepayer would be in deferring such costs into perpetuity. Regardless of the amortization period used for the ineligible overhead, the annual amortization of the deferral account charged to net income will

equate to the annual deferral amount of $20 million by the end of the amortization period. For example, if a 20 year amortization period is used, by year 21, the annual deferral amount of $20 million will equate to the annual amortization of $20 million such that the net income impact will be zero. This impact on net income holds true regardless of the amortization period used.

Manitoba Hydro is also supportive of finding an alternate process where the issue of the indefinite deferral of ineligible overhead can be discussed in more detail. Mr. Harper is supportive of the need for further clarity on this issue as he states on page 46 of Exhibit CC-46:

> *Manitoba Hydro's comments suggest that the Board's decision to defer ineligible overheads (and ELG/ASL depreciation differences) was based on rate smoothing considerations. However, it is not clear that this was the case. In the case of ineligible overheads, the Board's Decision appears to reflect a view that the level of overheads identified in the proceeding prior to the 2015/16 and 2016/17 GRA were the appropriate level to capitalize for rate-setting purposes. However, at the end of the day, it remains for the Board to confirm what its objective was in deferring the $20 M of ineligible overheads. If the Board was/is of the view that the $20 M is more appropriately capitalized, then there is no basis for ceasing the deferral after 2022/23.*

17.1.4 Gains and Losses on the Disposition of Assets

As explained by Ms. Bauerlein in direct evidence starting on Transcript Page 678, Manitoba Hydro is proposing that asset retirement gains and losses be deferred in a regulatory account and amortized on a straight-line basis over a period of 20 years for rate setting purposes. The proposal is consistent with the PUB findings in Order 73/15 (page 45) where the PUB ordered Manitoba Hydro to continue to determine depreciation expense based on its existing CGAAP-compliant ASL methodology for rate setting purposes. Under the CGAAP ASL method, Manitoba Hydro deferred and amortized the recognition of gains and losses on the disposition of assets by recognizing them initially in accumulated depreciation and subsequently amortizing these amounts over the remaining lives of the respective assets via an adjustment to future depreciation rates. This CGAAP form of accounting is not consistent with IFRS which requires asset retirement gains and losses to be recognized immediately to net income

in the year incurred. As such, Manitoba Hydro requires a regulatory deferral account to record these amounts in order to continue to defer and amortize asset retirement gains and losses for rate setting purposes.

Consistent with other regulatory deferral accounts, Manitoba Hydro requires endorsement from the PUB as to the 20 year amortization period it is proposing in its Application. Manitoba Hydro notes that Mr. Harper agrees with the proposed accounting treatment of Manitoba Hydro as he states on page 41 of his written evidence, "*As noted earlier, in such situations the choice of amortization period is a matter of judgment. Since an amortization period of 20 years is likely to achieve a result similar to that experienced prior to the implementation of IFRS, the period appears reasonable.*"

17.1.5 Bipole III Revenue Deferral

The Bipole III reserve account was established by Manitoba Hydro, consistent with the direction provided by the PUB in Order 43/13 (directive #3, page 4) which stated that:

> *That a 3.5 % overall increase in billed rates for the basic monthly charge, the demand charge, and the energy charge for all rate categories to take effect May 1, 2013, with revenues from a 1.5% portion of the rate increase accruing in a deferral account to be utilized to mitigate the required rate increases when Bipole III is placed in-service,* ***BE AND IS HEREBY APPROVED****.*

The rational provided by the PUB for establishing the Bipole III deferral account is documented on page 10 of Order 43/13:

> *The capital deferral account is to assist in funding the planned Bipole III transmission line. The cost of this project will be capitalized during the construction phase, but significant annual depreciation, operation, maintenance & administration, and interest costs will have to be recovered from domestic ratepayers once the project is placed in-service. The deferral account allows Manitoba Hydro to collect funds as the Bipole III project is being built, which will help to mitigate rate increases required once the infrastructure is placed in-service.*

As shown in Appendix 3.8, MH16 Update with Interim, as at March 31, 2017, cumulative revenues accrued to the Bipole III deferral account are $196 million reflecting rate increases received by Manitoba Hydro since 2014 that were directed to the Bipole deferral. The Bipole III deferral account is projected to grow to approximately $400 million by the Bipole III planned in-service date of July 2018. The MH16 Update with Interim forecast assumes that the deferral account is recognized in domestic revenues over a five year period following the Bipole III project in-service date (effective August 2018) through to July 2023 to coincide with the final in-service date of the Keeyask generating station. A five year period over which to recognize the deferred revenue was chosen so as to help mitigate the initial expected increases in annual depreciation, interest and operating costs following the in-service of the Bipole III project. Subsequent to the 2023 period, additional export revenues from the Keeyask project will be available to help offset such charges and therefore, no further recognition of the deferral is required following that date.

Manitoba Hydro notes that the timing of the recognition of the revenue will not impact the future cash flows of the Corporation as the money has already been received via previous year's rate increases/revenue collected. As explained by Mr. McCallum in his oral testimony, at Transcript Page 751:

> *I think the really important thing to appreciate here is that this is a – this is accounting rules dictating the recognition of revenue. The cash has already been paid. It's in the bank or its been spent,…, There's no incremental cash benefit that comes from this $400 million balance which we amortize. This is a recognition item. It's an accounting policy item.*

In addition to the comments of Mr. McCallum, Manitoba Hydro further notes that the revenues collected by way of the Bipole III deferral account have been included in equity balances when determining actual and projected debt-equity ratios of the corporation. As such, the timing of when the revenue is recognized into net income will not change the cash/debt position or equity ratio of Manitoba Hydro going forward and will therefore have no impact on customer rates.

The following continuity schedule in **Figure 17.1** displays the annual contributions and proposed drawdowns of the Bipole III reserve account by fiscal year:

Figure 17.1 Bipole III Reserve Account Reconciliation

Bipole III Reserve Account Reconciliation
(In thousands of dollars)

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Opening balance	-	18 825	49 074	100 278	196 296	347 313	345 845	266 035	186 225	106 415	26 605
Contributions	18 825	30 249	51 204	96 018	151 017	51 739	-	-	-	-	-
Drawdowns	-	-	-	-	-	(53 207)	(79 810)	(79 810)	(79 810)	(79 810)	(26 605)
Ending balance	18 825	49 074	100 278	196 296	347 313	345 845	266 035	186 225	106 415	26 605	-

Source: PUB/MH I-152b

Given that the Bipole III project is expected to go into service in July 2018 of the upcoming test year, Manitoba Hydro is seeking direction from the PUB as part of its Order issued in response to Manitoba Hydro's GRA as to the amortization period over which to recognize the revenues deferred in the Bipole III account.

17.2 Interim Orders

Manitoba Hydro has attached, as Appendix 17.1, a complete list of interim and ex parte Orders that require final approval by the PUB.

Second Session - Thirty-Seventh Legislature

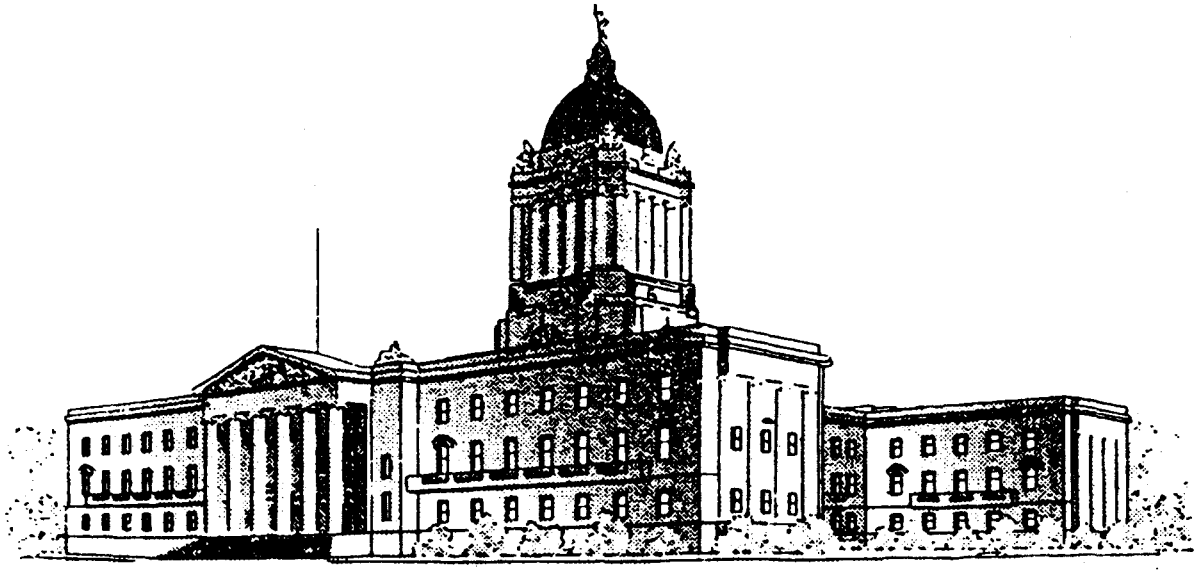
of the

Legislative Assembly of Manitoba

DEBATES
and
PROCEEDINGS

Official Report
(Hansard)

Published under the
authority of
The Honourable George Hickes
Speaker



Vol. LI No. 38 - 1:30 p.m., Wednesday, May 30, 2001

ISSN 0542-5492

MANITOBA LEGISLATIVE ASSEMBLY
Thirty-Seventh Legislature

Member	Constituency	Political Affiliation
AGLUGUB, Cris	The Maples	N.D.P.
ALLAN, Nancy	St. Vital	N.D.P.
ASHTON, Steve, Hon.	Thompson	N.D.P.
ASPER, Linda	Riel	N.D.P.
BARRETT, Becky, Hon.	Inkster	N.D.P.
CALDWELL, Drew, Hon.	Brandon East	N.D.P.
CERILLI, Marianne	Radisson	N.D.P.
CHOMIAK, Dave, Hon.	Kildonan	N.D.P.
CUMMINGS, Glen	Ste. Rose	P.C.
DACQUAY, Louise	Seine River	P.C.
DERKACH, Leonard	Russell	P.C.
DEWAR, Gregory	Selkirk	N.D.P.
DOER, Gary, Hon.	Concordia	N.D.P.
DRIEDGER, Myrna	Charleswood	P.C.
DYCK, Peter	Pembina	P.C.
ENNS, Harry	Lakeside	P.C.
FAURSCHOU, David	Portage la Prairie	P.C.
FRIESEN, Jean, Hon.	Wolseley	N.D.P.
GERRARD, Jon, Hon.	River Heights	Lib.
GILLESHAMMER, Harold	Minnedosa	P.C.
HELWER, Edward	Gimli	P.C.
HICKES, George	Point Douglas	N.D.P.
JENNISSEN, Gerard	Flin Flon	N.D.P.
KØRZENIOWSKI, Bonnie	St. James	N.D.P.
LATHLIN, Oscar, Hon.	The Pas	N.D.P.
LAURENDEAU, Marcel	St. Norbert	P.C.
LEMIEUX, Ron, Hon.	La Verendrye	N.D.P.
LOEWEN, John	Fort Whyte	P.C.
MACKINTOSH, Gord, Hon.	St. Johns	N.D.P.
MAGUIRE, Larry	Arthur-Virden	P.C.
MALOWAY, Jim	Elmwood	N.D.P.
MARTINDALE, Doug	Burrows	N.D.P.
McGIFFORD, Diane, Hon.	Lord Roberts	N.D.P.
MIHYCHUK, MaryAnn, Hon.	Minto	N.D.P.
MITCHELSON, Bonnie	River East	P.C.
MURRAY, Stuart	Kirkfield Park	P.C.
NEVAKSHONOFF, Tom	Interlake	N.D.P.
PENNER, Jack	Emerson	P.C.
PENNER, Jim	Steinbach	P.C.
PITURA, Frank	Morris	P.C.
PRAZNIK, Darren	Lac du Bonnet	P.C.
REID, Daryl	Transcona	N.D.P.
REIMER, Jack	Southdale	P.C.
ROBINSON, Eric, Hon.	Rupertsland	N.D.P.
ROCAN, Denis	Carman	P.C.
RØNDEAU, Jim	Assiniboia	N.D.P.
SALE, Tim, Hon.	Fort Rouge	N.D.P.
SANTOS, Conrad	Wellington	N.D.P.
SCHELLENBERG, Harry	Rossmere	N.D.P.
SCHULER, Ron	Springfield	P.C.
SELINGER, Greg, Hon.	St. Boniface	N.D.P.
SMITH, Joy	Fort Garry	P.C.
SMITH, Scott, Hon.	Brandon West	N.D.P.
STEFANSON, Heather	Tuxedo	P.C.
STRUTHERS, Stan	Dauphin-Roblin	N.D.P.
TWEED, Mervin	Turtle Mountain	P.C.
WOWCHUK, Rosann, Hon.	Swan River	N.D.P.

and farmers to discuss the economic disaster that is currently going on in the oilseed and grain seed sector, one would have given some praise to the Prime Minister. Yet people and farmers, a group of farmers that asked for an audience with him were told that if they paid $350 per plate for a dinner they might get to say hi to him. I think, Mr. Speaker, it is clearly an indication of what kind of a disastrous situation we have in this province in response to the leadership in federal and provincial relations. I think that has deteriorated dramatically, and I think we need to address that at some point. I criticize the Prime Minister for not meeting.

Ms. Janice Y. Lederman

Mr. Doug Martindale (Burrows): Mr. Speaker, it is with pleasure that I rise today to pay tribute to Ms. Jan Lederman, the former chair of the United Way of Winnipeg's board of trustees. She was presented with the André Mailhot Award at the United Way of Canada/Centraide Canada's national conference in Québec City on March 24, 2001. It is given to one individual annually, and this year Ms. Lederman was honoured with being the recipient of this award.

She was involved for eight years with the United Way of Winnipeg and spearheaded a community involvement initiative called Journey Forward which engaged people to look at social issues most important to them and to Winnipeggers and to find ways to work together to address these issues, which I might point out involved some 3000 people. This culminated in the Willing Community Forum in November 2000 which was considered a model across Canada and the United States. Ms. Lederman is a very deserving recipient of this award. She is also bright, articulate and personable as an individual. On behalf of all members, I would like to thank her for her volunteerism and her leadership with the United Way of Winnipeg.

* (14:30)

Thomas Report

Hon. Jon Gerrard (River Heights): Mr. Speaker, last week Paul Thomas tabled the report of the Review and Implementation Committee for the report of the Manitoba Pediatric Cardiac Surgery Inquest. Yesterday the Minister of Health (Mr. Chomiak) suggested in his comments that the Thomas report dealt only with the period 1994 to 1995. A read of the report shows that Paul Thomas is dealing with the present situation when he says clearly: Where provincial leadership and involvement ends and the responsibility of the RHAs begins is not clear.

Again, Paul Thomas says: The exact nature of the working relationship between the two parties–he is referring to the minister and the regional health authorities–is not clear.

It is a real disappointment that the Minister of Health has not in 20 months been able to clarify the relationship between himself, as minister, and the regional health authorities. This relationship should have been made clear within the minister's first two months in office.

Ending the overlap and duplication is essential, as Paul Thomas indicates, in order to achieve cost savings and to clarify accountability. It is time for the Minister of Health to clarify the present overlap and blurred accountability. It is time for the Minister of Health to attend to what he should have attended to as one of his first tasks when he assumed office.

ORDERS OF THE DAY

House Business

Hon. Gord Mackintosh (Government House Leader): Mr. Speaker, before dealing with the routine for today, would you canvass the House and determine if there is consent to adjourn today at 5 p.m.?

Mr. Speaker: Is there agreement to adjourn at 5 p.m. today? *[Agreed]*

Mr. Mackintosh: Mr. Speaker, would you please call bills in the following order: First, second readings, Bills 27 and 30; second, debate on second readings, in this order, please, Bills 11, 19, 12, 14, 15 and 29; and then return to second readings, Bill 25, and we will take it from there.

SECOND READINGS

Bill 27–The Manitoba Hydro Amendment Act (2)

Hon. Greg Selinger (Minister charged with the administration of The Manitoba Hydro Act): Mr. Speaker, I move, seconded by the

Minister of Transportation and Government Services (Mr. Ashton), that Bill 27, The Manitoba Hydro Amendment Act (2); Loi no 2 modifiant la Loi sur l'Hydro-Manitoba, be now read a second time and referred to a committee of this House.

Motion presented.

Mr. Selinger: I am pleased to give second reading to this bill. As I mentioned in the first reading, this legislation will require Manitoba Hydro to charge customers connected to the provincial power grid the same rate for electricity service, regardless of where they live in Manitoba.

Mr. Speaker, on December 5, 2000, the Speech from the Throne promised this single rate for residential hydro users. The Lieutenant-Governor said at that time: A household in The Pas or in Lac du Bonnet will pay the same basic rate for hydro service as a household in Winnipeg. This bill delivers on that commitment.

Our Government sees this as an issue of fundamental fairness to all Manitobans with respect to an important service. Currently, Manitoba Hydro maintains three rate zones reflecting different cost structures associated with serving a large number of customers in a small area compared to serving a few customers spread across a large area. However, this difference in actual terms is less than 10 percent, so for example the average residential customer living in Zone 2 will save approximately $2.70 a month on their electricity bill. These current Zone 2 customers are typically those living in small towns and medium density areas. The average customers living in what is currently called Zone 3 are typically farm families, low density areas. They will save $10.11 per month.

Mr. Speaker, this legislation is long overdue. Many other provinces have uniform rates, including Québec, British Columbia and Nova Scotia. It is an issue of fundamental fairness. I am very pleased that we are able to work with our Crown utility to make uniform electricity rates a reality in Manitoba and put everybody on an equal footing when it comes to the rates charged for basic service.

Mr. Marcel Laurendeau (St. Norbert): I move, seconded by the honourable Member for Lakeside (Mr. Enns), that debate be adjourned.

Motion agreed to.

Bill 30–The Securities Amendment Act

Hon. Scott Smith (Minister of Consumer and Corporate Affairs): I move, seconded by the Minister of Transportation and Government Services (Mr. Ashton), that Bill 30, The Securities Amendment Act (Loi modifiant la Loi sur les valeurs mobilières), be now read a second time and referred to a committee of the House.

Motion presented.

* (14:40)

Mr. Smith: Mr. Speaker, the amendments to The Securities Act proposed in this bill fall into two broad categories. The first are amendments that will modernize and harmonize the securities legislation in the province.

You can break this into five generalizations, five categories: No. 1, making provisions to the Manitoba Securities Commission to participate in a national registration database which will allow registrants to operate in the securities industry to become registered in several jurisdictions from a single-entry point. This will present a benefit to both the registrants and investors, as the dealers will be able to service their clients with a minimum amount of paperwork and filing delays.

Number two, providing authority for the Securities Commission to officially recognize self-regulating organizations such as the Investment Dealers' Association and the mutual fund dealers' association, to which those registrants selling equities and mutual funds must belong. Recognition will give the Securities Commission both the ability to form a closer relationship with those groups but also a greater opportunity for scrutiny and oversight. This will be beneficial to not only investors but all Manitobans.

Number three, adopting the concept of the reporting issuer. As in other jurisdictions, this will result in additional financial reporting to the Manitoba Securities Commission by non-resident issuers currently not filing in the province. This in turn will provide greater disclosure to Manitoba investments.

Number four, harmonizing on a national basis to extend the notice period for takeover

COURT FILE NO.: 273/07
DATE: 20080516

2008 CanLII 23487 (ON SCDC)

ONTARIO
SUPERIOR COURT OF JUSTICE

DIVISIONAL COURT

KITELEY, CUMMING, AND SWINTON JJ.

B E T W E E N:	
ADVOCACY CENTRE FOR TENANTS-ONTARIO and INCOME SECURITY ADVOCACY CENTRE on behalf of LOW-INCOME ENERGY NETWORK Appellant	***Paul Manning*** and ***Mary Truemner***, for the Appellant
- and -	
ONTARIO ENERGY BOARD Respondent	***Michael Millar***, for Ontario Energy Board ***Fred Cass*** and ***David Stevens,*** for Enbridge Gas Distribution Inc. ***Robert Warren,*** for Consumers Council of Canada **HEARD at Toronto:** February 25, 2008

KITELEY and CUMMING JJ.

The Appeal

[1] The Respondent Ontario Energy Board (the "Board") is the provincial economic regulator for the natural gas and electricity sectors. The Board exercises its jurisdiction within the statutory authority established by the Legislature, being the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, Schedule B (the "*Act*").

[2] By a majority (2:1) decision dated April 26, 2007, the Board determined that the *Act* does not explicitly grant to the Board jurisdiction to order the implementation of a low income affordability program: *Enbridge Gas Distribution Inc.* (April 26, 2007), EB-2006-0034 (Ont. Energy Bd.) (the "Board Decision"). The Board also found that the Board does not gain the requisite jurisdiction through the doctrine of necessary implication.

[3] Enbridge Gas Distribution Inc. ("EGD") sought approval by the Board of EGD's 2007 gas distribution rates based simply upon the Board's traditional, standard "cost of service" rate-making principles. The Appellant Low Income Energy Network ("LIEN") had intervened in the application before the Board. LIEN argues that without a rate affordability program, the interests of low-income consumers are not protected. LIEN proposed that the Board accept as an issue in the EGD proceeding the following matter:

> Should the residential rate schedules for EGD include a rate affordability assistance program for low-income consumers? If so, how should such a program be funded? How should eligibility criteria be determined? How should levels of assistance be determined?

[4] LIEN seeks from the Board the introduction of a rate affordability assistance program to make natural gas distribution rates affordable to poor people. The underlying premise of the proposal of LIEN is that low income consumers (estimated to be about 18% of households in Ontario) should pay less for gas distribution services than other consumers. LIEN emphasizes that the supply of natural gas (or other source of energy) serves to meet basic human needs such as warmth from heating and the generation of power. Those who cannot afford to use natural gas as a source of energy may be placed at a significant disadvantage. LIEN submits that the Board can consider ability to pay in setting rates if it is necessary to meet broad public policy concerns. Access to an essential service is arguably such a concern. The supply of natural gas can be considered a necessity that is available from a single source with prices set by the Board in the public interest.

[5] The majority of the Board held that the LIEN proposal amounted to an income redistribution scheme. The Board noted that such a scheme would require a consumer rate class based upon income characteristics and would implicitly require subsidization of this new class by other rate classes. It is undisputed that a common, if not universal, historical feature of rate-making for a natural monopoly is the application of the same charges to all consumers within a given consumer classification based upon cost of service, that is, cost causality.

[6] Section 33 of the *Act* provides for an appeal to this Court on a question of law or jurisdiction. LIEN seeks a declaration that the Board has the jurisdiction to order a "rate affordability assistance program" for low income consumers of the utility, EGD, within its franchise areas as the distributor of natural gas.

[7] The position of EGD, the Board and the intervenor, the Consumers Council of Canada, is that LIEN's quite understandable and commendable concern is an issue of public policy to be dealt with by the Legislature and falls outside the jurisdiction of the Board.

2008 CanLII 23487 (ON SCDC)

2008 CanLII 23487 (ON SCDC)

The Standard of Review

[8] The issue is whether the Board is correct in its determination that it does not have jurisdiction to implement a low income affordability program.

[9] There is common ground that the standard of review is correctness. That is, this Court will interpret the statutory grant of authority on the basis of its own opinion as to a statute's construction, rather than deferring to the Board's determination of the issue. A tribunal's determination that it has no jurisdiction will be set aside as a "wrongful declining of jurisdiction" if the Court is of the view that the tribunal's decision is wrong. Donald J.M. Brown and John M. Evans, *Judicial Review of Administrative Action in Canada*, looseleaf (Toronto: Canvasback Publishing, 1998) at 14-3 to 14-4.

Analysis of the Board's Jurisdiction

A. Applicable Principles

[10] The Court is to be guided by the principles of statutory interpretation as set forth in Ruth Sullivan, *Driedger on the Construction of Statutes*, 3rd ed., (Toronto: Butterworths, 1994) at 131:

> There is only one rule in modern interpretation, namely, courts are obliged to determine the meaning of legislation in its total context, having regard to the purpose of the legislation, the consequences of proposed interpretations, as well as admissible external aids. In other words, the courts must consider and take into account all relevant and admissible indicators of legislative meaning. After taking these into account, the court must then adopt an interpretation that is appropriate. An appropriate interpretation is one that can be justified in terms of (a) its plausibility, that is its compliance with the legislative text; (b) its efficacy, that is, its promotion of the legislative purpose; and (c) its acceptability, that is, the outcome is reasonable and just.

[11] The words of the *Act* are to be read in their entire context and in their grammatical and ordinary sense, harmoniously with the scheme and object of the legislation and the Legislature's intent. *ATCO Gas and Pipelines Ltd. v. Alberta (Energy and Utilities Board)*, [2006] 1 S.C.R. 140 at para. 37 [*Atco*].

[12] The statute shall be interpreted as being remedial and given such "fair, large and liberal interpretation as best ensures the attainment of its objects." *Legislation Act*, S.O. 2006, c. 21, Schedule F, s. 64 (1).

[13] A statutory administrative tribunal obtains its jurisdiction from two sources: explicit powers expressly granted by statute, and implicit powers by application of the common law doctrine of jurisdiction by necessary implication. *Atco*, *supra*, at para. 38.

[14] The Court must apply a "pragmatic or functional" analysis in determining the issue of jurisdiction, by considering the wording of the *Act* conferring jurisdiction upon the Board, the purpose of the *Act* creating the Board, the reason for the Board's existence, the area of expertise of its members and the nature of the problem before the Board. *Union des employés de Service, local 298 v. Bibeault,* [1988] 2 S.C.R. 1048 at 1088.

B. The Wording of the Act

[15] Section 36 of the *Act* confers the Board's jurisdiction:

> **36.** (1) No gas transmitter, gas distributor or storage company shall sell gas or charge for the transmission, distribution or storage of gas except in accordance with an order of the Board, which is not bound by the terms of any contract.
>
> ….
>
> (2) The Board may make orders approving or fixing just and reasonable rates for the sale of gas by gas transmitters, gas distributors and storage companies, and for the transmission, distribution and storage of gas.
>
> (3) In approving or fixing just and reasonable rates, the Board may adopt any method or technique that it considers appropriate.

[16] LIEN submits that the Board's authority to fix "just and reasonable rates" by adopting "any method or technique it considers appropriate", conferred by s. 36 (2) and (3) of the *Act* is very broad and the statutory language must be given its ordinary meaning.

[17] The Board argues that the word "rates" is in the plural form in s. 36 (2) to allow the Board to set different rates for different classes of consumers based upon the costs of serving those consumers. For example, large industrial users are typically considerably more expensive to serve than residential consumers. Separate rate classes are a necessity to ensure that consumers reimburse for the actual costs of the service they receive.

[18] The majority opinion in the Board Decision is of the view that the words "any method or technique" cannot reasonably be interpreted to mean "a fundamental replacement of the rate making process based on cost causality with one based on income level as a rate grouping determinant." (p.9)

[19] The phrase "approving or fixing just and reasonable rates" in the present s. 36 (2) was first introduced by s. 17 (1) of Bill 38, *An Act to Establish the Ontario Energy Board*, 1st Sess., 26th Leg., Ontario, 1960 by the then Minister of Energy Resources, the Hon. Robert Macaulay. He outlined for the Legislature the philosophy underlying rate setting (*Legislature of Ontario Debates*, 9 (8 February 1960) at 199 (Hon. Macaulay)):

2008 CanLII 23487 (ON SCDC)

> First, why are there rate controls? There are rate controls because, in effect, the distribution of natural gas is a monopoly, a public utility. Secondly…it is fair that whatever rate is charged should be one designated, not only in the interests of the consumer, but also in the interests of the distributor…[O]ne really should have in mind 3 basic objectives: First, the rate should be low enough to secure to the user a fair and just rate. Second, the rate should be adequate to pay for good service and replacement and retirement of the used portion of the assets. Third, it should be high enough to attract a sufficient return on capital….

[20] He went on to explain the purpose of the Government's policy (at 205):

> "[F]irst, to protect the consumer, and to see that he pays a fair and just rate, not more or less, and that is competitive with other fuels. Second, to make sure the rate is sufficient to provide adequate service, replacements and safety for the company providing the service. Third, it is that the company should be able to charge a rate which is sufficient to attract the necessary capital to expand.

[21] The present s.36 (3) replaced s.19 of the old *Ontario Energy Board Act*, R.S.O. 1980, c. 332, which required a traditional cost of service analysis in very prescriptive terms:

> 19 (2) In approving or fixing rates and other charges under subsection (1), the board shall determine a rate base for the transmitter, distributor or storage company, and shall determine whether the return on the rate base …is reasonable.
>
> The rate base …shall be the total of,
>
> (a) a reasonable allowance for the cost of the property that is used or useful in serving the public, less an amount considered adequate by the Board for depreciation, amortization and depletion;
>
> (b) a reasonable allowance for working capital; and
>
> (c) such other amounts as, in the opinion of the Board, ought to be included.

[22] The authority was granted in s. 36 (3) to use "any method or technique it considers appropriate" in approving "just and reasonable rates" i.e., employing methods other than simply on a traditional cost of service basis as proscribed in the repealed s. 19 to set rates for the gas sector. This aligned the approach for natural gas with the non-prescriptive authority seen governing Ontario Hydro as a Crown corporation in rate setting for electricity distributors.

[23] Thus, under the former *Act* the phrase "just and reasonable rates" was limited to the cost of service basis articulated in prescriptive detail in s. 19. The change in repealing s. 19 and allowing the Board to "adopt any method or technique it considers appropriate" provides greater flexibility to the Board to employ other methods of rate making in approving and fixing "just and

2008 CanLII 23487 (ON SCDC)

reasonable rates" rather than simply the traditional cost of service regulation seen in the former s. 19.

2008 CanLII 23487 (ON SCDC)

[24] Subsection 36 (3) allows the Board to adopt "any method or technique that it considers appropriate" in fixing "just and reasonable rates." The majority Board Decision view is that this provision, considered within the context of the *Act* as a whole, allows the Board to employ flexible techniques and methods for cost of service analyses in determining rates, for example, the incentive rate mechanisms currently used for the major gas utilities.

[25] In the same rate setting proceeding that is under review, EGD reportedly asked the Board to approve two fuel-switching programs to enable residential consumers to shift from electric-water heaters to gas-water heaters, given that the latter promote conservation inasmuch as there is greater energy efficiency. The programs are identical except that there is a subsidy offered for the low income group of $800 per participant but a subsidy of only $600 for other consumers. Vice Chair Kaiser in dissenting points out that none of the parties have objected to this proposal and no one has argued that the Board does not have jurisdiction to approve different subsidies based upon income levels.

[26] Indeed, the majority opinion in the Board Decision allows that the Board has ordered that specific funding be channeled aimed at low income consumers for "Demand Side Management Programs."

[27] As well, the Board on occasion has reduced a significant rate increase because of so-called "rate shock" by spreading the increase over a number of years. Although this does not in itself suggest an unequal approach as between residential consumers it does indicate that the Board considers it has jurisdiction to take "ability to pay" into account in rate setting.

[28] EGD, like other utilities, makes annual contributions to enable emergency financial relief through the so-called "Winter Warmth Program" which provides funds as a subsidy to some low income consumers, enabling them to be able to heat their homes in winter months. These subsidies are taken into account as costs of the utility in the approval and fixing of rates by the Board. Although the program is funded by all consumers, to some extent there is indirect cross-subsidization within the residential consumer class.

[29] The Board points out that this is a relatively small program in the nature of a charitable objective, involving the United Way, which is specific to individual consumers in a financial crisis situation. But the fact remains that its implementation means that some residential consumers are paying less for the distribution and purchase of natural gas than other residential consumers are paying. If the Board has jurisdiction to approve utilities paying subsidies to the benefit of low income consumers then it arguably has jurisdiction to order utilities to provide special rates on a low income basis.

[30] Section 79 of the *Act* explicitly authorizes the Board to provide rate protection for rural or remote consumers of an electricity distributor. The majority decision argues that it is a reasonable inference that the Legislature, by virtue of the explicit singling out of a single

2008 CanLII 23487 (ON SCDC)

category of consumers in s. 79, did not intend this benefit to apply to other categories of consumers. The Board argues that if s. 36 (2) and (3) are intended to allow for differential rate setting for subsets of residential consumers, then s. 79 is unnecessary. The majority decision considers the existence of s. 79 as indicating that the Legislature has been explicit on issues that it considers warrant special treatment through a subsidy. The majority decision argues that the existence of s. 79 implicitly excludes any intent to confer jurisdiction to depart from simply the cost of service approach employed to implement the mandate given to the Board by s. 36.

[31] Moreover, the majority decision points out that rural rate assistance through s. 79 does not consider income level as an eligibility determinant. Rather, eligibility is based upon location and the inherent higher costs of service related to density levels. The assistance from the program is conferred upon all consumers within a given geographical area irrespective of their income level. Hence, this program arguably serves simply to mitigate the effect of the cost differential related to geography and remains consistent with a rate making process based upon cost causality. Nevertheless, "rate protection" through s. 79 operates as a subsidy paid by some of Ontario's residential electricity consumers for the benefit of others and represents a departure from the principle of cost causality being applied on the same basis to all consumers within a given class (i.e., residential, commercial and industrial).

[32] As pointed out in the dissent by Board Vice Chair Gordon Kaiser, s. 79 was introduced in 1999 when the authority to regulate rates for *electricity* distributors was transferred to the Ontario Energy Board. Prior thereto, electricity distributors were regulated by Ontario Hydro, a Crown corporation which had established the policy of setting special rates in remote and rural areas through the now repealed s. 108 of the *Power Corporation Act,* R.S.O. 1990, c. P. 18. The inference can be made, as Vice Chair Kaiser asserts, that s. 79 was introduced into the *Act* to expressly indicate to the Board that this significant historical policy must continue.

C. The Purpose of the Act and the Reason for the Board's existence

[33] The objectives for the Board with respect to natural gas regulation are set forth in s. 2 of the *Act*:

> (2) The Board, in carrying out its responsibilities under this or any other Act in relation to gas, shall be guided by the following objectives:
>
> 1. To facilitate competition in the sale of gas to users.
> 2. To protect the interests of consumers with respect to prices and the reliability and quality of gas service.
> 3. To facilitate rational expansion of transmission and distribution systems.
> 4. To facilitate rational development and safe operation of gas storage.
> 5. To promote energy conservation and energy efficiency in a manner consistent with the policies of the Government of Ontario.

> 5.1To facilitate the maintenance of a financially viable gas industry for the transmission, distribution and storage of gas.
> 6. To promote communication within the gas industry and the education of consumers.

[34] The Board is charged under s. 2 of the *Act* with protecting "the interests of consumers with respect to prices …." The Board argues that this provision speaks to consumers as a single class, not to a particular subset of consumers. The majority decision of the Board says the Board's mandate is to balance the interests of consumers as a single group with the interests of the regulated utility in the setting of "just and reasonable rates."

[35] The Divisional Court has emphasized in the past that the Board's mandate to fix just and reasonable rates **"**is unconditioned by directed criteria and is broad; the board is expressly allowed to adopt any method it considers appropriate." *Natural Resource Gas Ltd. v Ontario Energy Board*, [2005] O.J. No. 1520 at para. 13 (Div. Ct.). The Divisional Court also stated in *Enbridge Gas Distribution Inc. v. Ontario Energy Board* (2005), 75 O.R. (3d) 72, [2005] O.J. No. 756 at para.24:

> …[T]he legislation involves economic regulation of energy resources, including setting prices for energy which are fair and reasonable to the distributors and the suppliers, while at the same time are a reasonable cost for the consumer to pay. This will frequently engage the balancing of competing interests, as well as consideration of broad public policy.

[36] Writing for the majority of the Supreme Court of Canada in *Atco, supra,* at para. 62 Bastarache J. stated that "[r]ate regulation serves several aims – sustainability, equity and efficiency – which underlie the reasoning as to how rates are fixed."

D. The Area of Expertise of its Members and the Nature of the Problem before the Board

[37] The Board was asked to consider the application of the utility to establish rates. In that context, an intervenor asked the Board to consider whether, as a factor in rate-setting, the Board could consider the interests of low-income consumers and establish a rate affordability program. That issue of rate-setting is squarely within the jurisdiction of the Board.

[38] The majority opinion in the Board Decision correctly states that the Board's mandate for economic regulation is "rooted in the achievement of economic efficiencies, the establishment of fair returns for natural monopolies and the development of appropriate costs allocation methodologies".. However, that does not answer the question as to the full scope of the Board's jurisdiction in approving or fixing "just and reasonable rates" and adopting "any method or technique that it considers appropriate" in so doing.

[39] The Board's regulatory power is designed to act as a proxy in the public interest for competition in view of a natural gas utility's geographical natural monopoly. Absent the intervention of the Board as a regulator in rate-setting, gas utilities (for the benefit of their

2008 CanLII 23487 (ON SCDC)

shareholders) would be in a position to extract monopolistic rents from consumers, in particular, given a relatively inelastic demand curve for their commodity. Clearly, a prime purpose of the *Act* and the Board is to balance the interests of consumers of natural gas with those of the natural gas suppliers. The Board's mandate through economic regulation is directed primarily at avoiding the potential problem of excessive prices resulting because of a monopoly distributor of an essential service.

[40] In performing this regulatory function, it is consistent for the Board to seek to protect the interests of *all* consumers vis-a-vis the reality of a monopoly. The Board must balance the respective interests of the utility and the collective interest of all consumers in rate setting. *Re Union Gas Ltd. and Ontario Energy Board et al.* (1983), 1 D.L.R. (4th) 698 (Div. Ct.), (1983) 43 O.R. (2d) 489 at 501. The Board's regulatory power is primarily a proxy for competition rather than an instrument of social policy. *Dalhousie Legal Aid Service v. Nova Scotia Power Inc.,* (2006), 268 D.L.R. (4th) 408 at para. 33 [*Dalhousie*].

[41] *Dalhousie* dealt with a request for a low income affordability program like that advanced by LIEN. However, it involved a consideration of rate setting under s. 67 (1) of the Nova Scotia *Public Utilities Act* ,R.S.N.S. 1989, c. 380, which is very different in wording with respect to jurisdiction to that seen in s. 36 of the *Act* at hand. The Nova Scotia provision expressly provides that "rates shall always, under substantially similar circumstances and conditions in respect of service of the same description, be charged equally to all persons and at the same rate …." Hence, the Nova Scotia Utility and Review Board found that it did not have jurisdiction to order low income affordability programs.

[42] Section 36 of the *Act* has broad language, empowering the Board to set "just and reasonable" rates for the distribution of natural gas. The supply of natural gas can be considered a necessity that is available from a single source with prices set by the Board in the public interest. The Board has traditionally set rates on a "cost of service" basis, that is, on the basis of cost causality and employing a complex cost allocation exercise. In brief, this approach first looks to the utility's capital investments and maintenance costs including a fair rate of return to determine revenues required. The revenue requirement is then divided amongst the utility's rate paying consumers on a rate class basis (i.e., residential, commercial, industrial, etc.).

[43] The rates have been traditionally designed with the principled objective of having each rate class pay for the actual costs that class imposes upon the utility. That is, the Board has sought to avoid inter-class and intra class subsidies. See RP-2003-0063 (2005) at 5. Consistent with this approach, the Board has refused the establishment of a special rate class to provide redress for aboriginal consumers. *Decision with Reasons* EBRO493 (1997) (O.E.B.). In that case, the Ontario Native Alliance ("ONA") requested the Board to order a utility to evaluate the establishment of a rate class for the purpose of providing a special rate class for aboriginal peoples. At 316-17, the Board stated:

> The Board is required by the legislation to "fix just and reasonable rates", and in doing so it attempts to ensure that no undue discrimination occurs between rate classes, and that

2008 CanLII 23487 (ON SCDC)

the principles of cost causality are followed in allocating the underlying rates. While the board recognizes ONA's concerns, the Board finds that the establishment of a special rate class to provide redress for aboriginal consumers of Centra does not meet the above criteria and it is not prepared to order the studies requested by ONA.

[44] This decision would be within the Board's jurisdiction and a like response to LIEN in the case at hand would arguably be consistent and reasonable. However, the Board in dealing with the ONA request did not decline on the basis of jurisdiction. Rather, it said that it should not exercise its jurisdiction as requested by ONA for the reasons given.

[45] A low income rate affordability program would necessarily lead to treating consumer groups on a differentiated basis with higher prices for a majority of residential consumers and subsidization of the low-income subset by the majority group and/or other classes of consumers.

[46] If the Board were to reduce the rates for one class of consumers based upon an income determinant, the Board would have to increase the rates for another class or classes of consumers. In effect, such a rate reduction would impose a regressive indirect tax upon those required to pick up the shortfall. Such an approach would arguably be a dramatic departure from the Board's regulatory function as implemented to date, which has been to protect the collective interest of consumers dealing with a monopoly supplier through a "cost of service" calculation and then to treat consumers equally through determining rates to pay for the "cost of service" on a cost causality basis for classes of consumers.

[47] The Board's mandate has not been directed to the public interest in social or distributive justice through a differentiation of rates on the basis of income. That need is seen to be met through other mechanisms and programs legislated by the provincial Legislature and/or Parliament, for example, by refundable tax credits and social assistance.

[48] Indeed, the provincial income tax legislation previously provided for public tax expenditures to assist low income consumers with rising electricity costs. This was done through an "Ontario home electricity payment" by reference to income levels. *Income Tax Act*, R.S.O. 1990, c.1.2, s. 8.6.1, as rep. by *Income Tax Amendment Act (Ontario Home Electricity Relief), 2006*, S.O. 2006, c. 18, s. 1. As well, Parliament has provided a one-time relief for energy costs to low income families and seniors in Canada through the *Energy Costs Assistance Measures Act*, S.C. 2005, c. 49.

[49] The Board is an economic regulator, rather than a formulator of social policy. While no doubt the Board must take into account broad policy considerations, rate-setting is at the core of the Board's jurisdiction. *Garland v. Consumers' Gas Company* (2000), 185 D.L.R. (4th) 536 at paras. 17, 45-46 (Ont. S.C.J.). Special rates for low income consumers would not be based upon economic principles of regulation but rather on the social principle of ability to pay. Any program to subsidize low income consumers would require a source of funding which is a matter of public policy. See generally *Re Rate Concessions to Poor Persons and Senior Citizens*, 14 Pub. Util. Rep. 4th 87 at 94 (Or. 1976).

2008 CanLII 23487 (ON SCDC)

[50] This view of the nature and limit of the regulatory function is generally accepted as the norm in other jurisdictions. See for example *Washington Gas light Co. v. Public Service Commission of the District of Columbia* (1982), 450 A.2d 1187 at para. 38 (D.C. Ct. App.); *State of Louisiana v. the Council of the City of New Orleans and New Orleans Public Service, Inc.* (1975), 309 So. 2nd 290 at 294 (La. Sup. Ct.).

[51] The historical common law approach for public utility regulation has been that consumers with similar cost profiles are to be treated equally so far as reasonably possible with respect to the rates paid for services. See, for example, *St. Lawrence Rendering Co. Ltd. v. The City of Cornwall,* [1951] O.R. 669-685 at 683; *Chastain et al. v. British Columbia Hydro and Power Authority* (1972), 32 D.L.R. (3d) 443 at 454 (B.C.S.C); *Canada (Attorney General)* v. *Toronto (City)* (1893), 23 S.C.R. 514 at 519-520.

Conclusions on the Board's Jurisdiction

[52] We agree that the traditional approach of "cost of service" is the root principle underlying the determination of rates by the Board because that is necessary to meet the fundamental, core objective of balancing the interests of all consumers and the natural monopoly utility in rate/price setting.

[53] However, the Board is authorized to employ "any method or technique that it considers appropriate" to fix "just and reasonable rates." Although "cost of service" is necessarily an underlying fundamental factor and starting point to determining rates, the Board must determine what are "just and reasonable rates" within the context of the objectives set forth in s. 2 of the *Act*. Objective #2 therein speaks to protecting "the interests of consumers with respect to prices."

[54] The "cost of service" determination will establish a benchmark global amount of revenues resulting from an estimated quantity of units of natural gas or electricity distributed. The Board could use this determination to fix rates on a cost causality basis. This has been the traditional approach.

[55] However, in our view, the Board need not stop there. Rather, the Board in the consideration of its statutory objectives might consider it appropriate to use a specific "method or technique" in the implementation of its basic "cost of service" calculation to arrive at a final fixing of rates that are considered "just and reasonable rates." This could mean, for example, to further the objective of "energy conservation", the use of incentive rates or differential pricing dependent upon the quantity of energy consumed. As well, to further the objective of protecting "the interests of consumers" this could mean taking into account income levels in pricing to achieve the delivery of affordable energy to low income consumers on the basis that this meets the objective of protecting "the interests of consumers with respect to prices."

[56] The Board is engaged in rate-setting within the context of the interpretation of its statute in a fair, large and liberal manner. It is not engaged in setting social policy.

2008 CanLII 23487 (ON SCDC)

[57] This is not, of course, to imply any preferred course of action in rate setting by the Board. The Board in its discretion may determine that "just and reasonable rates" are those that follow from the approach of "cost causality" once the "cost of service" amount is determined. That is, the principle of equality of rates for consumers within a given class (e.g., residential consumers) may be viewed as the most just and reasonable approach. A determination by the Board that all residential gas consumers (with relatively minor deviations through such programs as the "Winter Warmth Program") pay the same distribution rates is not in itself discriminatory on a prohibited ground. Indeed, it can be seen as a non-discriminatory policy in terms of prices paid.

[58] Nor is it to suggest that as a matter of public policy, objectives of distributive justice or conservation in respect of energy consumption are best achieved by rate setting as compared to, for instance, tax expenditures or social assistance devised and implemented by the Legislature through mechanisms independent of the operation of the *Act*. It is noted that the Minister is given the authority in s. 27 of the *Act* to issue policy statements as to matters that the Board must pursue; however, the Minister has not issued any policy statement directing the board to base rates on considerations of the ability to pay. Moreover, the power granted to a regulatory authority "must be exercised reasonably and according to the law, and cannot be exercised for a collateral object or an extraneous and irrelevant purpose, however commendable." *Re Multi Malls Inc. et al. and Minister of Transportation and Communications et al* (1977), 14 O.R. (2d) 49 at 55 (C.A.). As we have said, cost of service is the starting point building block in rate setting, to meet the fundamental concern of balancing the interests of all consumers with the interests of the natural monopoly utility.

[59] Nor does our conclusion presume as to what methods or techniques may be available in determining "just and reasonable rates." Efficiency and equity considerations must be made. Rather, this is to say only that so long as the global amount of return to the utility based upon a "cost of service" analysis is achievable, then the rates/prices (and the methods and techniques to determine those rates/prices) to generate that global amount is a matter for the Board's discretion in its ultimate goal and responsibility of approving and fixing "just and reasonable rates."

[60] The issue before the Court is that of jurisdiction, not how and the manner by which the Board should exercise the jurisdiction conferred upon it.

[61] In our view, and we so find, the Board has the jurisdiction to take into account the ability to pay in setting rates. We so find having taken into account the expansive wording of s. 36 (2) and (3) of the statute and giving that wording its ordinary meaning, having considered the purpose of the legislation within the context of the statutory objectives for the Board seen in s. 2, and being mindful of the history of rate setting to date in giving efficacy to the promotion of the legislative purpose.

[62] We also find that that interpretation is appropriate taking into account the criteria articulated in *Driedger,* above, namely it complies with the legislative text, it promotes the legislative purpose and the outcome is reasonable and just.

2008 CanLII 23487 (ON SCDC)

[63] As indicated above, a statutory administrative tribunal obtains its jurisdiction from explicit powers or implicit powers. Having found that the jurisdiction to consider ability to pay in rate setting is explicitly within the *Act,* we need not consider the doctrine of necessary implication or the related principle of implied exclusion.

The issue of the *Canadian Charter of Rights and Freedoms*

[64] Before concluding, it is appropriate to mention the submission made on behalf of LIEN in respect of s. 15 (1) of the *Canadian Charter of Rights and Freedoms*, Part 1 of the *Constitution Act, 1982*, being Schedule B to the *Canada Act, 1982* (U.K.), c. 11 (the "*Charter*").

[65] LIEN says it raises the *Charter* simply within the context of it being an interpretive tool in discerning the meaning of an asserted ambiguous s. 36 of the *Act*. LIEN says it does not raise any issue that the *Act* or the Board's actions or inactions are contrary to the *Charter*.

[66] LIEN argues that in the absence of clear statutory provisions, the requirement for "just and reasonable rates" must be interpreted to comply with s. 15. The *Charter* applies to provincial legislation and can be used as an interpretive tool. *R. v. Rogers*, [2006] 1 S.C.R. 554, [2006] S.C.J. No. 15 at para. 18. In our view, as stated above, the *Act* provides the Board with the requisite jurisdiction without having to look to the *Charter*.

[67] While we heard submissions from LIEN, we declined to hear from counsel for the respondents on this issue. We agree with our colleague Swinton J. that such an argument requires a full evidentiary record.

Disposition

[68] For the reasons given, the appeal is allowed and it is declared that the Board has the jurisdiction to establish a rate affordability assistance program for low income consumers purchasing the distribution of natural gas from the utility, EGD.

[69] All parties agree that there is not to be any award of costs in respect of this appeal.

KITELEY J.

CUMMING J.

2008 CanLII 23487 (ON SCDC)

Released: May , 2008

2008 CanLII 23487 (ON SCDC)

Swinton J. (dissenting):

[70] The sole issue in this appeal is whether the Ontario Energy Board (the "Board") erred in holding that it had no jurisdiction, when setting residential rates for gas distribution, to order a rate affordability program for low income consumers. In my view, the majority of the Board was correct in concluding that the Board lacked jurisdiction to make such an order.

[71] The majority of the Board predicated its decision on the understanding that the appellants' proposal contemplated the establishment of a rate group for low income residential consumers that would be funded by general rates. I, too, proceed on that assumption. While there were no details of a specific program put forth by the appellants during the hearing, it is inevitable that the Board, in setting lower rates for the economically disadvantaged, would have to impose higher rates on other consumers.

The Board's Practice in Setting Rates

[72] Pursuant to the *Ontario Energy Board Act, 1998,* S.O. 1998, c. 15, Schedule B (the "Act"), the Board has authority to set rates for both gas and electricity. It has traditionally set rates for gas through a "cost of service" assessment, in which it seeks to determine a utility's total cost of providing service to its customers over a one year period (the "test year"). According to the Board's factum, these costs include the rate base (which is essentially the net book value of the utility's total capital investments) and the utility's operational and maintenance costs for the test year, among other things. The utility's total costs for the test year (usually including a rate of return on the rate base portion) forms the revenue requirement. The revenue requirement is then divided amongst the utility's ratepayers on a rate class basis (that is, residential, small commercial, industrial, etc.).

[73] With respect to gas, it has always been the Board's practice to allocate the revenue requirement to the different rate classes on the basis of how much of that cost the rate class actually causes ("cost causality"). To the greatest extent possible, the Board has striven to avoid inter-class subsidies (see, for example, Decision with Reasons, RP-2003-0063 (2005), p. 5).

The Proper Approach to Statutory Interpretation

[74] To determine the issue in this appeal, it is necessary to consider the powers conferred on the Board by its constituent legislation, the *Ontario Energy Board Act*. That Act must be interpreted using the modern principles of statutory interpretation described by Professor Ruth Sullivan in *Driedger on the Construction of Statutes* (3rd ed.) (Toronto: Butterworths, 1994) as follows:

> There is only one rule in modern interpretation, namely, courts are obliged to determine the meaning of legislation in its total context, having regard to the purpose of the

2008 CanLII 23487 (ON SCDC)

> legislation, the consequences of proposed interpretations, the presumptions of special rules of interpretation, as well as admissible external aids. In other words, the courts must consider and take into account all relevant and admissible indicators of legislative meaning. After taking these into account, the court must then adopt an interpretation that is appropriate. An appropriate interpretation is one that can be justified in terms of (a) its plausibility, that is, its compliance with the legislative text; (b) its efficacy, that is, its promotion of the legislative purpose; and (c) its acceptability, that is, the outcome is reasonable and just. (at p. 131)

[75] The words of a statute are to be read in their entire context and in their grammatical and ordinary sense, harmoniously with the scheme of the Act, its objects, and the intent of the Legislature (*ATCO Gas and Pipelines Ltd. v. Alberta (Energy and Utilities Board)*, [2006] 1 S.C.R. 140 at para. 37).

The Words of the Provision in Issue

[76] Subsection 36(2) of the Act gives the Board the broad authority to approve or fix "just and reasonable" rates for the distribution of gas. On its face, those words might encompass the power to set rates according to income. However, the words do not explicitly confer the power to do so, and the Supreme Court of Canada commented in *ATCO, supra* that a discretionary grant of authority to a tribunal cannot be viewed as conferring unlimited discretion. A regulatory tribunal must interpret its powers "within the confines of the statutory regime and principles generally applicable to regulatory matters, for which the legislature is assumed to have had regard in passing that legislation" (at para. 50).

[77] The appellants also rely on s. 36(3), which states that in approving or fixing just and reasonable rates, the Board may adopt "any method or technique that it considers appropriate". These words were added to the Act in 1998. Examples of methods or techniques used by the Board for setting gas distribution rates are cost of service regulation and incentive regulation.

[78] On its face, the words of s. 36(3) do not confer the jurisdiction to provide special rates for low income customers. The subsection replaced an earlier provision of the Act which required a traditional cost of service analysis in setting rates. I agree with the conclusion of the Board majority as to the meaning of s. 36(3) (Reasons, p. 10):

> It gives the Board the flexibility to employ other methods of ratemaking in fixing just and reasonable rates, such as incentive ratemaking, rather than the traditional costs of service regulation specified in section 19 of the old Act. The change in the legislation was coincident with the addition of the regulation of the electricity sector to the Board's mandate. The granting of the authority to use methods other than cost of service to set rates for the gas sector was an alignment with the non-prescriptive authority to set rates for the electricity sector. The Board is of the view that if the intent of the legislature by the new language was to include ratemaking considering income level as a rate class determinant, the new Act would have made this provision explicit given the opportunity

2008 CanLII 23487 (ON SCDC)

at the time of the update of the Act and the resultant departure from the Board's past practice.

The Regulatory Context

[79] According to longstanding principles governing public utilities developed under the common law, a public utility like the respondent Enbridge Gas Distribution Inc. ("Enbridge") must treat all its customers equally with respect to the rates they pay for a particular service (*Attorney General of Canada v. The Corporation of the City of Toronto* (1892), 23 S.C.R. 514 at 519-20; St. *Lawrence Rendering Co. Ltd. v. Cornwall*, [1951] O.R. 669 (H.C.J.) at 683; *Chastain v. British Columbia Hydro and Power Authority* (1972), 32 D.L.R. (3d) 443 (B.C.S.C.) at 454).

[80] As noted in the Board's majority reasons, the Board is, at its core, an economic regulator (Reasons, p. 4). Rate setting is at the core of its jurisdiction (*Garland v. Consumer's Gas Company* (2000), 185 D.L.R. (4th) 536 (Ont. S.C.J.) at para. 45). I agree with the majority's description of economic regulation as being "rooted in the achievement of economic efficiencies, the establishment of fair returns for natural monopolies and the development of appropriate cost allocation methodologies" (Reasons, p. 4).

[81] Historically, in setting rates, the Board has engaged in a balancing of the interests of the regulated utility and consumers. The Board has not historically balanced the interests of different groups of consumers. As the Divisional Court stated in *Union Gas Ltd. v. Ontario (Energy Board)* (1983), 43 O.R. (2d) 489 at p. 11 (Quicklaw):

> … it is the function of the O.E.B. to balance the interest of the appellant in earning the highest possible return on the operation of its enterprise (a monopoly) with the conflicting interest of its customers to be served as cheaply as possible.

See, as well, *Northwestern Utilities v. The City of Edmonton*, [1929] 1 S.C.R. 186 at 192.

[82] In a similar vein, the Supreme Court in *ATCO, supra* spoke of a "regulatory compact" which ensures that all customers have access to a utility at a fair price. The Court went on to state (at para. 63):

> Under the regulatory compact, the regulated utilities are given exclusive rights to sell their services within a specified area at rates that will provide companies the opportunity to earn a fair rate of return for all their investors. In return for this right of exclusivity, utilities assume a duty to adequately and reliably serve all customers of their defined territories, and are required to have their rates and certain operations regulated…

The Court described the object of the Act "to protect both the customer *and* the investor" (at para. 64).

2008 CanLII 23487 (ON SCDC)

[83] The Legislature, in conferring power on the Board, must be taken to have had regard to the principles generally applicable to rate regulation (*ATCO, supra* at paras. 50 and 64). I agree with the submission of Enbridge that those principles are the following:

> (a) customers of a public utility must be treated equally insofar as the rate for a particular service or class of services is concerned; and
>
> (b) the Legislature will be presumed not to have intended to authorize discrimination among customers of a public utility unless it has used specific words to express this intention.

[84] Thus, the considerations of justice and reasonableness in the setting of rates have been and are those between the utility and consumers as a group, not among different groups of consumers based on their ability to pay.

Other Provisions of the Act

[85] In applying s. 36(2), the Board must be bound by the objectives set out in s. 2 of the Act, which includes

> 2. To protect the interests of consumers with respect to prices and the reliability and quality of gas service.

[86] The appellants submit that these words are broad enough to permit the Board to order a rate affordability assistance program. However, that is not obvious from the words used, which refer to "consumers" as a whole, and not to any particular subset of consumers. Indeed, it can be argued that any low income rate affordability program would run counter to the stated objective, given that such a program must almost certainly be funded through higher rates paid by other consumers. The result would be to provide benefits to one group of consumers at the expense of others.

[87] The reason for this conclusion lies in the Board's historical approach to rate setting, as described earlier in these reasons. The Board sets a revenue requirement for utilities before allocating those costs to the different rate classes. The only way the utility could recover its revenue requirement, given a rate class with lower rates for low income consumers, would be to increase the rates charged to other classes. Therefore, such higher prices can not be seen as protecting the interests of consumers with respect to prices, as set out in objective 2.

[88] Moreover, the Act contains an explicit provision in s. 79 that allows the Board to provide rate protection for rural and remote customers of electricity distributors. Subsection 79(1) provides:

> The Board, in approving just and reasonable rates for a distributor who delivers electricity to rural or remote consumers, shall provide rate protection for those consumers

2008 CanLII 23487 (ON SCDC)

> or prescribed classes of those consumers by reducing the rates that would otherwise apply in accordance with the prescribed rules.

Section 79 also provides grandfathering for those who had a subsidy prior to the change in the Act. As well, it explicitly allows the distributor to be compensated for the subsidized rates through contributions from other consumers, as provided by the regulations.

[89] This section was added to the Act in 1998, when the Board was given the authority over electricity rate regulation. Section 79 ensured the ongoing protection of rural rates put in place when electricity distribution was regulated by Ontario Hydro.

[90] One of the principles of statutory interpretation is "implied exclusion". As Professor Sullivan has stated, this principle operates "whenever there is reason to believe that if the legislature had meant to include a particular thing within its legislation, it would have referred to that thing expressly" (*supra,* p. 186). While the purpose of s. 79 of the Act was to protect a pre-existing policy to assist rural and remote residential consumers, nevertheless, it is telling that there is no similar explicit power to order special rates or rate subsidies for other groups elsewhere in the Act.

The Significance of Ordering Rate Affordability Programs

[91] An appropriate interpretation can be justified in terms of its promotion of the legislative purpose and the reasonableness of the outcome (see Sullivan, quoted above at para. 5).

[92] The ability to order a rate affordability program would significantly change the role that the Board has played – indeed, the majority of the Board stated a number of times that the proposal to base rates on income level would be a "fundamental" departure from its current practice. In the past, the Board has acted as an economic regulator, balancing the interests of the utility and its shareholders against the interests of consumers as a group. Were it to assume jurisdiction over rate affordability programs, it would carry out an entirely different function. It would enter into the realm of social policy, weighing the interests of low income consumers against those of other consumers. This is not a role that the Board has traditionally played. This is not where its expertise lies, nor is it well-suited to taking on such a role.

[93] An examination of the particular case before the Board illustrates this. The appellants seek a rate affordability assistance program for gas in response to Enbridge's application for a rate increase for gas distribution – that is, for the *delivery* of natural gas. Customers can make arrangements for the purchase of the commodity of natural gas with a variety of suppliers in the competitive market. Therefore, were the Board to assume jurisdiction to order a rate affordability assistance program here, it could address only one part of the problem that low income consumers face in meeting their heating costs – the cost of distribution of gas.

[94] In addition, the Board would have to consider eligibility criteria for a rate affordability assistance program that reasonably would take into account existing programs for assistance to

2008 CanLII 23487 (ON SCDC)

low income consumers. Obviously, this would include social assistance programs. As well, Enbridge, in its factum, has identified other programs which provide assistance for low income consumers. For example, the Ontario government has implemented a program to assist low income customers with rising electricity costs through amendments to income tax legislation (*Income Tax Act*, R.S.O. 1990, c. I.2, s. 8.6.1, as amended S.O. 2006, c.18, c.1). At the federal level, there was one-time relief for low income families and senior citizens provided by the *Energy Costs Assistance Measures Act*, S.C. 2005, c. 49.

[95] Moreover, in order to cover the lower costs, the Board would have to increase the rates of other customers in a manner that would inevitably be regressive in nature, as it is difficult to conceive how the Board would be able to determine, in a systematic way, the ability of these other customers to pay.

[96] Clearly, the determination of the need for a subsidy for low income consumers is better made by the Legislature. That body has the ability to consider the full range of existing programs, as well as a wide range of funding options, while the Board is necessarily limited to allocating the cost to other consumers. The relative advantages of a legislative body in establishing social programs of the kind proposed are well described in the following excerpt from a decision of the Oregon Public Utility Commissioner (*Re Rate Concessions to Poor Persons and Senior Citizens* (1976), 14 PUR 4th 87 at p. 94):

> Utility bills are not poor persons' only problems. They also cannot afford adequate shelter, transportation, clothing or food. The legislative assembly is the only agency which can provide comprehensive assistance, and can fund such assistance from the general tax funds. It has the information and responsibility to deal with such matters, and can do so from an overall perspective. It can determine the needs of various groups and compare those needs to existing social programs. If it determines a special program is needed to deal with energy costs, it can affect all energy sources rather than only those the commissioner regulates.
>
> With clear authority to establish social welfare policy, the legislative assembly also can monitor all state and federal welfare programs and the sources and extent of aid given to different groups. Without such overview, as independent agencies aid various segments of society, the total aid given each group is unknown, and unequal treatment of different groups becomes likely.

[97] Where the issue of rate affordability programs has arisen in other jurisdictions, courts and boards have ruled that a public utilities board does not have jurisdiction to set rates based on ability to pay (see, for example, *Washington Gas Light Co. v. Public Service Commission of the District of Columbia* (1982), 450 A. 2d 1187 (D.C. Ct. App.) at para. 38; *Dalhousie Legal Aid Service v. Nova Scotia Power Inc.* (2006), 268 D.L.R. (4th) 408 (N.S.C.A.) at 419; Alberta Energy and Utilities Board Decision 2004-066, Section 9.2.6 at 161, as well as the Oregon case, *supra*).

2008 CanLII 23487 (ON SCDC)

[98] The appellants distinguish the *Dalhousie Legal Aid* case because the Nova Scotia legislation is different from Ontario's. Specifically, s. 67(1) of the *Public Utilities Act*, R.S.N.S. 1989, c. 380 provides that "[a]ll tolls, rates and charges shall always, under substantially similar circumstances and conditions in respect of service of the same description, be charged equally to all persons and at the same rate".

[99] While the language of the two statutes does differ, nevertheless, the reasons of the Nova Scotia Court of Appeal make it clear that the Board's role is not to set social policy. At para. 33, Fichaud J.A, observed, "The Board's regulatory power is a proxy for competition, not an instrument of social policy."

[100] Moreover, the principle in s. 67(1) of the Nova Scotia Act requiring that rates be charged equally is a codification of the common law, set out earlier in these reasons. The Ontario Board has long operated according to the same principles.

[101] The appellants submit that the recent decision in *Allstream Corp. v. Bell Canada*, [2005] F.C.J. No. 1237 (C.A.) assists their case. There, the Federal Court of Appeal upheld a decision of the Canadian Radio-Television and Telecommunications Commission (the "CRTC") approving special facilities tariffs submitted by Bell for the provision of optical fibre services pursuant to certain customer-specific arrangements. All but one related to a Quebec government initiative aimed at supporting the construction of broadband networks for rural municipalities, school boards and other institutions. The Court determined that the Commission's decision approving the tariffs was not patently unreasonable, given the exceptional circumstances of the case that justified a deviation from the normal practice of rate determination. The Court noted that the Commission considered matters that were not purely economic, but noted that such considerations were part of the Commission's wide mandate under s. 7 of the *Telecommunications Act,* S.C. 1993, c. 38 (at paras. 34-35).

[102] Section 7 of that Act, unlike s. 2 of the *Ontario Energy Board Act,* expressly includes the power "to respond to the economic and social requirements of users of telecommunications services" (s. 7(h)), as well as to enrich and strengthen the social and economic fabric of Canada and its regions (s. 7(a)). Moreover, while s. 27(2)(b) of that Act forbids unjust discrimination in rates charged, s. 27(6) explicitly permits reduced rates, with the approval of the Commission, for any charitable organization or disadvantaged person.

[103] In contrast to the broad mandate given to the CRTC, the objectives of the Board are much more confined. When the Board's objectives go beyond the economic realm, specific reference has been made to other objectives, such as conservation and consumer education (s. 2 (5) and (6)). There is no reference to the consideration of economic and social requirements of consumers.

[104] The appellants have also pointed out that the Board has in the past authorized programs that transfer benefits to lower income customers. The Winter Warmth program is one in which individuals can apply for emergency financial relief with heating bills. It is triggered by an

2008 CanLII 23487 (ON SCDC)

application from a particular customer, and the program is funded by all customers. The fact that the Board has approved this charitable program does not lead to the conclusion that it has jurisdiction to set rates on the basis of income level.

[105] With respect to the Demand Side Management (DSM) programs, the majority of the Board explained that this is not equivalent to a rate class based on income level. At p. 11 of its Reasons, the majority stated,

> The Board is vigilant in ensuring that customer groups are afforded the opportunity to receive the benefits of the costs charged. In the case of Demand Side Management (DSM) programs, for example, the Board has ordered that specific funding be channeled for programs aimed at low income customers. It cannot be argued that this constitutes discriminatory pricing. Rather, the contrary. It is an attempt to avoid discrimination against low income customers who also pay for DSM programs but may not have equal opportunities to take advantage of these programs.

[106] Were the Board to assume jurisdiction to order a rate affordability assistance program, it would be taking on a significant new role as a regulator of social policy. Given the dramatic change in the role that it has historically played, as well as the departure from common law principles, it would require express language from the Legislature to confer such jurisdiction

Jurisdiction by Necessary Implication

[107] In order to impute jurisdiction to a regulatory body, there must be evidence that the exercise of the power in question is a practical necessity for the regulatory body to accomplish the goals prescribed by the Legislature (*ATCO, supra* at paras. 51, 77). In this case, there is no evidence that the power to implement a rate affordability assistance program is a practical necessity for the Board to meet its objectives as set out in s. 2.

The Role of the Charter

[108] The appellants submit that the values found in s. 15 of the *Canadian Charter of Rights and Freedoms* should be considered in the interpretation of the ratemaking provisions of the Act. However, the Charter has no relevance in interpretation unless there is genuine ambiguity in the statutory provision (*R. v. Rodgers*, [2006] 1 S.C.R. 554 at paras. 18-19). A genuine ambiguity is one in which there are "two or more plausible readings, each equally in accordance with the intentions of the statute" (at para. 18).

[109] In my view, there is no ambiguity in the interpretation of s. 36 of the Act, and therefore, there is no need to resort to the Charter.

[110] In any event, the appellants' argument is, in fact, that the failure of the Board to order a rate affordability program is discriminatory on the basis of sex, race, age, disability and social assistance, because of the adverse impact on these groups (Factum, para. 43, as well as para. 47).

2008 CanLII 23487 (ON SCDC)

Such an argument can not be made without a full evidentiary record, and the inclusion of statistical material in the Appeal Book is not a sufficient basis on which to address this equality argument.

2008 CanLII 23487 (ON SCDC)

Conclusion

[111] For these reasons, I am of the view that the majority decision of the Board was correct, and that the Board has no jurisdiction to order rate affordability assistance programs for low income consumers. Therefore, I would dismiss the appeal.

Swinton J.

Released: May 16, 2008

COURT FILE NO.: 273/07
DATE: 20080516

2008 CanLII 23487 (ON SCDC)

ONTARIO
SUPERIOR COURT OF JUSTICE

DIVISIONAL COURT

KITELEY, CUMMING AND SWINTON JJ.

B E T W E E N:

ADVOCACY CENTRE FOR TENANTS-ONTARIO and INCOME SECURITY ADVOCACY CENTRE on behalf of LOW-INCOME ENERGY NETWORK

Appellant

- and -

ONTARIO ENERGY BOARD

Respondent

REASONS FOR JUDGMENT

Released: May 16, 2008

2006 NSCA 74
Nova Scotia Court of Appeal

Dalhousie Legal Aid Service v. Nova Scotia Power Inc.

2006 CarswellNS 249, 2006 NSCA 74, [2006] N.S.J. No. 243, 149 A.C.W.S. (3d) 355, 245 N.S.R. (2d) 206, 268 D.L.R. (4th) 408, 777 A.P.R. 206

Dalhousie Legal Aid Service (Appellant) v. Nova Scotia Power Inc. (Respondent)

Fichaud J.A., Freeman J.A., and Saunders J.A.

Heard: May 29, 2006
Judgment: June 20, 2006
Docket: C.A. 248695

Counsel: Claire McNeil, Vincent Calderhead for Appellant
Daniel Campbell, Q.C. for Respondent
Richard Melanson for Nova Scotia Utility & Review Board
Stephen McGrath for Attorney General of Nova Scotia

Subject: Public; Civil Practice and Procedure

Headnote

Public law --- Public utilities — Regulatory boards — Practice and procedure — Judicial review — Jurisdiction of board
Power corporation served nearly half million customers in province — Corporation applied to board to institute rate increases — Intervenor requested board approve program featuring power rate credits for low income customers — Board concluded that it had no power to consider intervenor's proposal and declined to consider plan — Intervenor brought appeal from board's decision — Appeal dismissed — Board did not err in refusing to consider merits of plan — Board's regulatory power was proxy for competition, not instrument of social policy — Legislation mandated that rates were always to be charged equally to all persons in substantially similar circumstances and conditions — Board could not reduce rates to low income customers who received same service as high income customers — Previous decisions where board approved load retention rates for large industrial customers were not relevant to current proceedings — Such decisions dealt with distinct economic realities of demand and competition which were legitimately within board's purview.

Table of Authorities

Cases considered by *Fichaud J.A.*:

Allstream Corp. v. Bell Canada (2005), 2005 FCA 247, 2005 CarswellNat 1970, 338 N.R. 177, 2005 CAF 247, 2005 CarswellNat 5049 (F.C.A.) — considered

ATCO Gas & Pipelines Ltd. v. Alberta (Energy & Utilities Board) (2006), 2006 SCC 4, 2006 CarswellAlta 139, 2006 CarswellAlta 140, 344 N.R. 293, 54 Alta. L.R. (4th) 1, [2006] 5 W.W.R. 1, 263 D.L.R. (4th) 193, 39 Admin. L.R. (4th) 159 (S.C.C.) — followed

Baker v. Canada (Minister of Citizenship & Immigration) (1999), 174 D.L.R. (4th) 193, 1999 CarswellNat 1124, 1999 CarswellNat 1125, 243 N.R. 22, 1 Imm. L.R. (3d) 1, 14 Admin. L.R. (3d) 173, [1999] 2 S.C.R. 817 (S.C.C.) — referred to

Bell ExpressVu Ltd. Partnership v. Rex (2002), 2002 SCC 42, 2002 CarswellBC 851, 2002 CarswellBC 852, 100 B.C.L.R. (3d) 1, [2002] 5 W.W.R. 1, 212 D.L.R. (4th) 1, 287 N.R. 248, 18 C.P.R. (4th) 289, 166 B.C.A.C. 1, 271 W.A.C. 1, 93 C.R.R. (2d) 189, [2002] 2 S.C.R. 559 (S.C.C.) — considered

Capital District Health Authority v. N.S.G.E.U. (2006), 2006 NSCA 44, 2006 CarswellNS 154 (N.S. C.A.) — considered

 Copyright © Thomson Reuters Canada Limited or its licensors (excluding individual court documents). All rights reserved.

Doctors Nova Scotia v. Nova Scotia (Department of Health) (2006), 2006 NSCA 59, 2006 CarswellNS 195 (N.S. C.A.) — referred to

Eldridge v. British Columbia (Attorney General) (1997), 1997 CarswellBC 1939, 1997 CarswellBC 1940, 151 D.L.R. (4th) 577, 218 N.R. 161, 96 B.C.A.C. 81, 155 W.A.C. 81, [1998] 1 W.W.R. 50, 46 C.R.R. (2d) 189, 38 B.C.L.R. (3d) 1, [1997] 3 S.C.R. 624, 3 B.H.R.C. 137 (S.C.C.) — followed

Granite Environmental Inc. v. Nova Scotia (Labour Relations Board) (2005), 2005 NSCA 141, 2005 CarswellNS 471, 238 N.S.R. (2d) 59, 757 A.P.R. 59, 261 D.L.R. (4th) 98, 39 Admin. L.R. (4th) 292, (sub nom. *I.U.O.E., Local 721 v. Granite Environmental Inc.*) 120 C.L.R.B.R. (2d) 117 (N.S. C.A.) — referred to

Johnson v. Nova Scotia (2005), 2005 NSCA 99, 2005 CarswellNS 278, (sub nom. *Nova Scotia v. Johnson*) 256 D.L.R. (4th) 105, 87 L.C.R. 82, (sub nom. *Nova Scotia v. Johnson*) 234 N.S.R. (2d) 260, (sub nom. *Nova Scotia v. Johnson*) 745 A.P.R. 260 (N.S. C.A.) — considered

N.S.T.U. v. Nova Scotia Community College (2006), 2006 NSCA 22, 2006 CarswellNS 68 (N.S. C.A.) — referred to

Nova Scotia (Minister of Health) v. G. (R.) (2005), 232 N.S.R. (2d) 51, 737 A.P.R. 51, 2005 NSCA 59, 2005 CarswellNS 158, 15 E.T.R. (3d) 1 (N.S. C.A.) — referred to

Nova Scotia Power Inc., Re (May 24, 2000), Doc. NSUARB-NSPI-P-871 (N.S. Utility & Review Bd.) — referred to

Nova Scotia Power Inc., Re (2003), 2003 NSUARB 6 (N.S. Utility & Review Bd.) — referred to

Nova Scotia Power Inc., Re (2003), 2003 NSUARB 91 (N.S. Utility & Review Bd.) — referred to

Nova Scotia (Public Utilities Board) v. Nova Scotia Power Corp. (1976), 18 N.S.R. (2d) 692, 20 A.P.R. 692, 75 D.L.R. (3d) 72, 1976 CarswellNS 190 (N.S. C.A.) — considered

Parry Sound (District) Welfare Administration Board v. O.P.S.E.U., Local 324 (2003), (sub nom. *Parry Sound (District) Social Services Administration Board v. O.P.S.E.U., Local 324*) 230 D.L.R. (4th) 257, (sub nom. *Social Services Administration Board (Parry Sound) v. Ontario Public Service Employees Union, Local 324*) 308 N.R. 271, (sub nom. *Social Services Administration Board (Parry Sound District) v. Ontario Public Service Employees Union, Local 324*) 177 O.A.C. 235, (sub nom. *Parry Sound (District) Social Services Administration Board v. O.P.S.E.U., Local 324*) [2003] 2 S.C.R. 157, 31 C.C.E.L. (3d) 1, 47 C.H.R.R. D/182, 2003 SCC 42, 2003 CarswellOnt 3500, 2003 CarswellOnt 3501, 2003 C.L.L.C. 220-062, 7 Admin. L.R. (4th) 177 (S.C.C.) — referred to

Pushpanathan v. Canada (Minister of Employment & Immigration) (1998), 226 N.R. 201, (sub nom. *Pushpanathan v. Canada (Minister of Citizenship & Immigration)*) 160 D.L.R. (4th) 193, (sub nom. *Pushpanathan v. Canada (Minister of Citizenship & Immigration)*) [1998] 1 S.C.R. 982, 1998 CarswellNat 830, 1998 CarswellNat 831, 43 Imm. L.R. (2d) 117, 11 Admin. L.R. (3d) 1, 6 B.H.R.C. 387, [1999] I.N.L.R. 36 (S.C.C.) — referred to

Q. v. College of Physicians & Surgeons (British Columbia) (2003), (sub nom. *Dr. Q. v. College of Physicians & Surgeons of British Columbia*) [2003] 1 S.C.R. 226, 2003 SCC 19, 2003 CarswellBC 713, 2003 CarswellBC 743, 11 B.C.L.R. (4th) 1, [2003] 5 W.W.R. 1, 223 D.L.R. (4th) 599, 48 Admin. L.R. (3d) 1, (sub nom. *Dr. Q., Re*) 302 N.R. 34, (sub nom. *Dr. Q., Re*) 179 B.C.A.C. 170, (sub nom. *Dr. Q., Re*) 295 W.A.C. 170 (S.C.C.) — referred to

R. v. Jackpine (2006), 2006 SCC 15, 2006 CarswellOnt 2498, 2006 CarswellOnt 2499, 37 C.R. (6th) 1 (S.C.C.) — considered

R. v. Sharpe (2001), 2001 SCC 2, 2001 CarswellBC 82, 2001 CarswellBC 83, 194 D.L.R. (4th) 1, 150 C.C.C. (3d) 321, 39 C.R. (5th) 72, 264 N.R. 201, 146 B.C.A.C. 161, 239 W.A.C. 161, 88 B.C.L.R. (3d) 1, [2001] 6 W.W.R. 1, [2001] 1 S.C.R. 45, 86 C.R.R. (2d) 1 (S.C.C.) — referred to

Ryan v. Law Society (New Brunswick) (2003), (sub nom. *Law Society of New Brunswick v. Ryan*) [2003] 1 S.C.R. 247, 2003 SCC 20, 2003 CarswellNB 145, 2003 CarswellNB 146, 223 D.L.R. (4th) 577, 48 Admin. L.R. (3d) 33, 302 N.R. 1, 257 N.B.R. (2d) 207, 674 A.P.R. 207, 31 C.P.C. (5th) 1 (S.C.C.) — referred to

Voice Construction Ltd. v. Construction & General Workers' Union, Local 92 (2004), 2004 SCC 23, [2004] 1 S.C.R. 609, [2004] 7 W.W.R. 411, 14 Admin. L.R. (4th) 165, 29 Alta. L.R. (4th) 1, 2004 CarswellAlta 422, 2004 CarswellAlta 423, (sub nom. *Construction & General Workers' Union, Local 92 v. Voice Construction Ltd.*) 2004 C.L.L.C. 220-026 (S.C.C.) — referred to

Statutes considered:

Canadian Charter of Rights and Freedoms, Part I of the Constitution Act, 1982, being Schedule B to the Canada Act 1982 (U.K.), 1982, c. 11

 Copyright © Thomson Reuters Canada Limited or its licensors (excluding individual court documents). All rights reserved.

Generally — considered

s. 15 — referred to

Public Utilities Act, R.S.N.S. 1989, c. 380

Generally — considered

s. 2(f) "service" (iii) — considered

s. 42 — referred to

s. 44 — considered

s. 52 — considered

s. 63(1) — referred to

s. 64(1) — considered

s. 67(1) — considered

s. 73(3) — considered

s. 86 — considered

s. 107 — considered

Telecommunications Act, S.C. 1993, c. 38

s. 7 — referred to

s. 47(a) — considered

Utility and Review Board Act, S.N.S. 1992, c. 11

Generally — referred to

s. 26 — considered

s. 30(1) — considered

APPEAL by intervenor from board's decision to decline to consider proposal.

***Fichaud J.A.*:**

1 Nova Scotia Power applied to the Utility and Review Board for a rate increase. Dalhousie Legal Aid intervened and requested that the Board approve a program featuring power rate credits for low income customers. The Board declined. The Board was of the view that the legislation did not authorize the Board to reduce power rates based on the income level of the customer. Dalhousie Legal Aid appeals. The issue is whether the Board committed reviewable error by concluding that it had no statutory authority to adopt a rate assistance program for low income customers.

Background

2 Nova Scotia Power Incorporated ("NSP") produces and supplies electrical energy. As of December 31, 2003, NSP served approximately 460,000 customers throughout Nova Scotia. NSP is the successor to the Nova Scotia Power Corporation, a Crown corporation that was privatized in 1992. In January 1999, NSP became the principal subsidiary of what is now Emera Incorporated.

3 NSP is a public utility regulated under the *Public Utilities Act* RSNS 1989, c. 380, as amended. Section 64(1) reads:

 Copyright © Thomson Reuters Canada Limited or its licensors (excluding individual court documents). All rights reserved.

> 64 (1) No public utility shall charge, demand, collect or receive any compensation for any service performed by it until such public utility has first submitted for the approval of the Board a schedule of rates, tolls and charges and has obtained the approval of the Board thereof.

The "Board" is the Nova Scotia Utility and Review Board, created by the *Utility and Review Board Act* SNS 1992, c. 11, as amended ("*URB Act*").

4 In May 2004 NSP filed with the Board an application for approval of increased rates, followed by a revised application in June 2004. The application would have resulted in an average overall increase of 12.4% for all classes of customer.

5 The Board gave notice by advertisement as provided in s. 86 of the *Public Utilities Act*. Thirty-seven intervenors responded. One intervenor was the appellant Dalhouse Legal Aid Service ("DLA").

6 The Board conducted a public hearing over 16 days between November 16, 2004 and January 14, 2005. On March 31, 2005 the Board issued a decision (2005 NSUARB 27). The decision dealt with NSP's requested rate increase and related topics. Only one topic is relevant to this appeal. That is DLA's request that the Board approve a Rate Assistance Program for low income consumers of power.

7 The Board's decision summarized DLA's submission:

> **9.1 Rate Assistance Program (RAP)**
>
> [246] While DLAS has opposed the approval of a FAM [Fuel Adjustment Mechanism] and the SA [Settlement Agreement], and has detailed concerns regarding aspects of customer service provided by NSPI, its main focus at the hearing was the implementation of a proposed Rate Assistance Program ("RAP") to help low-income customers meet their electricity costs.
>
> [247] DLAS filed evidence from several individuals, including Dr. Richard Shillington, a principal of Tristat Resources and Roger Colton, a principal of Fisher, Sheehan & Colton, with respect to this issue. Dr. Shillington, in his direct evidence (Exhibit N-126), outlined the challenging costs of shelter and electricity for low-income Canadians. Mr. Colton's evidence focused on low-income energy assistance programs and his efforts, in a number of US states, in designing rate affordability programs. Mr. Colton's position is that NSPI should "... be directed toward allowing low-income consumers to obtain quality utility service at affordable prices within a reasonable budget constraint." Mr. Colton also submits that the costs of such a program, to be shared by customers, are offset, although perhaps not fully, by savings realized by the Utility resulting from the adoption of a 'universal service program'.

Mr. Colton's report summarized his fixed credit proposal:

> Although a variety of percentage-of-income based approaches exists, I recommend the delivery of rate affordability assistance using a fixed credit approach. The fixed credit approach begins as an income-based approach. In order to be eligible for the rate, a household must meet *both* eligibility criteria: (1) that the household income is at or below the Low-Income Cutoff (LICO) for Nova Scotia; and (2) that the household electric burden exceeds the burden deemed to be affordable.
>
> The fixed credit approach differs from a straight percentage of income approach in the calculation of the bill to the household. The fixed credit calculates what bill credit would need to be provided to the household in order to reduce the household's energy bill to a designated percent of income. To calculate the fixed credit involves three steps: (1) calculating a burden-based payment; (2) calculating an annual bill; and (3) calculating the fixed credit necessary to reduce the annual bill to the burden based payment. Each step is explained below.

 Copyright © Thomson Reuters Canada Limited or its licensors (excluding individual court documents). All rights reserved.

> 1. The first step in the fixed credit model is to calculate a burden-based payment. Assume that the household has an annual income of $8,000 and is required to pay three percent (3%) for its home energy bill. The required household payment is thus $240. This is simply $8,000 × 3% = $240.
>
> Distinctions are also made between heating and non-heating customers. A heating customer should be asked to pay six percent (6%) of the household's income toward her home heating bill, while a non-heating customer would be asked to pay three percent (3%) toward his or her electric bill.
>
> 2. The next step is to calculate a projected annual household energy bill. This calculation is to be made using whatever method NSPI *currently* uses to estimate annual bills for other purposes. NSPI, in other words, has an established procedure for estimating an annual bill for purposes of placing residential customers (low-income or not) on a levelized Budget Billing Plan (where bills are paid in equal installments over 12 months). Let me assume for purposes of illustration that this existing process results in an estimated annual bill of $960.
>
> 3. The final step is to calculate the necessary fixed credit to bring the annual bill down to the burden-based payment. Given an annual bill projection of $960 and a burden-based payment of $240, the annual fixed credit would need to be $720 ($960-$240 = $720). The household's *monthly* fixed credit would be $60 ($720 / 12 = $60).

8 The Board, in response to DLA's request, cited s. 67(1) of the *Public Utilities Act*:

> 67 (1) All tolls, rates and charges shall always, under substantially similar circumstances and conditions in respect of service of the same description, be charged equally to all persons and at the same rate, and the Board may by regulation declare what shall constitute substantially similar circumstances and conditions.

The Board accepted that "all customers, regardless of income, receive 'substantially similar' electrical service from NSP". The Board concluded that it had no power to consider DLA's proposed Rate Assistance Program:

> [256] After reviewing the submissions of DLAS, Board Counsel and the relevant provisions of the **Act**, the Board finds that it does not have the statutory authority to approve a RAP. The Board has the authority given to it by the Legislature to perform its duties in accordance with the provisions of the **Act**. The Board's role is to make decisions, based on fact and law, within the parameters of the statutory authority it has been given by the Legislature. The Board's duty is to follow public policy decisions made by the Legislature and expressed in statutes. The Board does not have jurisdiction to establish public policy. That is the role of elected officials who are accountable to the public for this function. It seems almost certain that the RAP, as described by Mr. Colton, would result in the electricity bills of certain customers, depending on their income, being subsidized by other customers. In the Board's view, this is a social and public policy question which falls within the purview of the Legislature rather than the Board. Should NSPI and DLAS wish to pursue this matter with Government, the Board would be pleased to offer assistance with respect to regulatory and ratemaking principles.

9 DLA appeals under s. 30(1) of the *URB Act*, permitting an appeal based on an error of law or jurisdiction.

Issue

10 The issue is whether the Board committed an appealable error by declining to consider the merits of DLA's proposed Rate Assistance Program for low income electricity customers.

Standard of Review

11 Under the pragmatic and functional approach, the court analyses the cumulative effect of four contextual factors: the presence, absence or wording of a privative clause or statutory appeal; the comparative expertise of the tribunal and the court on the appealed or reviewed issues; the purpose of the governing legislation; and the nature of the question, fact, law or mixed. The ultimate question is whether the legislature intended that the issue under review be left to

 Copyright © Thomson Reuters Canada Limited or its licensors (excluding individual court documents). All rights reserved.

the tribunal. From this analysis the court selects, for each issue, a standard of review of correctness, reasonableness or patent unreasonableness: *Pushpanathan v. Canada (Minister of Employment & Immigration)*, [1998] 1 S.C.R. 982 (S.C.C.), at ¶ 26; *Q. v. College of Physicians & Surgeons (British Columbia)*, [2003] 1 S.C.R. 226 (S.C.C.), at ¶ 26-35; *Ryan v. Law Society (New Brunswick)*, [2003] 1 S.C.R. 247 (S.C.C.), at ¶ 27; *Voice Construction Ltd. v. Construction & General Workers' Union, Local 92*, [2004] 1 S.C.R. 609 (S.C.C.) at ¶ 15-19; *Baker v. Canada (Minister of Citizenship & Immigration)*, [1999] 2 S.C.R. 817 (S.C.C.), at ¶ 55-62; *Granite Environmental Inc. v. Nova Scotia (Labour Relations Board)*, 2005 NSCA 141 (N.S. C.A.) , at ¶ 21; *N.S.T.U. v. Nova Scotia Community College*, 2006 NSCA 22 (N.S. C.A.) , at ¶ 11; *Capital District Health Authority v. N.S.G.E.U.*, 2006 NSCA 44 (N.S. C.A.) , at ¶ 36.

12 In *Johnson v. Nova Scotia*, 2005 NSCA 99 (N.S. C.A.) , at ¶ 33-46, Justice Oland applied the four contextual factors to the expropriation powers of the Utility and Review Board, and concluded:

> [46] After considering the four contextual factors of the functional and pragmatic approach, in my view the standard of review to be applied to questions of law, such as any entitlement for compensation for owner's time and for pension loss, the standard of review is correctness. For questions of mixed law and fact, such as matters related to compensation for market value and injurious affection, the standard is patent unreasonableness. For findings of fact, the standard is patent unreasonableness.

Though there is correspondence among the Board's different functions, the pragmatic and functional analysis for expropriation is not necessarily commutable to rate-making. So I will consider the four contextual factors from the perspective of utility rating.

13 Section 26 of the *URB Act* says that the Board's findings of fact are "binding and conclusive", while s. 30(1) prescribes an appeal to this court on questions of law or jurisdiction. The Legislature contemplated a serious judicial role in the review for legal error, particularly on threshold issues.

14 Section 44 of the *Public Utilities Act* entitles the Board to fix rates "as it deems just". Section 67(1) quoted earlier directs equal charges for "similar circumstances and conditions" of service and authorizes the Board to enact regulations that define "substantially similar circumstances and conditions". The Board has a standing membership, repeatedly has examined NSP rate applications and has developed a body of governing jurisprudence. Clearly, the Board has more expertise than the court in the architecture of rate-making.

15 In *Nova Scotia (Public Utilities Board) v. Nova Scotia Power Corp.* (1976), 18 N.S.R. (2d) 692 (N.S. C.A.), at ¶ 17, Chief Justice MacKeigan summarized the purposes of the *Public Utilities Act*:

> 17 The scheme of regulation established by the Act envisages and indeed compels control by the Board of all aspects of a utility's operation in providing a controlled service. Two great objects are enshrined — that all rates charged must be just, reasonable and sufficient and not discriminatory or preferential, and that the service must be adequately, efficiently and reasonably supplied to the public. Almost all provisions of the Act are directed toward securing these two objects — that a public utility give adequate service and charge only reasonable and just rates.

The legislation considered by Chief Justice MacKeigan included ss. 42 and 63(1), the equivalents to the current ss. 44 and 67(1) that are central to this appeal (see *NS (PUB)* at ¶ 15, 28).

16 DLA says its argument is "jurisdictional" and therefore the standard of review must be correctness. It may be that, after the court reviews the four contextual factors, true jurisdictional issues usually will attract the correctness standard. But I disagree that every labelled "jurisdictional" argument is tethered to correctness, and I reiterate this court's comment in *Capital District Health Authority v. N.S.G.E.U.* :

> [28] . . . The court no longer reviews for pigeonholed "jurisdictional errors." The phrase "goes to jurisdiction" describes a type of issue for which the proper standard of review is correctness, after the reviewing court has performed the pragmatic and functional analysis. But the "jurisdictional" inquiry is not a substitute for the pragmatic

 Copyright © Thomson Reuters Canada Limited or its licensors (excluding individual court documents). All rights reserved.

> and functional approach. [Citing *Pushpanathan* at ¶ 28; *Dr.* Q. at ¶ 20-25; *Voice* at ¶ 21; *Granite* at ¶ 41(b) and *ATCO Gas & Pipelines Ltd. v. Alberta (Energy & Utilities Board)*, 2006 SCC 4 (S.C.C.) at ¶ 21-32.]

17 A similar issue arose in *ATCO Gas & Pipelines Ltd. v. Alberta (Energy & Utilities Board)*, 2006 SCC 4 (S.C.C.) . A public utility applied to Alberta's Energy and Utilities Board for approval of a sale of assets and allocation of the sale proceeds. The Board allocated a portion of the proceeds of sale to the rate-paying customers. On appeal from the judicial review, the Supreme Court of Canada considered whether the Board had statutory authority to allocate any sale proceeds to the ratepayers. Despite the "jurisdictional" aspect of the issue, Justice Bastarache for the majority said that the pragmatic and functional analysis was necessary:

> 23 In the case at bar, one should avoid a hasty characterizing of the issue as "jurisdictional" and subsequently be tempted to skip the pragmatic and functional analysis. A complete examination of the factors is required.

In *ATCO*, a threshold issue of statutory interpretation determined whether the Board could exercise its core functions. Justice Bastarache selected a correctness standard, having reasoned as follows:

> 30 While at first blush the purposes of the relevant statutes and of the Board can be conceived as a delicate balancing between different constituencies, i.e., the utility and the customer, and therefore entail determinations which are polycentric (*Pushpanathan*, at para. 36), the interpretation of the enabling statutes and the particular provisions under review (s. 26(2)(d) GUA and s. 15(3)(d) AEUBA) is not a polycentric question, contrary to the conclusion of the Court of Appeal. It is an inquiry into whether a proper construction of the enabling statutes gives the Board jurisdiction to allocate the profits realized from the sale of an asset. The Board was not created with the main purpose of interpreting the AEUBA, the GUA or the PUBA in the abstract, where no policy consideration is at issue, but rather to ensure that utility rates are always just and reasonable (see *Atco Ltd.*, at p. 576). In the case at bar, this protective role does not come into play. Hence, this factor points to a less deferential standard of review.
>
> 31 Fourth, the nature of the problem underlying each issue is different. The parties are in essence asking the Court to answer two questions (as I have set out above), the first of which is to determine whether the power to dispose of the proceeds of sale falls within the Board's statutory mandate. The Board, in its decision, determined that it had the power to allocate a portion of the proceeds of a sale of utility assets to the ratepayers; it based its decision on its statutory powers, the equitable principles rooted in the "regulatory compact" (see para. 63 of these reasons) and previous practice. This question is undoubtedly one of law and jurisdiction. The Board would arguably have no greater expertise with regard to this issue than the courts. A court is called upon to interpret provisions that have no technical aspect, in contrast with the provision disputed in *Barrie Public Utilities v. Canadian Cable Television Assn.*, [2003] 1 S.C.R. 476, 2003 SCC 28, at para. 86. The interpretation of general concepts such as "public interest" and "conditions" (as found in s. 15(3)(d) of the AEUBA) is not foreign to courts and is not derived from an area where the tribunal has been held to have greater expertise than the courts. ...
>
> 32 In light of the four factors, I conclude that each question requires a distinct standard of review. To determine the Board's power to allocate proceeds from a sale of utility assets suggests a standard of review of correctness. As expressed by the Court of Appeal, the focus of this inquiry remains on the particular provisions being invoked and interpreted by the tribunal (s. 26(2)(d) of the GUA and s. 15(3)(d) of the AEUBA) and "goes to jurisdiction" (*Pushpanathan*, at para. 28). Moreover, keeping in mind all the factors discussed, the generality of the proposition will be an additional factor in favour of the imposition of a correctness standard, as I stated in *Pushpanathan*, at para. 38:
>
> > ... the broader the propositions asserted, and the further the implications of such decisions stray from the core expertise of the tribunal, the less likelihood that deference will be shown. Without an implied or express legislative intent to the contrary as manifested in the criteria above, legislatures should be assumed to have left highly generalized propositions of law to courts.

 Copyright © Thomson Reuters Canada Limited or its licensors (excluding individual court documents). All rights reserved.

18 The Board's rate-making power is a core function entitled to deference. But the issue here is whether the statute precludes the Board from exercising that power. After considering the four contextual factors, and given the statutory right of appeal and the comments in *ATCO*, in my view the Legislature intended no deference on that issue. The threshold legal question is governed by a correctness standard.

Did the Board Err in Law by Declining to Consider the Rate Assistance Program?

19 This is a question of statutory interpretation. The words of a statute are read in their entire context and in their grammatical and ordinary sense, harmoniously with the scheme of the *Act*, the object of the *Act* and the intention of the Legislature: *Parry Sound (District) Welfare Administration Board v. O.P.S.E.U., Local 324*, 2003 SCC 42 (S.C.C.) , at ¶ 41; *R. v. Sharpe*, [2001] 1 S.C.R. 45 (S.C.C.) at ¶ 33; *Nova Scotia (Minister of Health) v. G. (R.)*, 2005 NSCA 59 (N.S. C.A.) , at ¶ 24; *Doctors Nova Scotia v. Nova Scotia (Department of Health)*, 2006 NSCA 59 (N.S. C.A.) , at ¶ 25.

20 DLA focusses on the grammatical and ordinary meaning of the Board's general rate-making power in s. 44 of the *Public Utilities Act*:

> 44 The Board may make from time to time such orders as it deems just in respect to the tolls, rates and charges to be paid to any public utility for services rendered or facilities provided, and amend or rescind such orders or make new orders in substitution therefor.

DLA submits that the Board is mandated to consider whether a rate assistance program for low income customers is "just".

21 The court must also grapple with the basis of the Board's ruling, s. 67(1):

> 67 (1) All tolls, rates and charges shall always, under substantially similar circumstances and conditions in respect of service of the same description, be charged equally to all persons and at the same rate, and the Board may by regulation declare what shall constitute substantially similar circumstances and conditions.

DLA says that its Rate Assistance Program would provide a credit against the rate, but would not alter the rate itself. DLA says that s. 67(1) refers to pure "rates", not credits, and is irrelevant to DLA's Program.

22 In my respectful view, DLA's rate/credit distinction is artificial and analytically flawed. A gross rate subject to an automatic credit is just a net rate charged to the customer by NSP. The "charge" under s. 67(1) is the net amount. The Board's "rate" making power is not a blind stab at gross revenue. The rating involves a projection of NSP's expenses, net income and rate of return. The Board must consider the effect of a credit against rates just as it must consider NSP's expenses to generate power. DLA cites s. 44 of the *Public Utilities Act* as authority for its Rate Assistance Program, including the credit. Yet, s. 44, quoted earlier, empowers the Board to approve "tolls, rates and charges", saying nothing of "credits". Rate credits are integrated with "rates and charges" in s. 67(1) no less than rate credits pertain to the Board's "rating" power in s. 44, upon which DLA relies.

23 DLA's factum said that low income customers do not have "substantially similar circumstances" to higher income customers. So, different rates would not be barred by s. 67(1). At the appeal hearing DLA's counsel retreated somewhat from this submission.

24 With respect, the factum's submission misinterprets s. 67(1). The provision refers to "substantially similar circumstances and conditions *in respect of service of the same description*." To justify a rate difference, the relevant dissimilarity is not in customers' incomes. It is in the service from NSP. The Board accepted, and there is no basis to question, that NSP provides substantially similar electrical service whatever the domestic customer's income.

 Copyright © Thomson Reuters Canada Limited or its licensors (excluding individual court documents). All rights reserved.

25 Section 67(1) is mandatory. The rates and charges "shall always . . . be charged equally" to persons of similar circumstances and conditions in respect of service. The statute does not endow the Board with discretion to consider the social justice of reduced rates for low income customers. It is not for the Board or this court to read into s. 67(1) the words:

> . . . similar circumstances and conditions in respect of ***the income level of customers and*** service of the same description,

It is for the Legislature to decide whether to expand the Board's purview with the italicized words.

26 This point is illustrated by *Allstream Corp. v. Bell Canada*, 2005 FCA 247 (F.C.A.) , cited by DLA. The Federal Court of Appeal upheld the decision of the CRTC to provide low rates to schools and municipalities for fibre optic service. DLA's factum says:

> This case stands for the proposition that the jurisdiction to regulate utilities ***includes*** non cost-based rates and by analogy would include programs similar to a rate assistance program for low income consumers. [emphasis in original]

27 I disagree with DLA's measure of *Allstream*'s reach. The Federal Court of Appeal said:

> 34. ... It is apparent that the Commission was greatly concerned about the effect of a denial of services on the communities concerned and the dislocation of complex equipment and facility configurations at a significant cost and to the detriment of school boards and municipalities in the relevant areas and that such concerns outweighed, in its view, Bell's failure to seek prior approval of these rates. These are considerations that a specialized board can entertain and weigh relative to other considerations. It is true that these considerations are not purely economic in the sense referred to by the appellant such as costs, investment, allowance for necessary working capital, rate of return, etc. These considerations, however, are ***part of the Commission's wide mandate under section 7***, a mandate it alone possesses and are quite distinct from the grant of a rate under paragraph 27(6)(b) of the Act, a power the Commission did not invoke. [emphasis added]

Section 47(a) of the *Telecommunications Act*, S.C. 1993, c. 38 directed the CRTC to implement the telecommunications policy objectives from s. 7. Those included enriching the "social and economic fabric", rendering "affordable" and "accessible" service, and responding to "the economic and social requirements of users." [legislation quoted in ¶ 10 of *Allstream*]. Nova Scotia's Utility and Review Board has no such statutory mandate.

28 The grammatical and ordinary interpretation of s. 67(1), outlined above, is consistent with the statutory context, scheme and object of the *Act*, and intention of the Legislature.

29 The *Act* connects the Board's rate-making to NSP's "service". Section 2(f) of the *Public Utilities Act* defines "service" as including:

> (iii) the production, transmission, delivery or furnishing to or for the public by a public utility for compensation of electrical energy for purposes of heat, light and power,

Section 44 authorizes the Board to make rates "for services rendered or facilities provided". Section 52 requires the public utility to "furnish services and facilities that are adequate, just and reasonable". Section 64(1) prohibits the utility from charging compensation for any "service" until the Board has approved the rate for that service. Section 107, entitled "offence and penalty for unjust discrimination", prohibits the utility from charging "for any service" a rate that is higher or lower than charged to any other person "for a like and contemporaneous service".

30 Section 73 of the *Public Utilities Act* allows preferential rates for

 Copyright © Thomson Reuters Canada Limited or its licensors (excluding individual court documents). All rights reserved.

> (3) . . . a senior citizens club, service club, volunteer fire department, a Royal Canadian Legion, community hall or recreational facility owned by a community and used for general community purposes, a charitable or religious organization or institution . . .

and authorizes the Lieutenant Governor-in-Council to extend this list by order-in-council.

31 The legislative context ties the Board's rate levels to the utility's services. The Legislature enacts, or assigns to order-in-council, non-compliant rates for specific classes of customer based on social criteria.

32 The Board sets rates for a utility that has a virtual monopoly on the supply of electric power. The Board's decision discusses this process: (2005 NSUARB 27)

> [17] . . . NSPI is not like an unregulated retailer. It is a virtual monopoly which operates its business on a cost-of-service basis. Providing electricity to all communities in the Province was not (and likely still is not) financially feasible for private, competitive companies. For that reason, the Province's electric service supplier is a cost-of-service monopoly. In return for undertaking and continuing the costs of electrification of the Province, the utility is permitted, under the *Act*, to recover the reasonable and prudent costs of providing the service. Because it is a monopoly, regulation operates as a surrogate for competition. One of the regulator's tasks is to balance the need for the Utility to recover its reasonable and prudent costs with the need to ensure that ratepayers are charged fair and reasonable rates.
>
> [18] It is in the interests of all Nova Scotians to ensure that NSPI continues to be a stable and financially sound company. This is a reality which the Board must consider when determining what, if any, rate increase is warranted.
>
> [19] In short, rates charged to customers are based on costs incurred by the Utility in providing service. If the Board finds certain costs to be imprudent or unreasonable, it can (and has) disallowed such expenditures and reduced proposed rate increases accordingly.

33 I agree with this portrayal of the background to the Board's rate-making function. The Board's regulatory power is a proxy for competition, not an instrument of social policy.

34 DLA points to the Board's approval of rates that prefer large industrial power customers. In *Nova Scotia Power Inc., Re*, [2000] N.S.U.R.B.D. No. 72 (N.S. Utility & Review Bd.), the Board approved NSP' s application for a load retention rate. This rate would be determined between the individual customer and NSP, then submitted to the Board for approval. Paragraph 5 of the Board's decision describes the features of NSP's proposed load retention rate:

> 5 NSPI states in its application that "the proposed rate is an appropriate approach to retaining existing customers who, in the absence of this rate, would reduce their purchases from the Company, to the detriment of all other customers". The rate would be available to customers "who are considering an alternate supply of at least 2000 KVA or 1800 KW". It would not be available for new load. The rate would only be available if the following conditions are satisfied:
>
> > 1. The customer's option to use a supply of power and energy (alternate supply) other than NSPI's is both technically and economically feasible.
> >
> > 2. Retaining the customer's load, at the price offered by this rate, is better for other electric customers than losing the customer load in question.
> >
> > 3. The price offered by this rate is not less than that necessary to make the customer in question indifferent with respect to alternate supply versus continuing to purchase the electric power and energy from NSPI.

 Copyright © Thomson Reuters Canada Limited or its licensors (excluding individual court documents). All rights reserved.

DLA says that, if the Board can approve a load retention rate for large industrial customers, then it can approve a rate assistance program for low income customers.

35 The Board's decision in [2000] N.S.U.R.B.D. No. 72 (N.S. Utility & Review Bd.) is not under appeal. Neither are its decisions on similar issues such as the extra large industrial interruptible rate: *Nova Scotia Power Inc., Re*, 2003 NSUARB 6 (N.S. Utility & Review Bd.) and *Nova Scotia Power Inc., Re*, 2003 NSUARB 91 (N.S. Utility & Review Bd.) . I make no comment on those rulings, except to say that they do not support DLA's submission here that the Board can implement social policy. The Board's approval of the load retention rate was premised on the finding that, otherwise, the large customer could leave NSP, obtain its energy from another source, and this would hike NSP's rates to its remaining customers. The Board's approach affirms the Board's role as a competition surrogate. The Board's load retention rate recognizes the microeconomic reality that NSP is not an absolute energy monopoly with a vertical customer demand curve, and is subject to elastic demand from high volume customers with other energy options. No such factors govern DLA's proposed Rate Assistance Program.

36 DLA says that legislation should be interpreted in a manner that is consistent with the *Charter of Rights and Freedoms*. DLA's counsel makes a forceful submission that the impoverished are a protected category under s. 15 and, following *Eldridge v. British Columbia (Attorney General)*, [1997] 3 S.C.R. 624 (S.C.C.), this court may direct the institution of a program to ameliorate their disadvantage. DLA's submission is interpretive and does not challenge the validity of the legislation.

37 I make no comment on s. 15. The statutory language does not accommodate the suggested construction.

38 The constructive principle applies only when the statute is ambiguous. In *R. v. Jackpine*, 2006 SCC 15 (S.C.C.) , at ¶ 18, Justice Charron for the majority said:

> It has long been accepted that courts should apply and develop common law rules in accordance with the values and principles enshrined in the *Charter*: *RWDSU v. Dolphin Delivery Ltd.*, [1986] 2 S.C.R. 573, at p. 603; *Cloutier v. Langlois*, [1990] 1 S.C.R. 158, at p. 184; *R. v. Salituro*, [1991] 3 S.C.R. 654, at p. 675; *R. v. Golden*, [2001] 3 S.C.R. 679, 2001 SCC 83, at para. 86; *R. v. Mann*, [2004] 3 S.C.R. 59, 2004 SCC 52, at paras.17-19. However, it is equally well settled that, in the interpretation of a statute, *Charter* values as an interpretative tool can only play a role where there is a genuine ambiguity in the legislation. In other words, where the legislation permits two different, yet equally plausible, interpretations, each of which is equally consistent with the apparent purpose of the statute, it is appropriate to prefer the interpretation that accords with *Charter* principles. However, where a statute is not ambiguous, the court must give effect to the clearly expressed legislative intent and not use the *Charter* to achieve a different result. In *Bell ExpressVu Ltd. Partnership v. Rex*, [2002] 2 S.C.R. 559, 2002 SCC 42, at para. 62, Iaccobuci J., writing for a unanimous court, firmly reiterated this rule:
>
> > ... to the extent this Court has recognized a "*Charter* values" interpretive principle, such principle can only receive application in circumstances of genuine ambiguity, i.e., where a statutory provision is subject to differing, but equally plausible, interpretations. [Emphasis in original.]

To the same effect: *Bell ExpressVu Ltd. Partnership v. Rex*, [2002] 2 S.C.R. 559 (S.C.C.) at ¶ 27-30, 60-66.

39 Section 67(1) is not ambiguous: "rates . . . shall always . . . be charged equally to all persons and at the same rate" in substantially similar "circumstances and conditions in respect of service of the same description". The Board cannot reduce the rate to a low income customer who receives the same service as a high income customer. There is no latitude for the interpretive presumption.

Conclusion

 Copyright © Thomson Reuters Canada Limited or its licensors (excluding individual court documents). All rights reserved.

40 The Board did not err in its conclusion that s. 67(1) precludes the Board from considering DLA's rate assistance program for low income customers. I would dismiss the appeal without costs.

Appeal dismissed.

End of Document Copyright © Thomson Reuters Canada Limited or its licensors (excluding individual court documents). All rights reserved.

COURT OF APPEAL FOR BRITISH COLUMBIA

Citation: *British Columbia Old Age Pensioners' Organization v. British Columbia Utilities Commission,* 2017 BCCA 400

Date: 20171117
Dockets: CA44248; CA44557

Docket: CA44248

2017 BCCA 400 (CanLII)

Between:

British Columbia Old Age Pensioners' Organization, Active Support Against Poverty, Council of Senior Citizens' Organizations of BC, Disability Alliance BC, Together Against Poverty Society, and the Tenant Resource and Advisory Centre ("BCOAPO et al.") and Movement of United Professionals

Appellants
(Intervenors)

And

British Columbia Utilities Commission

Respondent
(Administrative Tribunal)

And

British Columbia Hydro and Power Authority

Respondent
(Applicant)

And

FortisBC Energy Inc. and FortisBC Inc. (collectively, "Fortis"), Commercial Energy Consumers' Association of British Columbia, British Columbia Sustainable Energy Association, Sierra Club of British Columbia, Association of Major Power Customers, Non Integrated Areas Ratepayers Group, Zone II Ratepayers Group

Respondents
(Intervenors)

And

Attorney General of British Columbia

Respondent

- and -

Docket: CA44557

Between:

British Columbia Old Age Pensioners' Organization, Active Support Against Poverty, Council of Senior Citizens' Organizations of BC, Disability Alliance BC, Together Against Poverty Society, and the Tenant Resource and Advisory Centre ("BCOAPO et al.") and Movement of United Professionals

Appellants
(Intervenors)

And

British Columbia Utilities Commission

Respondent
(Administrative Tribunal)

And

British Columbia Hydro and Power Authority

Respondent
(Applicant)

And

FortisBC Energy Inc. and FortisBC Inc. (collectively, "Fortis"), Commercial Energy Consumers' Association of British Columbia, British Columbia Sustainable Energy Association, Sierra Club of British Columbia

Respondents
(Intervenors)

And

Attorney General of British Columbia

Respondent

Before: The Honourable Mr. Justice Goepel
(In Chambers)

On appeal from: Decisions and Orders of the British Columbia Utilities Commission, dated January 20, 2017 (Order Number G-5-17) and June 2, 2017 (Order Number G-87-17).

2017 BCCA 400 (CanLII)

Counsel for the Appellant, British Columbia Old Age Pensioners' Organization et al.:	M.G. Underhill E. Pritchard L. Worth
Counsel for the Appellant, Movement of United Professionals:	J. Quail
Counsel for the Respondent, FortisBC Energy Inc. and FortisBC Inc.:	L.B. Herbst, Q.C. N.T. Hooge
Counsel for the Respondent, British Columbia Hydro and Power Authority:	M. Vesely C.C. Ferguson
Counsel for the Respondent, British Columbia Utilities Commission:	P. Miller T. Shoranick
Place and Date of Hearing:	Vancouver, British Columbia September 19, 2017
Place and Date of Judgment:	Vancouver, British Columbia November 17, 2017

2017 BCCA 400 (CanLII)

Summary:

BCOAPO and MoveUp apply for leave to appeal two orders of the BC Utilities Commission. The orders were made in the context of a Rate Design Application submitted by BC Hydro, which proposed utility rates for classes of customers. BCOAPO and MoveUp had intervened in the application process, requesting the implementation of strategies to assist low-income ratepayers. In the first order, the Commission denied most of the low-income proposals on the basis that it lacked jurisdiction under the Utilities Commission Act to set low-income rates without an economic or cost of service justification. The second order denied a request for reconsideration.

Held: Applications for leave to appeal dismissed. In the circumstances of this case the decision of whether or not to grant leave comes down to a consideration of the merits. Assessing whether there is some prospect the appeal will succeed on its merits must be done in light of the standard of review on which the merits of the appeal would be judged. In this case, the Commission interpreted and applied provisions of its home statute and thus its decision would be reviewed on a standard of reasonableness. Given the standard of review, this appeal has no prospect of success.

2017 BCCA 400 (CanLII)

Reasons for Judgment of the Honourable Mr. Justice Goepel:

INTRODUCTION

[1] The applicants, British Columbia Old Age Pensioners' Organization, Active Support Against Poverty, Council of Senior Citizens' Organizations of BC, Disability Alliance BC, Together Against Poverty Society, and the Tenant Resource and Advisory Centre (collectively, "BCOAPO") and the Movement Of United Professionals ("MoveUp") seek leave under s. 101 of the *Utilities Commission Act*, R.S.B.C. 1996, c. 473 [*UCA*] to appeal the following orders of the British Columbia Utilities Commission:

1. Order G-5-17, pronounced on January 20, 2017 (the "Original Decision"); and

2. Order G-87-17, pronounced on June 2, 2017 (the "Reconsideration Decision").

[2] The orders were made in the context of a Rate Design Application submitted by BC Hydro, which proposed utility rates for classes of customers. BCOAPO and MoveUp had intervened in the application process, requesting the implementation of strategies to assist low-income ratepayers. In the first order, the Commission denied most of the low-income proposals on the basis that it lacked jurisdiction under the *UCA* to set low-income rates without an economic or cost of service justification. The second order denied a request for reconsideration

[3] The application for leave is opposed by the respondents, British Columbia Hydro and Power Authority ("BC Hydro") and FortisBC Energy Inc. and FortisBC Inc. (collectively, "Fortis"). BC Hydro and Fortis both submit that if leave is granted, it should be limited to the Reconsideration Decision.

[4] The Commission takes no position on the application for leave to appeal from the Reconsideration Decision. It does submit, however, that it is improper to grant leave to appeal the Original Decision because that decision has been the subject of reconsideration by the Commission and only the Commission's final decision should be subject to appellate review.

[5] For the reasons that follow, I would dismiss the applications for leave to appeal.

BACKGROUND

A. Legislative Scheme

[6] BC Hydro is the publicly owned monopoly electricity provider to the vast majority of the province. The Commission is empowered to regulate BC Hydro to ensure its quality of service, infrastructure, operations and rates are in the public interest. Pursuant to sections 23, 38, 59 and 60 of the *UCA*, the Commission is charged with ensuring that utilities provide safe, adequate, efficient and secure service to their customers and that the rates are fair, just and reasonable, and not unduly discriminatory or preferential. Those sections read as follows:

2017 BCCA 400 (CanLII)

General supervision of public utilities

23 (1) The commission has general supervision of all public utilities and may make orders about

(a) equipment,

(b) appliances,

(c) safety devices,

(d) extension of works or systems,

(e) filing of rate schedules,

(f) reporting, and

(g) other matters it considers necessary or advisable for

(i) the safety, convenience or service of the public, or

(ii) the proper carrying out of this Act or of a contract, charter or franchise involving use of public property or rights.

(2) Subject to this Act, the commission may make regulations requiring a public utility to conduct its operations in a way that does not unnecessarily interfere with, or cause unnecessary damage or inconvenience to, the public.

Public utility must provide service

38 A public utility must

(a) provide, and

(b) maintain its property and equipment in a condition to enable it to provide,

a service to the public that the commission considers is in all respects adequate, safe, efficient, just and reasonable.

Discrimination in rates

59 (1) A public utility must not make, demand or receive

(a) an unjust, unreasonable, unduly discriminatory or unduly preferential rate for a service provided by it in British Columbia, or

(b) a rate that otherwise contravenes this Act, the regulations, orders of the commission or any other law.

(2) A public utility must not

(a) as to rate or service, subject any person or locality, or a particular description of traffic, to an undue prejudice or disadvantage, or

(b) extend to any person a form of agreement, a rule or a facility or privilege, unless the agreement, rule, facility or privilege is regularly and uniformly extended to all persons under substantially similar circumstances and conditions for service of the same description.

(3) The commission may, by regulation, declare the circumstances and conditions that are substantially similar for the purpose of subsection (2) (b).

(4) It is a question of fact, of which the commission is the sole judge,

2017 BCCA 400 (CanLII)

(a) whether a rate is unjust or unreasonable,

(b) whether, in any case, there is undue discrimination, preference, prejudice or disadvantage in respect of a rate or service, or

(c) whether a service is offered or provided under substantially similar circumstances and conditions.

(5) In this section, a rate is "unjust" or "unreasonable" if the rate is

(a) more than a fair and reasonable charge for service of the nature and quality provided by the utility,

(b) insufficient to yield a fair and reasonable compensation for the service provided by the utility, or a fair and reasonable return on the appraised value of its property, or

(c) unjust and unreasonable for any other reason.

Setting of rates

60 (1) In setting a rate under this Act

(a) the commission must consider all matters that it considers proper and relevant affecting the rate,

(b) the commission must have due regard to the setting of a rate that

(i) is not unjust or unreasonable within the meaning of section 59,

(ii) provides to the public utility for which the rate is set a fair and reasonable return on any expenditure made by it to reduce energy demands, and

(iii) encourages public utilities to increase efficiency, reduce costs and enhance performance,

(b.1) the commission may use any mechanism, formula or other method of setting the rate that it considers advisable, and may order that the rate derived from such a mechanism, formula or other method is to remain in effect for a specified period, and

(c) if the public utility provides more than one class of service, the commission must

(i) segregate the various kinds of service into distinct classes of service,

(ii) in setting a rate to be charged for the particular service provided, consider each distinct class of service as a self contained unit, and

(iii) set a rate for each unit that it considers to be just and reasonable for that unit, without regard to the rates set for any other unit.

(2) In setting a rate under this Act, the commission may take into account a distinct or special area served by a public utility with a view to ensuring, so far as the commission considers it advisable, that the rate applicable in each area is adequate to yield a fair and reasonable return on the appraised value

2017 BCCA 400 (CanLII)

> of the plant or system of the public utility used, or prudently and reasonably acquired, for the purpose of providing the service in that special area.
>
> (3) If the commission takes a special area into account under subsection (2), it must have regard to the special considerations applicable to an area that is sparsely settled or has other distinctive characteristics.
>
> (4) For this section, the commission must exclude from the appraised value of the property of the public utility any franchise, licence, permit or concession obtained or held by the utility from a municipal or other public authority beyond the money, if any, paid to the municipality or public authority as consideration for that franchise, licence, permit or concession, together with necessary and reasonable expenses in procuring the franchise, licence, permit or concession.

2017 BCCA 400 (CanLII)

[7] Pursuant to s. 79 of the *UCA*, determinations of the Commission on questions of fact within its jurisdiction are binding and conclusive on all persons and all courts.

[8] Section 99 gives the Commission the power to reconsider a decision.

[9] Pursuant to s. 105(1) of the *UCA*, the Commission has exclusive jurisdiction in all cases and for all matters in which jurisdiction is confirmed on the Commission by statute. Section 105(2) provides that unless otherwise provided in the *UCA*, any order or decision of the Commission must not be questioned, reviewed or restrained by or on application for judicial review or other process or proceeding in any court.

[10] Section 101 of the *UCA* provides that an appeal lies from of an order or decision of the Commission to the Court of Appeal with leave of a justice of that court. Appeals from the Commission are restricted to questions of law or jurisdiction: *Plateau Pipe Line Ltd. v. British Columbia Utilities Commission*, 2002 BCCA 246 at paras. 8–9.

B. Procedural History

[11] The orders which are the subject matter of these leave applications were made in the context of a Rate Design Application ("RDA"). In an RDA the Commission is tasked with determining utilities rates for various classes of customers. The Commission hears evidence and submissions from the applicant utility and intervenor groups regarding the costs to serve each rate group, and the

proper rate structure to recover those costs from each rate group. The Commission then makes a determination regarding the costs of service, rate structures, and terms and conditions of service for residential, business, industrial and all other customers.

2017 BCCA 400 (CanLII)

[12] On September 24, 2015, BC Hydro filed an application with the Commission, known as the 2015 RDA. It was the first comprehensive rate design application since 2007. BCOAPO, Move Up and Fortis were amongst the groups granted intervenor status in the 2015 RDA.

[13] BCOAPO asked the Commission to order BC Hydro to implement a strategy to assist low-income ratepayers. More specifically, BCOAPO asked that the Commission direct BC Hydro to:

(a) implement an "essential services usage block" ("ESUB") rate, which would allow low-income customers to receive the first 400 kWh of service each month at a discount; and

(b) amend the BC Hydro electric tariff to exempt low-income customers from late payment, minimum reconnection and account charges and security deposits (collectively, the "Low-Income Proposals").

[14] The Low-Income Proposals were opposed by BC Hydro as well as two intervenor groups, including Fortis.

THE ORIGINAL DECISION

[15] On January 20, 2017, the Commission issued the Original Decision and accompanying reasons. The Commission denied the majority of the Low-Income Proposals. It found that the *UCA* did not provide the Commission with the jurisdiction to approve a low-income rate in the absence of an economic or a cost of service justification. It found as a fact that it did not cost BC Hydro less to serve low-income customers than it did to serve other residential customers. It further found that low-income rates unsupported by an economic or cost of service justification would be

unjust, unreasonable and unduly discriminatory and therefore not in accordance with s. 59 of the *UCA* — and accordingly not within the Commission's jurisdiction to approve. Order G-5-17 contains the following paragraphs relevant to this appeal:

> 14. [BCOAPO's] request to establish an essential services usage block (ESUB) rate for qualified low-income ratepayers is denied.
>
> 16. BCOAPO's proposals to amend the Electric Tariff to exempt low-income customers from the minimum reconnection charge and account charge and to waive security deposits for low-income customers are denied.
>
> 17. BCOAPO's proposal to exempt low-income customers from late payment charges … [is] denied.

THE RECONSIDERATION DECISION

[16] On February 17, 2017, BCOAPO filed a request pursuant to s. 99 of the *UCA* that the Commission reconsider its decision. The grounds advanced were that the Commission erred in law in finding sections 23, 38, 59 and 60 of the *UCA* do not provide the Commission with jurisdiction to order or approve low-income rates.

[17] The Commission addresses reconsideration applications in two phases. The first phase is a preliminary examination: essentially a threshold test. In the case of a reconsideration application based on errors of law with respect to jurisdiction, the Commission examines the following two criteria to determine whether a reconsideration application should proceed to the second phase and be considered on its merits: (a) whether the claim of error is substantiated on a *prima facie* basis; and (b) whether the error has material implications.

[18] In the Original Decision, the Commission found no evidence of legislative intent to provide the Commission with jurisdiction to set low-income rates and no evidence the legislature intended the *UCA* to provide jurisdiction for low-income rates in the absence of economic or cost of service justification. It found as a fact

2017 BCCA 400 (CanLII)

that low-income rates unsupported by an economic or cost of service justification are unjust, unreasonable and unduly discriminatory, and are therefore not in accordance with s. 59 of the *UCA*.

[19] On June 2, 2017, by way of Order G-87-17 the Commission denied the reconsideration request finding the errors claimed had not been substantiated on a *prima facie* basis. In the result, the reconsideration application did not proceed to phase two and was not considered on its merits.

2017 BCCA 400 (CanLII)

TEST FOR LEAVE TO APPEAL

[20] Pursuant to s. 101 of the *UCA*, an appeal lies to this Court with leave of a justice. The judge who hears the leave application acts as a gatekeeper. The judge's task is to ensure judicial resources are not expended on matters that do not merit the attention of a division of the Court: *Teck Cominco Metals Ltd. v. British Columbia (Minister of Revenue)*, 2009 BCCA 3 (in Chambers) at para. 27.

[21] The factors to be considered in deciding whether leave to appeal from a statutory tribunal should be granted were summarized in *Queens Plate Development Ltd. v. Vancouver Assessor, Area 09* (1987), 16 B.C.L.R. (2d) 104 at 109–110:

> (a) whether the proposed appeal raises a question of general importance as to the extent of jurisdiction of the tribunal appealed from …;
>
> (b) whether the appeal is limited to questions of law involving:
>
> (i) the application of statutory provisions ...;
>
> (ii) a statutory interpretation that was particularly important to the litigant ...; or
>
> (iii) interpretation of standard wording which appears in many statutes …;
>
> (c) whether there was a marked difference of opinion in the decisions below and sufficient merit in the issue put forward ...;
>
> (d) whether there is some prospect of the appeal succeeding on its merits ... although there is no need for a justice before whom leave is argued to be convinced of the merits of the appeal, as long as there are substantial questions to be argued;
>
> (e) whether there is any clear benefit to be derived from the appeal ...; and

> (f) whether the issue on appeal has been considered by a number of appellate bodies ...
>
> [Case citations omitted.]

[22] Determining whether the issue raised by an application for leave to appeal has arguable merit must be done in light of the standard of review on which the merits of the appeal will be judged: *Sattva Capital Corp. v. Creston Moly Corp.*, 2014 SCC 53 at para. 75. While *Sattva* concerned leave to appeal a decision under the *Commercial Arbitration Act*, R.S.B.C. 1996, c. 55, the same principle applies to a leave application pursuant to s. 101 of the *UCA*: *Collins v. British Columbia Utilities Commission*, 2012 BCCA 455.

2017 BCCA 400 (CanLII)

POSITIONS ON APPLICATION

[23] The applicants submit they should be granted leave to appeal both the Original Decision and the Reconsideration Decision. They submit the proposed appeal raises an important question about the Commission's jurisdiction under the *UCA* to order or approve low-income rates. They submit the answer to this jurisdictional question will have significant implications for BC Hydro, other utilities and low-income ratepayers all over the province.

[24] The applicants submit that whether the Commission has jurisdiction under the *UCA* to approve low-income rates is a question of statutory interpretation which should be determined on the basis of correctness. They submit the Commission erred in law in finding that it had no jurisdiction under the *UCA* to set low-income rates. The applicants submit that the appeals would have the clear benefit of settling an important jurisdictional question and would clarify whether the Commission can, as part of its public interest function, make distinctions between customers based on income to ensure vulnerable ratepayers can access essential services. The applicants note that while the issue of a regulatory body's jurisdiction to order low-income rates has been considered by other appellate bodies, none have considered the specific legislation set out in the *UCA*.

[25] In response, BC Hydro and Fortis both submit that if there is an appeal, it would lie only from the Reconsideration Decision. They submit that the factors in the *Queens Plate* test have not been met and the application for leave to appeal should be dismissed. In that regard, they submit that the proposed appeal does not raise a true question of jurisdiction that would justify appellate review. Furthermore, they submit the appeal has no prospect of success given the high level of deference that would be shown to the Commission, which interpreted and applied provisions of its home statute. They submit the applicants have failed to show the appeal has some prospect of success or that there is a substantial question to be argued. They further submit the Commission did in fact consider the applicants' proposals and found as a fact the low-income rates would be unduly discriminatory and therefore not in accordance with s. 59 of the *UCA*. They submit this finding of fact cannot be challenged on appeal.

[26] The Commission takes no position as to whether or not leave to appeal should be granted. It does however submit that if leave is granted, it should be limited to the Reconsideration Decision.

DISCUSSION

A. Which Decision Can Be Appealed?

[27] The Commission, BC Hydro and Fortis all submit that if leave is to be granted, it should only be from the Reconsideration Decision. The applicants do not seriously argue otherwise.

[28] This Court in *Yellow Cab Company Ltd. v. Passenger Transportation Board*, 2014 BCCA 329, set out the framework governing the determination of whether leave to appeal should be from a tribunal's original or reconsideration decision. Where a party has taken advantage of a tribunal's reconsideration power, and the tribunal has undertaken the reconsideration, the reconsideration decision represents the final decision of the tribunal and it is the decision which should be reviewed: *Yellow Cab Company Ltd.* at para. 40.

2017 BCCA 400 (CanLII)

[29] The original decision of course gives rise to the reconsideration decision. It forms part of the appeal record and will inform the court's review of the reconsideration which is, in this case, an affirmation of the original order. This is the situation that arose in *Zellstoff Celgar Limited Partnership v. British Columbia Hydro and Power Authority et al.* (21 October 2014), Vancouver CA041888; CA042066 (B.C.C.A. in Chambers). In that case, as in this, the parties sought leave to appeal both the original and reconsideration decisions of the Commission. Madam Justice MacKenzie held that leave should only be granted in regard to the reconsideration decision. She noted that since the original decision forms part of the record and will inform the court's review on appeal, there was no prejudice in granting leave to appeal only the reconsideration decision. The same considerations apply in this case. If leave to appeal is to be granted, leave should only be granted with respect to the Reconsideration Decision.

2017 BCCA 400 (CanLII)

B. Should Leave Be Granted?

[30] I turn to the question of whether leave to appeal should be granted. This requires a consideration of the *Queens Plate* factors. The applicants place particular emphasis on factors (a), (b) and (d).

[31] In their submission, the applicants stress that the proposed appeal raises a question of general importance concerning the Commission's jurisdiction. They submit that the jurisdictional question is critically important, as it will determine whether the Commission is empowered to order BC Hydro to implement low-income rates. They submit the proposed appeal is limited to questions involving statutory interpretation and will focus on the Commission's finding that sections 23, 38, 59 and 60 of the *UCA* do not provide the Commission with the jurisdiction to order and approve low-income rates. They submit the Commission erred in law in finding that the *UCA* did not confer jurisdiction on the Commission to set low-income rates. They submit the appeal has some prospect of success and their submissions raise a substantial question to be tried.

[32] The applicants further submit pursuant to factor (e) that there is a clear public benefit to be derived from the appeal. In this regard, they submit that the impact of the decision on BC Hydro's low-income customers is severe. They submit the appeal can settle an important jurisdictional question and if successful, will enable the Commission to consider a substantive issue of important public interest.

[33] The applicants also point out that the issue of a regulatory body's jurisdiction to order low-income rates has been considered by other appellate bodies, albeit not with respect to the specific legislation that governs the Commission. In that regard, they point to the decisions in *Dalhousie Legal Aid Service v. Nova Scotia Power Inc.*, 2006 NSCA 74; *Advocacy Centre for Tenants-Ontario v. Ontario Energy Board*, 293 D.L.R. (4th) 684, 2008 CanLII 23487 (Ont. S.C.J.) and a recent Manitoba hydro general rate application: Manitoba Public Utilities Board Order No. 73/15, Final Order with respect to Manitoba Hydro's 2014/15 and 2015/16 General Rate Application.

[34] In my respectful opinion, the question of whether or not to grant leave on this application comes down to a consideration of the merits.

[35] The merits analysis plays a major role in the courts' gatekeeper function. In *Collins*, Mr. Justice Chiasson in discussing the merits test observed:

> [32] It is apparent to me that this Court equates "some prospect of success" with "a substantial question to be argued". I would not apply a test that limits the consideration to whether a proposed appeal is "not wholly devoid of merit". In my mind, that is not consistent with the gatekeeper function described by Frankel J.A. It also is not consistent with the development of the reasonableness standard in the law of judicial review and the deference owed by courts to tribunals where the issue does not concern true jurisdiction, and particularly, where the issue involves the construction of a tribunal's home statute or one closely related to its function.

[36] In this case, I find that the applicants' appeal is not one with some prospect of success. The foundation of the applicants' submission is that their appeal raises a jurisdictional issue which is to be determined on the question of correctness. The jurisprudence, however, suggests otherwise. This case involves the interpretation by the Commission of its home statute. A decision of an administrative tribunal

2017 BCCA 400 (CanLII)

interpreting or applying its home statute is to be reviewed on a reasonableness standard: *Alberta (Information and Privacy Commissioner) v. Alberta Teachers' Association*, 2011 SCC 61 at para. 39. The Supreme Court of Canada has recently reiterated this point in the context of a statutory right of appeal: *Edmonton (City) v. Edmonton East (Capilano) Shopping Centres Ltd.*, 2016 SCC 47.

2017 BCCA 400 (CanLII)

[37] This case turns on the Commission's interpretation of its jurisdiction to approve a low-income rate in the absence of economic or cost of service justification. The Commission interpreted and applied the provisions of its home statute governing rate making. This lies at the core of its expertise and competence. In reaching its decision the Commission undertook a textual, contextual and purposive analysis of the key provisions. It considered the Hansard evidence tendered by each party and concluded that this extrinsic evidence reinforced its interpretation. It also extended its review to decisions of courts and tribunals from other Canadian jurisdictions and examined with care whether the relevant statutory provisions in those jurisdictions were comparable.

[38] Ultimately the Commission rejected the appellants' submissions and held that the *UCA* did not provide the Commission with the jurisdiction to approve a low-income rate in the absence of an economic or cost of service justification. In their submissions the applicants do not suggest the Commission's findings are unreasonable. They have not put forward a credible argument or basis for this Court, given the deferential standard of review, to reverse the Commission's conclusion. Given the standard of review, I have reached the conclusion that there is no prospect that this appeal can succeed.

[39] I would also note that pursuant to s. 59(4) of the *UCA*, it is a finding of fact of which the Commission is the sole judge, whether a rate is unjust, unreasonable or unduly discriminatory. The Commission in its reasons found as a fact that the low-income rates proposed by the applicants were unjust, unreasonable and unduly discriminatory and therefore not in accordance with sections 59–60 of the *UCA*. Pursuant to s. 79 of the *UCA* that finding, which goes to the heart of the applicants'

rate submissions, cannot be challenged on appeal. In the result, even if the applicants could convince this Court that the Commission's interpretation of its home statute was unreasonable the appeal would have no practical utility.

[40] The applications for leave to appeal are dismissed.

"The Honourable Mr. Justice Goepel"

2017 BCCA 400 (CanLII)

Appendix 17.1 - Public Utilities Board Ex-Parte and Interim Orders

Order No.	Date	Curtailable Rates Program
54/16	April 26, 2016	Approval of the Curtailable Rate Program Reference Discount Effective April 1, 2016
45/17	April 27, 2017	Approval of the Curtailable Rate Program Reference Discount Effective April 1, 2017

Order No.	Date	General Consumer Rates
79/14	July 15, 2014	Approval for New Light Emitting Diode (LED) rates for Area and Roadway Lighting Class Effective August 1, 2014
59/16	April 28, 2016	Order in Respect of an Application by Manitoba Hydro for April 1, 2016 Interim Rates
68/16	May 17, 2016	Approval of August 1, 2016 Rate Schedules flowing from Order 59/16
80/17	July 31, 2017	Order in Respect of an Application by Manitoba Hydro for August 1, 2017 Interim Rates
85/17	August 3, 2017	Approval of August 1, 2017 Rate Schedules flowing from Order 80/17

Order No.	Date	Surplus Energy Program
43/13	April 26, 2013	Approval of Surplus Energy Program Option 1 Terms and Conditions
76/15	July 29, 2015	Approval for Surplus Energy Program Rates, Schedule SEP-1
79/15	August 6, 2015	Approval for Surplus Energy Program Rates, Schedule SEP-1
82/15	August 12, 2015	Approval for Surplus Energy Program Rates, Schedule SEP-1
85/15	August 19, 2015	Approval for Surplus Energy Program Rates, Schedule SEP-1
86/15	August 26, 2015	Approval for Surplus Energy Program Rates, Schedule SEP-1
87/15	September 2, 2015	Approval for Surplus Energy Program Rates, Schedule SEP-1
88/15	September 9, 2015	Approval for Surplus Energy Program Rates, Schedule SEP-1
89/15	September 16, 2015	Approval for Surplus Energy Program Rates, Schedule SEP-1
91/15	September 23, 2015	Approval for Surplus Energy Program Rates, Schedule SEP-1
93/15	September 30, 2015	Approval for Surplus Energy Program Rates, Schedule SEP-1
99/15	October 7, 2015	Approval for Surplus Energy Program Rates, Schedule SEP-1
100/15	October 14, 2015	Approval for Surplus Energy Program Rates, Schedule SEP-1
104/15	October 21, 2015	Approval for Surplus Energy Program Rates, Schedule SEP-1
105/15	October 28, 2015	Approval for Surplus Energy Program Rates, Schedule SEP-1
111/15	November 4, 2015	Approval for Surplus Energy Program Rates, Schedule SEP-1
113/15	November 10, 2015	Approval for Surplus Energy Program Rates, Schedule SEP-1
116/15	November 18, 2015	Approval for Surplus Energy Program Rates, Schedule SEP-1
122/15	November 25, 2015	Approval for Surplus Energy Program Rates, Schedule SEP-1
134/15	December 2, 2015	Approval for Surplus Energy Program Rates, Schedule SEP-1
135/15	December 9, 2015	Approval for Surplus Energy Program Rates, Schedule SEP-1
138/15	December 16, 2015	Approval for Surplus Energy Program Rates, Schedule SEP-1
143/15	December 23, 2015	Approval for Surplus Energy Program Rates, Schedule SEP-1
145/15	December 30, 2015	Approval for Surplus Energy Program Rates, Schedule SEP-1

Appendix 17.1 - Public Utilities Board Ex-Parte and Interim Orders

Order No.	Date	Surplus Energy Program
2/16	January 6, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
6/16	January 13, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
10/16	January 20, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
13/16	January 27, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
19/16	February 3, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
20/16	February 10, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
22/16	February 17, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
25/16	February 24, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
29/16	March 2, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
32/16	March 9, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
35/16	March 16, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
42/16	March 23, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
44/16	March 30, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
47/16	April 6, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
50/16	April 13, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
51/16	April 20, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
58/16	April 27, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
62/16	May 4, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
66/16	May 11, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
67/16	May 18, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
69/16	May 25, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
70/16	June 1, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
73/16	June 8, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
77/16	June 15, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
80/16	June 22, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
81/16	June 29, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
82/16	July 6, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
87/16	July 13, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
92/16	July 20, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
101/16	July 27, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
103/16	August 3, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
109/16	August 10, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
110/16	August 17, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
112/16	August 24, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
113/16	August 31, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
116/16	September 7, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
118/16	September 14, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
119/16	September 21, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
124/16	September 28, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
126/16	October 5, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1

Appendix 17.1 - Public Utilities Board Ex-Parte and Interim Orders

Order No.	Date	Surplus Energy Program
129/16	October 12, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
133/16	October 19, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
138/16	October 26, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
140/16	November 2, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
141/16	November 9, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
143/16	November 16, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
144/16	November 23, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
150/16	November 30, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
152/16	December 7, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
161/16	December 14, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
165/16	December 21, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
166/16	December 28, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
1/17	January 4, 2017	Approval for Surplus Energy Program Rates, Schedule SEP-1
2/17	January 11, 2017	Approval for Surplus Energy Program Rates, Schedule SEP-1
4/17	January 18, 2017	Approval for Surplus Energy Program Rates, Schedule SEP-1
9/17	January 25, 2017	Approval for Surplus Energy Program Rates, Schedule SEP-1
11/17	February 1, 2017	Approval for Surplus Energy Program Rates, Schedule SEP-1
17/17	February 8, 2017	Approval for Surplus Energy Program Rates, Schedule SEP-1
22/17	February 15, 2017	Approval for Surplus Energy Program Rates, Schedule SEP-1
24/17	February 22, 2017	Approval for Surplus Energy Program Rates, Schedule SEP-1
27/17	March 1, 2017	Approval for Surplus Energy Program Rates, Schedule SEP-1
29/17	March 8, 2017	Approval for Surplus Energy Program Rates, Schedule SEP-1
30/17	March 15, 2017	Approval for Surplus Energy Program Rates, Schedule SEP-1
31/17	March 22, 2017	Approval for Surplus Energy Program Rates, Schedule SEP-1
34/17	March 29, 2017	Approval for Surplus Energy Program Rates, Schedule SEP-1
36/17	April 5, 2017	Approval for Surplus Energy Program Rates, Schedule SEP-1
38/17	April 12, 2017	Approval for Surplus Energy Program Rates, Schedule SEP-1
41/17	April 19, 2017	Approval for Surplus Energy Program Rates, Schedule SEP-1
42/17	April 26, 2017	Approval for Surplus Energy Program Rates, Schedule SEP-1
47/17	May 3, 2017	Approval for Surplus Energy Program Rates, Schedule SEP-1
48/17	May 10, 2017	Approval for Surplus Energy Program Rates, Schedule SEP-1
49/17	May 17, 2017	Approval for Surplus Energy Program Rates, Schedule SEP-1
54/17	May 24, 2017	Approval for Surplus Energy Program Rates, Schedule SEP-1
56/17	May 31, 2017	Approval for Surplus Energy Program Rates, Schedule SEP-1
58/17	June 7, 2017	Approval for Surplus Energy Program Rates, Schedule SEP-1
63/17	June 14, 2017	Approval for Surplus Energy Program Rates, Schedule SEP-1
65/17	June 21, 2017	Approval for Surplus Energy Program Rates, Schedule SEP-1
67/17	June 28, 2017	Approval for Surplus Energy Program Rates, Schedule SEP-1
72/17	July 5, 2017	Approval for Surplus Energy Program Rates, Schedule SEP-1
74/17	July 12, 2017	Approval for Surplus Energy Program Rates, Schedule SEP-1

Appendix 17.1 - Public Utilities Board Ex-Parte and Interim Orders

Order No.	Date	Surplus Energy Program
75/17	July 19, 2017	Approval for Surplus Energy Program Rates, Schedule SEP-1
78/17	July 26, 2017	Approval for Surplus Energy Program Rates, Schedule SEP-1
84/17	August 2, 2017	Approval for Surplus Energy Program Rates, Schedule SEP-1
87/17	August 9, 2017	Approval for Surplus Energy Program Rates, Schedule SEP-1
88/17	August 16, 2017	Approval for Surplus Energy Program Rates, Schedule SEP-1
92/17	August 23, 2017	Approval for Surplus Energy Program Rates, Schedule SEP-1
93/17	August 30, 2017	Approval for Surplus Energy Program Rates, Schedule SEP-1
94/17	September 6, 2017	Approval for Surplus Energy Program Rates, Schedule SEP-1
96/17	September 13, 2017	Approval for Surplus Energy Program Rates, Schedule SEP-1
102/17	September 20, 2017	Approval for Surplus Energy Program Rates, Schedule SEP-1
104/17	September 27, 2017	Approval for Surplus Energy Program Rates, Schedule SEP-1
107/17	October 4, 2017	Approval for Surplus Energy Program Rates, Schedule SEP-1
109/17	October 11, 2017	Approval for Surplus Energy Program Rates, Schedule SEP-1
111/17	October 18, 2017	Approval for Surplus Energy Program Rates, Schedule SEP-1
114/17	October 25, 2017	Approval for Surplus Energy Program Rates, Schedule SEP-1
119/17	November 1, 2017	Approval for Surplus Energy Program Rates, Schedule SEP-1
122/17	November 8, 2017	Approval for Surplus Energy Program Rates, Schedule SEP-1
125/17	November 15, 2017	Approval for Surplus Energy Program Rates, Schedule SEP-1
127/17	November 22, 2017	Approval for Surplus Energy Program Rates, Schedule SEP-1
129/17	November 29, 2017	Approval for Surplus Energy Program Rates, Schedule SEP-1
131/17	December 6, 2017	Approval for Surplus Energy Program Rates, Schedule SEP-1
133/17	December 13, 2017	Approval for Surplus Energy Program Rates, Schedule SEP-1
137/17	December 20, 2017	Approval for Surplus Energy Program Rates, Schedule SEP-1
141/17	December 27, 2017	Approval for Surplus Energy Program Rates, Schedule SEP-1
1/18	January 3, 2018	Approval for Surplus Energy Program Rates, Schedule SEP-1
8/18	January 10, 2018	Approval for Surplus Energy Program Rates, Schedule SEP-1
15/18	January 17, 2018	Approval for Surplus Energy Program Rates, Schedule SEP-1
17/18	January 24, 2018	Approval for Surplus Energy Program Rates, Schedule SEP-1
20/18	January 31, 2017	Approval for Surplus Energy Program Rates, Schedule SEP-1

Tab 61

M A N I T O B A	Order No. 43/13
THE PUBLIC UTILITIES BOARD ACT	April 26, 2013

Before: Régis Gosselin, B.A., M.B.A., C.G.A., Chair
Raymond Lafond, B.A., C.M.A., F.C.A., Member
Larry Soldier, Member

FINAL ORDER WITH RESPECT TO
MANITOBA HYDRO'S 2012/13 AND 2013/14
GENERAL RATE APPLICATION

TABLE OF CONTENTS

1.0.0 EXECUTIVE SUMMARY 2

2.0.0 IT IS ORDERED: 4

3.0.0 IT IS RECOMMENDED: 7

4.0.0 THE RATE APPLICATION 8
4.1.0 Issues 8
4.2.0 Board Findings 9

5.0.0 OPERATION, MAINTENANCE & ADMINISTRATION EXPENSES 12
5.1.0 Issues 12
5.2.0 Board Findings 14

6.0.0 DEPRECIATION AND AMORTIZATION 16
6.1.0 Issues 16
6.2.0 Board Findings 18

7.0.0 FINANCE EXPENSE 20
7.1.0 Issues 20
7.2.0 Board Findings 20

8.0.0 FINANCIAL TARGETS 21
8.1.0 Issues 21
8.2.0 Board Findings 23

9.0.0 WUSKWATIM GENERATING STATION PROJECT 25
9.1.0 Issues 25
9.2.0 Board Findings 27

10.0.0 CAPITAL EXPENDITURES 29
10.1.0 Issues 29
10.2.0 Board Findings 33

11.0.0 LOAD FORECAST 35
11.1.0 Issues 35
11.2.0 Board Findings 36

12.0.0 EXPORT MARKETS 38
12.1.0 Issues 38
12.2.0 Board Findings 39

13.0.0 DEMAND-SIDE MANAGEMENT 41
13.1.0 Issues 41
13.2.0 Board Findings 44

14.0.0 SPECIAL RATES 46
14.1.0 Curtailable Rate Program 46
14.2.0 Surplus Energy Program 46
14.3.0 Time-of-Use Rates 47
14.4.0 Diesel Communities 47

15.0.0 PRESENTER SUBMISSIONS 49
15.1.0 Industry Presentations 49
15.2.0 Individual Presenters 50

APPENDIX A – APPROVALS SOUGHT BY MANITOBA HYDRO 54

APPENDIX B – APPEARANCES 56

APPENDIX C – WITNESSES FOR MANITOBA HYDRO 57

APPENDIX D – INTERVENERS OF RECORD 58

APPENDIX E – INTERVENER WITNESSES 59

APPENDIX F – PRESENTERS 60

APPENDIX G - UNITS OF MEASUREMENT 61

1.0.0 EXECUTIVE SUMMARY

In this Order, the Public Utilities Board of Manitoba ("Board") approves a 3.5% increase in Manitoba Hydro consumers' billed rates effective May 1, 2013. However, of this increase, the revenues from a 1.5% rate increase are to mitigate rate increases when Bipole III comes into service.

Since a portion of the granted increase is dedicated to major capital, the Board expects Manitoba Hydro to realize internal cost savings to meet its net income projections. The key will be controlling Operation, Maintenance & Administration costs.

The major reasons for this rate increase are to address:

- Reduced revenues from export sales;
- Higher operating costs related to the Wuskwatim Generating Station;
- Higher Operation, Maintenance & Administration costs;
- Funding of capital expenditures undertaken to support the reliability of electrical service; and
- Manitoba Hydro's financial and credit rating integrity over the longer term.

Overall net export revenues projected, by Manitoba Hydro, over a 20-year forecast have declined by over $6 billion in the current forecast compared to the prior forecast presented at the last General Rate Application. Lower revenues mean increased borrowing to pay for capital expenditures.

The Wuskwatim Generation Station and transmission project came on-line in 2012/13 with a capital cost of $1.8 billion, which was almost double the initial cost estimate. The Board calculates that the project's incremental in-service cost is approximately $160 million/yr (excluding any internally generated funds). This amounts to an in-service unit cost of approximately 10.5¢/kWh, which is three times higher than the current average export revenue rate of 3.3¢/kWh. Wuskwatim energy sales may not be profitable for a sustained period.

The Board is concerned with the projected future deterioration of Manitoba Hydro's financial targets, in particular the debt-to-equity ratio that will fall from a current level of 75:25 to 90:10 by 2021, even with projected annual rate increases of approximately 4%, which is twice the projected level of inflation. This deterioration will put Manitoba Hydro in a weaker financial position given its planned capital spending over the next two decades.

Manitoba Hydro has identified over $33 billion in capital spending over the next twenty years. The planned major capital investments in the Keeyask Generating Station and Conawapa Generating Station will be the subject of a future Needs For and Alternatives To (NFAT) proceeding before the Board. However, part of the spending is also required to maintain aging infrastructure for reliability purposes.

Electricity rates are forecast, by Manitoba Hydro, to more than double from current levels over the next 20 years at approximately twice the forecast level of inflation. The Board therefore believes that Manitoba Hydro should increase its energy conservation and load management (Demand-Side Management) targets from its 2011 Power Smart Plan to assist consumers to reduce their energy consumption and the impact of projected rate increases. The rate increase granted by this Order contains specific funds designated to be used to implement energy-savings programs.

In this Order, the Board also finalizes several other interim orders with respect to Manitoba Hydro rendered by the Board since the last General Rate Application.

The specific details of Manitoba Hydro's Application are set out in Appendix A to this Order.

The Board was ably assisted in its extensive review by Interveners and their witnesses. The transcripts of evidence and Exhibits from the 21 days of oral hearings that have been considered by the Board in reaching its decisions in this Order can be found on the Board's website at www.pub.gov.on.ca. Likewise, Manitoba Hydro's complete Application, including Appendices, is posted on Manitoba Hydro's website at www.hydro.mb.ca.

2.0.0 IT IS ORDERED:

1. That the 1% rate deferral and associated revenues, which formed part of interim rates granted in Order 30/11 and 40/11 to be included in Manitoba Hydro's revenue and base rates effective April, 2012 **BE AND IS HEREBY APPROVED AS FINAL**.

2. That the interim rate increases of 2% granted April 1, 2012 and 2.4% granted September 1, 2012 **BE AND ARE HEREBY APPROVED AS FINAL**.

3. That a 3.5 % overall increase in billed rates for the basic monthly charge, the demand charge, and the energy charge for all rate categories to take effect May 1, 2013, with revenues from a 1.5% portion of the rate increase accruing in a deferral account to be utilized to mitigate the required rate increases when Bipole III is placed in-service, **BE AND IS HEREBY APPROVED**.

4. That Manitoba Hydro recalculate and refile, for Board approval, a schedule of rates reflecting a 3.5% increase to the basic monthly charge, demand charge and energy charge across all consumer classes, effective May 1, 2013, together with all supporting schedules including proof of revenue and customer impacts.

5. That Manitoba Hydro file with the Board, as part of any future interim application for rate increases, the following information on a monthly basis for the previous three months, and on an on-going basis until a rate Order in respect of the Application is issued:

    (a) Hydraulic generation monthly data (GWh) for the Winnipeg River System, Grand Rapids, Upper Nelson River Generating Station(s), Lower Nelson River Generating Station(s), and Wuskwatim Generating Station;

    (b) Monthly adjusted system energy-in-storage curves and Lake Winnipeg water levels;

    (c) Average monthly flow data for the Winnipeg River, Saskatchewan River, and Upper Nelson River (Kelsey Generating Station) and Lower Nelson River (Kettle Generating Station);

    (d) Monthly extra-provincial energy exchange data (volumes and prices) for National Energy Board-filed sales and purchases (by permit / license number), Midwest Independent System Operator day-ahead and real-time sales and purchases, and Canadian sales and purchases; and

    (e) Monthly updates to Manitoba Hydro's financial results relative to its forecast.

6. That Manitoba Hydro file with the Board an International Financial Reporting Standards status update report prior to the next General Rate Application that will provide the Board options available for rate-setting purposes.

7. That Manitoba Hydro complete and file with the Board an Asset Condition Assessment Study no later than the filing of the next updated depreciation study with the Board.

8. That Manitoba Hydro file updated depreciation rates and schedules based on an International Financial Reporting Standards-compliant Average Service Life methodology with the next General Rate Application.

9. That Manitoba Hydro file with the Board, with the next General Rate Application, a chart showing a comparison of the impact on its Integrated Financial Forecast (i.e. 'Budget') of asset depreciation pursuant to the Average Service Life methodology (without net salvage) and the Equal Life Group methodology (without net salvage), applying both methodologies to all planned major capital additions.

10. That Manitoba Hydro file, with its next General Rate Application, a detailed quantitative and probabilistic risk assessment and review of all of its operating and financial risks in order to allow the Board to assess the adequacy of the reserves. Commercially sensitive information in the report is to be redacted from the public version and filed in confidence with the Board.

11. That Manitoba Hydro file with the Board any negotiated agreements or changes with respect to the Wuskwatim Power Limited Partnership when finalized, and detail the impacts on Manitoba Hydro's operating results and rates.

12. That Manitoba Hydro's revenue requirements are determined based on the level of Demand-Side Management spending as set out in Manitoba Hydro's 2011 Power Smart report, i.e., $34 million for 2012/13 and $35 million for 2013/14, for a total of $69 million. To the extent Manitoba Hydro's spending on Demand-Side Management in the test years, including the Affordable Energy Fund and the Lower Income Energy Efficiency Program, falls below $69 million, Manitoba Hydro shall establish a deferral account for the discrepancy, the disposition of which the Board will consider at the next General Rate Application.

13. That Manitoba Hydro's proposed changes to the Curtailable Rate Program **BE AND ARE HEREBY APPROVED ON AN INTERIM BASIS**, to be reviewed by the Board at a General Rate Application to follow the Needs For And Alternatives To (NFAT) hearing with respect to Manitoba Hydro's Preferred Development Plan.

14. That all Curtailable Rate Program Orders from Order 52/12 up to and including all Curtailable Rate Program Orders issued prior to the date of this Order **BE AND ARE HEREBY APPROVED AS FINAL**.

15. That Manitoba Hydro's Option 1 Surplus Energy Program rate offering **BE AND IS HEREBY APPROVED ON AN INTERIM BASIS**, to be reviewed by the Board at a Cost of Service/Time of Use hearing.

16. That Options 2 and 3 of the Surplus Energy Program **BE AND ARE HEREBY APPROVED** as permanent rate offerings.

17. That Manitoba Hydro is permitted to file any future Surplus Energy Program applications based on the review and approval of a Division Manager in lieu of the current requirement for a Professional Engineer's Seal.

18. That all weekly Surplus Energy Program interim ex-parte rate Orders – from Order 6/12 up to and including all Surplus Energy Program Orders issued prior to the date of this Order – **BE AND ARE HEREBY APPROVED AS FINAL**.

Board decisions may be appealed in accordance with the provisions of Section 58 of *The Public Utilities Board Act*, or reviewed in accordance with section 36 of the Board's Rules of Practice and Procedure (Rules). The Board's Rules may be viewed on the Board's website at www.pub.gov.mb.ca.

3.0.0 IT IS RECOMMENDED:

1. That Manitoba Hydro control Operation, Maintenance & Administration costs to keep increases below inflation.

2. That Manitoba Hydro prepare a business case with a thorough analysis of the economic rationale for the rebuilding of Pointe du Bois (estimated to cost $2.4 billion), and that the Board be mandated, by the Province of Manitoba, to conduct a Needs For And Alternatives To (NFAT) review before proceeding further.

3. That Manitoba Hydro target higher levels of domestic customer energy savings and therefore spend, in its energy efficiency plan, at minimum, the budgeted amounts set out in the 2011 Power Smart Plan.

4. That Manitoba Hydro undertake an independent assessment of its Power Smart Plan with the goal of evaluating and improving the plan.

5. That Manitoba Hydro continue and increase its efforts with respect to the Lower Income Energy Efficiency Program, as low income individuals will find it more difficult to meet ever increasing energy rates contemplated in Manitoba Hydro's rate increase forecast.

4.0.0 THE RATE APPLICATION

4.1.0 Issues

4.1.1 Previous Rate Increases

In its final Order arising from Manitoba Hydro's last General Rate Application (Order 5/12), the Board awarded a 1.9% rate increase effective April 1, 2010 and a 2.0% rate increase effective April 1, 2011. Since the April 1, 2010 final rate increase was lower than the interim rates approved and collected by Manitoba Hydro, the Board directed the Corporation to create a deferral account. Manitoba Hydro sought to Review and Vary Order 5/12, indicating a deteriorating financial condition as a result of a mild winter, below-normal precipitation and lower export revenues due to the U.S. economic downtown. In Order 19/12, the Board denied the Review and Vary request but indicated that the matter would be dealt with as part of the current General Rate Application.

Total revenues accumulated in the deferral account total $36 million as of March 31, 2013, with another $14 million to accumulate by March 31, 2014.

On March 30, 2012, Manitoba Hydro filed an interim application seeking reinstatement of the 1% rollback accumulating in the deferral account balance, maintaining the base rates approved in Orders 30/10 and 40/11, and seeking an additional 3.5% rate increase effective April 1, 2012, all based on lower than forecast export revenues and a winter that was warmer than normal. In Order 32/12, the Board awarded a 2.0% inflation-based rate increase effective April 1, 2012 and denied a reinstatement of the 1.0% rollback.

Effective September 1, 2012, Manitoba Hydro requested a mid-year 2.5% rate increase based on lower-than projected domestic and export revenues and a projection that 2012/13 total hydraulic generation would be approximately 1,000 GWh below the post-Wuskwatim average, resulting in a net export revenue reduction of $30-40 million. In Order 117/12, the request for an interim 2.5% rate increase was granted, based on the lower projected revenues.

During the General Rate Application proceeding, it was determined that Manitoba Hydro's hydraulic generation and export projections presented as part of the Application for an interim September 1, 2012 rate increase (which were based exclusively on 1st-quarter (Q1) data) were much better than expected. The utility's Q1 projection was for 7,200 GWh of generation and 2,100 GWh of export in 2012/13. By the 2nd quarter (Q2) the projections had increased to 9,029 GWh of generation and 3,500 GWh of export. In July and August 2012, monthly exports were about 1,300 GWh. Energy-in-storage peaked substantially above historical averages in July 2012, suggesting above-average flow conditions. However, the Board was not advised that Manitoba Hydro's situation had improved until December 13, 2012.

4.1.2 April 1, 2013 Rate Increase

Manitoba Hydro's application for a 3.5% April 1, 2013 overall revenue increase is based on its expressed need to lessen the projected deterioration of its financial ratios in future years and maintain the financial and credit rating integrity of Manitoba Hydro. Manitoba Hydro also indicated that rate increases were needed to compensate for reduced non-firm export prices and address increased costs to maintain its aging infrastructure. Manitoba Hydro's financial forecast indicates annual increases of 3.95% will be required over the next twenty years, while annual inflation is forecast at 2% per annum.

The Consumers' Association of Canada (Manitoba) Inc. while recommending that the Board accept Manitoba Hydro's request for the 1.0% deferral account rollback for 2012/13 and finalize the April 1, 2012 2.0% and September 1, 2012 2.5% interim rate increases, requested that the Board require Manitoba Hydro to refund the amounts accrued in the 2010/11 and 2011/12 deferral accounts. The Consumers' Association of Canada (Manitoba) Inc. further opposed the request for an April 1, 2013 3.5% rate increase, stating that the economic slowdown, coupled with private and public-sector restraint, has brought some hardship to Manitobans, and a 4.5% rate increase (2.0% April 1, 2012 + 2.5% September 1, 2012) in 2012 compounded by a further 3.5% rate increase in 2013 would put substantial pressure on individuals with limited discretionary incomes, particularly those who rely on electric heat.

The Green Action Centre supported Manitoba Hydro's application for rate increases, stating that there was a need to invest in existing infrastructure for reliability purposes, and that Manitoba Hydro had demonstrated that it was negatively affected by a decline in export revenue.

The Manitoba Industrial Power Users Group recommended against Manitoba Hydro retaining any of the deferral account balance accrued prior to March 31, 2012, but recommended that the 2.0% increase in effect as of April 1, 2012 and the 2.5% interim rate increase in effect as of September 1, 2012 be made final. The Manitoba Industrial Power Users Group further requested that the Board implement rate adjustments of up to 0.2% to the appropriate customer classes to ensure that the rate increase is appropriately applied on an "across-the-board" basis when energy, demand and customer charges are taken into account, which issue will be addressed at a Cost of Service hearing. The Manitoba Industrial Power Users Group asked the Board to reject the request for a 3.5% rate increase as of April 1, 2013, stating that this was not needed to fund revenue requirements or set appropriate reserves.

4.2.0 Board Findings

The Board is called upon to balance the interests of consumers with those of the utility. While two of the interveners recommended that the rate increases sought by Manitoba Hydro be denied or rebated, the Board is concerned about the deteriorating financial

condition of Manitoba Hydro in the face of pending significant major capital expenditures.

Interveners recommended various accounting changes to lessen rate increases over the test years. The Board rejects this approach as it would have the effect of reducing Manitoba Hydro's revenues, weakening its financial situation, and increasing borrowing costs. It is important that Manitoba Hydro remain a financially strong and viable organization. The Board supports the staged approach to accounting changes planned by Manitoba Hydro.

The Board will allow Manitoba Hydro to include the 1% rollback in its revenues as final and confirm as final the 2% interim rate increase in effect as of April 1, 2012 approved in Order 32/12. The Board will also confirm as final the 2.5% interim rate increase in effect as of September 1, 2012 approved in Order 117/12. These decisions reflect an overall concern about the projected decline in Manitoba Hydro's financial targets in the upcoming years due to various factors, including the in-service costs of the Wuskwatim Generating Station, major capital expenditures, as well as continued low export revenues as a result of low export prices.

The Board will further permit a 3.5% increase to the basic monthly charge, demand charge and energy charge across all customer classes effective May 1, 2013 with a 2% portion of the increase included in general revenues and the balance to accrue to a deferral account. This reflects the Board's view that Manitoba Hydro must achieve a proper balance between cost containment and rate increases to meet its financial position. Manitoba Hydro is to establish a deferral account in which the revenues from the 1.5% increase accrues until further Order of the Board (2% to general revenues + 1.5% to deferral account = 3.5%) . The capital deferral account is to assist in funding the planned Bipole III transmission line. The cost of this project will be capitalized during the construction phase, but significant annual depreciation, operation, maintenance & administration, and interest costs will have to be recovered from domestic ratepayers once the project is placed in-service. The deferral account allows Manitoba Hydro to collect funds as the Bipole III project is being built, which will help to mitigate rate increases required once the infrastructure is placed in-service.

To address a problem the Board experienced with out-dated information in respect of Manitoba Hydro's request for a September 1, 2012 interim rate increase, the Board will direct Manitoba Hydro to file the following documentation as part of any future interim application for rate increases, for the three months immediately preceding the filing of such applications, and on an on-going basis until such time as a rate Order in respect of the Application is issued:

(a) Hydraulic generation monthly data (GWh) for the Winnipeg River System, Grand Rapids, Upper Nelson River Generating Station(s), Lower Nelson River Generating Station(s), and Wuskwatim Generating Station;

(b) Monthly adjusted system energy-in-storage curves and Lake Winnipeg water levels;

(c) Average monthly flow data for the Winnipeg River, Saskatchewan River, and Upper Nelson River (Kelsey Generating Station) and Lower Nelson River (Kettle Generating Station);

(d) Monthly extra-provincial energy exchange data (volumes and prices) for; NEB-filed sales and purchases (by permit / license number), Midwest Independent System Operator (Midwest Independent System Operator) day-ahead and real-time sales and purchases, and Canadian sales and purchases; and

(e) Monthly updates to Manitoba Hydro's financial results relative to its forecast.

5.0.0 OPERATION, MAINTENANCE & ADMINISTRATION EXPENSES

5.1.0 Issues

5.1.1 Overall Growth

From 2009/10 to 2013/14, Manitoba Hydro's total annual electric Operation, Maintenance & Administration cost has grown from $662 million to $802.4 million. When capitalized costs are factored out, Operation, Maintenance & Administration relating to electric operations has increased from $377.6 million in 2009/10 to a forecast $470.6 million in 2013/14. The increase is due to a growth in staffing levels and accounting policy changes.

5.1.2 Staffing Levels

Over 75% of Manitoba Hydro's Operation, Maintenance & Administration costs relate to labour costs, including employee benefits. Wages and salaries increased by an average of 4.5% per year, primarily as a result of contract settlements with bargaining units and an increase in total Equivalent Full-Time employees. The increase in Equivalent Full-Time employees has been attributed to growth in Manitoba Hydro's capital program, including new generation and transmission projects such as Bipole III, Keeyask Generating Station, Conawapa Generating Station, and Pointe du Bois Generating Station. To a lesser degree, Manitoba Hydro attributes the employee growth to operational support for various initiatives, including the commissioning of Wuskwatim Generating Station and the meter compliance program.

Both the Consumers' Association of Canada (Manitoba) Inc. and the Manitoba Industrial Power Users Group were critical of the growth in Operation, Maintenance & Administration costs. The Consumers' Association of Canada (Manitoba) Inc. took the position that Manitoba Hydro should be directed to develop a plan to have Operation, Maintenance & Administration expenses increase at less than inflation when accounting changes are removed from the equation. The Manitoba Industrial Power Users Group suggested that the level of staffing increases cannot be maintained, and that the utility's staffing should be thoroughly examined on employee-level basis. The Manitoba Industrial Power Users Group also took issue with the vacancy rate used in forecasting and suggested it be adjusted to be more consistent with recent experience of 8% rather than forecast 6.2%. Making this adjustment to the forecast would reduce the revenue requirement by $10 million. The Manitoba Industrial Power Users Group recommended that the Board ask the Minister to undertake an independent external review and evaluation of Manitoba Hydro's Operation, Maintenance & Administration spending, similar to the review undertaken for BC Hydro in British Columbia.

5.1.3 Capitalization of Operation, Maintenance & Administration

Manitoba Hydro capitalized $321.8 million (44%) of Operation, Maintenance & Administration cost in 2011/12 and forecasts to capitalize $324.4 million (42%) in 2012/13 and $331.8 million (41%) in 2013/14. The vast majority of cost capitalized is labour and benefits. Capitalized Equivalent Full-Time employees have grown from 2,369 Equivalent Full-Time employees in 2007/08 to a forecast of 2,825 Equivalent Full-Time employees for the two test years.

5.1.4 Accounting Changes

Since 2007/08, Manitoba Hydro has made changes to its capitalization practice to move away from "full cost" accounting and provide consistency with other Canadian utilities. Manitoba Hydro capitalizes overhead costs directly attributable to capital initiatives and has identified certain previously capitalized costs that would exist regardless of whether or not Manitoba Hydro incurred capital spending. Since 2009/10, Manitoba Hydro has removed approximately $29 million from capitalized overhead, with a further $27 million forecast for 2012/13, for a total of $56.5 million in 2012/13 and $57.6 million in 2013/14. The change in capitalization practice is consistent with Canadian Generally Accepted Accounting Principles and is directionally consistent with International Financial Reporting Standards.

Manitoba Hydro has also identified an additional $36 million in overhead costs that it plans on expensing when Manitoba Hydro adopts International Financial Reporting Standards in 2015/16. In total, over $93 million in overhead costs will be expensed when International Financial Reporting Standards are implemented. The new standards do not allow the capitalization of advertising and promotional activities, administrative and other general overhead expenditures, property and business taxes and interest on common assets.

International Financial Reporting Standards do not currently recognize "rate-regulated accounting". To comply with International Financial Reporting Standards, Manitoba Hydro may be required to write off the accumulated balance of its rate-regulated assets against retained earnings and expense, as incurred, expenditures previously deferred due to rate regulation. A major annual rate-regulated expense for Manitoba Hydro is Demand-Side Management. Under its existing rate-regulated accounting practices, Manitoba Hydro capitalizes Demand-Side Management expenses and depreciates them over a period of ten years. Manitoba Hydro's rate-regulated assets were $310 million as of March 31, 2012, of which $233 million relate to electric operations and $77 million to gas operations.

The Accounting Standards Board has granted deferrals for Canadian utilities with rate-regulated assets and liabilities, which will delay Manitoba Hydro's implementation of International Financial Reporting Standards until 2015/16. The International Accounting

Standards Board has indicated that it will be issuing an interim standard that may grandfather rate-regulated accounting practices. That interim standard is expected to be issued in 2013.

The Consumers' Association of Canada (Manitoba) Inc. did not support the $27 million in accounting changes in the test years related to information technology infrastructure and building depreciation in the revenue requirement. Furthermore, both the Consumers' Association of Canada (Manitoba) Inc. and the Manitoba Industrial Power Users Group recommended that Manitoba Hydro's approach to capitalization should be based on full-cost accounting. The Manitoba Industrial Power Users Group stated that accounting changes should not be the driver for rate increases as the economic reality of operations has not changed, and recommended that the Board should direct Manitoba Hydro to conduct a third-party review of its accounting policies.

5.1.5 Cost Containment Measures

Manitoba Hydro expects an annual productivity factor of 0.5-1.0% in setting Operation, Maintenance & Administration targets and states that it continues to implement several cost containment measures, including an external hiring freeze, overtime restrictions, restrictions on out-of-town travel, restrictions in community sponsorships and donations, and a leveraging of technology. However, Manitoba Hydro was unable to quantify the savings attributable to these measures, stating that they were internalized in the budgeting process.

5.2.0 Board Findings

Manitoba Hydro's Operation, Maintenance & Administration expenses have grown significantly, increasing by almost 25% over four years. While part of this increase is attributable to a change in accounting policies, the single biggest factor is an increase in staffing levels. Since 2003/04, staffing levels have grown by over 1,000 Equivalent Full-Time positions. Since the economic downturn in 2007/08, levels have increased by 771, with total payroll increasing by $197 million or 41% since that time.

Manitoba Hydro's cost containment measures appear to be modest at best, and despite a hiring freeze, the utility's current projections still reflect a growth in staffing of 243 Equivalent Full-Time positions from 2011/12 levels. The Board expects Manitoba Hydro to control Operation, Maintenance & Administration costs, the key to which will be capping or reducing staffing levels. The award of only a 2.0% portion of the 3.5% increase to accrue to general revenues reflects the utility's need to find internal savings, and to demonstrate those savings at the next General Rate Application.

The Board understands that Manitoba Hydro has been making changes to its accounting policies since 2007/08 to be more consistent with other electric utilities as well as to be consistent with International Financial Reporting Standards. The Board in

past orders had expressed concern with the level of capitalization and Manitoba Hydro has begun to address these concerns. In the Board's view, Manitoba Hydro's proposed accounting changes are appropriate for the test years. The Board will direct Manitoba Hydro to file an International Financial Reporting Standards status update at the next General Rate Application. Until such time, the Board expects Manitoba Hydro not to make any further accounting changes for rate-setting purposes.

6.0.0 DEPRECIATION AND AMORTIZATION

6.1.0 Issues

6.1.1 Asset Lives and New Asset Classes

Depreciation expense is recognized on a straight-line basis over the estimated remaining service lives of assets, which lives are determined pursuant to periodic depreciation studies. Manitoba Hydro filed a March 31, 2010 depreciation study prepared by Gannett Fleming. In this most recent study, Gannett Fleming recommended several extensions of assumed service lives and the creation of several new asset classes, most notably through the creation of a new "Dams, Dykes & Weirs" category with a 125-year service life, whereas previously all dams were depreciated over 100 years. The composite average service life of a generating station was thereby increased from 100 years to 104 years. Gannett Fleming also recommended an increase in the terminal life of most generating stations from 100 years to 140 years.

Overall, the new depreciation rates resulting from updated account groupings and changed service lives resulted in a reduction of depreciation expense by $40 million in 2012/13 and $44 million in 2013/14. This also means there currently is an accumulated depreciation surplus of $555 million, which will be refunded over the remaining service life of each asset account, consistent with Generally Accepted Accounting Principles.

The Consumers' Association of Canada (Manitoba) Inc. supported the changes to service lives and recommended that the estimates be revisited once an Asset Condition Assessment report has been obtained. However, the Consumers' Association of Canada (Manitoba) Inc. suggested that the accumulated depreciation surplus should be returned over a 20-year period rather than over the remaining service lives of the assets.

6.1.2 Equal Life Group vs. Average Service Life

Gannett Fleming testified on behalf of Manitoba Hydro and recommended a switch from Manitoba Hydro's current methodology of Average Service Life to Equal Life Group, a procedure whereby the investment of a group of assets is subdivided to specifically recognize the life expectancy of each subgroup. In Mr. Kennedy's view, Equal Life Group is superior as it reduces the need to recognize losses on interim retirements of assets within a category, thus providing for lower depreciation volatility.

Both Equal Life Group and Average Service Life are International Financial Reporting Standards-permissible methodologies and Manitoba Hydro indicated that the adoption of Equal Life Group was a policy decision. However, it would not be implemented until the utility adopts International Financial Reporting Standards. In 2015/16, the switch to Equal Life Group is expected to increase depreciation expense by $38 million.

Notably, Gannett Fleming used Average Service Life to determine depreciation rates for Wuskwatim Generating Station due to uncertainty about when the facility will come into service. By using Average Service Life compared to Equal Life Group for Wuskwatim, the calculated depreciation rate was approximately $3.0 million lower than it otherwise would have been. Similarly, Manitoba Hydro based the projected depreciation expenses for Keeyask Generating Station, Conawapa Generating Station, and Bipole III on Average Service Life proxy rates (without net salvage) until Gannett Fleming provides proposed Equal Life Group rates.

Neither the Consumers' Association of Canada (Manitoba) Inc. nor the Manitoba Industrial Power Users Group supported the switch to Equal Life Group, stating that many other utilities follow the Average Service Life approach. The Consumers' Association of Canada (Manitoba) Inc. raised issues of data reliability at a time of a rapidly increasing capital base. The Manitoba Industrial Power Users Group's witness testified that Equal Life Group leads to higher depreciation expenses in the early years of an individual asset's life. In a growing utility where newer and costlier assets are routinely added to plant in service, it can result in higher initial costs to ratepayers.

In the Manitoba Industrial Power Users Group's view, high depreciation in the early years does not match the economic benefit profile of utility assets, which provide the most benefit in later years. It further testified that Equal Life Group is very sensitive to the shape of the "Iowa Curve" chosen to calculate depreciation rates, and that Manitoba Hydro's asset retirement data is insufficient to support Equal Life Group, as data exists for only a small number of large assets.

6.1.3 Removal of Net Salvage

Manitoba Hydro's current depreciation rates include a provision for net salvage, representing the cost of decommissioning and disposal of an asset when taken out of service. The rationale for including net salvage in depreciation rates is to ensure that ratepayers benefitting from the use of the asset over time are shouldering the burden of paying for the eventual decommissioning costs.

Mr. Kennedy advised that International Financial Reporting Standards would no longer permit the inclusion of net salvage in depreciation rates. Manitoba Hydro plans to remove net salvage from depreciation rates at the same time as it switches to the Equal Life Group methodology in 2015/16. Manitoba Hydro indicated the impact of removing net salvage would lower depreciation expense by approximately $56 million in 2013/14, $63 million in 2014/15, and $66 million in 2015/16.

Both the Consumers' Association of Canada (Manitoba) Inc. and the Manitoba Industrial Power Users Group recommended that net salvage be removed from depreciation immediately rather than waiting for a possible implementation of Equal Life Group.

6.2.0 Board Findings

The Board accepts the depreciation rates applied April 1, 2011, which rates reflect the changes in service lives and the true-up of the accumulated depreciation surplus for the two test years. The Board also accepts Manitoba Hydro's position that net salvage should be removed from depreciation rates when International Financial Reporting Standards are implemented rather than during the test years.

The Board understands that Manitoba Hydro is enhancing its asset condition assessment tools and will direct Manitoba Hydro to complete an Asset Condition Assessment Study no later than the filing of an updated depreciation study with the Board.

With respect to the possible switch from an Average Service Life methodology to Equal Life Group, the Board notes that both are acceptable methodologies under International Financial Reporting Standards and that any proposed changes would take place in 2015/16, which is beyond the test years. The Board understands that the decision to move towards Equal Life Group is a policy decision very much interrelated with other International Financial Reporting Standards accounting policy considerations. Given continued uncertainty regarding the application of International Financial Reporting Standards on rate-regulated entities, the Board will expect Manitoba Hydro to file additional information, including an update on any accounting policy changes, that will impact depreciation rates at the next General Rate Application.

The Board also is concerned that not enough information has been provided to date to assess the true impact on ratepayers of a switch to Equal Life Group. As such, the Board will require Manitoba Hydro to file additional information, including a determination of depreciation rates and schedules based on the Average Service Life methodology, to provide a meaningful comparison between the two approaches. The Board further expects Manitoba Hydro to file, as part of its next General Rate Application, additional information to specify what, if any, increased componentization is required, and at what cost. The work undertaken by Manitoba Hydro and Gannett Fleming Inc. with respect to component groupings to date can serve as a foundation towards determining what additional component groupings and costs, if any, are required for an International Financial Reporting Standards-compliant Average Service Life methodology.

The Board will require Manitoba Hydro to provide a comparison, for the next General Rate Application, of the impact on the Integrated Financial Forecast of an Average Service Life methodology (without net salvage) and an Equal Life Group methodology (without net salvage), where each of the accounting methodologies are applied to planned major capital additions in the Integrated Financial Forecast. Given the forecast to increase net plant by over $21 billion over a 20 year period, it will be important to understand the implications on ratepayers of using each approach at the next General Rate Application.

The Board further expects Manitoba Hydro to file, as part of its next General Rate Application, additional information to support Manitoba Hydro's view that an Average Service Life methodology compliant with International Financial Reporting Standards requires increased componentization. As part of this information, the Board expects to see evidence as to what level of componentization would be required, and how such level of componentization would increase Manitoba Hydro's costs, if at all.

7.0.0 FINANCE EXPENSE

7.1.0 Issues

Finance expense to be recovered in electricity rates is forecast to be $452 million in 2012/13 and $444 million in 2013/14. Finance expense is forecast to be over $1.6 billion in 2028, an increase of almost $1.2 billion from 2013/14 levels.

Manitoba Hydro capitalizes (and does not recover in current consumer's rates) all interest on capital projects until the project is placed in service. Manitoba Hydro is forecasting to capitalize interest costs of $141.5 million (or 23%) in 2012/13 and $161.4 million (or 27%) in 2013/14. Overall, Manitoba Hydro is forecasting to capitalize over $5.3 billion in interest costs relating to capital projects by 2032.

Long-term interest rates in Integrated Financial Forecast IFF12 are projected to be 3.15% in 2013 and 3.3% in 2014 (excluding the 1% Provincial Debt Guarantee Fee). Manitoba Hydro is forecasting long-term interest rates to increase from 3.85% in 2015 to 4.55% by 2016, to peak at 5.3% in 2022 and remain at that level for the remainder of the forecast through 2032.

7.2.0 Board Findings

Manitoba Hydro's annual finance expense is set to grow substantially over the next two decades as Manitoba Hydro completes major capital projects. The Board notes that Manitoba Hydro's long-term debt is expected to grow from $9.4 billion in 2013 to $29 billion by 2027, which will lead to a finance expense exceeding $1.6 billion in 2028; three times the current level.

The Board sees a genuine risk that the capital cost for the major capital projects will escalate further and that interest rates will be higher than forecast. Manitoba Hydro's current risk analysis reflects that a 1.0% increase in the interest rate yield curve over the entire forecast will increase total interest costs by $700 million. It is expected that this risk will be reviewed by the Board at an upcoming Needs For And Alternatives To hearing with respect to Manitoba Hydro's Preferred Development Plan.

8.0.0 FINANCIAL TARGETS

8.1.0 Issues

Manitoba Hydro has three self-imposed financial targets:

1. A minimum debt-to-equity ratio of 75:25;

2. A gross interest coverage ratio of greater than 1.20; and

3. A capital coverage ratio of greater than 1.20, to facilitate funding all new base capital construction requirements, excluding major new generation and transmission facilities, from internal sources.

Manitoba Hydro acknowledges that the targets will not be attained during years of major investments in the generation and transmission system.

8.1.1 Debt-to-Equity Ratio

The debt-to-equity ratio measures the relationship of long-term and short-term debt to equity. This ratio is used to assess the overall financial risk to Manitoba Hydro.

Manitoba Hydro's capital structure is forecast to weaken to a debt-to-equity ratio of 90:10 in 2021 due to planned capital spending on major projects. Manitoba Hydro filed Integrated Financial Forecast IFF12, which indicates planned capital spending of $33.4 billion, of which $22.9 billion relate to major projects over the next 20 years. According to Manitoba Hydro's forecast, the debt-to-equity ratio target of 75:25 will not be reached until 2031/32.

At the last General Rate Application, Manitoba Hydro had forecast long-term debt to grow from $7.8 billion in 2010 to $23 billion in 2029. Based on Integrated Financial Forecast IFF12, long-term debt is now forecast to be over $29 billion by 2029, an increase of $6.0 billion (26%) from the level forecast at the previous General Rate Application. Higher debt servicing costs, coupled with lower forecast export revenues, have resulted in reductions in forecast and actual net income of $5.9 billion since Integrated Financial Forecast IFF09.

The Consumers' Association of Canada (Manitoba) Inc. expressed concern with the increase in capital costs and noted the promise made by Manitoba Hydro two years ago that a decade of investment was to be followed by a decade of returns. This appears to have been replaced by rate increases up to twice the level of inflation until 2030. In light of the significant planned capital expenditures, the Consumers' Association of Canada (Manitoba) Inc. further questioned the continued reliance on the debt-to-equity ratio to determine Manitoba Hydro's ability to withstand adverse events.

The Manitoba Industrial Power Users Group proposed adjusting the current method of calculating the debt-to-equity ratio to exclude Accumulated Other Comprehensive Income as well as the dedicated debt for the capital spending on the Keeyask Generating Station and Conawapa Generating Station, as the projects are currently not "used and useful" and not serving customers.

8.1.2 Interest Coverage Ratio

The Interest Coverage Ratio is calculated to measure the degree to which Manitoba Hydro can meet its interest payment obligations with the net income generated. An interest coverage ratio below 1.0 indicates that Manitoba Hydro must borrow to meet its interest obligations. Absent the requested rate increases for the two test years, Manitoba Hydro forecasts an interest coverage ratio of 0.95% in 2012/13 and 0.9% in 2013/14. In Integrated Financial Forecast IFF12-1, the 1.20 target is not achieved throughout the forecast period, with the ratio falling below 1.0 from fiscal 2019 to 2021.

8.1.3 Capital Coverage Ratio

The Capital Coverage Ratio measures Manitoba Hydro's ability to fund base capital expenditures out of current cash flow from operations. A capital coverage ratio less than 1.0 indicates that Manitoba Hydro must borrow to fund its annual sustaining (base) capital requirements. Absent the requested rate increases, Manitoba Hydro forecasts a capital coverage ratio of 0.90 in 2012/13 and 0.67 in 2013/14. Manitoba Hydro's target capital coverage ratio is set at >1.20. When the ratio exceeds 1.0, Manitoba Hydro internally generates funds from its operations that are used to fund major capital projects. This reduces the amount that must be borrowed to fund major capital projects.

8.1.4 Drought Reserves

Manitoba Hydro's existing Retained Earnings reserve to address a major drought is $2.4 billion. Historically, Manitoba Hydro has experienced drought situations in approximately 25 of the last 100 years. Manitoba Hydro's opening presentation at the General Rate Application suggested that a five-year drought would have a cost impact of at $1.6 billion. This suggests that Manitoba Hydro may have an adequate level of reserves.

Manitoba Hydro Exhibit #38 and Manitoba Hydro Exhibit #40 (Exhibits are available on the Board's website) have provided analyses of the impact of droughts, relative to Integrated Financial Forecast IFF11-2, as follows:

Impact of a 5-Year Drought ($millions)

	5-Year Starting 2014/15	7-Year Starting 2014/15	5-Year Starting 2021/22	7-Year Starting 2021/22
Net Revenue Impact*	**$1,341**	**$1,945**	**$2,473**	**$3,130**

*Excludes finance costs

In Integrated Financial Forecast IFF12, Manitoba Hydro's retained earnings were forecast to be at about $2.4 billion through 2022. Manitoba Hydro's drought history (1930's & 1940's) included a five-year drought followed two years later by a seven-year drought. A repeat of such a situation using the above net revenue impacts would nearly eliminate retained earnings in the absence of additional rate increases.

8.2.0 Board Findings

Manitoba Hydro currently has achieved its debt-to-equity target of 75:25. However, the Board is concerned about the contemplated deterioration in the utility's financial targets, particularly the fact that by 2021, the debt-to-equity ratio is projected to be 90:10. Any further escalations in the capital cost for Manitoba Hydro's major new capital projects will cause the financial structure to deteriorate further.

The rate increases contemplated by Manitoba Hydro in the test years and beyond are significantly lower than what would be required to keep the Corporation at its current level of financial strength in the medium to long term. Progress in meeting these financial targets will require further rate increases, but more importantly, a concerted effort at cost containment within Manitoba Hydro.

The Board is concerned that, by moving towards a 90:10 debt-to-equity ratio by the end of the decade, there will be an insufficient retained earnings reserve to deal with droughts and other risks such as infrastructure failure or rising interest rates. The Board sees a need to further examine and quantify the other risks that Manitoba Hydro faces at the next General Rate Application and determine whether these should be subject to separate reserve provisions. The Board will require Manitoba Hydro to provide an analysis of risks on a quantitative and probabilistic basis at the next General Rate Application.

The Board notes that Manitoba Hydro shares the benefit of the flow-through credit rating of the Province, which affords it preferential interest rates on its debt and access to funds to meet its major capital spending program. However, as its debt grows, there is a potential for Manitoba Hydro's financial condition to affect the credit rating of the Province. It is important that Manitoba Hydro remains a financially strong and viable organization.

The Board does not believe that establishing a debt-to-equity ratio that ignores real debt, as was proposed by the Manitoba Industrial Power Users Group, is a reasonable proposition when credit rating agencies focus on actual debt levels.

9.0.0 WUSKWATIM GENERATING STATION PROJECT

9.1.0 Issues

9.1.1 Cost Escalation

The Clean Environment Commission in 2003 conducted a hearing examining the Need For and Alternatives To the Wuskwatim project. The projected cost of the project at the Clean Environment Commission hearing was $901 million for the generating station and transmission facilities.

Since then, the capital cost estimate increased on an annual basis, almost doubling to $1,77 million.

9.1.2 Tendering Problems with Northern Generation

Manitoba Hydro experienced tendering difficulties with the primary contract(s) for building the generating station. This led to a retendering on a component basis. Productivity problems with respect to major civil, mechanical, and electrical components were also experienced.

9.1.3 The Wuskwatim Power Limited Partnership Agreement

The Wuskwatim Power Limited Partnership Agreement provided for a first-ever First Nations ownership stake in a Manitoba Hydro generating facility. Pursuant to the terms of the Agreement, the Nisichawayasihk Cree Nation was given the option of being a Limited Partner in the Wuskwatim Generating Station with an interest of up to 33%.

Revenues received by the Partnership from the sale of power to Manitoba Hydro were based on the actual output of Wuskwatim Generating Station and be priced in accordance with an agreed methodology which reflected Manitoba Hydro's actual selling prices for exports. The Partnership would pay Manitoba Hydro a percentage of gross revenues to contribute towards the marketing and transmission risks borne by Manitoba Hydro.

Wuskwatim's revenue related to energy generated during the on-peak (5x16) hours is determined based on the average price Manitoba Hydro realizes for long-term export sales and import transactions. Wuskwatim's revenue related to energy generated during the off-peak hours is determined from the average price Manitoba Hydro realizes for all on-peak and off-peak opportunity export and import transactions, excluding the on-peak long-term contract transactions. The total of gross revenue related to on-peak and off-peak energy is reduced by transmission and related market participation charges and Manitoba Hydro's 3% marketing risk fee. Domestic sales are not included in the determination of the revenue allocated to the Wuskwatim Power Limited Partnership.

Because of low export prices, Manitoba Hydro is now forecasting losses for the first ten years of operations of Wuskwatim. Those losses are projected to total $341 million as Manitoba Hydro forecasts the project will not be profitable until 2023. The current agreement also requires the partners to invest more money to cover operating losses.

The total cost of Wuskwatim as identified by Manitoba Hydro (in Exhibit #108) was $1.77 billion. Manitoba Hydro only applied $1.25 billion of project costs to the Wuskwatim Power Limited Partnership, as it subtracted $526 million of Manitoba Hydro's internally generated funds. On this basis, there is a net cost to the partnership of $43 million in 2012/13 and $75 million in 2013/14. This net cost results from the apportionment of both project costs and export revenues to the Partnership, with low export revenues contributing to a shortfall in both years.

If Manitoba Hydro's attribution of internally generated funds is removed from the calculation of partnership costs, the shortfalls would increase to $68 million and $114 million in 2012/13 and 2013/14, respectively. Because internally generated funds are the result of ratepayer contributions, they constitute a real cost to ratepayers that cannot be ignored when assessing the total impact of the project. In the absence of the Partnership covering the shortfalls, these costs flow through to domestic ratepayers.

During the hearing, Manitoba Hydro indicated its intention to re-negotiate the Agreement with the Wuskwatim Power Limited Partnership. Manitoba Hydro provided a calculation that attributed revenues based on the average of domestic and export revenues rather than just export revenue, upon which the Wuskwatim Power Limited Partnership Agreement is currently based. That potential change would still leave the Partnership with a shortfall in both test years, albeit a reduced amount. However, in the absence of a recovery in export prices, the net impact on ratepayers would actually increase, as a portion of domestic revenue would now be allocated to the Partnership.

Wuskwatim Generating Station in average flow years adds about 1,500 GWh/yr to the existing 29,500 GWh of energy, for a total Manitoba Hydro energy capability of 31,000 GWh. With average annual domestic load and firm export contract commitments less than 29,000 GWh until 2020, Wuskwatim energy is forecast to be sold at prices in the range of 3.0-3.5¢/kWh.

Wuskwatim Generation came on-line in 2012/13 with a Board-calculated (all-in) incremental in-service cost of $160 million/yr (10.5¢/kWh). This is about three times the current average export revenue rate (for both firm and spot market sales) of about 3.2¢/kWh.

The Consumers' Association of Canada (Manitoba) Inc. did not object to the renegotiation of the Wuskwatim Power Limited Partnership agreement. However, it expressed great concerns about the Wuskwatim project's cost growth. It further questioned whether the full impact of the Wuskwatim losses should be borne by current

ratepayers, as the extent of the losses were not contemplated when the project was initiated.

9.2.0 Board Findings

The Board has difficulty rationalizing the increase in the cost of the Wuskwatim project from the $900 million estimate presented to the Clean Environment Commission in 2003, to the most recent estimate of a $1.77 billion in-service cost. The increase in costs, in conjunction with a substantial decrease in export prices, means that the anticipated results have not been achieved and will not be achieved for many years.

The capital cost escalation of the Wuskwatim project is of serious concern to the Board. The reasons for the increased costs need to be more specifically broken down with respect to the various project components and construction activities. The utility's northern generation projects experienced competing demands for skilled labour from the Alberta market, resulting in the need to hire unskilled labour that had to be trained locally. This resulted in overall low productivity. These concerns should be more fully addressed and mitigated in future northern capital projects to the extent possible.

The Board understands that Manitoba Hydro is currently renegotiating its Wuskwatim Power Limited Partnership Agreement with its First Nations Partner as the economics of the project have changed substantially since the time the Agreement was first concluded. The revenues to be attributed to the Wuskwatim Power Limited Partnership were to be based on export revenues. The Wuskwatim Power Limited Partnership financial forecast now projects many years of losses. Absent adequate export revenues, the losses now have to be funded by domestic ratepayers. The Board expects to be notified when any changes to the current Agreement are finalized and apprised of the impact of such changes on Manitoba Hydro's operating results and domestic rates.

As for the cost consequences of Wuskwatim on Manitoba Hydro, the current rate increase requests are required to meet the operating losses from Wuskwatim. The Board finds that, as a rule-of-thumb, the average incremental annual operating cost of a capital project can be approximated at 9% of the capital cost minus the incremental export revenue gained. This makes for an additional revenue requirement of the Wuskwatim project viewed in isolation (without internally generated funds) equivalent to about $100 million in 2012/13 and $160 million in 2013/14. These costs are significantly greater than the $74 million and $117 million (respectively) set out in Information Request CAC/MH I-15(a) where Manitoba Hydro used financial costs that were net of internally generated funds:

	Partial Year 2012/13	**2013/14**
9% of $1.77B Capital Cost	$100M	$160M
Average Output/year	900 GWh	1520 GWh
Unit Output Cost	10.0 ¢/kWh	10.5 ¢/kWh
Incremental Revenues	$26M	$43M
Average Net Export Revenue Rate*	2.8 ¢/kWh	2.8 ¢/kWh
Net Cost Impact on Rate Payers**	**$74M**	**$117M**

*While MH calculates its total Export Sales (including long term firm export contract) average price of approximately 3.2 ¢/kWh [Exhibit MH-17], the output of Wuskwatim is not committed to a long term firm Export contract, so the average price of Wuskwatim output is only 2.8 ¢/kWh. [Exhibits MH-11 and MH-34]

**This assumes no new firm export contracts for Wuskwatim output.

The Board also understands that Manitoba Hydro intends to allocate only $1.25 billion of capital cost to the Wuskwatim Power Limited Partnership, employing $526 million of Manitoba Hydro's internally generated funds (accumulated since 2003). This would result in net costs to the Wuskwatim Power Limited Partnership of $43 million (2012/13) and $75 million (2013/14), assuming Manitoba Hydro ratepayers have already invested approximately $500 million that could have been utilized to reduce its overall level of borrowing.

10.0.0 CAPITAL EXPENDITURES

10.1.0 Issues

10.1.1 Base Capital Expenditures

Manitoba Hydro divides its annual capital expenditures into two broad categories, namely (i) “base capital”, meaning investments in maintaining existing infrastructure that will not create new generation and are generally funded entirely from internal revenue sources, and (ii) “major new generation & transmission”, which is financed out of a mix of internally generated funds and new debt.

Actual base capital expenditures have grown from $361 million in 2004/05 to $458 million in 2011/12. Base capital expenditures are forecast to be $433 million in 2012/13 and increase to $503 million in 2013/14. Until 2011/12 internally-generated funds were more than sufficient to cover the base capital costs.

10.1.2 Major New Generation and Transmission Expenditures

Manitoba Hydro’s most significant new generation and transmission investments consist of Wuskwatim Generating Station, which has since come into service, as well as Keeyask Generating Station, Conawapa Generating Station, and the Bipole III Transmission Line. Major new generation & transmission projects are financed out of a mix of internally generated funds and new debt. Major new generation and transmission annual expenditures have grown from $159 million (2004/05) to $656 million (2011/12). Future forecast annual expenditures on major new generation and transmission will total (in $ million):

2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20
909	1,352	1,435	1,536	1,781	1,797	1,437	1,299

10.1.3 Capital Cost Escalations

The following table illustrates the progression of major generation and transmission project costs since Capital Expenditure Forecast CEF06. When Manitoba Hydro defined the major new generation & transmission program (circa 2008) the projected project costs at the time were about 60% of what they are currently projected to be.

Capital Cost of Major Projects ($millions)

	CEF-6	CEF-07	CEF-08	CEF-09	CEF-10	CEF-11	CEF-12
Wuskwatim G.S	$1,094	$1,275	$1,275	$1,275	$1,275	$1,375	$1,449
Wuskwatim Transmission	257	320	316	316	291	298	323
Wuskwatim Total Project	**1,351**	**1,595**	**1,591**	**1,591**	**1,566**	**1,673**	**1,772**
Pointe du Bois Improvements and Upgrade	834	818	818	-	-	-	-
Pointe du Bois Spillway	-	-	-	318	398	398	560
Pointe du Bois Transmission	-	83	86	86	86	86	86
Pointe du Bois Rebuild	-	-	-	-	1,538	1,538	1,538
Pointe du Bois Safety & Rehabilitation	-	-	-	-	50	50	183
Point du Bois Total Project		**901**	**904**	**404**	**2,072**	**2,072**	**2,367**
Herblet Lake Transmission	54	95	93	93	75	75	77
Bipole III	1,880	2,248	2,248	2,248	3,280	3,280	3,280
Riel C.S	103	105	268	268	268	268	268
Kelsey G.S	166	184	190	190	302	302	302
Kettle G.S	61	61	76	76	166	166	166
Slave Falls G.S	179	192	198	198	223	230	-
Conawapa	4,978	4,978	4,978	6,325	7,771	7,771	10,192
Keeyask G.S	-	-	3,700	4,592	5,637	5,637	6,220
500 KV Dorsey US Border	-	-	205	205	205	205	205
Northern Generating Station Improvements	-	-	-	-	536	649	649
Gillam Redevelopment and Expansion Program	-	-	-	-	-	-	367
Firm Import Upgrades	-	-	5	5	-	20	20
Additional North South Transmission	-	-	-	-	-	318	396
Total	**$9,606**	**$10,359**	**$14,456**	**$16,195**	**$22,101**	**$22,666**	**$26,281**

Manitoba Hydro advised that it has now added a Management Reserve to its estimates for remote northern Manitoba projects (Keeyask and Conawapa) to cope with cost escalations. The Management Reserve has not specifically defined the components of remote major generation and transmission projects that need upward cost adjustments. Lower construction productivity has been cited, as well as a broader North American demand for heavy construction resources.

The Consumers' Association of Canada (Manitoba) Inc. argued that Manitoba Hydro's Capital Expenditure Forecast CEF09 grossly understated the expected capital costs of Conawapa, Keeyask and Bipole III. The Consumers' Association of Canada (Manitoba) Inc. also expressed great concern about the actual cost increases experienced on the Wuskwatim project. In light of the on-going escalations of Bipole III, Keeyask and Pointe du Bois, The Consumers' Association of Canada (Manitoba) Inc. questioned Manitoba Hydro's forecasting capability as well its ability to manage its capital program.

The Consumers' Association of Canada (Manitoba) Inc. and the Green Action Centre both spoke to the need for greater Demand-Side Management spending in light of the proposed capital spending and supported the evidence of Mr. Dunsky, which advocated greater Demand-Side Management investments to mitigate the need for additional power resources. Mr. Dunsky stated that Demand-Side Management is the lowest cost resource for balancing supply and demand. The cost of Demand-Side Management is 2¢/kWh to 4¢/kWh. He stated that much could be done by Manitoba Hydro to increase its savings by using Demand-Side Management measures. Mr. Dunsky further stated that Demand-Side Management can defer expensive capital investment in new dam construction.

10.1.4 Incremental Cost and Revenue Assumptions

Between Capital Expenditure Forecasts CEF08 and CEF12, Manitoba Hydro's cost and revenue forecasts with respect to major new generation and transmission have changed materially. With respect to Wuskwatim, the changes suggest that the incremental export electricity generated by Wuskwatim will be sold at less than 50% of the incremental cost of generation. Similarly, under current assumptions, the cost of Bipole III will no longer be covered by export electricity sales from Keeyask Generating Station and Conawapa Generating Station, as the capital cost of those projects has nearly doubled. The following table highlights the Board's understanding of the most recent cost and revenue impacts based on projections taken from Capital Expenditure Forecast CEF12 and Integrated Financial Forecast IFF12, which suggest that annual revenues generated by these projects will not be enough to cover their incremental costs at the start of their operation.

Project	**Wuskwatim G.S & T**	**Keeyask G.S.**	**Conawapa G.S.**	**Bipole III**
In service Date	2012/13	2019/20	2025/26	2025/26
Capital Cost ($B)	$1 .77	$6.22	$10.19	$3.28
Annual In-Service Cost ($M)	$160	$560	$900	$300
Average Year Output (GWh)	1,520	4,400	7,000	11,400 *
Unit Output Costs (¢/kWh)	10.5¢	12.7¢	12.9¢	*2.6¢
Export Revenue Rate (¢/kWh)	3.2¢	8.0¢	9.0¢	N/A
Net Export Loss (¢/kWh)	7.3¢	4.7¢	3.9¢	N/A

*Incremental transmission capacity for output from Keeyask and Conawapa

The cost and revenue data will be further reviewed by the Board at the upcoming Needs For And Alternatives To (NFAT) hearing with respect to Manitoba Hydro's Preferred Development Plan.

10.1.5 Pointe Du Bois Spillway

When Manitoba Hydro purchased Winnipeg Hydro (circa 2003) there was an expectation that the Pointe du Bois station output could be significantly increased above 600 GWh. Replacement of the spillway was not contemplated. However, by Capital Expenditure Forecast CEF09 Manitoba Hydro had moved away from consideration of facility improvements and upgrades to the concept of total station replacement by 2016/17, including a replacement of the spillway.

In the 2010/11 Power Resource Plan, Manitoba Hydro indicated that the decision to rebuild the Pointe du Bois powerhouse has been deferred to 2030/31; decommissioning of the powerhouse at that time had not been ruled out.

In PUB/MH Pre-Ask 16, it is stated that Manitoba Hydro extensively studied decommissioning Pointe du Bois but assumed a new spillway would be required to maintain the upstream water regime and safely manage river flow. The cost was, at that time, estimated at $400 million. In Capital Expenditure Forecast CEF12, Manitoba Hydro is budgeting over $2.4 billion in capital spending on Pointe du Bois.

Manitoba Hydro is currently proceeding with the new spillway and substantial improvements to the main dam, stating that a 2007 guideline published by the Canadian Dam Association requires the spillway to be capable of handling a flow of 5,040 m^3/s, while the existing capacity is only 2,840 m^3/s. Manitoba Hydro's view is that this requires a replacement of the spillway. However, when the capacity of the powerhouse is added

to that of the spillway, Pointe du Bois can currently handle a maximum flow of 3,250 m^3/s at full supply level (4,560 m^3/s at overtopping). The Board received submissions from Mr. Per Stokke, P. Eng., a retired Manitoba Hydro engineer, suggesting that this capacity was sufficient to allow the deferral of the spillway replacement until such time as the powerhouse is rebuilt. Mr. Stokke further questioned whether modifications to the river regime were seriously explored. His presentation is summarized in Section 15 of this Order.

10.2.0 Board Findings

The Board accepts that Bipole III is being constructed to improve domestic reliability and to permit exports into the United States. However, the Board is concerned that Bipole III may not achieve any incremental positive revenue from exports within the 20-year planning period. Accordingly, the Board will establish a deferral account to assist in funding Bipole III in-service costs. The deferral account will be established based on the revenues from a 1.5% portion of the 3.5% rate increase to be collected from customers commencing May 1, 2013.

In the Board's view, the introduction of a Management Reserve to define project cost escalation in future major capital projects, while justifiable, provides little or no assurance that the project costs will not increase further in light of the overlapping construction schedules of the many projects to be undertaken by Manitoba Hydro.

With respect to Manitoba Hydro's Power Resource Plan, the Board is of the view that the Plan does not clearly define Manitoba Hydro's firm contract obligations in terms of long-term/short-term/diversity sales and assured purchase opportunities. Manitoba Hydro's Recommended Plan and Alternatives identified in its recent Power Resource Plans is expected to be a subject of the Needs For And Alternatives To hearing process.

Regarding the planned Pointe du Bois spillway replacement, the Board understands that Manitoba Hydro's decision to replace the spillway to provide capacity of 5,000 m^3/s for a maximum probable flood was made prior to Sept 24, 2010 on the basis that a new powerhouse would be in service in 2030/31 and the existing spillway and main dam could not be economically rehabilitated, and operational safety issues precluded the longer term usage of the existing spillway.

The Board understands the cost implications of Pointe du Bois to be as follows:

2013/14 to 2015/16	**Total Capital Cost ($M)**	**In-Service Incremental Cost ($M)**	**Incremental Output Costs (¢/kWh)**	
Spillway Rebuild	560	50	8.2	(600 GWh)
Transmission Upgrade	86	8	1.3	(600 GWh)
Powerhouse Temporary Rehabilitation	183	18	3.0	(600 GWh)
Subtotal	829	76	12.5	(600 GWh)
2022/23 – 2031/32				
Powerhouse Rebuild	1,538	138	18.4	(750 GWh)
Overall Total (if station output increased to 750 GWh)	2,367	214	28.5	(750 GWh)

In the Board's view, based on the above analysis, the Pointe du Bois project, if developed, does not on the face of it appear to provide cost-effective energy to Manitoba Hydro customers. The decision to proceed with a Pointe du Bois rebuild should be subject to a more thorough review of the economics of the project before it proceeds. The Board recommends that it be mandated by the government of Manitoba to conduct a Needs for and Alternatives To (NFAT) process in order to review the economic rationale for the project.

11.0.0 LOAD FORECAST

11.1.0 Issues

Manitoba Hydro's domestic load growth history and forecast shows that the utility's actual gross firm domestic energy load peaked in 2008/09. The weather-adjusted gross firm load in that year was also near a historical peak, subsequently exceeded in 2011/12. Over the past 22 years, Manitoba Hydro's actual load grew by about 1.3%/year, while the weather-adjusted load grew by 1.5%/year.

In Integrated Financial Forecast IFF12 Manitoba Hydro anticipates a rebound in domestic load at generation from the ±24,000 GWh levels experienced in 2009/10, 2010/11 and 2011/12 to:

25,148 GWh (2012/13) including projected load losses of 3,400 GWh

25,597 GWh (2013/14) including projected load losses of 3,267 GWh

25,754 GWh (2014/15) including projected load losses of 3,197 GWh

26,006 GWh (2015/16) including projected load losses of 3,225 GWh

It appears that Manitoba Hydro's domestic load growth forecast is primarily predicated on a shift to electric heating as experienced prior to 2012. This assumption differs from Manitoba Hydro's Fuel Switching Report. It does not recognize the relatively lower natural gas cost since 2010 and the natural gas price outlook for the next decade.

Manitoba Hydro attributes almost all of the lower actual domestic loads to lower Top Consumer industrial energy consumption, partly as a result of the closure of a pulp and paper plant and the economic downturn. However, Manitoba Hydro continues to project a new industrial customer load of 100 GWh/yr being added in each and every year. Manitoba Hydro has also suggested that a new load, equivalent to Manitoba Hydro's largest customer, can be anticipated in the near future to offset the impact of pending northern Manitoba smelter closures.

Energy conservation (Demand-Side Management) apparently is not credited with any of the load reductions.

The Consumers' Association of Canada (Manitoba) Inc. has raised concerns about Manitoba Hydro's assumption that domestic load is non-responsive to on-going rate increases. This, in the Consumers' Association of Canada (Manitoba) Inc.'s experience, is inconsistent with most models, although perhaps it is reflective of limited price elasticity.

The Green Action Centre sees potential for Demand-Side Management-related load reductions in both the neart-term and long-term. The Green Action Centre is concerned about the information contained in the Fuel Switching Report filed by Manitoba Hydro

that suggests fuel switching will account for 11% of the increase in net firm energy requirements from 2011/12 to 2030/31.

The Fuel Switching Report cited two reasons for fuel switching. The first is that some existing customers replace their natural gas space and water heating equipment with electric equipment. The second is that developers choose the installation of electric heating equipment in new homes in areas that are serviced by natural gas. Manitoba Hydro's study concludes that switching to electricity for space and water heating has consistently adverse impacts from the perspective of the customer, the utility, and the global environment.

The Green Action Centre believes that proper measures ought to be introduced to ensure that better choices are made by customers in order to reduce the unwarranted electricity load growth. As recommended by the Green Action Centre's witness, Demand-Side Management programs that provide better information, rely upon trustworthy vendors with appropriate incentives, pay an adequate share of capital cost, and offer low-cost, on-bill financing transferable to future residents would assist customers in making choices that are environmentally more preferable. The Green Action Centre's witness also suggested that builders of electrically heated homes should pay connection fees that reflect the true cost of installation to the home buyers and the Province.

The Manitoba Industrial Power Users Group questioned Manitoba Hydro's industrial load growth assumptions considering that no new large industry has come to Manitoba since the late 1990's. Large customers use significant amounts of electricity. For example, Manitoba Hydro's largest industrial customer uses the equivalent of the entire output of the Wuskwatim Generating Station. If less expensive electricity options are available in other jurisdictions, such industrial customers could consider locating current, new and additional facilities in those other jurisdictions. This situation will likely be exacerbated by Manitoba Hydro's forecast of rate increases over the next two decades.

11.2.0 Board Findings

The Board is aware of several recent reports that predict lower electricity demand in the United States. Similarly, the Board is concerned that Manitoba Hydro's projected domestic load growth of 1,700 GWh over the next four years is overly optimistic. Manitoba Hydro's projections that 60% of new homeowners will opt for electric heat appears at odds with the utility's Fuel-Switching Report and the low natural gas prices available to homeowners. The utility's projected load growth of 1.5% per year also does not reflect the potential impacts of Demand-Side Management and rising electricity rates.

The Board is also concerned about Manitoba Hydro's weather adjustment calculation process, domestic loss assumptions and all-electric load growth assumptions. However,

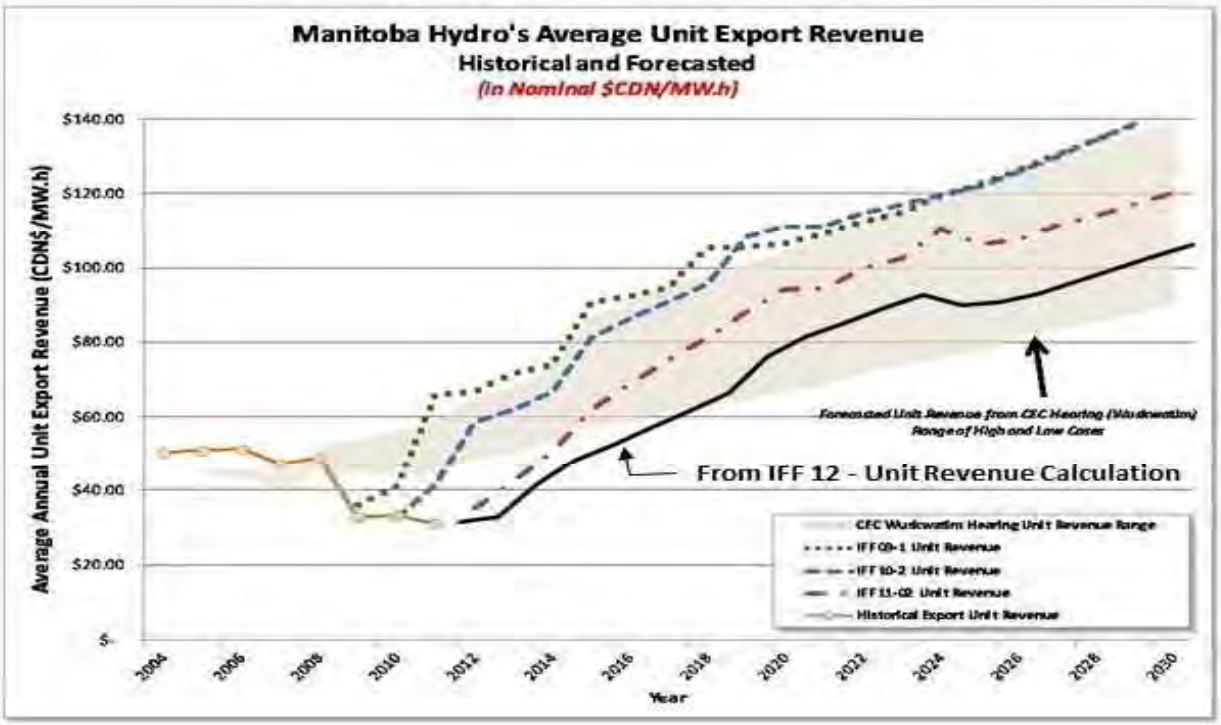
the Board expects that these issues will be more fully canvassed at a Needs For And Alternatives To hearing into Manitoba Hydro's Preferred Development Plan.

12.0.0 EXPORT MARKETS

12.1.0 Issues

Manitoba Hydro's primary export market is the market operated by the Midwest Independent System Operator, which, over the past several years, has seen reduced load-growth, an increase in subsidized wind power from U.S.-based wind farms, increased utilization of combined-cycle combustion turbine gas generation, imports into the Midwest Independent System Operator market from other U.S.-based utilities, and no increase in exports from Manitoba Hydro. Since 2008/09, spot market export prices have decreased from about 8.0¢/kWh to an average of 3.2¢/kWh.

The chart filed by Manitoba Hydro in response to Information Request PUB/MH II-14 illustrates Manitoba Hydro's actual average export price experience and Manitoba Hydro's average price forecasts in successive Integrated Financial Forecasts IFF09-1, IFF10-2, IFF11-02 and IFF12, as well as Manitoba Hydro's Clean Environment Commission Wuskwatim Hearing "high" and "low" forecast in 2003.



From the chart, it is apparent that from Integrated Financial Forecasts IFF09-1 to IFF12, the average export price forecast has dropped by about 3.5¢/kWh for the entire period until 2030/31. This represents revenue decreases of more than $120 million/yr until 2019/20 compared to Integrated Financial Forecast IFF09-1. Beyond 2024/25, it

represents an export revenue loss of more than $200 million/yr. After 2024/25 the reduced export revenue would be about $300 million/yr.

As illustrated in Information Request PUB/MH I-18(a) and PUB/MH II-12(a) and (c), post-2008 to 2011, Manitoba Hydro sales into the Midwest Independent System Operator market have not increased, but have actually declined by about 600 GWh. Electricity suppliers from other regions have increased their supply into that market by about 14,000 GWh. Wind energy sales have increased by 25,000 GWh. Natural gas generation output has increased by about 10,000 GWh. Overall load growth of about 35,000 GWh was served despite lower coal and nuclear output.

Purported new or pending supply resources in the Midwest Independent System Operator market include 2,200 MW of new combined-cycle combustion turbine generation, 3,000 MW of additional wind generation (not including new Northern States Power ventures) and increasing imports as renewable energy surpluses resources grow.

The installed capacity of combined-cycle combustion turbine generation in the Midwest Independent System Operator region in 2008 was about 20,000 MW but was only being utilized 12% of the time. By 2011 this capacity had increased to about 21,000 MW but utilization had increased to 18%.

Manitoba Hydro's Northern States Power, Minnesota Power and Wisconsin Public Service existing and pending export contracts provide assured revenues for capacity and energy. Manitoba Hydro's firm contract fixed-price long-term export commitments are about 2,000 GWh per year (prior to 2015/16), about 1,200 GWh a year from 2015/16 to 2019/20, about 3,200 GWh a year from 2020/21 to 2024/25 and about 1,500 GWh a year until 2035. In average flow years, this means firm contract prices will apply to no more than approximately 50% of the energy sold to 2024/25 and less than 20% thereafter.

Both the Consumers' Association of Canada (Manitoba) Inc. and the Manitoba Industrial Power Users Group expressed concerns about the reliability of Manitoba Hydro's export forecasts, and noted that post-shale gas forecasts present a challenge. However, in the Manitoba Industrial Power Users Group's view, the decline in Midwest Independent System Operator energy prices is close to having reached its bottom, so the risk involved as a result of low export prices is less than previously anticipated.

12.2.0 Board Findings

The Board questions Manitoba Hydro's projection that average export market prices are set to increase to 4.1¢/kW in 2014/15 and 4.8¢/kWh in 2015/16, and believes that prices around 3.2¢/kWh are more realistic. In light of low shale gas prices and increasing availability, the Board is not confident that Manitoba Hydro will return to pre-2009/10 export revenue levels within the next decade.

The Board accepts that once Manitoba Hydro's new export contracts come into effect, the average export price realized by Manitoba Hydro will increase. However, with firm prices applying to only 25-50% of average export sales, revenues will still be primarily driven by the opportunity market and likely lower than forecast in Integrated Financial Forecast IFF12. The Board further notes that the Integrated Financial Forecast IFF12 first predicts export prices to rise above 10¢/kWh after 2028; this suggests that a project, such as Wuskwatim, would not be profitable based on export sales, until after 2028, and possibly even later, if market prices do not rebound as predicted by the Forecast.

13.0.0 DEMAND-SIDE MANAGEMENT

13.1.0 Issues

13.1.1 Manitoba Hydro's Power Smart Plan

Manitoba Hydro's Power Smart Plan consists of Demand-Side Management energy conservation and load management activities designed to lower the demand for both electricity and natural gas in Manitoba. Manitoba Hydro's 2011 Power Smart plan reflects spending of $34.4 million in 2012/13 and $34.7 million in 2013/14. However, in the course of the General Rate Application, Manitoba Hydro filed an update which lowered estimated spending to $28.5 million in 2012/13 and $28.0 million in 2013/14. The reductions were part of Manitoba Hydro's capital prioritization plan, reflecting a decreased availability of economically beneficial Demand-Side Management opportunities in the Manitoba marketplace. Manitoba Hydro amortizes its Demand-Side Management spending over a 10-year period.

The current 15-year Power Smart Plan targets 597 MW and 1,944 GWh of energy savings, representing 3.8% of the estimated electric load forecast for 2025/26. Cumulative energy and demand reduction achieved (including savings to date) is forecast to achieve 3,283 GWh/year of energy savings and 906 MW of winter demand by 2025/26. The cumulative savings are forecasted to reduce carbon dioxide (CO_2) equivalent emissions by 2.5 million tonnes.

Manitoba Hydro initially evaluates new Demand-Side Management programs based on a Marginal Resource Cost Screen, which compares the expected benefits to the incremental capital costs. If programs pass the initial screening, they are subjected to a more detailed analysis based on the Total Resource Cost and Rate Impact Measure tests.

Manitoba Hydro utilizes a marginal cost value of 8.5 ¢/kWh in its Demand-Side Management screening, which includes the expected value of electricity exports. However, consecutive Integrated Financial Forecasts since IFF09 have shown a material decline in the export revenues forecast. Manitoba Hydro has indicated that if incremental export revenues were to decline to a level where they no longer offered an offsetting value, the marginal benefits of Demand-Side Management would then shift from the export market value to a valuation of the benefit of deferring new generation facilities, recognizing that there is an economic benefit to achieving load savings in the Province.

Both the Consumers' Association of Canada (Manitoba) Inc. and the Green Action Centre expressed concern about Manitoba Hydro's reduction in Demand-Side Management programming, especially in light of increasing electricity prices. Philippe Dunsky, an expert retained jointly by the Consumers' Association of Canada (Manitoba)

Inc. and the Green Action Centre, indicated that Power Smart was costing the utility 1.8¢/kWh but could create 8.5¢/kWh in additional revenue, and that it could be in the public interest to have a slight increase in rates offset by a reduction in consumption, such that overall costs are lowered. Mr. Dunsky's benchmarking study indicated that comparable utilities are targeting 1.0-2.6% savings from Demand-Side Management, while Manitoba Hydro only targets 0.3%.

Considering Manitoba Hydro's significant proposed rate increases for the two test years, and with indicated rate increases of close to double the rate of inflation until 2030, the dramatic decline in Demand-Side Management savings is a matter of grave concern to the Consumers' Association of Canada (Manitoba) Inc. In their view, there are many opportunities for Manitoba Hydro to promote its existing products and Manitoba Hydro's failure to maintain and enhance its Demand-Side Management portfolio will result in considerable foregone opportunity in terms of cost reductions.

The Consumers' Association of Canada (Manitoba) Inc. argued that the $23 million amount related to the deferral account for the 2010/11 and 2011/12 years belonged to ratepayers, but that if there was a mechanism within the Board's jurisdiction to target the funds for Demand-Side Management, the Consumers' Association of Canada (Manitoba) Inc. would be open to dialogue. It argued that there would be a benefit to an independent review of Manitoba Hydro's Demand-Side Management measures.

The Green Action Centre's witness suggested that the marginal cost used by Manitoba Hydro to evaluate Demand-Side Management programs was too low and should be based on the cost of bringing new hydro generation for domestic consumption into service. He further recommended that the specific marginal cost for each customer class should be used for the test.

The Green Action Centre recommended that the Board require Manitoba Hydro to increase its Demand-Side Management programming to target energy savings of 1.0% by 2015 and sustain that ratio thereafter. The Green Action Centre further recommended that the Board build into the rate application an amount to supplement Demand-Side Management spending of $41 million per year, as suggested by Mr. Dunsky.

13.1.2 Lower Income Energy Efficiency Program

The objective of Manitoba Hydro's Lower Income Energy Efficiency Program is to ensure that the financial benefits associated with implementing Power Smart measures can be realized by low-income consumers. Targeted measures addressed by the program include low-cost or no-cost energy efficiency initiatives such as compact fluorescent light bulbs, low-flow water faucets, and subsidized measures such as increased basement and attic insulation and the installation of high-efficiency gas furnaces. The program is delivered through community-based organizations and the participation of individual households.

2011 Power Smart Plan target participation in the Lower Income Energy Efficiency Program has been set at 557 homes per year, down from 883 homes per year in the 2009 Power Smart Plan. The revised target is based on actual participation experience gathered from working with community based organizations and social agencies. With respect to the First Nations Power Smart Program, which focuses on 24 different communities, Manitoba Hydro has completed 597 homes by the end of August 2012. Manitoba Hydro is forecasting to complete 751 additional households by 2016/17.

The Consumers' Association of Canada (Manitoba) Inc. recognized that the Lower Income Energy Efficiency Program is making good progress with respect to government-owned social housing and First Nations, but expressed concern about the program not being able to effectively reach tenants.

The Manitoba Industrial Power Users Group focused its submissions on the accounting implications of the Demand-Side Management program, disagreeing with Manitoba Hydro's proposition that, as of the date of International Financial Reporting Standards implementation, Demand-Side Management expenditures be written off in the year in which they are incurred rather than treated as retained earnings. In the Manitoba Industrial Power Users Group's view, this does not fairly represent the economic profile of Demand-Side Management spending, and the Board should ensure that rates continue to be based on the existing practices.

13.1.3 The Affordable Energy Fund

The Provincial Government passed *The Winter Heating Cost Control Act* in 2006. The Act established the Affordable Energy Fund, requiring Manitoba Hydro to contribute 5.5% of its fiscal 2006/07 gross export revenues to the Affordable Energy Fund. This resulted in a fund of $37.4 million to be utilized for various energy efficiency initiatives, including assisting low-income electricity and natural gas customers. Manitoba Hydro has spent $17 million of the fund by the end of 2011/12 and forecasts depleting the fund by 2020/21.

Manitoba Hydro has $19 million reserved for low-income programs that would mostly benefit electricity and natural gas space-heated homes, and would provide for programs that would not otherwise be funded from Manitoba Hydro/Centra's rate-based Demand-Side Management programs.

Manitoba Hydro has forecast to spend approximately $2.5 million on the Lower Income Energy Efficiency Program during the two test years, including $1.8 million from the Affordable Energy Fund.

The Affordable Energy Fund is continued under *The Energy Savings Act,* passed in 2012, that leaves it up to the discretion of the board of Manitoba Hydro to allocate additional funds in the future. The new statute further requires Manitoba Hydro to

prepare an energy efficiency plan in consultation with the minister responsible for Manitoba Hydro by March 31, 2013.

13.2.0 Board Findings

The Board believes that it is fundamental that Manitoba Hydro enhances Demand-Side Management efforts from those reflected in the 2011 Power Smart Plan. Given an outlook where rates are forecast to more than double over the next twenty years, which is twice the expected level of inflation, the Board is of the view that Manitoba Hydro should be providing ratepayers with the tools to mitigate their exposure to rising electricity bills through Demand-Side Management.

The Board does not agree with Manitoba Hydro's decision to cut Demand-Side Management spending and targeted savings. For rate-setting purposes, Demand-Side Management spending and its related revenue requirement costs will be established at a minimum of $34 million for 2012/13 and $35 million in 2013/14, consistent with the 2011 Power Smart Plan. If monies are not spent on the Demand-Side Management programs to meet the minimum threshold, any underspend from the set levels will be accumulated in a deferral account.

DSM spending is beneficial to ratepayers and will be more prominent in the future as pressures from increasing rates continue in future years. The Board urges Manitoba Hydro to incorporate Demand-Side Management programs into its plan that target higher levels of energy efficiency, as was recommended by Mr. Dunsky and endorsed by the Consumers' Association of Canada (Manitoba) Inc. and the Green Action Centre. The Board further notes that Demand-Side Management may have a role in limiting future load growth and expects to evaluate Demand-Side Management options in the upcoming Needs For And Alternatives To hearing into Manitoba Hydro's Preferred Development Plan. The Board notes Mr. Dunsky's testimony that Keeyask could be delayed several years and Conawapa could be delayed indefinitely with an increased focus on Demand-Side Management.

In evaluating Demand-Side Management programs, the Rate Impact Measure test should not be a barrier to higher levels of Demand-Side Management savings and should be applied only at the portfolio level, not the individual program level. The Board recommends that Manitoba Hydro undertake an independent assessment of its Power Smart Plan with a goal of evaluating and improving the Plan. The Board further recommends that Manitoba Hydro should consider revising the marginal cost used to evaluate Demand-Side Management to include the cost of new generation. In light of low export rates, a marginal cost focus on generation deferral rather than export pricing may be preferable.

Manitoba Hydro has made modest progress in implementing the Lower Income Energy Efficiency Program, and the Board believes that the reduction in homes being targeted for the Lower Income Energy Efficiency Program is a reflection of the difficulty in reaching the target market. The Board urges Manitoba Hydro to continue or increase its

efforts in implementing the Lower Income Energy Efficiency Program, as increasing energy prices will place a significant burden on low-income individuals.

14.0.0 SPECIAL RATES

14.1.0 Curtailable Rate Program

Manitoba Hydro's Curtailable Rate Program allows the Utility to curtail a portion of a large industrial customer's peak load in exchange for reduced rates on that same portion of the load when not curtailed. The objective of the program is to be able to reduce electrical load at peak times when the system is near maximum capacity.

Manitoba Hydro is proposing to reduce the maximum amount of Curtailable Rate Program capacity that Manitoba Hydro will contract for with General Service Large customers, but expects to achieve this with minimal impact to existing customers. Presently the Curtailable Rate Program cost is about $6 million/yr or about 10% of Manitoba Hydro's annual demand billing to General Service Large >100 customers. The apparent value of short-term capacity in the Midwest Independent System Operator Capacity market has dropped substantially due to lower load growth in the area and also due to the greater availability of quick response natural gas generation. Additionally, when Manitoba Hydro brings Keeyask Generating Station on-line, there will be surplus capacity in Manitoba Hydro's system. That, coupled with lower Midwest Independent System Operator reserve requirements, removes much of the benefit to Manitoba Hydro of the Curtailable Rate Program.

The Consumers' Association of Canada (Manitoba) Inc. suggested that Demand-Side Management expansion in lieu of new generation could include more Curtailable Rate Program demand reduction initiatives. The Manitoba Industrial Power Users Group believes that the Curtailable Rate Program should continue at current or expanded levels of capacity available with the program. The Curtailable Rate Program is valuable to existing customers who are looking to expand operations. Manitoba Hydro should investigate additional rate options for industry such as Demand Response and Feed-in Self-Generation.

The Board accepts Manitoba Hydro's rationale for reducing the Curtailable Rate Program offering in response to the current capacity market decline. However, recognizing the potential Demand-Side Management resource expansion proposals that may be put forward during the pending Needs For And Alternatives To process, the Board will approve Manitoba Hydro's proposed Curtailable Rate Program cutback on an interim basis until a subsequent General Rate Application.

14.2.0 Surplus Energy Program

The Surplus Energy Program is a mechanism by which Manitoba Hydro prices electricity generated in excess of its immediate requirements and sells it based on pricing determined by a Board-approved methodology. Manitoba Hydro plans to make the Surplus Energy Program a permanent offering. This, along with some other

changes, is intended to broaden the appeal of Surplus Energy Program to the General Service Medium and General Service Large <100 customer sub-classes which currently have enrolled in the Option 2 Surplus Energy Program. Manitoba Hydro is also looking for a final approval of a revised Option 1 which currently has no customers. The change would also allow some General Service Medium and General Service Large customers to nominate different levels of Surplus Energy Program energy purchases in peak periods (5x8 weekdays – day time), off-peak periods (7x8 weekdays – night time), and shoulder periods (other weekday or weekend periods). These changes would allow customers to tailor their optional Option 1 purchases to minimize costs and/or maximize purchase effectiveness. Manitoba Hydro has not set any overall limits on the size of the Surplus Energy Program purchases, but only on individual customers' proportion of load.

Manitoba Hydro would also like to eliminate the need for a professional engineering seal on the weekly Surplus Energy Program pricing.

The Consumers' Association of Canada (Manitoba) Inc. and the Green Action Centre took no position with respect to the Surplus Energy Program. The Manitoba Industrial Power Users Group is supportive of the time-of-use amendment of Option 1 and making the Surplus Energy Program a permanent offer.

The Board agrees that making the Surplus Energy Program Options 2 and 3 permanent rate offerings has no obvious downside and will grant approval subject to the continuation of annual reports. It is the Board's view that allowing Option 1 to designate different reference levels based on time of use appears to have merit as an interim Surplus Energy Program amendment. However, permanent approval should await actual events with respect to load shifting.

The Board believes that the Surplus Energy Program involves the defining of surplus electricity and detailing of an acceptable pricing strategy for summer and winter sales and purchases. Surplus Energy Program price schedules are a weekly commitment by Manitoba Hydro to supply energy and not just a price schedule. As such, the Board would consider a division manager's signature as an adequate substitute for a professional engineer's seal.

14.3.0 Time-of-Use Rates

Time-of-Use Rates for industry will be addressed at a Cost of Service/Time of Use Hearing before the Board.

14.4.0 Diesel Communities

In Order 116/12 the Board approved a 6.5% interim rate increase on the full-cost portion of the rate applicable to General Service and government customers in the diesel zone. This increase is projected to provide $200,000 in 2012/13 and $300,000 in 2013/14. In

total, there are eight interim diesel orders identified in Manitoba Hydro's filing. Manitoba Hydro requested that if Manitoba Keewatinawi Okimakanak files the true copies of the settlement agreement prior to the issuance of the General Rate Application Order, the interim orders be approved as final. If the true copies are not filed, Manitoba Hydro requests the Board's final approval be granted conditional upon the filing of the true copies of the settlement agreement.

The Board is not prepared to finalize the interim orders until it has received true copies of the settlement agreement. Accordingly, the Board will address finalization when a true copy has been received.

15.0.0 PRESENTER SUBMISSIONS

15.1.0 Industry Presentations

The Manitoba Industrial Power Users Group

Mr. Bill Turner stated that the recent change in available lower-cost natural-gas-produced power in the U.S. is making it more difficult for some major Manitoba companies to be competitive in the export of finished goods. Given the relative importance of electricity to industry, both the actual price and the predictability of electrical costs are extremely important. The Manitoba Industrial Power Users Group asked the Board to help them retain their competitive position in Manitoba and in North America. In their view, dedication to providing reliable firm power at fair and reasonable rates, ensuring rates reflect cost of service, and developing innovative rate options that benefit both industry and Manitoba Hydro are important for the future growth of large industry in Manitoba.

Mr. Turner stated that the Manitoba Industrial Power Users Group questions if the timing is correct for Wuskwatim, Keeyask and Conawapa to go forward, and would like to understand the justifications for trying to complete as many of the expansions in a short order of time as proposed by Manitoba Hydro. Mr. Turner indicated that there are other opportunities to help alleviate some of the immediate concerns for increased power, such as the Curtailable Rate Program which was cut back by Manitoba Hydro. Mr. Turner also stated that if there were other options for curtailable rate programs that plants could be involved with, it would postpone some of that major development and spread it out until the U.S. economy changes, which would then promote higher export values. The Manitoba Industrial Power Users Group supports expansion and exports to other markets by Manitoba Hydro, but not at the sake of loss of domestic power loads.

Canexus

Mr. Dale Bossons stated that Canexus has made a lot of business decisions based on Manitoba's competitive power pricing. Canexus expanded its plant numerous times and continues to reinvest in the Brandon facility. However, it will not proceed with the expansion it was planning for economic reasons. As electrical pricing in Manitoba is forecast to increase, it makes it harder to justify capital expenditures into the facility. Mr. Bossons further stated that the Louisiana plant Canexus relocated to Brandon several years ago would now be more competitive in Louisiana, considering the current economic environment.

In that regard, Mr. Wayne Yan spoke of special programs available in Louisiana, in particular, a special rate program for electrochemical producers through Entergy, in which the demand cost is not charged. Mr. Yan suggested such a program could be beneficial to attract investments and to retain companies in Manitoba.

Mr. Bossons indicated that the proposed increase of 3.5 percent for this year is equivalent to electricity costs of $2 million for Canexus, and the planned increases over the next five years amount to $24 million for the plant in Brandon. These extremely significant amounts have major decision-making impacts on Canexus' future growth. Mr. Bossons mentioned that through the Curtailable Rate Program, Canexus has the ability to supply Manitoba Hydro with up to 168 megawatts of power on short notice to assist it in its times of need. Canexus is very interested in seeing this program continue into the future.

Gerdau Steel

Mr. Dave Forsyth indicated that with the current Application, by April 1st, 2013, Manitoba Hydro's rates will have increased by almost 35% for industrial customers since 2004, with a rate increase of over 9% for the 15 month period started in January 2012. This recent rate uncertainty has resulted in budget variances for the Gerdau Manitoba plant, preventing the plant from making investment decisions with confidence.

Mr. Forsyth stated that Manitoba Hydro developed the Demand Billing Concession Program, which helped Gerdau following the 2008 economic downturn. However, the previous Board ordered repayment of the concession long after the period had passed, creating another episode of uncertainty for the plant. Mr. Forsyth indicated that participating in the Curtailable Rate Program is the only option available for Gerdau to lower the limit of Option A megawatts.

Mr. Forsyth stated that Gerdau recommends this Board to advise Manitoba Hydro to explore other opportunities in demand response, such as economic demand response or price response and expanding interruptible contracts. In Gerdau's view, regulation should achieve firm, low cost, stable power rates that are necessary to maintain investment and jobs in the province. Rate stability is a key input when making long-term investment decisions. Mr. Forsyth requested that the Public Utilities Board reconsider the contemplated increases in this Application, and since the industrial class has been paying above the measured cost of service for a very long time, Gerdau requests that the rates reflect the cost of service for their customer class.

15.2.0 Individual Presenters

Doug Biggs

Mr. Biggs stated that Manitoba Hydro should cut back on its expenses rather than require the customers paying more at the whim of Manitoba Hydro's revenue shortfalls.

Carol Boitson

Carol Boitson presented her objection to the 4% rate increase being sought every year by Manitoba Hydro. In her opinion, Manitoba Hydro's executives should have lower salaries instead.

Allan Ciekiewicz

Mr. Ciekiewicz provided the Board with a written presentation together with his oral presentation. The presentation by Mr. Ciekiewicz covered a variety of topics from Manitoba Hydro's forecasts and projections, including an emphasis on rate increases.

Mr. Ciekiewicz also provided the Board with a series of recommendations that can be found starting at page 550 of the Transcript.

John Corden

Mr. Corden requested the Board to deny the increase being sought by Manitoba Hydro. Mr. Corden also questions Manitoba Hydro's plan to develop the infrastructure for exports while export revenues are currently decreasing due to the US using other forms of energy. Mr. Corden requested the Board to put a stop to Manitoba Hydro's mismanagement.

Brandy Fleury & Jennifer Pacaud

Ms. Fleury & Ms. Pacaud expressed concerns over Manitoba Hydro's requested rate increase. Since Manitoba Hydro sells Manitoba's power at a low premium price to the US, the maintenance of the power lines should be paid out of the revenue generated to supply those states with their power. Mrs. Fleury & Mrs. Pacaud believe the citizens of Manitoba should not have to pay to supply those in the US.

Sandra Giese

Ms. Giese provided the Board with her concerns and disapproval for the proposed rate increases for 2013. In Ms. Giese's view, Manitoba Hydro customers should not go through rate increases of 3-4% for each of the next 18 years to bail out Manitoba Hydro from losses due to poor management and planning. Ms. Giese questions Manitoba Hydro's expectations for exports from their future dam projects considering US energy attitude currently is to be self-reliant.

Ms. Giese stated that alternatives and new energy technologies should be investigated and encouraged. Ms. Giese also spoke of Manitoba taxpayers experiencing a wave of increases at every level, creating vulnerability for some segments of the population.

Justin Jaron Lewis

Mr. Lewis objected to the proposed rate increases being sought by Manitoba Hydro. As a Crown Corporation, Manitoba Hydro has a responsibility to serve the public interest, which does not require maximizing its profits or proceeding with new large-scale dam projects when the market for exported hydroelectricity is in steep decline. Mr. Lewis further stated that in light of U.S. plans for energy self-sufficiency, it is likely that Manitoba energy will not continue to be in demand in the United States, and that Manitoba Hydro will need to reframe its business model.

Gary Luby

Mr. Luby stated his outrage at Manitoba Hydro's proposed rate increases for the next 18 years. In Mr. Luby's opinion, the costs of building dams, and the proposed hydro line down the east side of Lake Winnipeg, should be incurred by the customers in the United States and the other Provinces, as they will be the ones supplied by those major projects. Mr. Luby further stated that it is unacceptable for Manitoba Hydro to sell inexpensive hydroelectricity to American customers. Mr. Luby indicated that Manitoba Hydro appears to be mismanaged, and that it should be run as a business or be privatized.

Douglas Macduff

Mr. Macduff provided comments on why the Public Utilities Board should refuse Manitoba Hydro's request for a 3.5% increase on April 1, 2013 and rates be rolled back instead. Mr. Macduff questions the necessity of building another series of dams, considering Manitoba Hydro is having problems selling the extra hydroelectricity. Mr. Manitoba Hydro should also not be supporting and/or sponsoring various organizations, and should end the Power Smart Program.

Allison Reid

Mrs. Reid presented her concerns over the new rate increase proposed by Manitoba Hydro. Mrs. Reid questioned why she was on the hook for an 8% increase for a single year. She is concerned the cost of living is going up but not the wages. In Mrs. Reid's opinion, Manitoba Hydro should cut back its expenses, or decrease its executive salaries and she urges the Board to not allow this increase.

Per Stokke

Mr. Stokke, a former Manitoba Hydro engineer previously involved in the planning of Pointe du Bois, provided the Board with a written presentation together with his oral presentation. Mr. Stokke questions Manitoba Hydro's decision to replace the spillway at

Pointe du Bois, and whether Manitoba Hydro had credible and defensible evidence that the spillway does not meet the Canadian Dam Safety Guidelines with respect to required capacity and that it therefore must be replaced. Mr. Stokke stated that Manitoba Hydro does not appear to have an open and transparent document with a detailed account of the decision-making process, as required by the Guidelines.

Mr. Stokke indicated that in 2002, a world-renowned engineering consultant and contractor suggested a repair of the existing spillway was possible at a cost of about 4 to $6 million, a pittance compared to the $400 million cost of the replacement spillway.

Mr. Stokke indicated that to determine if an existing dam is safe enough, Manitoba Hydro has neglected to use the necessary Guideline's risk-based approach and only used the standards approach. It is Mr. Stokke's opinion that Manitoba Hydro owes it to the ratepayers and owners to provide higher-level studies.

THE PUBLIC UTILITIES BOARD

"RÉGIS GOSSELIN, B.A., M.B.A., C.G.A."
Chair

"HOLLIS SINGH"
Secretary

Certified a true copy of Order No. 43/13
issued by The Public Utilities Board

Secretary

APPENDIX A – APPROVALS SOUGHT BY MANITOBA HYDRO

Manitoba Hydro requested the following:

(a) Approval, on an interim basis, of rate schedules incorporating an across the board 2.5% rate increase on currently billed rates, effective September 1, 2012, sufficient to generate additional revenues of $20 million in 2012/13;

(b) Approval of a further 3.5% increase in overall revenue effective April 1, 2013, sufficient to generate additional revenues of $48 million in 2013/14;

(c) Approval to maintain in base rates the rates approved by the Public Utilities Board in Orders 30/10 and 40/11, and include in current year revenues the revenues previously billed and collected, which have been accumulated in the deferral account pertaining to rates implemented April 1, 2010;

(d) Final approval of Orders 32/12 and 34/12 approving interim rates effective April 1, 2012, and final approval of any other interim rate Orders issued subsequent to the filing of the Application and prior to conclusion of this proceeding;

(e) Approval, on an interim basis, of rate schedules incorporating a 6.5% rate increase effective September 1, 2012 (consistent with previous and proposed rate increases for grid customers), for the full-cost portion of the rate applicable to general service and government customers in four remote communities served by diesel generation, sufficient to generate additional revenue of $0.2 million in 2012/13;

(f) Confirmation that the Board accepts the rate approval process given proposed modifications to the Terms and Conditions of the Surplus Energy Program, as will be discussed in Tab 12 of this Application;

(g) Confirmation that the Board accepts the rate approval process given proposed modifications to the Curtailable Rate Program ("Curtailable Rate Program");

(h) Final approval of all Surplus Energy Program interim *ex parte* rate orders as will be set forth in Tab 11 of this Application, as well as any additional Surplus Energy Program *ex parte* rate orders issued subsequent to the filing of this Application and prior to the Board's order in this matter;

(i) Final approval of Curtailable Rate Program *ex parte* Order 52/12 as well as any additional *ex parte* orders issued in respect of the Curtailable Rate Program issued subsequent to the filing of this Application and prior to the Public Utilities Board's order in this matter; and

(j) Final approval of diesel zone interim Orders (17/04, 46/04, 159/04, 176/06, 1/10, 134/10, 1/11 and 148/11), subject to confirmation that MKO has provided the parties to the agreement with the required affidavits from representatives of signatories to the agreement, as well as any additional diesel zone interim orders issued subsequent to the filing of this Application and prior to the Public Utilities Board's order in this matter.

APPENDIX B – APPEARANCES

R. Peters A. Southall	Counsel for The Manitoba Public Utilities Board (Board)
P. Ramage O. Fernandes	Counsel for the Manitoba Hydro Electric Board (Manitoba Hydro)
B. Williams	Counsel for Consumers' Association of Canada (Manitoba) Inc.
A. Hacault	Counsel for the Manitoba Industrial Power Users Group
W. Gange P. Miller	Counsel for the Green Action Center
D. Pambrun	Counsel for the City of Winnipeg
M. Anderson	Manitoba Keewatinowi Okimakanak

APPENDIX C – WITNESSES FOR MANITOBA HYDRO

S. Thomson	President and CEO
V. A. Warden	Senior Vice-President, Finance & Administration and Chief Financial Officer
R. Wiens	Division Manager, Rates & Regulatory Affairs
D. Cormie	Division Manager, Power Sales and Operations Division
D. Rainkie	Corporate Controller, Corporate Controller Division
M. Schulz	Corporate Treasurer
T. Miles	Manager of Resource Planning and Market Analysis
L. Morrison	Division Manager of Consumer Marketing and Sales
J. Hall	Division Manager of Distribution, Engineering, and Construction
W. Wittmeier	Division Manager, Apparatus Maintenance
M. Morin	Manager, Distribution Asset Maintenance
L. Kennedy	Vice President, Gannett Fleming Canada ULC.

APPENDIX D – INTERVENERS OF RECORD

Interveners of Record

Consumers' Association of Canada (Manitoba) Inc.

Green Action Centre

Manitoba Industrial Power Users Group

City of Winnipeg

Manitoba Keewatinowi Okimakanak

APPENDIX E – INTERVENER WITNESSES

The Consumers' Association of Canada (Manitoba) Inc. & The Green Action Centre

P. Dunsky	President, Dunsky Energy Consulting

The Green Action Centre

P. Chernick	President, Resource Insight Inc.

The Manitoba Industrial Power Users Group

P. Bowman	Consultant, InterGroup Consultants Ltd.

APPENDIX F – PRESENTERS

D. Biggs (written only)	Private Citizen
C. Boitson (written only)	Private Citizen
D. Bossons	Canexus, Brandon Plant Manager
A. Ciekiewicz	Private Citizen
J. Corden (written only)	Private Citizen
B. Fleury (written only)	Private Citizen
D. Forsyth	Gerdau Steel, Regional Energy Manager
S. Giese (written only)	Private Citizen
J. J. Lewis (written only)	Private Citizen
G. Luby (written only)	Private Citizen
D. MacDuff (written only)	Private Citizen
J. Pacaud (written only)	Private Citizen
A. Reid (written only)	Private Citizen
P. Stokke	Retired Manitoba Hydro engineer
G. Tobin	Gerdau Steel, Vice President, Plant Manager
B. Turner	The Manitoba Industrial Power Users Group, Interim Chair, retired Brandon Plant Manager, Canexus
W. Yan	Canexus, Manager Operational Services, Calgary

APPENDIX G - UNITS OF MEASUREMENT

Demand/Power represents the size of electricity load over a specific period of time.

expressed in:

- Watts (W)
- Kilo-watts (kW) - 1,000 watts
- Mega-watts (MW) - one million watts
- Giga-watts (GW) - one billion watts

Energy represents the amount of electricity provided to customers to do work or create heat, light, or sound. It is typically expressed as:

- Kilo-watt hours (kWh) - 1,000 watt hours
- Mega-watt hours (mWh) - 1,000 kilo-watt hours
- Giga-watt hours (GWh) - one million kilo-watt hours

Voltage represents the electric potential between two points expressed in**:**

- Volts
- Kilo-volts (kV) – 1,000 volts

Water Flow represents the rate at which water enters or leaves a system, expressed in:

- Cubic Meters per Second (m^3/s)

Tab 62

Before the Public Utilities Board of Manitoba

Manitoba Hydro

General Rate Application

2017/18 and 2018/19

Expert Testimony

of

Adonis Yatchew

November 15, 2017

Executive Summary

Background

1. **Projected Rate Increases** In May 2017, Manitoba Hydro filed a General Rate Application seeking rate increases of 7.9% for 2017/2018 and 2018/2019. Manitoba Hydro was granted an interim rate of increase of 3.36% effective August 1, 2017. In a subsequent letter, dated September 5, 2017, Manitoba Hydro advised the Board that it projects rate increases of 7.9% for each of the upcoming six fiscal years followed by an increase of 4.54% in the seventh year. The cumulative effect would be to increase electricity rates by close to 50% in real terms over the coming decade.

2. **Purpose of Testimony** In broad terms, the purpose of this testimony is to assess the likely impacts on, and responses of various customer groups to rate increases of this magnitude, as well as the implications for the Manitoba economy as a whole.

3. **Manitoba Resources and GDP** From a resource perspective, the Province of Manitoba has the good fortune of being endowed with vast hydroelectric resources, very productive agricultural lands as well as deposits of some metals and minerals. Manitoba has a diversified economy. Much like most advanced economies, the dominant share of GDP – 71% – is in the service sector. Manufacturing comprises about 10% of GDP, construction 9%, agriculture 4%, mining about 2%. There is considerable variation in energy intensity and electricity intensity across the various sectors and sub-sectors.

4. **Sources of Energy** The dominant source of Manitoba energy (approximately 37% in 2015) is hydroelectricity. About 60% of energy consumed in the residential sector is electricity, the industrial sector electricity share is 50%, and the commercial sector share is about 40%. These shares are considerably higher than the corresponding Canada-wide electricity shares which are 42% for the residential sector, 19% for the industrial sector and 35% for the commercial sector. Manitoba's reliance on electricity has been largely the result of low-priced electricity over many years. It is also suggestive of the potential for substitution to other energy sources, for example to natural gas where it is available, in the event of large and sustained electricity price increases.

Key Energy Trends Affecting Manitoba and Manitoba Hydro

5. **Natural Gas Prices** Natural gas prices are low and are likely to remain low for the foreseeable future. The extraction of natural gas from shale using hydraulic fracturing ('fracking') has revolutionized North American natural gas markets leading to excess supply.

    a. In the U.S., low natural gas prices have led to increased reliance on natural gas for generation of electricity; the cost is approximately 5 cents U.S. per kWh for high capacity combined-cycle generation. This in turn has a direct impact on the competitiveness of Manitoba Hydro in export markets.

b. In Canada, low natural gas prices influence energy choices made by all classes of customers. The potential for substitution towards natural gas in the face of major electricity price increases is a significant risk for Manitoba Hydro.

6. **Oil Prices** The shale revolution has triggered profound change in world oil markets, not only because it has led to new sources of supply, but more importantly, because it is *scalable*. Shale oil can be brought on in tiny increments, allowing rapid response to increases in price and thereby reducing OPEC market power. Oil market analysts consider a return to the high oil prices (which exceeded $100 USD/barrel prior to 2014) unlikely. Continued low oil prices have a strong influence on the prosperity of Alberta and on future development of the oil sands, which indirectly affect the Manitoba economy.

7. **Exchange Rates** Canada's exchange rate has historically been closely linked to world oil prices. Exchange rates have an important effect on Manitoba's economy as they influence demand for, and revenues from exports, including those in the electricity sector. Expectations about future oil prices inform forecasts of Canada/U.S. exchange rates.

8. **New Energy Technologies** The costs of new key energy technologies have been declining rapidly. Since 2008, costs of wind generation have dropped by 41%; photovoltaic costs have dropped more than 50%; battery costs by 73%; and LED bulbs by a stunning 94%. Continuation of these trends could have an important impact on Manitoba Hydro domestic and export markets.

9. **Decentralization of Electricity Systems** Electricity systems are facing powerful decentralizing forces, in part as a result of the scalability of new generation and storage technologies, and the enabling effects of information technologies. On the other hand, Manitoba Hydro, because of its vast hydroelectric resources, continues to operate with a highly centralized model, relying on massive investments in generation and transmission. These large investments have long life-times, and face financial risks in a world of rapid technological innovation.

Demand Modeling and Elasticities

10. **Types of Energy Models** There is a voluminous literature on the estimation of energy models of supply and demand. Many of the papers pertain to the electricity sector. Broadly speaking, three types of data can be used to infer the impacts of prices and of many other variables.

    a. **Time-Series Models** By observing patterns of demand over time within a specific geographic area, one can infer impacts of price changes on demand, and how energy users adjust to such price changes. There needs to be sufficient variation in prices for such models to produce useful results.

    b. **Cross-Section Models** By observing patterns of demand across various geographical areas at a single point in time, one can infer how different locations have adapted to varying price points, the kinds of industries that have been attracted, and the response of residential and commercial customers.

c. **Panel Data Models** Time-series and cross section data can be combined into more comprehensive specifications which permit estimation of impacts across locations and through time.

Each approach has advantages and disadvantages, and each can inform the present discussion of the potential impacts of large price changes on demand.

11. **Types of Demand Elasticities** Two classes of response measures, or 'elasticities' are particularly germane to the current discussion: the responsiveness of electricity demand to changes in the price of electricity (the 'own-price' elasticity, or usually just the price elasticity of demand); and, the responsiveness of electricity demand to changes in economic activity, which in this case is Provincial GDP (the GDP elasticity).

    a. The price elasticity can be further refined to be sector specific, i.e., separate values may be estimated for the residential, commercial and industrial sectors.

    b. There is also a distinction between short-term (say one-year) and long-term elasticities. Energy use is determined to a large degree by capital goods which take time to replace. Thus, short-run responses are usually much more attenuated than longer-term ones.

    c. A separate critical objective of energy modeling is the identification of trends which are evolving over time, in particular energy intensity and electricity intensity trends.

12. **Estimates of Demand Elasticities** The vast demand modeling literature produces a *very* broad range of electricity demand elasticities. So-called meta-analyses seek to aggregate and distill the results from many papers into single estimates. Defensible, empirically based values which are relevant for the present Manitoba environment are presented below:

    a. a short-term price elasticity of -0.1 across all sectors; that is, an electricity price increase of 10% leads to a 1% decline in electricity demand in the short-term;

    b. a long-term overall price elasticity of -0.4; that is, an electricity price increase of 10% leads to a 4% decline in electricity demand in the long-term;

    c. long-term price elasticities of -0.35 for the residential and commercial sectors, and -0.5 for the industrial sector;

    d. a GDP elasticity of 0.8; that is, an increase in GDP of 10% eventually leads to an increase in electricity consumption of 8%.

    Recent analyses suggest that long-term price elasticities are roughly three times short-term elasticities. Thus, impacts of price increases within the test period will not be fully realized for some time to come.

    While elasticities proposed by Manitoba Hydro are not unreasonable, especially given the degree of uncertainty associated with estimation of demand parameters, those recommended above are better supported by the literature.

13. **Stagnant Electricity Demand** These recommended elasticities suggest that basic load (unadjusted for certain demand management activities) is likely to be stagnant over the coming decade. Suppose that cumulative increases in electricity prices are about 50% and that the economy grows at 2% per year, so that GDP is 22% larger ten years hence. Then the price increase reduces electricity demand by about 20% (-0.4 x 50%) and GDP growth increases demand by about 18% (.8 x 22%).

14. **Business Cycle Risks** The current economic expansion is in its ninth year, so that a recession may not be far off. This will have an adverse effect on electricity demand.

15. **Declining Energy Intensity** Over the last 25 years, energy intensity, that is the amount of energy used per dollar of GDP, has been falling by more than 1% per year in Canada, a figure comparable to the average for OECD countries. Manitoba energy intensity has been dropping more rapidly, at a rate closer to 2% per year.

16. **Electricity Intensity** Patterns of electricity intensity in Manitoba have been mixed. In the service sector, which is by far the largest, intensity dropped by about 25% between 2005 and 2012, but by 2015 it had recovered to 2005 levels. Intensity in the manufacturing sector peaked in 2005, and has been displaying a fairly steady decline since that time. Agricultural sector intensity remained high until 2005, but subsequently dropped significantly.

17. **Energy Poverty** Manitoba has a relatively low rate of energy poverty in comparison to some other provinces: about 7% of households spend 10% or more of their income on energy. However, the incidence of energy poverty varies significantly across the Province and is particularly high in remote communities where prices of many goods, among them energy, are high. The projected growth in electricity prices will increase rates of energy poverty.

18. **First Nations** The impact on energy poverty, which is already high in remote and First Nations communities, is likely to be especially acute given the limited possibilities for energy substitution. In addition, low incomes will hamper substitution of capital goods, such as improved insulation, and efficient windows and doors. Commercial and industrial establishments will also be adversely affected, particularly in the absence of energy substitutes such as natural gas.

Macroeconomic Issues

19. **Energy Price Shocks** Market economies have experienced major energy price shocks. Past experiences are helpful in bounding the likely effects of significant electricity price increases in Manitoba. The dramatic oil price shocks of the 1970s which were largely unanticipated, led to economic contractions of half a per cent or less. The cumulative impact on U.S. GDP of the oil price shock in the late 1970s is estimated to be about 3%.

20. **Risks Associated With Exchange Rates and Commodity Prices** Certain sectors of the Manitoba economy are subject to large, difficult-to-predict variations in key variables. Exporters are subject to exchange rate variations: over the last decade, the Canadian dollar has varied from below 70 cents/USD to well above parity. Wheat prices, which reached a post-recession high of

$9 US/bushel in 2012, have since declined to $4 - $5 US/bushel in 2017. Nickel, copper, zinc and gold prices have also exhibited large swings.

21. **Vulnerable Economic Sectors** Electricity prices affect all households, firms, institutions and agencies. The extent of response depends on the electricity intensity and alternatives available.

    a. In the manufacturing sector, the most vulnerable industries appear to be 'basic chemicals' and 'pulp and paper' where electricity comprises high shares of costs. Iron and steel mills, foundries and non-ferrous metal production also have significant electricity cost shares.

    b. In the agricultural sector, 'greenhouses' and 'animal production' have significant electricity cost shares.

    c. In the mining sector, 'support activities for oil and gas production' and extraction of metals also have significant electricity cost shares.

    Where natural gas is available, some of these industries may engage in fuel substitution. Others are likely to carefully consider, or reconsider future investment plans.

22. **Macroeconomic Impacts of Large Electricity Price Increases** In the event that large electricity price increases are approved over the coming years, the Manitoba economy will adapt.[1]

    a. The *net* effect on GDP may eventually be modest, but in the interim, there are likely to be significant adjustment costs.

    b. In some locations, particularly those which are heavily dependent on an industry that is sensitive to electricity prices, there could be large local impacts on employment, incomes and output.

    c. The projected rate increases are not of the same magnitude as the energy price shocks of the 1970s. However, given that in the short-term, demand for electricity is highly price-inelastic, the steepness of the projected rate increases will impose a significant burden, particularly on households, businesses and institutions that do not have access to substitutes, such as natural gas.

Concluding Observations

23. **Regulatory Signaling** The regulatory decision made in this proceeding, which ostensibly deals with rate increases over a two-year test period, will have an important impact on decision making by industry because it will signal the likely future path of rate increases. Approval of

[1] Ontario has experienced electricity price increases in excess of 50% since 2009. Notwithstanding these increases, and the fluctuations in exchange rates, the Ontario economy continued to grow and the manufacturing share remained steady at about 13% of Provincial GDP.

increases that are close to the proposed 7.9% will suggest the acceptance of Manitoba Hydro arguments, and its focus on the time profile of future financial ratios.

24. **Excess Capacity** Large increases will induce a price response, which in a period of excess capacity may be sub-optimal as it will erode revenues at a time when marginal costs of production are low.

25. **Cost Reductions** Manitoba Hydro operates under a 'cost-of-service' regulatory regime. (Many other jurisdictions have moved to a mode of incentive regulation in order to improve incentives for cost minimization.) Manitoba Hydro is implementing a "Workforce Reduction Plan" which would eliminate 900 positions (15% of the workforce) over the course of two to three years.[2]

26. **Intergenerational Fairness** One might ask whether the projected rate increases are equitable from an intergenerational standpoint.

    a. Expansion of hydroelectric systems, such as that in Manitoba, involves lumpy investments in generation (to exploit scale economies) and transmission (as supply sources are distant from load). They do not enjoy the beneficial scalability features of solar, wind and natural gas generation.[3]

    b. This leads to long-term cyclical pressures on rates. Current customers have benefited from past investments, particularly those that have been largely depreciated, but remain functional. Future customers will need to pay for current projects. The calculus of intergenerational fairness is therefore, at a minimum, complex, and may not lead to unequivocal answers.

    c. Rate-smoothing is a useful tool for promoting inter-generational equity. The projected profile is more in the nature of a step function over six years, followed by a rapid decline to increases close to the rate of inflation. A ramped sequence of increases, perhaps linked to a clear demonstration of efficiencies achieved by Manitoba Hydro, may provide a useful framework for promoting internal efficiencies, allowing time to adjust to electricity rates, and distributing costs more equitably over each generation of consumers.

27. **Mitigation of Rate Increases** The effects of the large projected increases, should they be approved, could in theory, be mitigated.

    a. Special industrial rates could be offered to those firms with large electricity cost shares. But this would be viewed as inequitable by other customers.[4] Alternatively, the Government might implement incentives to retain major industrial customers.

---

[2] Manitoba Hydro, 2017/18 & 2018/19 General Rate Application, Integrated Financial Forecast, May 12, 2017, Tab 3, page 10 of 22.

[3] Or for that matter, shale oil extraction.

[4] Though rate design has inherent ambiguities. When there are significant common costs, there is no unique cost allocation based on the principle of cost causality.

b. There would be a substantial increase in the number of households facing energy poverty, however it is measured. To alleviate this effect will require funds either from other Manitoba Hydro customers, or from Government coffers.

28. **The Current U.S. Administration** In any discussion of Canada's economic circumstances, consideration of the effects of the current U.S. administration cannot be ignored. The North American Free Trade Agreement is being re-negotiated at the initiative of the U.S. At a minimum, this injects considerable uncertainty into trade relations with our largest trading partner. The U.S. administration has also altered direction on its decarbonization policies, disengaging from the Paris Agreement and making efforts to revive the coal industry. Together, these factors are likely to have a dampening effect on investment, and weaken prospects for long-term power sales agreements that are premised on clean hydro-electric power.

Contents

A. Introduction 1
B. Background 2
B.1 Economic Setting 2
B.2 The Manitoba Energy Sector 4
B.3 Oil and Natural Gas Markets 8
B.4 Costs of Key Technologies Have Been Dropping Dramatically 12
B.5 Decentralization of Electricity Systems 13
B.6 Regulatory Considerations 17
C. Demand Modeling 21
C.1 Energy Demand Modeling 21
C.2 Price Elasticities 25
C.3 GDP Elasticities, and Energy and Electricity Intensities. 28
D. Manitoba Hydro Electricity Prices 32
D.1 Rates, Costs and Intergenerational Equity 32
D.2 Bill Affordability and Energy Poverty 35
E. Macroeconomic Impacts of Electricity Price Increases 42
E.1 Energy Price Shocks 42
E.2 Exchange Rates 45
E.3 Commodity Prices 48
E.4 Electricity Intensity Varies Widely Across Some Sectors of the Manitoba Economy 49
F. Concluding Observations 51
Appendix 1: Scope of Work and Summary Responses 54
Appendix 2: Curriculum Vitae – Adonis Yatchew 61
Appendix 3: References on Elasticities 71
Appendix 4: Manitoba Electricity Cost Shares by Sub-Sector 77

A. Introduction

1. In May 2017, Manitoba Hydro filed a General Rate Application seeking rate increases of 7.9% for 2017/2018 and 2018/2019. Manitoba Hydro was granted an interim rate increase of 3.36%, effective August 1, 2017.[5] In a subsequent letter, dated September 5, 2017, Manitoba Hydro advised the Board that it projects rate increases of 7.9% for each of the upcoming six fiscal years followed by an increase of 4.54% in the seventh year.[6] The cumulative effect would be to increase electricity rates by close to 50% in real terms over the coming decade.

2. In broad terms, the purpose of this testimony is to assess the impacts on various customer groups and their likely responses; and to provide an analysis of the likely macroeconomic consequences of electricity price increases. We begin by situating the discussion within the context of Manitoba's economy, its patterns of energy and electricity use, critical trends related to energy, and the regulatory environment. In order to assess customer responses, we draw upon the large literature of energy modeling and in particular the estimation of price and income elasticities. Consideration is given to the incidence of energy poverty and the impacts on remote and First Nations communities. Subsequent sections discuss the likely macroeconomic effects of the projected rate increases.

3. In the concluding section, comments are provided relating the projected price increase to Manitoba's decarbonization agenda.

[5] PUB Order 80/17, July 31, 2017, available at http://www.pubmanitoba.ca/v1/proceedings-decisions/orders/pubs/2017%20orders/80-17.pdf.

[6] Manitoba Hydro letter to the PUB, available at https://www.hydro.mb.ca/regulatory_affairs/pdf/electric/general_rate_application_2017/00.0000001_cover_letter_dated_september_5.pdf.

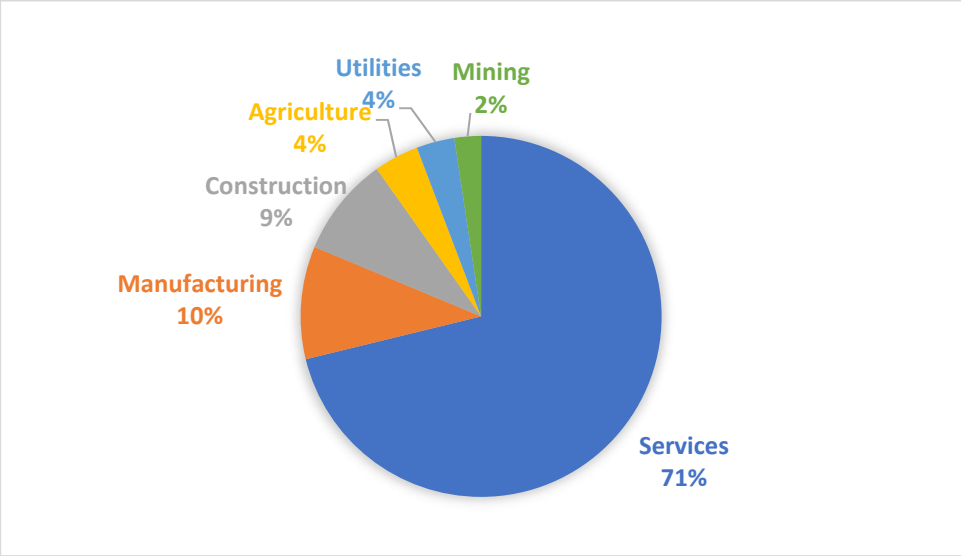
B. Background

B.1 Economic Setting[7]

4. Manitoba has a population of approximately 1.3 million. Its 2016 GDP was $67 billion with per capita output of $51,500. In part as a response to declines in commodity prices, Manitoba economic growth slowed during the 2014-2016 period, but is expected to have improved for the 2017 year. As a result of its industrial diversity, inter-provincial and international exports, high labour force participation and low per-capita debt, Manitoba's economic growth has been strong in comparison to a number of other provinces.

5. Manitoba is endowed with excellent fresh water and hydraulic resources, very productive agricultural lands, and a variety of deposits of metals and minerals. Its economy is well diversified. There is considerable variation in energy and electricity intensity across sub-sectors, making some firms more vulnerable to electricity price increases, while others more resilient to such price changes.

Figure 1: Manitoba GDP Shares 2016[8]

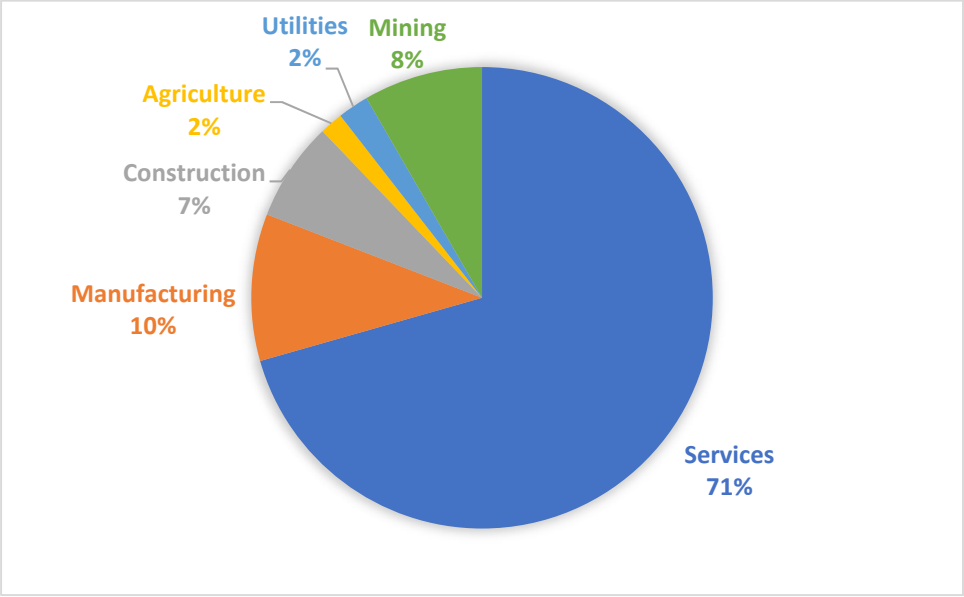


[7] See Manitoba Provincial Budget & Supporting Documents, available at http://www.manitoba.ca/budget2017/index.html and Manitoba Economic Highlights, https://www.gov.mb.ca/finance/pubs/highlights.pdf .

[8] Source: Statistics Canada, Table 379-0028 Gross domestic product (GDP) at basic prices.

6. Much like most advanced economies, the largest portion of Manitoba GDP -- 71% -- is in services. This sector comprises a virtually identical portion of Canada-wide GDP. (See Figures 1 and 2.) Major sub-sectors include real estate and rental and leasing (12%), wholesale and retail trade (11%), health care and social assistance (9%), public administration (8%), transportation and warehousing (6%), finance and insurance (6%), and educational services (5%).

Figure 2: Canada GDP Shares 2016[9]



7. Manufacturing comprises about 10% of Manitoba GDP. This sector consists of food processing, manufacture of transportation equipment (aerospace and motor vehicle), agricultural implements, chemicals (pharmaceutical and agricultural), metal and wood products and electrical equipment. Most manufactured goods are sold in other provinces or exported to the U.S. Export demand is sensitive to both exchange rates and economic activity in recipient countries.

[9] Source: Statistics Canada, Table 379-0031 Gross domestic product (GDP) at basic prices.

8. Exchange rates have an important effect on Manitoba's economy as they affect demand for, and revenues from exports, including those in the electricity sector. Canada's exchange rate has historically been closely linked to world oil prices, as we will discuss further below. Expectations about future oil prices inform forecast exchange rates.

9. In any discussion of Canada's economic circumstances, consideration of the effects of the current U.S. administration cannot be ignored. The North American Free Trade Agreement is being re-negotiated at the initiative of the U.S. At a minimum, this injects considerable uncertainty into trade relations with our largest trading partner. The U.S. administration has also altered direction on its decarbonization policies, disengaging from the Paris Agreement and making efforts to revive the coal industry.[10] Together, these factors are likely to dampen the Manitoba investment climate in the manufacturing sector, and weaken prospects for long-term power sales agreements that are premised on clean hydro-electric power.

B.2 The Manitoba Energy Sector

10. A particularly informative visual representation of energy sources and uses is provided by 'Energy Flow' diagrams, also known as Sankey diagrams. Figure 3 depicts this type of diagram for the Province of Manitoba. 'Pipe' diameters reflect the magnitudes of flows. [11]

[10] Notwithstanding these developments, the U.S. Government released a major report confirming the anthropogenic nature of climate change. See "Climate Science Special Report", Fall 2017, available at https://science2017.globalchange.gov/chapter/front-matter-about/.

[11] Such diagrams have been in existence since the 1800s. They are widely used to depict energy flows, for example Lawrence Livermore National Laboratories (LLNL) produce such diagrams for all U.S. states, see https://flowcharts.llnl.gov/. LLNL also produces U.S. national carbon flow diagrams. The International Energy Agency produces Sankey diagrams at national and continental levels http://www.iea.org/Sankey/index.html#?c=World&s=Balance.

Figure 3 was produced using *e!Sankey* software, https://www.ifu.com/e-sankey/ based on CANSIM data.

For further discussion of uses of Sankey diagrams, see *Economist*, "Data Visualisation, Sankey or Harness?" July 4th,2011; A. Yatchew, "Economics of Energy: Big Ideas for the Non-Economist", *Energy Research and Social Science*, 1(1), 2014, pages 74-78; "Using Sankey diagrams to map energy flow from primary fuel to end use", Veena Subramanyam, Deepak Paramshivan, Amit Kumar, Md. Alam Hossain Mondal, *Energy Conversion and Management*, 91, 2015, pages 342–352; and A. Yatchew 2016: "Rational vs 'Feel-Good' Carbon Policy", *Energy Regulation Quarterly*, Vol. 4, Issue 3,

11. At the top left is the total 'primary' energy of all types which in 2015, the latest year for which comprehensive data are available, was 334 peta joules (PJ). The total is obtained by summing the values of the five primary sources of energy on the left (wind, hydro, natural gas, coal and petroleum).

12. The left side of the diagram represents the supply side, while the pink boxes on the right represent the demand side.

13. The largest source of energy in Manitoba is hydraulic, which comprises about 125 PJ, or 37% of total energy. Almost all electricity produced in Manitoba comes from hydraulic sources. The second largest source of energy is petroleum at 116 PJ, or 35% of provincial energy, the vast majority of which is used in the transportation sector. The third largest energy source is natural gas at 88 PJ or 26% of total energy.

14. Next consider the demand side, which is comprised of residential, commercial, industrial and transportation sectors.[12] Manitoba's successful development of cheap and accessible hydraulic electricity is reflected in its share of total energy, and its shares within each end-use sector.

    a. About 60% (30 PJ of 50 PJ) of energy used in the residential sector is electricity.
    b. For the industrial sector the share is 50% (33 PJ of 66 PJ).
    c. For the commercial sector the share is 39% (19 PJ of 49 PJ).

In short, Manitoba is an electricity intensive province where hydraulic energy represents the largest energy source. This is a price phenomenon, thanks to abundant hydraulic sources.[13]

---

http://www.energyregulationquarterly.ca/articles/ rational-vs-feel-good-carbon-policy-transferability-subsidiarity-and-separation#sthash.GBtFuIOG.dpbs.

[12] There is also a non-energy sector which corresponds primarily to petrochemical feedstocks.

[13] A comparison with Canada-wide numbers illustrates the point. Natural gas is the dominant fuel in the residential, commercial and particularly the industrial sector where more than 50% of energy comes directly from this source (as well as a portion that comes indirectly through gas-fired electricity generation). See Canada-wide Sankey diagrams available at https://www.economics.utoronto.ca/yatchew/.

15. The Sankey diagram depicting energy flows in Manitoba (Figure 3) also provides a departure point for considering the impacts of changes in the price of electricity. Where natural gas is available, substantial increases in electricity prices could lead to substitution to gas in the residential, commercial and industrial sectors, particularly given the relatively low shares of natural gas there.

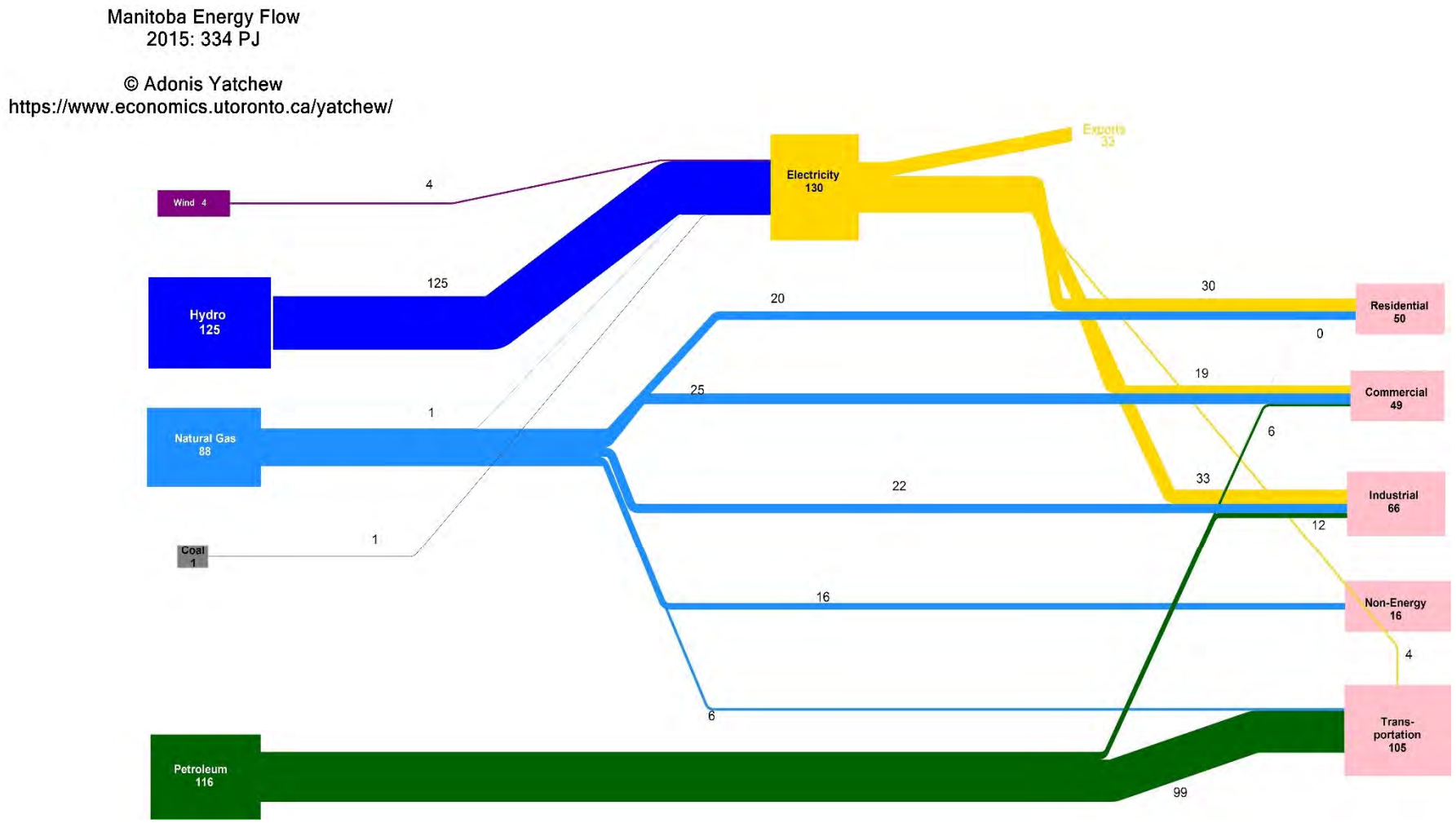
16. There is great potential for increased electricity consumption in the transportation sector, but a dramatic shift awaits further large drops in the costs and range of future generations of electric vehicles. In Manitoba, such a shift would contribute greatly to the decarbonization agenda as Manitoba has large supplies of clean hydraulic sources for the foreseeable future.

17. The energy in each sector either produces 'energy services' or is lost, usually in the form of heat. The least 'efficient' sector is transportation where 75%-80% of energy is 'rejected'. Depending on the source of energy and the types of uses, efficiency in the residential, commercial and industrial sectors ranges from 50% to 80%. While it might appear that we are very inefficient, 'wasting' well over half of the energy we produce, this is primarily a reflection of the state of technology and the second law of thermodynamics which states that whenever energy is transformed from one form to another, a portion is lost.[14]

18. The Sankey diagram is also useful for informing decarbonization discussions. Manitoba is very well positioned with such a large share of hydraulic source energy. Its use of coal is minimal and the remainder of non-transportation energy comes from natural gas, the hydrocarbon with the lowest carbon footprint (roughly half that of coal). The dominant share of energy-related carbon generated in Manitoba is in the transportation sector, which is the most difficult to decarbonize.

[14] Estimates produced by Lawrence Livermore National Laboratories suggest that roughly two-thirds of energy in the U.S. is 'rejected' and only one third produces energy services. See https://flowcharts.llnl.gov/content/assets/images/energy/us/Energy_US_2016.png.

Figure 3: Manitoba Energy Flow (Sankey Diagram)



B.3 Oil and Natural Gas Markets

19. An understanding of oil and natural gas markets and scenarios of their future price paths is important to the current analysis in several ways.

    a. First, natural gas competes with electricity in certain industrial, commercial and residential applications, particularly if the end-use is space heating or process heat. A large increase in electricity prices could lead to loss of electricity load to natural gas.

    b. Second, low-priced natural gas is the 'go-to' fuel for electricity generation in many parts of North America, including states neighboring Manitoba, and the MISO transmission system to which Manitoba belongs.[15] This in turn affects Manitoba Hydro export markets.

    c. Third, oil prices have an important impact on Canadian export revenues and on exchange rates. The precipitous decline in oil prices which began in mid-2014 has had a dramatic impact on the economy of Alberta and to a lesser degree on Saskatchewan and Manitoba. Canada has vast reserves of oil, mainly in the form of bitumen. But these reserves are among the highest priced in the world.

20. What is the outlook for natural gas prices? A decade ago, it was widely believed that the U.S. would need to begin importing natural gas. Liquid natural gas (LNG) terminals were planned and some were built.[16] Then came the shale revolution. By efficiently combining

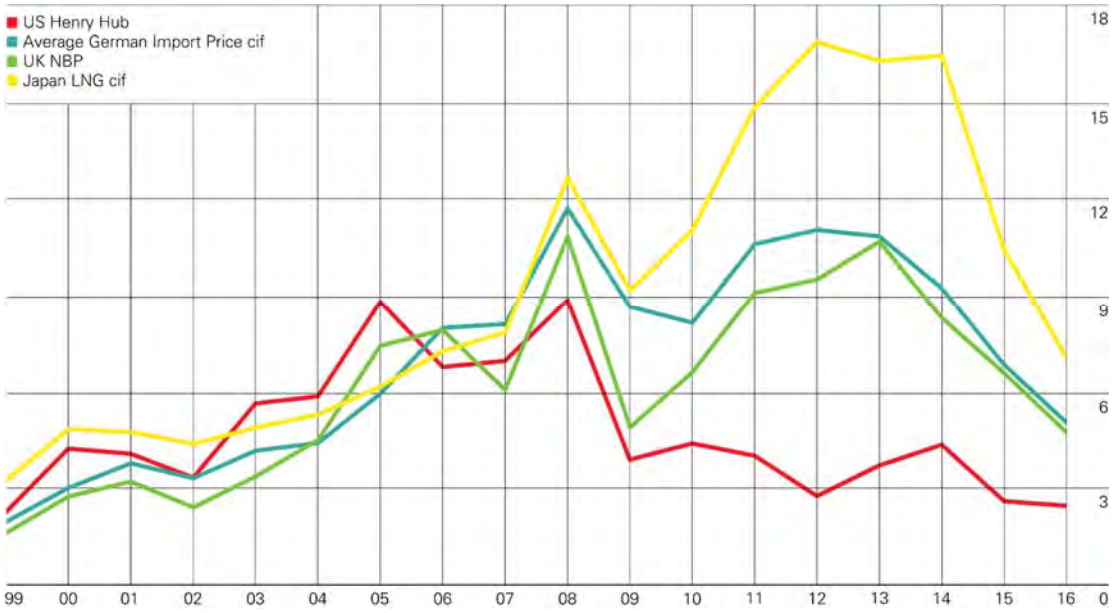
[15] Low natural gas prices have led to a significant shift away from coal-fired electricity generation in the U.S. towards natural gas generation. Roughly comparable amounts of electricity are generated from each of these two sources in the U.S.

[16] LNG shipping requires liquefaction terminals at the exporting site, and re-gasification at the importing site. Initially, the U.S. began to build re-gasification terminals. These sites have been largely converted to liquefaction. Qatar is the largest LNG exporter, followed by Australia. Floating storage and re-gasification carriers can serve as LNG importing terminals.

two technologies – horizontal drilling and hydraulic fracturing (fracking) – cost-effective North American gas reserves grew very rapidly.

Figure 4: Gas prices

USD/mmBtu



BP Statistical Review of World Energy 2017 © BP p.l.c. 2017

21. Natural gas prices worldwide dropped dramatically in 2009, as a result of the financial crisis. However, by 2012 they had recovered *except* in North America (Figure 4).[17] What we observed were the consequences of shale revolution. This in turn led to a reconfiguration of natural gas flows across North America as major natural gas supplies were developed, for example, in Texas and Pennsylvania, reducing the need for Canadian natural gas and leading to reduced use of the TransCanada Mainline.

22. In the past, natural gas markets have been continental (hence the separate benchmark prices in Figure 4). But recently, there has been a gradual globalization as LNG becomes

[17] LNG prices in Japan sky-rocketed in 2011 as a result of the Fukushima meltdown.

increasingly competitive in overseas markets. By 2015 about 40% of total natural gas trade moved by sea, and prices in distant markets began to converge.[18]

23. While globalization increases the demand for North American natural gas, there is little evidence to suggest that a dramatic price increase is likely; natural gas will continue to provide strong competition to electricity.

24. Though largely unanticipated, the revolution in natural gas would eventually lead to perhaps the most dramatic change in oil markets since the 1970s OPEC price increases.[19,20] One might think that the main effect of the fracking revolution on oil prices is through the increase in recoverable supplies. However, the peculiar features of the shale revolution have altered the nature of oil markets in another critical way. For the first time, additional oil can be brought online in tiny increments – the cost of a productive shale well is *three orders of magnitude* smaller than Arctic or deep-sea projects.

25. The ***scalability*** of shale has fundamentally altered the strategic behavior of OPEC. Whereas in the past OPEC might have coordinated a supply reduction to sustain prices, it is far more limited now in its ability to do so because shale producers (and others) can fill the gap. Shale has provided for a scalable response by many producers as market conditions change. This feature further limits unilateral or cartelized market power.

[18] "Long Promised, the Global Market for Natural Gas Has Finally Arrived", Russell Gold and Alison Sider, *Wall Street Journal*, June 6, 2017. See also MIT Energy Initiative, *The Future of Natural Gas*, Cambridge: June 2011.

[19] Though in 2012, Berkeley physics Professor Richard Muller writes "Shale oil production could truly be a disruptive technology, with a large and positive impact on the US balance of trade, severe repercussions for the OPEC oil cartel, and a serious challenge to alternative-transportation technologies, particularly natural gas and synfuel. Shale oil could turn conventional oil into the new whale oil, replaced by a far more abundant source." Richard A. Muller, *Energy for Future Presidents: The Science Behind the Headlines*, 2012, (Kindle Locations 1679-1682). W. W. Norton & Company. Kindle Edition. In that same book, Muller sees $60 USD / barrel as a long-term limit price for oil. At the time of his writing, the world price of oil was well over $100 USD / barrel.

[20] The historic paths of oil and (North American) natural gas prices display a surprising degree of correlation. In fact, some have argued that the drop in world oil prices beginning in 2014 was signaled by the decline in North American natural gas prices which began in 2008. See, e.g., Dimitri Dimitropoulos, and Adonis Yatchew 2017, "Discerning Trends in Commodity Prices", *Macroeconomic Dynamics*, doi:10.1017/S1365100516000511.

Scalability of shale also reduces risks – wells do not last long, but capital requirements are low and lead-times short.

26. Not long ago, 'peak oil' meant that one day, in the not too distant future, we would reach peak production as supplies ran out. Now 'peak oil' refers to the day when demand levels off and begins to fall. Technological innovations to a post-carbon world are leading the way. Shale, bitumen and undersea resources are unlikely to run out, and the key question is what fraction of proven reserves will *not* be extracted. This in turn creates incentives for those with large cheap reserves (such as Saudi Arabia) to sell more today rather than saving reserves for an uncertain future.[21]

27. In the absence of innovation in electric vehicles which would lead to their wide spread adoption in growing economies such as China and India, demand for oil should continue to grow for a time. The question is when we will reach the tipping point in the sector that is the most difficult to decarbonize – transportation.

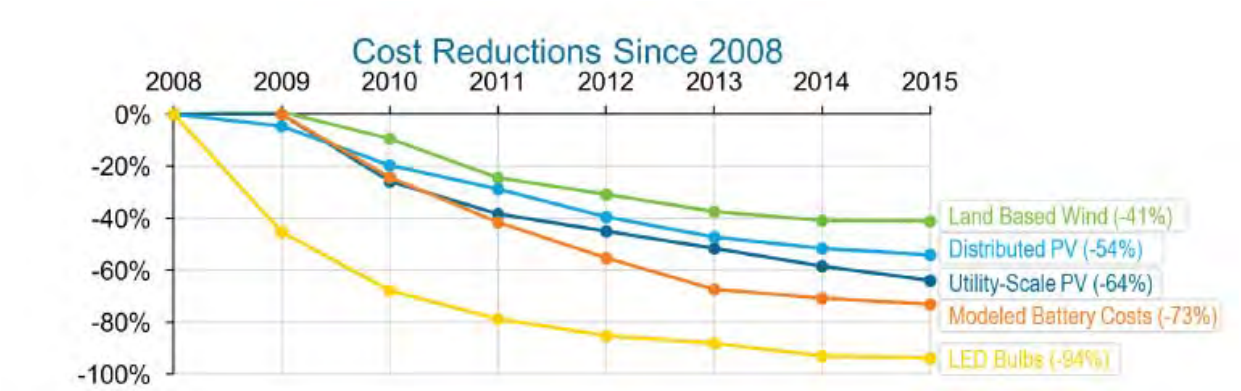
28. To summarize, low natural gas prices exert competitive pressures on Manitoba Hydro in domestic markets to the extent that they provide a viable alternative to electricity, and in export markets because they drive down electricity prices there. Low oil prices put downward pressure on the exchange rate, which enhances export competitiveness of Manitoba industries and improves Canadian dollar revenues of Manitoba Hydro electricity sales.

[21] See, for example, "Get Ready for Peak Oil Demand. There's a growing consensus that the end of ever-rising consumption is in sight. The big question that many oil companies are debating: When?", Lynn Cook and Elena Cherney, *Wall Street Journal*, May 26, 2017.

B.4 Costs of Key Technologies Have Been Dropping Dramatically

29. The costs of emerging technologies which are transforming electricity industries have been dropping at a rapid pace. Since 2008, costs of wind generation have dropped by 41%; photovoltaics have dropped more than 50%; battery costs by 73%; and LED bulbs by a stunning 94%. (See Figure 5 below.)

Figure 5 – Cost Reductions in Key Technologies[22]



30. Non-dispatchable generation such as on-shore wind is priced at about 5 U.S. cents/kWh for new installations at a capacity factor of 39%. Solar photo-voltaic is at 7 U.S. cents/kWh at a capacity factor of 26%. Combined cycle natural gas electricity generation for new installations costs about 5 U.S. cents/kWh if used at high capacity (87%), and conventional combustion turbine generation is at about 9 U.S. cents/kWh if used at low capacity (30%).[23]

[22] Source: "Revolution … Now, The Future Arrives for Five Clean Energy Technologies – 2016 Update", U.S. Department of Energy, September 2016. Available at https://www.energy.gov/eere/downloads/revolutionnow-2016-update. "Notes: Land based wind costs are derived from levelized cost of energy from representative wind sites… Distributed PV cost is average residential installed cost... Utility-Scale PV cost is the median installed cost… Modeled battery costs are at high-volume production of battery systems, derived from DOE/UIS Advanced Battery Consortium PHEV Battery development projects. LED bulb costs are cost per lumen for A-type bulbs..."

[23] These are Levelized Cost of Energy (LCOE) numbers which embed assumptions about depreciation lifetimes, cost of fuel and, as indicated, utilization capacity factors. U.S. Energy Information Administration April 2017 *Table A1a. Estimated LCOE (weighted average of regional values based on projected capacity additions) for new generation resources, for plants entering service in 2019* ", available at https://www.eia.gov/outlooks/aeo/pdf/electricity_generation.pdf. Combined heat and power systems, because of their high efficiency, have the potential for

B.5 Decentralization of Electricity Systems

31. Historically, the centralized structure of electricity industries has been driven by three critical features. First, non-storability of electricity meant that supply and demand needed to be balanced virtually instantaneously. Second, scale economies in generation led to electricity being produced at a relatively small number of locations. Third, the essentiality of electricity to every-day life underscored the need for a very high degree of reliability.

32. Scale economies in electricity generation increased into the 1970's, at which time they began to level off. Minimum efficient scale declined. Electricity networks, both transmission and distribution, which would transport and distribute electrons, were and continue to be natural monopolies, but at different spatial scales.[24]

33. In many jurisdictions, as a result of scale economies, (and some have argued due to vertical economies of scope), the electricity industry was vertically integrated, as is the case in Manitoba. In other jurisdictions, the distribution segment of the industry was serviced by a number of distributors.

34. By the late 20th century, the centripetal forces which centralized electricity industry structure began to weaken. The generation segment in many instances was no longer seen as a natural monopoly.[25] In various jurisdictions, the separation of natural monopoly components (i.e., transmission and distribution) from potentially competitive segments (i.e., generation and energy services) took place. This 'unbundling' was intended to lead

---

increasing market penetration. See *Combined Heat and Power Technical Potential in the United States,* U.S. Department of Energy, March 2016, available at https://www.energy.gov/sites/prod/files/2016/04/f30/CHP%20Technical%20Potential%20Study%203-31-2016%20Final.pdf; also *Many industries use combined heat and power to improve energy efficiency*, U.S. Energy Information Administration, July 27, 2016, available at https://www.eia.gov/todayinenergy/detail.php?id=27252.

[24] The power grid was named the greatest engineering achievement of the 20th century by the U.S. National Academy of Engineering. The main selection criterion was "how much an achievement improved people's quality of life". See "Great Achievements and Grand Challenges", *The Bridge*, September 1, 2000 Volume 30 Issue 3 and 4, pages 5-10.

[25] Previously, efficient scale for coal-fired and nuclear units was on the order of 1000 MW. The size of hydro-electric units depended critically on siting.

to increased competition, primarily in generation. In a few jurisdictions, industries were restructured and competitive forces were introduced, with varying degrees of success.

35. Still, the need for coordination, reliability and the natural monopoly characteristics of the grid, continued to be the fundamental centralizing drivers of the structure of the industry.

36. Transformation of electricity industries began gradually in the first decade of the 21st century. The information revolution had spawned new technologies, often called 'smart' technologies, which would improve responsiveness of the grid, facilitate more rapid identification and correction of faults, and eventually enable demand side response to grid or market conditions.

37. At the same time, the decarbonization agenda, which was being pursued most aggressively in Europe, began to drive innovation in renewables. Feed-in-tariffs and other stimuli were producing rapid cost declines and efficiency improvements in renewable technologies, particularly in solar and wind generation.[26] While one tends to associate successful implementation of solar technology with sun-lit locations and relatively little precipitation, grid parity is being achieved in some countries that are not endowed with either of these traits.[27]

38. Because solar and wind generation are non-dispatchable, i.e., intermittent, the value to the system is not fully reflected by the costs of production. Backup generation (usually natural gas) or electricity storage is required to ensure that sufficient electricity is available when needed.

[26] Between 2010 and 2016, average prices resulting from auctions have declined from about $90 USD/MWh to below $50 USD/MWh for wind generation. For solar, the decline for the same period has been from $250 USD/MWh to about $50 USD/MWh, a precipitous drop. See *Renewable Energy Auctions. Analysing 2016*, International Renewable Energy Agency, 2017, page 16, Figure 2.1, available at http://www.irena.org/DocumentDownloads/Publications/IRENA_Renewable_Energy_Auctions_2017.pdf.

[27] A 10 MW solar farm in the UK has recently been built without government subsidy. See "Solar Power Breakthrough as Subsidy Free Farm Open", by Nathalie Thomas, *Financial Times*, September 25, 2017, accessed at https://www.ft.com/content/8ea432e4-a1e9-11e7-9e4f-7f5e6a7c98a2. Note that this facility is two orders of magnitude smaller than conventional coal-fired stations of 1000 MW.

39. Storage technologies have also been experiencing major cost reductions, but have not yet reached a tipping point. Though, in some instances, solar-cum-battery installations have achieved unexpectedly low costs.[28]

40. Solar is extremely scalable (think solar powered calculators and parking meters) though larger facilities enjoy a significant cost advantage over small scale roof-top installations.

41. Scalability and storage, supported by innovative uses of information technologies, are combining to disrupt the conventional utility model. And that model is more susceptible to disruption if the price of electricity is relatively high. Residential and commercial customers are then more likely to invest in on-site solar to reduce their overall electricity costs.

42. Self-generation and 'net-metering' is posing a serious challenge to the conventional electricity utility model. In some jurisdictions this has led to a confrontation between utilities and their owners, and companies selling and installing distributed solar generation, and their customers.[29]

[28] In January 2017, a Hawaii electricity cooperative signed an agreement paying $110 USD / MWh for dispatchable electricity from a combined solar and battery storage system. See "Hawaii co-op signs deal for solar+storage project at 11¢/kWh", by Gavin Bade, *UtilityDive*, January 10 2017, accessed at http://www.utilitydive.com/news/hawaii-co-op-signs-deal-for-solarstorage-project-at-11kwh/433744/ . A few months later, Tucson Electric signed a similar deal but at a much lower price. See "Updated: Tucson Electric signs solar + storage PPA for 'less than 4.5¢/kWh'", by Gavin Bade, *UtilityDive*, May 23, 2017, accessed at http://www.utilitydive.com/news/updated-tucson-electric-signs-solar-storage-ppa-for-less-than-45kwh/443293/ .

[29] Perhaps the most prominent clash has been between Warren Buffet, whose Berkshire Hathaway owns NV Energy, a Nevada electricity utility, and Elon Musk, whose SolarCity company installs solar panels. See "In a clash of titans, Warren Buffett beat Elon Musk in Nevada", Nick Cunningham, *Business Insider*, December 30, 2015, http://www.businessinsider.com/warren-buffett-beat-elon-musk-on-solar-in-nevada-2015-12?pundits_only=0&get_all_comments=1&no_reply_filter=1; "Warren Buffett controls Nevada's legacy utility. Elon Musk is behind the solar company that's upending the market. Let the fun begin", Noah Buhayar, *Bloomberg Businessweek,* January 28, 2016, https://www.bloomberg.com/features/2016-solar-power-buffett-vs-musk/; "Solar Showdown In The Nevada Desert: Warren Buffett Vs. Elon Musk?", Michael Lynch, *Forbes*, February 23, 2016, https://www.forbes.com/sites/michaellynch/2016/02/23/solar-showdown-in-the-nevada-desert-buffett-vs-musk/#5b845aed1766; "Buffett vs. Musk: The clash of old and new energy titans", Daniel Rothberg, *Las Vegas Sun*, May 2, 2016, https://lasvegassun.com/news/2016/may/02/buffett-vs-musk-the-clash-of-old-and-new-energy-ti/.

43. In a landmark study entitled *Utility of the Future,* a group at MIT has conducted a wide-ranging analysis of how the electricity utility business is changing, and how companies, regulators and policy-makers need to adapt.[30] That study argues that fundamental changes are underway in the supply and consumption of electricity. Among the major factors driving the change are "emerging distributed technologies -- including flexible demand, distributed generation, energy storage, and advanced power electronics and control devices". Rapidly decreasing costs in information technologies are enabling synchronization of various energy supply, demand and storage resources.

44. The MIT study identifies a series of core findings ranging from the importance of accurate price signals (locational and temporal), the need to improve regulatory models, the potential for cost savings arising out of more efficient use of existing assets, and even privacy and cybersecurity issues as interconnectedness increases (for example, through 'smart appliances').

45. While at first it might appear that the *Utility of the Future* study may bear little relationship to the main objectives of this proceeding, particularly as Manitoba Hydro is in a position of excess capacity for some time to come, there are at least two reasons why an appreciation of industry evolution is relevant.

    a. First, an understanding of how other utilities are adapting to the proliferation of new technologies and uses of electricity, can inform Manitoba Hydro's planning and forecasting. In the presence of sufficiently high rate increases, there may be significant risk of loss of load in one or more market segments, in ways that cannot be directly extrapolated from price elasticities based on historical data, but may be heralded by experience elsewhere.

    b. Second, understanding how electricity and energy industries are evolving, particularly in neighbouring jurisdictions, can provide insights into Manitoba's electricity export markets.

[30] *Utility of the Future. An MIT Energy Initiative response to an industry in transition*, MIT Energy Initiative, December 2016, available at http://energy.mit.edu/publication/utility-future-report/.

46. While generation will likely be progressively decentralized, some have argued that electrification of energy systems (think transportation sector in the Sankey diagram at Figure 3) will require modernization and even expansion of electricity grids.[31]

47. Finally, in a world where infrastructure security (including cybersecurity) is becoming an increasingly important issue, decentralization of electricity system may provide an important measure of protection.

B.6 Regulatory Considerations

48. Manitoba Hydro operates in what is essentially a 'cost-of-service' regulatory regime. This form of regulation, and its sibling 'rate-of-return' regulation, have been in existence since the late 19th century. Under these regimes, the regulator reviews the 'revenue requirement', that is the amounts required to meet costs, in some cases disallowing or trimming certain ones, then sets rates to each customer class.

49. Cost-of-service regulation prevailed for much of the 20th century. Keeping in mind that increasing returns to scale and productivity growth were driving down unit costs in North America until the 1970s, the task of regulators was easier as the objective was to determine how to allocate these benefits to customers and producing firms.

50. During the 1970s, oil price shocks led to upward pressure on electricity prices, particularly in jurisdictions where the generation mix relied to a significant degree on hydrocarbons. A significant portion of electricity in the U.S. was generated using oil. What is less understood is the indirect effects of oil price increases on natural gas and coal prices. The

[31] See "Utility Touts Electrification to Meet California Climate Goals" Russell Gold, *Wall Street Journal*, October 31, 2017, available at https://www.wsj.com/articles/utility-touts-electrification-to-meet-california-climate-goals-1509457320.

flight from oil by generators to these other hydrocarbons put upward pressure on those prices as well, spreading the impact.[32]

51. Pressure began to accumulate on regulators and policy-makers to control electricity prices. In some instances, accounting devices were used to mitigate rate increases. For example, asset lifetimes were extended, thereby reducing annual depreciation expense. In other cases, rate increases were delayed (so-called regulatory lag) to put pressure on electricity companies to reduce costs.

52. Theorists had already identified limitations of the prevailing regulatory model. Costs of regulated monopolies were not being disciplined by market forces, leading to inefficiency and 'gold-plating'.[33] Developments in the economic theory of regulation suggested new directions. The crux of the regulatory problem was that regulators, no matter how skilled, experienced and well-supported, were greatly disadvantaged in trying to assess what 'reasonable costs' should be. The mountains of data that one would need to process and evaluate represented a Herculean task. (This became known as the 'asymmetry of information' problem.)

53. Rather than relying exclusively on a regulatory process to discover the achievable minimum costs, theorists suggested that instead, the regulatory mechanism should enhance the incentives for regulated firms to minimize costs, and to reveal the savings and productivity gains to the regulator, at least over some period of time.

[32] There is a surprising degree of co-movement of oil, natural gas and coal prices. See Dimitropoulos and Yatchew 2017, *op. cit.*

[33] For example, the so-called Averch-Johnson effect asserts that under rate-of-return regulation, firms expand capital expenditures in order to earn a higher volume of returns. This in turn leads to excess capital, and potentially inefficient input mix. Averch, Harvey; Johnson, Leland L. (1962) "Behavior of the Firm Under Regulatory Constraint", *American Economic Review*, 52 (5): 1052–1069.

54. These regulatory models fall under the general rubric of incentive regulation.[34] The most commonly applied version is price-cap regulation.[35] The emergence of incentive regulation coincided with the broad world-wide trends towards deregulation, privatization and an increased reliance on the market-place and individual choice.[36]

55. How are these regulatory considerations relevant to this proceeding?

a. First, Manitobans have been fortunate to have had the benefit of low electricity rates for many years. However, given current and future cost projections, there may be increasing pressure to shift towards a model which creates greater incentives for cost containment. This, at least, has been the pattern in other jurisdictions.

b. Second, the business community, particularly those segments for which electricity costs comprise an important share, are forming their expectations about future electricity prices in part based on whether the regulatory framework is well equipped to incentivize productivity growth and cost savings at Manitoba Hydro. Their decisions to expand or even situate themselves here are informed by these expectations.

c. Third, the financial community, which assesses debt worthiness, is carefully attuned to the regulatory model. The ability of Manitoba Hydro to service its debt and maintain healthy financial ratios, or at least to have them trending in the right direction, depends on Manitoba Hydro costs and rates, both of which are dependent on the regulatory

[34] Though the idea comes in many flavours, e.g., performance-based regulation, yardstick regulation, and so on.

[35] Price-cap regulation was first applied in the telecommunications industry in the U.K. It then spread to other network and energy industries. Steven Littlechild is often associated with its earliest implementation, though many economists contributed to the development of the ideas.

[36] An admittedly over-simplified narrative would describe the 'market failure' known as the Great Depression of the 1930s leading to decades of increased regulation and government intervention. The 1970s, a period of high inflation and unemployment, was seen by many as a 'government failure' which in turn brought a period of deregulation and privatization. It is during this period that incentive regulation had its intellectual and practical roots. See Yatchew, A. 2014 "Economics of Energy: Big Ideas for the Non-Economist", *Energy Research and Social Science*, 1(1), 74-82.

model, the decisions of the regulator and the direction set by the Government and policy makers.

56. Governments are perpetually under pressure to influence electricity prices, particularly in jurisdictions where the utility is publicly owned, such as is the case in Manitoba.[37] This in turn, can lead to delays in cost recovery and inter-generational redistributions.[38]

[37] The public complains when oil prices increase, but does not assign blame to the government. In fact, the variation in oil and gasoline prices has been far larger than the changes in electricity prices which are deliberately stabilized.

[38] The Ontario Government's financing of electricity rate reductions through debt flotation has come under heavy criticism from the Office of the Auditor General of Ontario, *The Fair Hydro Plan: Concerns About Fiscal Transparency, Accountability and Value For Money*, October 17, 2017, http://www.auditor.on.ca/en/content/specialreports/specialreports/FairHydroPlan_en.pdf

C. Demand Modeling

C.1 Energy Demand Modeling

57. In order to formulate a view on price elasticities of electricity demand, it is first helpful to understand how they are obtained. Elasticities are not estimated in isolation, but rather derived from more general models that try to incorporate various factors that influence the demand for electricity.

58. Numerous studies of energy demand have been conducted in many geographic locations. In the first instance, studies may be organized by the type and origin of data upon which they rely, such as
    a. geographical area
    b. individual data vs. aggregate data
    c. customer type -- residential, commercial, industrial
    d. time series, cross-section, or data that combine both time and spatial dimensions (i.e., panel data)
    e. sample period and frequency of data (e.g., monthly vs. annual)
    f. single equation vs multi-equation (e.g., electricity, natural gas and oil). [39]

59. Studies also differ by virtue of the econometric specification and their degree of sophistication. Distinguishing features include the flexibility that the model allows, for example, whether it captures potentially nonlinear responses to price changes; and whether key parameters evolve over time.

60. The work-horse of demand modeling is the log-linear model which in its very simplest form is given by $\log(y) = \alpha + \beta \log(x) = \varepsilon$ where x is price and y is demand. Such models are especially convenient because the coefficient β is the response elasticity. For

[39] There are also studies which focus on demand for energy services rather than energy types. Other models combine capital decisions with energy consumption. A classic, widely cited paper in this literature is "An Econometric Analysis of Residential Electric Appliance Holdings and Consumption" J. Dubin and D. McFadden, *Econometrica*, Vol. 52, No. 2, Mar., 1984, pp. 345-362.

example, if $\beta = -.1$ then a 10% increase in price leads to a 1% reduction in demand. Additional explanatory variables, such as prices of competing energy sources, GDP and characteristics of the purchasers can be readily added.[40]

61. Classical economic theory teaches us that prices adjust to 'clear the market', that is to bring supply and demand into balance. In most industries, this complicates modeling because the price variable cannot be treated as given (i.e., as being exogenous). This in turn requires either joint modeling of supply and demand, or the application of estimation techniques which correct for the problem. In much of the electricity demand estimation literature, this 'endogeneity' problem is moot because prices are set in advance and regulators ensure that there is sufficient supply to meet demand at expected prices.

62. A critical part of assessing the impacts of price trajectories requires distinguishing between short-term and long-term effects. For example, suppose there is the expectation that electricity prices will increase by 7% each year, roughly doubling in a decade. Next year, one might expect some response from residential, commercial and industrial customers, for example in the form of increased conservation. But adaptation takes time, mainly because processes and appliances that use electricity are costly to replace. Over time, more efficient appliances will be put in place, and there could be substitution to other sources of energy (such as natural gas). Thus, the short-run response is likely to be substantially smaller than the long-term response. Furthermore, the expectation of an increasing price trajectory may not only lead to efficiency improvements, migration to other fuels, and a more electricity efficient capital stock, but it may discourage future industrial investments, particularly in very electricity intensive industries.

63. At any given point in time, electricity prices vary widely across jurisdictions. Such 'cross-section' data are useful in identifying long-term effects of price changes (and therefore long-term elasticities). Locations with historically high prices are likely to have lower unit

[40] Richer but more complicated models which incorporate nonlinearities include *translog* and 'generalized Leontief' specifications. Semiparametric and nonparametric models allow the shape of price response to be fully data-driven rather than being imposed *ex ante*.

levels of electricity consumption, those with historically low prices are likely to have higher consumption levels, and a larger share of electricity intensive industries.

64. Time-series data are generally more useful in identifying short-term responses (and therefore short-term elasticities). Such models can be extended to try to capture long-term effects as well, though focusing on a single jurisdiction over time, usually limits the identification of larger and long-term price impacts. On the other hand, time series models enjoy the advantage of being able to capture smooth trends (e.g., resulting from efficiency improvements and technological innovation) as well as disruptive changes that eventually can result in a tipping point (such as we have seen in natural gas and oil markets).[41]

[41] Within the class of time-series models, there are two important and large sub-classes: stationary and non-stationary models.

a. Stationary models apply to data in which the main characteristics (means, variances, covariances and so-forth) do not change over time, hence this model property is referred to as 'stationarity'. In the simplest versions, co-movement of variables is modeled using correlations and regression models (the latter are in effect partial correlations). Within the class of stationary models, time dependencies of observed variables (e.g., the effect of previous price changes on current consumption) are often estimated using so-called distributed lag models. Unobserved components (i.e., residuals) are typically modeled using autoregressive (AR) or moving average (MA) structures. Stationary models can be static or dynamic. In static models, variables respond contemporaneously to drivers. Dynamic models allow one to model impacts which take time to be fully realized. For example, consumers and businesses do not respond to price changes instantaneously, but rather adapt over time. Partial adjustment models constitute one type of dynamic specification which incorporates responses over a period of time.

b. Non-stationary models allow for evolution over time, such as through trends which can be deterministic or stochastic (i.e., random). Trends play an important role in energy and electricity demand modeling (and more generally in the modeling of commodity prices). For example, the study of trends in energy intensity has experienced rapidly growing interest as governments and policy makers try to address the challenges of decarbonization. In nonstationary settings, co-movement is typically modeled using cointegration techniques. One of the most common specifications in this literature is the error correction model which posits a long-term equilibrium relationship between variables and an adjustment mechanism that moves the system towards that equilibrium.

c. Models of energy use may also incorporate cyclical components, such as diurnal and seasonal effects. Cyclicality is especially important in modeling electricity and natural gas consumption.

d. Time-series models may contain stationary, non-stationary and cyclical components.

65. Panel data models combine both time-series and cross-section data. For example, a data-set of this type might contain say ten years of monthly data on electricity consumption in each of the 13 sub-national jurisdictions of Canada, that is the Provinces and Territories, (yielding 1,560 data points).

66. Energy industries continue to evolve, and in some areas technological innovation is a critical driver. Prominent among the changes, as noted earlier, are rapidly dropping costs of solar and wind generation. Electric vehicle research, design and manufacturing is attracting a growing list of participants. Innovation in (chemical) battery technology and more generally energy storage technologies, is also proceeding rapidly. Statistical models provide useful tools for projecting future time-paths of technology adoption.[42]

67. Individual papers in the literature on energy typically focus on one or another technique, determined largely by the structure of the data-set, (time-series, cross-section, panel data). How does one inform one's judgement about price elasticities from such a massive collection of results and approaches? One might be inclined to construct an architectonic model which incorporates data from multiple sources. In a sense, that is what meta-analytic papers are comprised of: meta-analyses are a genre of (usually academic) undertakings which assemble the results obtained in many other papers, then use statistical techniques to weight the various results that have been obtained therein, and thereby to arrive at an overall summary view.[43]

[42] So-called 'convergence' models can be used to project adoption of LED lightbulbs and other energy saving devices, solar roof panels, and electric vehicles, to name a few.

[43] For example, suppose one has a dozen independent estimates of the price elasticity of electricity demand. One option would be to simply take the average of the estimates. A more sensible approach would be to give more accurate estimates (i.e., those that are estimated with greater precision as reflected by their lower standard errors) greater weight, and those that are estimated less precisely, less weight.

C.2 Price Elasticities

68. Given this very broad range of modeling techniques, data types, geographic locations and time spans, how does one organize one's thinking about the impacts of price changes on electricity demand in Manitoba and the trends in demand?

69. Our objective will be to inform the following questions:

    a. What are the short-term and long-term impacts of increases in the price of electricity on residential, commercial and industrial demand? To address these questions, we will focus on sectoral elasticities of electricity demand with respect to the price of electricity (known as own-price elasticities).[44]

    b. What is the relationship between economic growth and electricity demand? What electricity and energy industry trends can inform judgements about future electricity consumption? Here we will focus on the GDP elasticity of demand, and on energy intensity and electricity intensity trends.

    c. How can technological innovation be taken into account in constructing scenarios of future demand? Are there scenarios under which electricity demand could rise rapidly, or others under which it could fall?

70. Surveys of estimated demand elasticities reveal a very broad range of estimates.[45] It should be kept in mind that these ranges cover studies conducted over various time periods and in very different geographic locations. (Appendix 3 of this document contains a bibliography, focusing primarily on North American studies.)

[44] A related elasticity measures the degree to which substitution to natural gas is likely to take place in the residential, commercial and industrial sectors. This is a known as a cross-price elasticity.

[45] K. Gillingham, R. Newell and K Palmer, in "Energy Efficiency Economics and Policy" *Annual Review of Resource Economics,* 2009, 1:597–619 summarize the ranges of estimates at Table 1. Short term residential electricity demand elasticities lie in the range -0.14 and -0.44; their long-run counterparts are between -0.32 and -1.89. Commercial and industrial elasticities also lie in very broad ranges.

71. A recent 'meta-analysis', which as indicated earlier, is a methodology which weights the results of various studies, arrives at empirical results which are useful to the present proceeding.

    a. The first is that the short-term elasticity of demand for electricity is -0.126; that is a 10% increase in the price of electricity results in a 1.26% decline in demand.

    b. The second is that the long-term average elasticity is -0.365; thus a 10% increase in price will eventually lead to a 3.65% decline in demand.[46]

    c. A third useful finding is that long-term elasticities of demand for various energy types are roughly three times short-term elasticities.[47]

72. In contrast, a recent study which uses state-level American data finds a comparable short-term elasticity of -0.1 in all sectors, but much higher long-term elasticities of approximately -0.5 for the commercial sector, -1.1 for the residential sector and -1.4 for the industrial sector. These results are likely driven by the cross-sectional nature of the data. The authors attribute the large industry price elasticity to concentration of electricity intensive industries in low-price states.[48] While these elasticity estimates are certainly large when compared to those in other studies, they serve to bound the range of reasonable estimates: in short, a price elasticity of -1 in the long-term is within the limits of empirical evidence.

[46] Labandeira, X., Labeaga, J.M., López-Otero, X., 2017." A meta-analysis on the price elasticity of energy demand". *Energy Policy* 102, 549-568, Table 5.

[47] *Ibid.* p. 554 "Indeed, considering the papers that report both short (ST) and long-term (LT) price elasticities, the LT average elasticity slightly triples (3.08) the ST average elasticity. Moreover, all energy products are around that figure: electricity (3.04), natural gas (3.03), gasoline (3.05), diesel (3.20) and heating oil (3.73)."

[48] "The Price Elasticity of Electricity Demand in the United States: A Three-Dimensional Analysis", 2017, Paul J. Burke and Ashani Abayasekara, forthcoming, *The Energy Journal*.

73. A literature search for studies that estimated demand elasticities in a uniform fashion across the Provinces and Territories of Canada has turned up very little. [49]

74. **For present purposes, short-term sectoral elasticities of -0.1 and an overall long-term electricity price elasticity of -0.4 provide reasonable benchmarks. Long-term elasticities of -0.35 for the residential and commercial sectors, and -0.5 for the industrial sector would also provide reasonable reference points.**

75. These price elasticities are somewhat higher, in absolute terms, than those provided by Manitoba Hydro in its load forecast documents, as summarized in the table below. While elasticities proposed by Manitoba Hydro are not unreasonable, especially given the degree of uncertainty associated with estimation of demand parameters, those recommended above are better supported by the literature.

	2016 Electric Load Forecast[50]	2017 Electric Load Forecast[51]
Residential Basic	-0.29	-0.28
GS Mass Mkt Small/Medium	-0.18	-0.13
GS Mass Mkt Large	-0.47	-0.46
GS Top Consumers	-0.48	-0.37
Gross Firm energy	-0.32	-0.27

76. Manitoba Hydro is projecting rate increases of 7.9% through 2023/24 followed by 4.54% in 2024/25 for a cumulative nominal increase of about 65%. If realized, they will have a

[49] One report, however, summarizes the results of analyses conducted by researchers at the University of Alberta which was conducted on a Provincial basis. They find a short-term residential electricity demand elasticity of -0.57 for Manitoba; for the commercial sector, the elasticity is -0.44; and for the industrial sector, the estimated elasticity is effectively zero, signifying inelastic demand. See D. Ryan and N. Razek, 2012, "The Likely Effect of Carbon Pricing on Energy Consumption in Canada", Sustainable Prosperity Background Paper, available at http://institut.intelliprosperite.ca/sites/default/files/likely-effect-carbon-pricing-energy-consumption-canada.pdf. These estimates need to be interpreted with some caution, as they are obtained using historic Manitoba data. Electricity prices in Manitoba have displayed somewhat less variation than prices across many jurisdictions.

[50] Electric Load Forecast 2016, Manitoba Hydro 2017/18 & 2018/19 General Rate Application Appendix 7.1, page 57.

[51] Electric Load Forecast 2017, Manitoba Hydro, page 57.

significant impact on electricity sales in all residential, commercial and industrial sectors. Indeed, the *anticipation* of a succession of rate increases will likely have an impact on business investment decisions in the near future.

C.3 GDP Elasticities, and Energy and Electricity Intensities.

77. Numerous studies have analyzed the relationship between GDP growth, and growth in demand for energy in general, and electricity in particular. For many decades, these variables moved very closely together. [52]

78. However, in recent years, this relationship has been weakening in advanced economies. In earlier stages of growth, energy demand grows rapidly in part because manufacturing industries are intensive energy users. As their share of GDP increases, energy demand rises rapidly. In the post-industrial phase, the GDP share of service industries increases. As these industries are less energy intensive, demand for energy and electricity slows. These effects are due to the *composition of GDP*.

79. Increases in GDP which lead to increases in per-capita incomes, in turn drive household energy and electricity consumption. As incomes rise, families increase the size of their living space, they purchase more appliances, computers and entertainment systems, they acquire additional vehicles and they are likely to drive more. These are *income effects*.

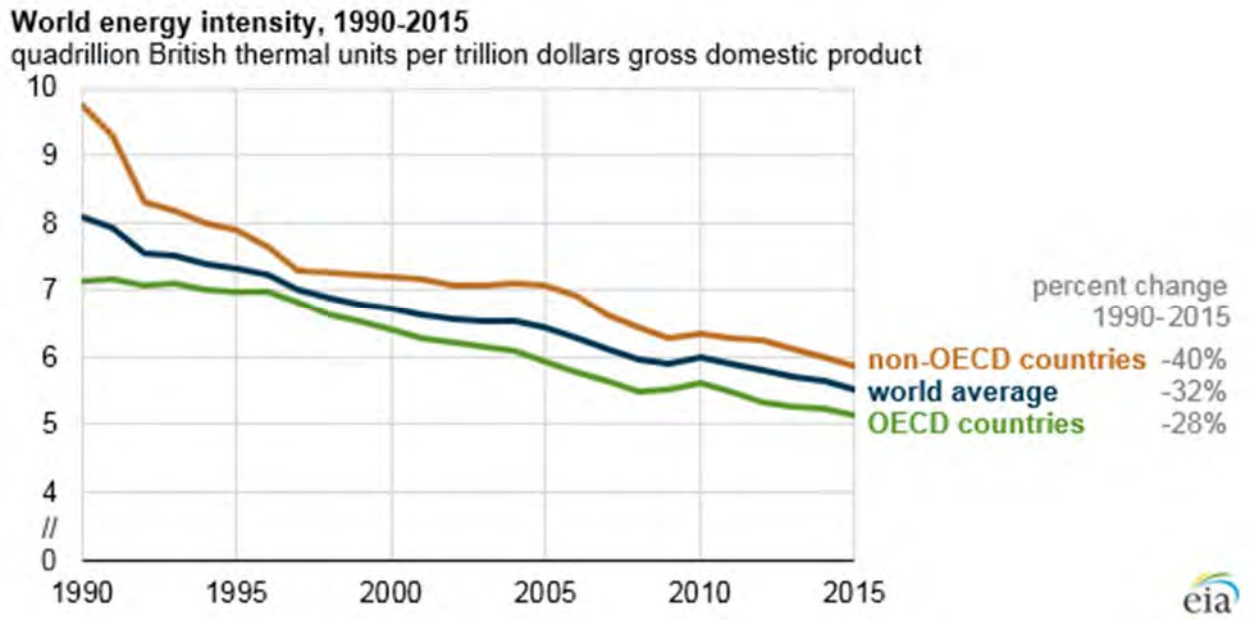
80. The decarbonization agenda also has impacts on energy demand. Energy efficiency programs reduce the energy or electricity required to produce a given level of service. Consider for example lighting where just a few years ago, incandescent light bulbs were the dominant source of light in homes; these used only about 3% of the energy input to produce light, the rest was lost as heat. Compact fluorescent light bulbs are four times as

[52] Standard models and tests assessed whether electricity demand and GDP were co-integrated. Causality testing was conducted to assess whether electricity demand led growth, or whether the reverse was a better representation of reality. The most convincing story is that causality runs both ways. See, e.g., "A survey of the electricity consumption-growth literature", J. Payne, 2010, *Applied Energy*, 87(3), 723-731.

efficient and LED efficiencies are six times higher and increasing.[53] Building envelopes are becoming progressively more efficient at conserving energy, and retro-fitting is common.

81. The net effect of these various forces is that energy intensity -- that is the quantity of energy used in producing say a dollar of GDP -- has been declining at over 1% per year for the last two decades in advanced economies.[54] See Figure 6 below. Over that same time period, energy intensity in Canada declined at a rate in excess of 1% per year, while per capita energy use remained flat.

Figure 6 – World Energy Intensity Trends[55]



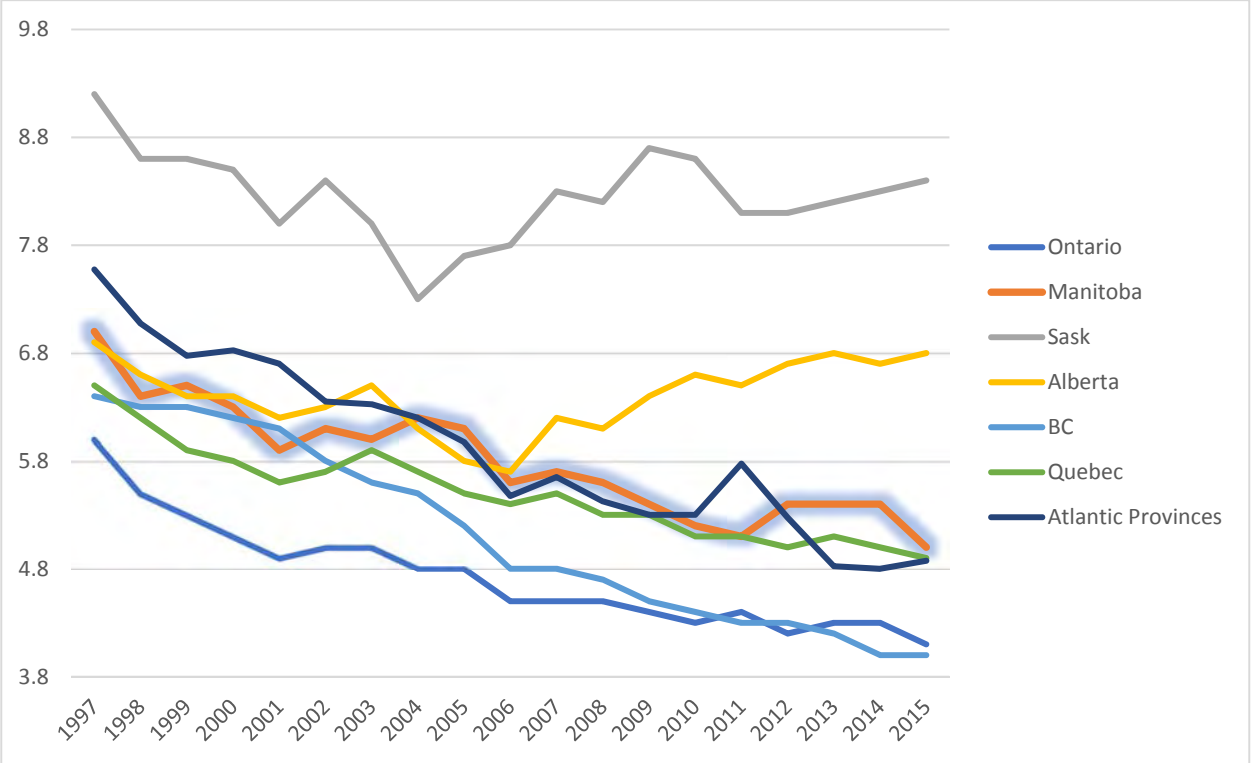
[53] For example, a standard Philips LED bulb, which replaces a 60W incandescent bulb required 9.5W.

[54] For OECD countries, energy intensity, declined 32% between 1990 and 2015.

[55] Source: EIA, International Energy Outlook 2016, International Energy Statistics, and Oxford Economics
Note: OECD is the Organization for Economic Cooperation and Development. GDP calculated in purchasing power parity terms. Available at https://www.eia.gov/todayinenergy/detail.php?id=27032.

82. However, the decline has not been uniform across provinces. Over the period 1997-2015 Manitoba energy intensity declined by close to 2% per year, a number very similar to Ontario. Alberta energy intensity first declined, then increased in large part because of the oil sands, so that overall its energy intensity in 2015 was at approximately the same level as in 1997. British Columbia had the most rapid decline over this period of about 2.6% per year.[56]

Figure 7 – Provincial Energy Intensity Trends



83. Energy intensity varies considerably by sector. As noted earlier, the service sector has relatively low energy intensity. The manufacturing sector can have an energy intensity five to ten times higher than the service sector, depending on the specific type of goods being produced.

[56] There have been few careful empirical analyses of the drivers underlying energy intensity trends at sub-national levels in Canada. For a recent detailed study, see Moshiri, A. and Duah N. (2016), Changes in Energy Intensity in Canada, *The Energy Journal*, 37 (4), 315-342, and references therein.

84. In Manitoba, the service sector has exhibited a steady decline in energy intensity over the period 1997 to 2015. The agricultural sector has exhibited a downward trend, though the pattern has been irregular. The mining sector has experienced an increase in intensity in recent years. And the manufacturing sector intensity increased from 1997 to 2005, but has been steadily decreasing since that time.[57]

85. Turning now to electricity (as opposed to energy) intensity, the patterns in Manitoba have been mixed.

    a. In the service sector, which is by far the largest, intensity dropped by about 25% between 2005 and 2012, but by 2015 it had recovered to 2005 levels.
    b. Intensity in the manufacturing sector peaked in 2005, but has been displaying a fairly steady decline since that time.
    c. Agricultural sector intensity remained high until 2005, but subsequently dropped by more than 50%.

86. Electricity demand continues to be very closely linked the level of GDP. Given the declining electricity intensity, a GDP elasticity of about 0.8 is a reasonable reference number for present purposes.

[57] In the U.S., energy intensity in manufacturing has also been decreasing in recent years, but this has been largely attributed to a shift to less energy intensive industries within the manufacturing segment. "Intensity of U.S. energy use in manufacturing decreased as output outpaced fuel use", U.S. Energy Information Administration, October 18, 2017, available at https://www.eia.gov/pressroom/releases/press450.php.

D. Manitoba Hydro Electricity Prices

D.1 Rates, Costs and Intergenerational Equity

87. Manitoba electricity prices are low by national standards. Even the projected rate increases will not produce especially high rates compared to other provinces, with the exception of Quebec. It is possible that at low electricity prices, the response to an increase would be attenuated until the price crosses a certain threshold. The elasticities we are proposing should then be seen as an average response, keeping in mind that Manitoba Hydro projects a large cumulative increase in the coming years.

88. Consider the following simplified calculation. Assume an electricity price elasticity of -0.4 and a GDP elasticity of 0.8. Assume further that real electricity prices will increase by 50% over the next decade and that the economy grows at 2% per year, so that the economy is 22% larger ten years hence. Then the price increase will have a long-term effect of reducing electricity demand by about 20% (-.4 x 50%) and GDP growth will increase demand by about 18% (.8 x 22%). These calculations suggest Provincial electricity demand will be stagnant. While there will certainly be fluctuations in the short term, and economic growth may not be steady as a result of business cycles, the longer-term outlook for electricity demand growth is not favourable under the high price scenario.

89. This assessment is not unprecedented. In 2005, Ontario electricity demand exceeded 157 TWh. In subsequent years, prices increased by about 50%. Ontario demand declined to 137 TWh by 2016.[58]

90. Price induced impacts on electricity demand can come through many channels including:

    a. where natural gas is available, switching to natural gas in space heating and process heat applications, particularly as it is expected that natural gas prices are expected to remain low;

[58] Data available at http://www.ieso.ca/en/power-data/demand-overview/historical-demand.

b. improved energy efficiency of building envelopes: inexpensive measures include weather-stripping and caulking; more expensive measures include insulation and installation of efficient windows and doors to reduce heating costs in winter and cooling costs in summer;
c. purchase of energy efficient appliances;
d. accelerated migration from incandescent, to compact fluorescent and higher efficiency LED bulbs;
e. increased use of smart technologies such as programmable thermostats for heating and air conditioning, and motion-sensitive lighting;
f. increased use of low-flow shower-heads to reduce hot water use;
g. proliferation of solar panel installation by residential, commercial and even industrial customers.

91. There are significant risks to the forecast, for example, growth could be slower, or the price response could be stronger. But there are potentially upside risks as well.

a. In time, the current momentum towards decarbonization of transportation sectors will lead to accelerated adoption of electric vehicles. The price of electric vehicles, and particularly the cost of batteries has been declining.[59] This will increase demand for electricity. It is in this sector that electricity will play a "pivotal role".[60] However, the attractiveness of electric cars to Manitobans is unclear for at least two reasons. First, lower population density requires larger batteries to overcome range anxiety. Second, cold harsh winters have an adverse effect on battery output and electric vehicle range.

[59] Electric car batteries have dropped in cost by 80% in the last half dozen years. Tesla claims that its battery costs are around $190 US/kWh. Thus, a battery with say 80 kWh capacity would comprise about $15,000 US of vehicle costs. The Chevy Bolt now lists for $37,495 USD with a range of 380 kilometers, "Chevy Bolt: Meet the First Practical, Mass-Market Electric Vehicle", Dan Neil, *Wall Street Journal*, October 29, 2017.

[60] See "The technology path to deep greenhouse gas emissions cuts by 2050: the pivotal role of electricity", Williams, J.H., De Benedictis, A., Ghanadan, R., Mahone, A., Moore, J., Morrow, W.R., Price, S., Torn, M.S., 2012, *Science* 335, 53-59.

b. Increased emphasis on reducing carbon should stimulate demand for carbon-free electricity, such as hydro. The present U.S. administration however, is retreating on this issue, and instead promoting the use of hydrocarbons, including coal. Thus, increased U.S. demand as a result of decarbonization initiatives is unlikely to materialize in the near future.

c. Average residential rates in the U.S. in July 2017 were 13.12 cents U.S./kWh. For commercial customers they were 11.00 cents U.S. and for industrial they were 7.33 cents U.S. There is considerable variation across states. In neighbouring states and MISO members, electricity prices are much higher than in Manitoba, leaving room for potential growth in exports. [61]

92. As noted earlier, Manitoba Hydro operates under a 'cost-of-service' regulatory regime. (Many other jurisdictions have moved to a mode of incentive regulation in order to improve incentives for cost minimization.) Manitoba Hydro is implementing a "Workforce Reduction Plan" which would eliminate 900 positions (15% of the workforce) over the course of two to three years.

93. One might ask whether the projected rate increases are equitable from an intergenerational standpoint.

a. Expansion of hydroelectric systems, such as that in Manitoba, involves lumpy investments in generation (to exploit scale economies) and transmission (as supply sources are distant from load). They do not enjoy the positive scalability features of solar, wind and natural gas generation.

b. This leads to long-term cyclical pressures on rates. Current customers have benefited from past investments, particularly those that have been largely depreciated, but remain functional. Future customers will need to pay for

[61] U.S. Energy Information Administration, *Electric Power Monthly,* September 26, 2017, available at https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.

current projects. The calculus of intergenerational fairness is therefore, at a minimum, complex, and may not lead to unequivocal answers.

c. Rate-smoothing is a useful tool for promoting inter-generational equity. The projected profile is more in the nature of a step function over six years, followed by a rapid decline to increases close to the rate of inflation. A ramped sequence of increases, perhaps linked to a clear demonstration of efficiencies achieved by Manitoba Hydro, may be a useful framework for promoting internal efficiencies, allowing time to adjust to electricity rates, and distributing costs more equitably over each generation of consumers.

94. The effects of the large projected increases, should they be approved, could in theory, be mitigated.

a. Special industrial rates could be offered to those firms with large electricity cost shares. But this would be viewed as inequitable by other customers. Alternatively, the Government might implement incentives to retain major industrial customers.

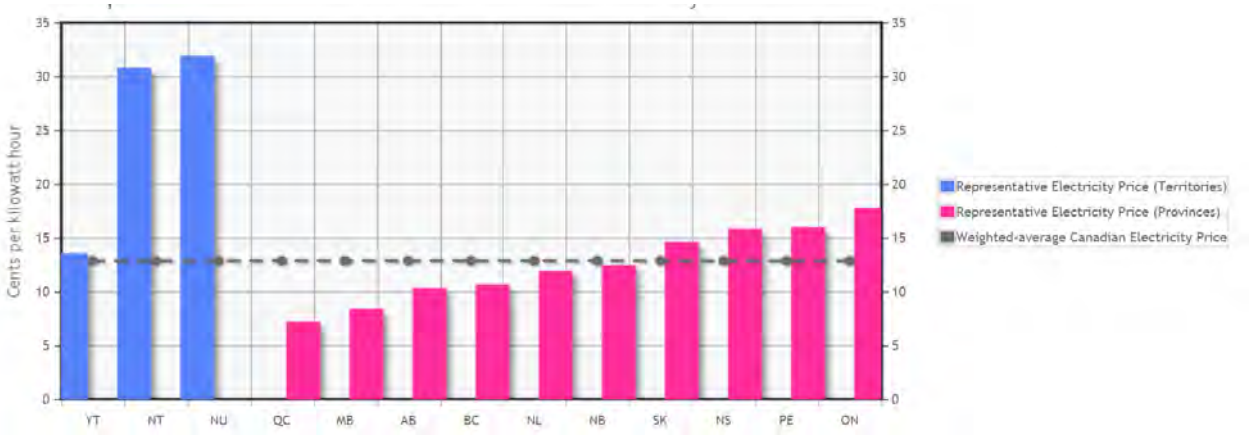
b. There would be a substantial increase in the number of households facing energy poverty, however it is measured. To alleviate this effect will require funds either from other Manitoba Hydro customers, or from Government coffers.

D.2 Bill Affordability and Energy Poverty

95. Electricity prices vary widely across the Canadian Provinces and Territories. Quebec and Manitoba have the lowest prices, mainly due to their hydroelectric resources. British Columbia, which is also overwhelmingly hydraulic has somewhat higher prices. Of the provinces, Ontario has the highest prices, due to a variety of factors including the nuclear program and feed-in-tariffs. But even Ontario prices, at about 18 cents per kWh, are far

below those in the North-West Territories and Nunavut, which are heavily reliant on diesel and oil to generate electricity. (Yukon Territory prices are lower because of hydraulic resources.) See Figure 8.

Figure 8 – Representative Electricity Prices 2016[62]



96. On average, Canadians pay about 3% of income on household energy (excluding transportation fuels). These expenditures are almost entirely on electricity and natural gas, with a relatively small portion of households still relying on heating oil.[63] The National Energy Board defines households to experience energy poverty if they spend 10% or more of income on energy. (Some others set a lower threshold of 6%.)

97. Generally, the share of income spent on essentials such as energy and food (another form of energy) declines with the level of household income.[64]

98. There is an extensive literature on energy poverty, and various critiques have been put forth of simple income thresholds (such as the 10% indicated above). For example, a family may be spending less than 10% of income on energy because it has more urgent

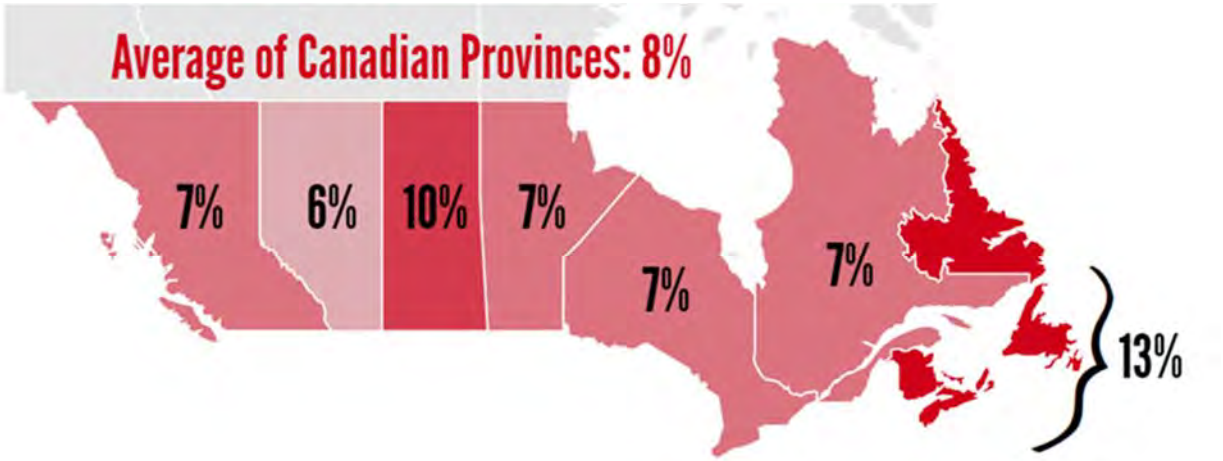
[62] "Explaining the high cost of power in northern Canada", National Energy Board, February 16, 2017, available at https://www.neb-one.gc.ca/nrg/ntgrtd/mrkt/snpsht/2017/02-03hghcstpwr-eng.html.

[63] See Canada Energy Flow Diagram 2014, (residential sector) available at https://www.economics.utoronto.ca/yatchew/ .

[64] Such relationships are called Engel Curves after Ernst Engel a 19th century statistician and economist.

demands on its income, and as a result, household temperatures are too cold. More sophisticated measures attempt to quantify how much a household *should* be spending on energy, and compares this to total income to determine whether the theoretical amount represents too large a fraction. Alternatively, one can subtract the required expenditures from household income and then assess whether the residual income places the family below the poverty line.[65]

Figure 9: Household Fuel Poverty Rates in Canadian Provinces in 2015[66]



99. Nevertheless, a 10% threshold provides a common departure point for the discussion. By this measure, 7% of Manitoba households experience energy poverty, a level comparable to British Columbia, Ontario and Quebec. Saskatchewan and the Atlantic Provinces have much higher levels. See Figure 9.

100. Lower income households face the additional hurdle of inadequate access to moneys to invest in energy efficiency improvements. The empirical evidence put forth by the

[65] This is the methodology used in England, see https://www.gov.uk/government/collections/fuel-poverty-statistics. See also *Fuel Poverty, Methodology Handbook*, Department for Business, Energy and Industrial Strategy, UK Government, June 2017 Edition; and, "Special Section - Fuel Poverty Comes of Age: Commemorating 21 Years of Research and Policy", *Energy Policy*, Volume 49, October 2012.

[66] Source: "Market Snapshot: Fuel poverty across Canada – lower energy efficiency in lower income households", National Energy Board, https://www.neb-one.gc.ca/nrg/ntgrtd/mrkt/snpsht/2017/08-05flpvrt-eng.html.

National Energy Board suggests that higher income households have lower energy intensities, that is, they use less energy per square meter of dwelling size.[67] This may be partly due to implementation of more energy efficient measures.

101. Utilities across Canada are heavily involved in the development, administration and implementation of numerous energy efficiency programs ranging from informational initiatives, financial incentives and rebates, and energy management and monitoring. There are also programs available through various levels of government, municipal, Provincial, Territorial and Federal. Some specifically target low income households. A detailed listing is provided by the National Energy Board.[68]

102. Manitoba Hydro offers a wide range of energy efficiency and alternative energy programs targeting various segments of its customer base – residential, commercial and industrial. There are also programs specifically targeting First Nations and lower income households.[69]

103. The succession of proposed rate increases will have a particularly intense impact on low income households. In the short run, demand for electricity is highly inelastic. For low income households, facing constraints on cash flow and borrowing, expenditures on electricity saving alternatives may not be realistic. Households that heat with electricity, and therefore experience bills that are much higher than those that do not, are particularly vulnerable. Households in remote communities are especially vulnerable as there is little in the way of alternatives to electric heating. One of the likely consequences of rate shock will be greater 'uptake' of the various conservation programs that are available. However, investments that have multi-year payback periods, such as insulation,

[67] *Ibid.* Tables 3.5 and 3.7 provide data on electricity and natural gas intensity for households based on a Statistics Canada survey conducted in 2011.

[68] See "Directory of Energy Efficiency and Alternative Energy Programs in Canada", National Energy Board, available at http://oee.nrcan.gc.ca/corporate/statistics/neud/dpa/policy_e/programs.cfm.

[69] *Ibid.* "First Nations Program" and "Power Smart Affordable Energy Program".

thermal pane windows[70] and natural gas furnaces (where gas is available), may require greater incentives if they are to contribute to mitigating energy poverty.

104. The question arises as to where responsibility should lie for ensuring that high electricity prices do not drive low income households into poverty.

a. A valid case can be made that affordability of essential goods and services resides with governmental authorities. Supports should be designed to ensure sufficient income and to protect low income households from price increases of all essentials, electricity being one of them. Transfers come from the public purse, rather than from other ratepayers. Increases in electricity prices would be reflected in the escalation factors embedded in income supports, *if* these factors are properly calibrated.

b. A counter-argument can be put forth that in complex societies, multiple mechanisms are needed to protect the poor and disadvantaged. A social *safety net* which has multiple intersecting and reinforcing strands, is required to ensure that individuals and families do not 'fall through'.

105. Both arguments have validity. More recent sophisticated arguments based on behavioural economics suggest that individuals can be encouraged to make better decisions (for themselves and for society) if they are 'nudged' in the right direction. This year's Nobel Prize in economics was awarded to Richard Thaler, co-author with Cass Sunstein of the widely acclaimed 2008 book entitled *Nudge: Improving Decisions About Health, Wealth, and Happiness*. (At several points, the book discusses energy efficiency.) Arguably, many energy conservation programs may be seen as 'nudging' individuals, households and firms in a direction which serves both their individual interests as well as the public interest.[71]

[70] Low cost alternatives, such as reducing window heat loss using plastic, are poor substitutes.

[71] The 'nudge' approach may be interpreted as a mechanism which bridges the differences between social models focusing on individual responsibility, and those that argue for a larger role for government and its institutions.

106. Ultimately, which approach prevails, is a matter of public policy. The first approach is *transparent and simple administratively*. It does not reduce the price of electricity to households, and places expenditure decisions at the level of the household. The second targets an essential good that needs to be directly supported.[72]

107. In many markets, prices that diverge from marginal costs lead to economically inefficient consumption levels. This argument has less weight in electricity industries where prices do not reflect marginal costs to begin with, as rates are regulated so as to recover average costs.

108. On the other hand, in remote communities, where electricity is generated by diesel, high unit costs serve the purpose of sending a price signal that more correctly reflects the (marginal) cost of the electricity that is consumed.

109. The Manitoba Public Utilities Board recently directed Manitoba Hydro to lead a collaborative process to study 'bill affordability'. The report contains simulations of impacts on energy poverty under alternative future rate scenarios. Even with rate profiles somewhat lower than currently projected, energy poverty is forecast to increase by 10% over the next decade.[73]

110. That report also reiterates a previous finding contained in the Manitoba Hydro's 2014 Residential Energy Use Survey which "suggests that energy poverty is greater among customers who identify as Indigenous (i.e. of First Nations, Metis or Inuit ancestry), customers with older homes and/or homes that are electrically heated, and households with either a single member or five or more members."[74]

---

[72] Food stamp programs provide another example of support for a particular category of essential goods.

[73] "For example, if a rate increase scenario of approximately 8% for 4 years or 6% for 6 years and a 6% threshold is used, rates of energy poverty are projected to be approximately 24% higher in 2026. When the same rate scenario and a 10% energy poverty threshold is used, a 10% increase is observed. This underscores the degree to which potential rate increases could increase energy poverty in Manitoba." *Manitoba Hydro Bill Affordability Collaborative Process. Summary Report & Recommendations, January 2017*, page 26, available at http://billaffordabilitymb.ca/.

[74] *Ibid.* page 16.

111. The impact of large increases in electricity prices is likely to be especially acute in remote and First Nations communities, where the possibilities for energy substitution are limited and electricity is generated using diesel.[75] In addition, low incomes will hamper substitution of capital goods, such as improved insulation, and efficient windows and doors. While representative establishment level data do not appear to be available, commercial and industrial enterprises in these communities will also be adversely affected, particularly in the absence of energy substitutes such as natural gas.

[75] The 2017 Federal Budget allocates funds, beginning in 2018-2019 for the implementation of "renewable energy projects in off-grid Indigenous and northern communities that rely on diesel and other fossil fuels to generate heat and power", see https://www.aadnc-aandc.gc.ca/eng/1481305379258/1481305405115.

E. Macroeconomic Impacts of Electricity Price Increases

E.1 Energy Price Shocks

112. In order to provide a broader perspective, it is useful to reflect upon the impacts of changes -- even sudden and unexpected changes -- in key energy variables on economic activity.

113. A great deal of attention has been devoted to the impacts of oil prices on the macroeconomy. Many economists attribute several of the past recessions to oil price shocks, particularly those resulting from OPEC increases in 1973, and the subsequent increases in 1979 at the time of the Iranian Revolution. Between 1973 and 1974, oil prices *tripled*, from $17.77 to $56.39 USD (2016 dollars) per barrel; between 1978 and 1979, they *doubled*, from $51.51 to $104.50 USD (2016 dollars), see Figure 10 below. Both of these occurred at a time when western economies were in a state of stagflation (high inflation *and* high unemployment), and both were unanticipated.

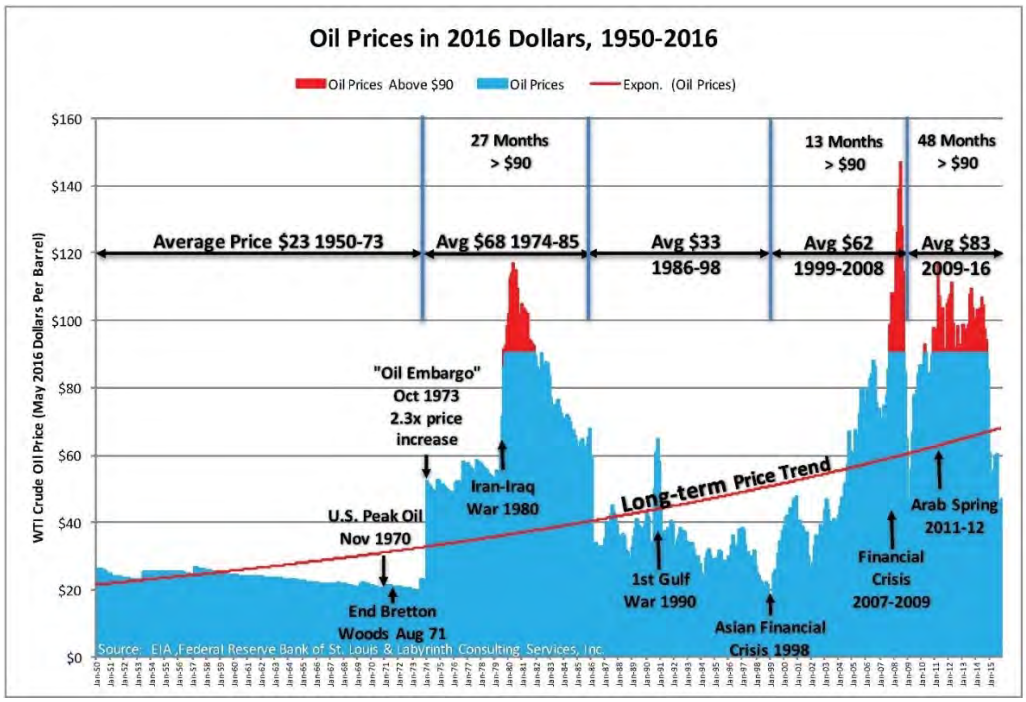
114. As may be seen from Figure 11, the two oil price shocks in the 1970s led to dramatic drops in GDP growth: from 5.6% in 1973 to -0.5% in 1974; and from 3.2% in 1979 to -0.2% in 1980. Kilian and Vigfusson estimate that US GDP is lower by 3% as a result of the doubling of oil prices in the late 1970s. [76]

115. Consider now oil prices in more recent years. Figure 10 reveals that oil prices increased from about $30 in 1998 to over $120 USD/barrel in 2008, a factor of four, which is much larger than the magnitude of the oil price shocks of the 1970s. During this period, U.S. real GDP growth averaged 3%, and the Great Recession which began in late 2008 was triggered by a financial crisis, not by the inexorable rise in oil prices. (In fact, many

[76] …"oil price shocks explain a 3% cumulative reduction in U.S. real GDP in the late 1970s and early 1980s and a 5% cumulative reduction during the financial crisis." See "The Role of Oil Price Shocks in Causing U.S. Recessions", by Lutz Kilian and Robert J. Vigfusson, The Federal Reserve Board, 2014 available at https://www.federalreserve.gov/pubs/ifdp/2014/1114/default.htm.

attribute the rise in oil prices to macroeconomic growth, particularly in China and the concomitant growth elsewhere.)

Figure 10: Oil Prices[77]



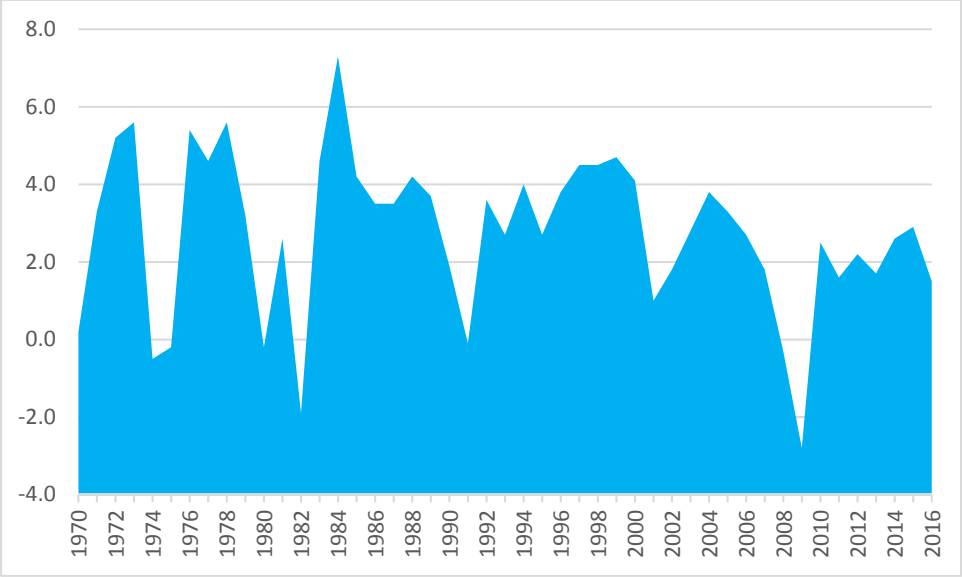
116. A key lesson from these contrasting macroeconomic responses to energy price increases is the critical difference between 'supply-push' and 'demand-pull' forces. The increases during the 1970s were supply shocks, resulting from decisions by major oil producing countries (OPEC). The increases in the 21st century were driven by increasing demand without sufficient opportunity or willingness on the part of suppliers to respond.

117. A second important lesson is that steady energy price increases, that are spread over a number of years, do not necessarily lead to disastrous adverse effects on aggregate economic activity. One of the reasons, of course, is that energy purchasers (consumers and producers) have some opportunity to adjust and to take the price effects into account

[77] Source: "Oil Prices Lower Forever? Hard Times In A Failing Global Economy" Art Berman, Forbes.com, July 25, 2016, http://www.artberman.com/wp-content/uploads/Oil-Prices-in-2016-Dollars-1950-2016-.jpg.

in their planning for the future. In contrast, large unexpected energy price changes can have a significant disruptive effect on the economy.

Figure 11: US GDP (% changes) [78]



118. Some who examine the data may also be surprised that, notwithstanding the *magnitudes* of the oil price increases in the 1970s, the contractions in both 1974 and 1980 were modest, half a per cent or less. In fact, the largest contraction over this period was 3% and it occurred as a result of the 2008 financial crisis.

119. Variations in oil prices have resulted in wide swings in gasoline prices. Between late 2008 and 2014, Manitoba pump prices increased from about 75 cents/liter to 128 cents/liter, an increase of about 70%.[79, 80]

[78] Source: Bureau of Economic Analysis, U.S. Department of Commerce, available at https://www.bea.gov/iTable/iTable.cfm?reqid=19&step=2#reqid=19&step=3&isuri=1&1910=x&0=-99&1921=survey&1903=1&1904=1970&1905=2017&1906=a&1911=0.

[79] Source: Gas Buddy, http://www.manitobagasprices.com/retail_price_chart.aspx.

[80] Natural gas prices have also experienced large changes since the turn of the century, driven in North America by the fracking revolution. The price declines have brought considerable benefits directly, to those households and businesses that have access to natural gas, and to a lesser degree to those that purchase goods for which natural gas is an input in the production process.

120. The implication for the electricity price increases, projected by Manitoba Hydro, is that they are not likely to have a disastrous impact on *aggregate* macroeconomic activity. This is further reinforced by the fact that over 70% of the Manitoba economy provides services, and electricity in this sector comprises a relatively small proportion of total costs.

121. However, that it not to say that certain industries will not be negatively impacted, possibly severely. As we discuss further below, some companies may choose to relocate or to scale back production. Some will consider very carefully whether to make major new capital investments in the Province. Indeed, the specter of increasing rates, in the near or more distant future, may have already discouraged investment. The risk of future price increases, that cumulate to 50% or more, must be part of the decision matrix for any electricity intensive firm in Manitoba.

122. Furthermore, there will be distributional effects that will be particularly felt by those in lower income brackets and those who do not have access to alternative sources of energy, in particular, natural gas.

123. In the past, electricity prices in Manitoba have increased steadily, but relatively smoothly over similar time-frames, largely due to regulatory decisions. The current proposal, for large increases over a sequence of years, is more in the nature of a rate shock.

E.2 Exchange Rates

124. The Manitoba economy is driven to a substantial degree by its exports markets, some of which involve sales to other Provinces and Territories (about 27% of Manitoba GDP), others involve international sales, primarily the United States (also about 27% of GDP).[81] Thus exchange rates have an important impact on the Manitoba economy.

[81] Budget Paper A, Economic Review and Outlook, page A14, Province of Manitoba, April 2017, available at http://www.manitoba.ca/budget2017/index.html.

125. Manitoba has a broad export base which includes grains and oilseed products (20.2%); transport equipment (12.7%); livestock and processed meats (10.7%); machinery and electrical equipment (9.5%); and chemical products (8.9%).[82]

126. The linkage between Canada's exchange rate and oil prices is illustrated in Figure 12 below; indeed the two series appear to be tethered to each other.[83]

Figure 12: Oil Prices[84] (blue) vs CAD/US Exchange Rate (orange)



127. In the early part of the 21st century, the exchange rate hovered around 80 US cents. As oil prices increased, the value of the Canadian dollar rose, achieving parity in 2007. The financial crisis of 2008 led to the 'Great Recession' through 2009, during which oil prices plummeted and the dollar returned to about the 80 cent level. As economies stabilized and recovered, oil prices rose once again. The Canadian dollar hovered around parity from

[82] *Ibid.* page A15.

[83] There is likely a co-integrated relationship between these series, as well as causality running from oil prices to the Canadian dollar value.

[84] West Texas Intermediate (WTI).

2010 to 2013. Then in 2014, oil prices collapsed and the Canadian dollar, which began its decline earlier, followed it down, at one point trading well below 70 cents US.

128. While oil prices have risen far above their lows of late 2015 when oil was trading below $30 USD/barrel, it is unlikely that they will return to $100 USD/barrel any time soon, if ever. As suggested earlier, the issue now is when worldwide demand (rather than supply) will reach its peak.

129. A stronger Canadian dollar has an adverse impact on the competitiveness of Canadian products on international markets. During the period of high oil prices, Western Canada benefited, while manufacturing industries in Ontario, and in other provinces, suffered the so-called 'Dutch Disease'.[85]

130. Presently, the dollar is near the 80 cent mark and Manitoba Hydro is projecting a gradual return to the 87 cent level over the course of the next few years.[86] Clearly much depends on the future price of oil.

131. But other factors may also have an important influence on the exchange rate. The NAFTA renegotiations are presently in limbo, and an adverse outcome for Canada will likely have a negative effect on Canadian and Manitoba exports to the U.S. and on the CAD/USD exchange rate.

132. To summarize, the exchange rate has important impacts on Manitoba and Manitoba Hydro.

a. International exports are affected: as the dollar appreciates, the competitiveness of Manitoba exporting industries (agriculture, manufacturing, chemicals) is adversely affected. Those that are electricity intensive are particularly sensitive to the kinds of electricity price increases that are being proposed.

[85] See, for example, "What Dutch disease is, and why it's bad", The Economist, November 5, 2014, available at https://www.economist.com/blogs/economist-explains/2014/11/economist-explains-2.

[86] Manitoba Hydro, GRA, Appendix 3.2 Revised, Economic Outlook, 2016-2037, Winter 2016, page 13.

b. Manitoba Hydro is also directly affected, in that its export sales to U.S. markets generate lower Canadian dollar revenues.

c. On the other hand, to the extent that some industries import inputs, particularly from the U.S., a stronger Canadian dollar is helpful.

E.3 Commodity Prices

133. Commodity prices are driven by a complexity of forces – depletion and discovery, innovation and obsolescence, competition and strategic behaviour, and of course, supply and demand. Each of these have played an important role in driving oil prices.

134. Metals markets are also driven by similar factors. The principal metals mined in Manitoba are nickel, copper, zinc and gold.[87] The first three exhibit both long term trends and cyclical behaviour. Gold prices are subject primarily to forces in financial markets, and are very much affected by market perceptions of risk and stability in geopolitical conditions.

135. The prices of each of these metals exhibit wide variations:

a. Nickel prices have dropped by a factor of two from $13 US/lb. in 2010 to less than $6 US/lb. in November 2017.

b. Copper prices also dropped by a factor of two between 2010 and 2016 (from $4 US/lb. to $2 US/lb.) but have since recovered to about $3 US/lb.[88]

[87] Budget Paper A, Economic Review and Outlook, page A11, Province of Manitoba, April 2017, available at http://www.manitoba.ca/budget2017/index.html.

[88] The long-term paths of nickel and copper prices exhibit similar patterns. See Dimitropoulos and Yatchew.

c. Zinc prices were at about $2400 US/metric ton in 2009, declined to $1600 in 2015 and have since increased to $3200.

d. Gold prices peaked at $1800 US/ounce in 2011, but have since dropped to about $1300 US/ounce in 2017.

The purpose of these examples is to illustrate the degree of price variation that mining companies experience in metals markets. By comparison, electricity prices have historically been a source of stability for Manitoba metal extractors.[89]

136. Agricultural products also exhibit large price variations and are affected by growth conditions (such as droughts) in various parts of the world. Wheat prices, which reached a post-recession high of $9 US/bushel in 2012, have since declined to $4 - $5 US/bushel in 2017.

E.4 Electricity Intensity Varies Widely Across Some Sectors of the Manitoba Economy

137. It is helpful to put into perspective the share of electricity costs in various segments of the Manitoba economy. The most electricity intensive sectors are manufacturing and agriculture with electricity comprising 1.23% and 1.21% of inputs respectively. Mining is not far behind with a share of 1.12% The service sector (aggregated over a broad range of services and comprising 71% of GDP) has an electricity input share of 0.75%.

138. Based on these figures, one might be inclined to conclude that even substantial increases in electricity prices (on the order of 50% over the coming years) would have a minimal impact on decisions made by firms in these sectors. However, this level of aggregation masks those instances where sub-sectors and firms may be particularly vulnerable to electricity price rises. A more refined look by specific sub-sectors is required.

[89] There is a large literature which attempts to model commodity prices in terms of trends and 'super cycles', however such modeling exercises have little predictive value as the length and amplitude of cycles varies over time.

In the following paragraphs we highlight certain electricity intensive sub-sectors. Detailed tables are available in Appendix 4: Manitoba Electricity Cost Shares by Sub-Sector.

Electricity Shares by Major GDP Sector[90]		
	GDP Shares	Electricity as Share of Inputs
Services	71.2	0.75%
Manufacturing	10.1	1.23%
Construction	8.9	0.05%
Agriculture	4.0	1.21%
Utilities	3.4	0.01%
Mining	2.4	1.12%

139. In the manufacturing sector, the most vulnerable industry would appear to be 'basic chemicals' which has an 18% share for electricity costs. This is followed by pulp and paper which has an electricity share of 7%. Iron and steel mills, foundries and non-ferrous metal production have shares of about 3%. Fertilizer and pesticide has a 2% share. Motor vehicle, engine and electric lighting equipment manufacturing have shares of about 2%.

140. In the agricultural sector, greenhouses, nurseries and floriculture establishments have a 3% electricity share of total inputs. Animal production has a 2% share.

141. In the mining sector, support activities for oil and gas extraction have a 6% share. Copper, nickel, zinc and gold extraction have electricity cost shares of 2%-3%.

142. These sub-sectors of the manufacturing, agricultural and mining industries face competitive pressures in export markets. Their locational decisions are determined by various factors, including proximity to certain resources and inputs, and past capital investments. Manitoba may continue to be a preferred location for operations. However, future production and investment decisions by existing entities, and the attractiveness of

[90] The electricity input shares are based on 2013 data, the most recently posted data in CANSIM Tables 381-0033.

Manitoba to potential new enterprises, will be affected if electricity prices are expected to increase substantially in coming years.[91]

F. Concluding Observations

143. The regulatory decisions made in this proceeding, which deals with rate increases over a two-year test period, will have an important impact on decision making by industry because they will signal the likely future path of rate increases. Approval of increases that are close to the proposed 7.9% will suggest the acceptance of Manitoba Hydro arguments and its focus on the time profile of future financial ratios.

144. Large increases will induce a price response. Our review of the extensive modeling literature suggests an overall price elasticity of -0.4. In a period of excess capacity, such increases may be sub-optimal as they will erode revenues at a time when marginal costs of production are low.

145. From the standpoint of carbon emissions, Manitoba's energy sector is very well placed: 37% of all energy (including the transportation sector) comes from hydraulic sources, and 1% comes from wind generation (recall the Sankey diagram in Figure 3). Natural gas provides 26% of total energy, coal a miniscule 0.3%, and the remaining 35% consists of transportation fuels.[92] Other jurisdictions are focusing on decarbonizing the electricity sector, but Manitoba has already accomplished this.

[91] There are also portions of the service sector that have high electricity cost shares. Social assistance and educational services have electricity shares in the 4% to 6% range. Dry cleaning and laundry services have an electricity share of 5%. Crude oil and other pipeline transportation have an electricity share of 2%. While these services will continue to be provided, large electricity cost increases will impact their bottom line.

[92] In total, about 60% of Manitoba energy is from hydrocarbons. Compare this to Canada-wide numbers where about 80% of domestic energy comes from hydrocarbons, see https://www.economics.utoronto.ca/yatchew/ . U.S. dependence on hydrocarbons is of a similar magnitude, see Lawrence Livermore National Labs Sankey diagrams at https://flowcharts.llnl.gov/content/assets/images/charts/Energy/Energy_2016_United-States.png.

146. Three decarbonization strategies suggest themselves.[93] The first involves reductions in energy intensity. While the energy intensity trends we have reviewed suggest that 2% annual reductions have been achievable in the past, this would just compensate for annual GDP growth rates of 2%. The second involves moving away from natural gas, which would be unappealing to residential, commercial and industrial consumers, especially when gas prices are expected to continue to remain low and electricity prices are increasing. The third involves decarbonization of transportation, which is by far the most difficult sector to decarbonize.

147. Increasing energy prices, whether in the electricity sector (for fiscal reasons) or in the natural gas sector (via a carbon tax), may be counter-productive for other reasons: if Manitoba's energy intensive industries decamp to other jurisdictions, the net effect on global emissions is likely to be negative. (To put it simply, how many industry-friendly jurisdictions are there with an energy mix as clean as that of Manitoba?) Reductions in carbon emissions may make Manitobans feel that they are doing 'their share' with respect to global warming, but it may not be rational unless the 'carbon leakage' problem is solved.[94]

148. The projected rate increases are likely to have a modest *net* effect on aggregate Manitoba output in the long-run, though there could very well be job losses and reduced output in the short-run. The immediate main effects will be distributional, impacting low income households and remote and First Nations communities more strongly. Such increases may also lead to structural changes in industry with the largest impacts on electricity intensive enterprises. Neither of these consequences constitute a basis for keeping rates inappropriately low for *all* purchasers, as there are superior mechanisms for handling distributional impacts in residential, commercial and industrial sectors.

[93] The recently released Manitoba Government discussion paper outlines strategies for decarbonization, including of the energy sector. See "A Made-in-Manitoba Climate and Green Plan Hearing from Manitobans" available at https://www.gov.mb.ca/asset_library/en/climatechange/climategreenplandiscussionpaper.pdf, released on October 27, 2017.

[94] See, e.g., Yatchew, A. 2016, "Rational vs. 'Feel-Good' Carbon Policy – Transferability, Subsidiarity and Separation" Energy Regulation Quarterly, 4:3, 31-40, available at http://www.energyregulationquarterly.ca/articles/rational-vs-feel-good-carbon-policy-transferability-subsidiarity-and-separation#sthash.KdjIk0vV.dpbs.

Appendices

Appendix 1: Scope of Work and Summary Responses

DR. ADONIS YATCHEW

(Summary responses in **bold**, report references in ***bold italics***)

For Microeconomic Issues:

1. Review, assess and comment on the reasonableness of the price elasticity information incorporated in Appendix 7.1 of Manitoba Hydro's General Rate Application.

The elasticities proposed by Manitoba Hydro are not unreasonable, given the degree of uncertainty associated with estimation of demand parameters. However, based on the extant literature, more negative price elasticities and a substantially larger income/GDP elasticity are recommended. See sections *"C.2 Price Elasticities"* and *"C.3 GDP Elasticities, and Energy and Electricity Intensities"*.

2. Provide a review of the relevant literature on the price elasticity of demand for electricity, drawing from the North American experience in particular. This should distinguish between how different customer classes ("Residential," Commercial" and "Industrial") and how different sectors of the economy (including industry, small business, agriculture, manufacturing, and any other relevant sectors) respond to price changes in light of their different substitution possibilities and geographical mobility. This literature review should include consideration of any impacts on First Nations consumers, including residential and commercial and/or industrial First Nations ratepayers.

The literature on demand modeling is voluminous and there are a variety of approaches, usually determined by the type of available data. These include time-series, cross-section, panel data, and meta-analyses. See section *"C.1 Energy Demand Modeling"*. The studies produce a very broad range of price elasticity estimates. Based on a review of the literature, the following elasticities are recommended:

   a. **a short-term price elasticity of -0.1 across all sectors; that is, an electricity price increase of 10% leads to a 1% decline in electricity demand in the short-term;**

b. a long-term overall price elasticity of -0.4; that is, an electricity price increase of 10% leads to a 4% decline in electricity demand in the long-term;

c. long-term price elasticities of -0.35 for the residential and commercial sectors, and -0.5 for the industrial sector;

d. a GDP elasticity of 0.8; that is, an increase in GDP of 10% eventually leads to an increase in electricity consumption of 8%.

The literature on estimation of sub-sectoral elasticities (such as manufacturing, agriculture) is limited. Some results are available on energy and electricity intensity trends at disaggregate levels. See sections *"C.2 Price Elasticities"* and *"C.3 GDP Elasticities, and Energy and Electricity Intensities"*.

Substitution possibilities are mainly in the form of natural gas, where it is available; capital investments, such as insulation, efficient windows and doors, LED lighting, and energy efficient appliances and equipment. Solar self-generation is progressively becoming a partial substitution option. Locational decisions for energy intensive industries are affected by energy prices. See sections *"B.2 The Manitoba Energy Sector", "B.3 Oil and Natural Gas Markets", "B.4 Costs of Key Technologies Have Been Dropping Rapidly", "C.2 Price Elasticities"* and *"C.3 GDP Elasticities, and Energy and Electricity Intensities"*.

Unavailability of natural gas limits substitution options for remote and First Nations communities in all sectors (residential, commercial and industrial). Low incomes also hamper capital substitutions that require large investments. See section *"D.2 Bill Affordability and Energy Poverty"*.

3. Review

- Tab 9 and Appendix 9.13 (Survey of Canadian Electricity Bills) in Manitoba Hydro's General Rate Application; Manitoba Public Utilities Board's Needs For and Alternatives To Report with respect to ratepayer impacts;

- Available information regarding consumption patterns of Manitoba industries, including PUB/MH 1-54 and PUB 11-58 from Manitoba Hydro's 2015/16 General Rate Application.

Provide analysis and comment on what, if any, inferences can be drawn from the general literature on the price elasticity of demand for electricity to the Manitoba context, specifically given:

a) The history of the levels of electricity prices in Manitoba; and

b) substitution possibilities due to technological improvements in renewable energy sources.

Manitoba has a history of low electricity prices, which has shaped the patterns of energy consumption: very high reliance on electricity, compared for example to Canada-wide averages. Substitution to natural gas, where it is available, is likely to occur if projected electricity prices are realized. The costs of renewable technologies, such as solar and wind energy, have been dropping dramatically, and may gain penetration, particularly in areas where gas is unavailable.

The response to price increases may be nonlinear, with limited initial changes in patterns of consumption, but the response is likely to strengthen if rates reach substantially higher levels. (Since 2009, electricity rates in Ontario have increased by more than 50% and demand has been stagnant.) See sections *"B.2 The Manitoba Energy Sector", "B.4 Costs of Key Technologies Have Been Dropping Rapidly"* and *"D.1 Rates, Costs and Intergenerational Equity"*.

4. In light of Manitoba Hydro's request for an annual increase in average electricity rates of 7.9%, including for the fiscal years of 2017/18 and 2018/19, as well as the proposed rate trajectory over the next 10 years, provide comment on how various domestic customer classes might be expected to respond to an increase of the proposed levels.

See responses to 2. and 3. above, and 9. below.

5. Review, assess and provide an explanation of any implications for the economy of the Province of Manitoba arising from the impact of the proposed or alternative rate increases, including rate increases proposed for the years beyond the test years.

See responses to 8. and 9. Below.

6. Provide comment on issues of rate shock, pacing of rate increases and the intergenerational impacts of rate increases in the Manitoba context, including with reference to the rate increases sought by Manitoba Hydro in its General Rate Application.

Expansion of hydroelectric systems, such as that in Manitoba, involves lumpy investments in generation (to exploit scale economies) and transmission (as supply sources are distant from load). They do not enjoy the scalability advantages of solar, wind and natural gas generation.

This leads to long-term cyclical pressures on rates. Current customers have benefited from past investments, particularly those that have been largely depreciated, but remain functional. Future customers will need to pay for current projects. The calculus of intergenerational fairness is therefore, at a minimum, complex, and may not lead to unequivocal answers.

Rate-smoothing is a useful tool for promoting inter-generational equity. Rates projected by Manitoba Hydro are more in the nature of a step function lasting six years, followed by a rapid decline to increases close to the rate of inflation. A ramped sequence of increases, perhaps linked to a clear demonstration of efficiencies achieved by Manitoba Hydro, may be a useful framework for promoting internal efficiencies, allowing time to adjust to electricity rates, and distributing costs more equitably over each generation of consumers.

See section *"D.1 Rates, Costs and Intergenerational Equity"*.

7. Review and assess Manitoba Hydro's General Rate Application Appendices 10.4, 10.5, 10.6 and 10.7 (B ill Affordability). Provide comment on the issue of "Energy Poverty", including as the issue applies to Indigenous and Northern communities, and an analysis of the experience in other Canadian jurisdictions as to measuring the extent of this problem and potential remedies that have been suggested. What lessons can be learned from other Canadian provinces as to measuring the extent of this problem and potential remedies that have been suggested.

Manitoba has a relatively low rate of energy poverty in comparison to other provinces: about 7% of households spend 10% or more of their income on energy. However, the incidence of energy poverty varies significantly across the Province and is particularly high in remote communities where prices of many goods, among them energy, are high. The projected growth in electricity prices will increase rates of energy poverty.

The impact on energy poverty, which is already high in remote First Nations communities, is likely to be especially acute given the limited possibilities for energy substitution. In addition, low incomes will hamper substitution of capital goods, such as improved insulation, and efficient windows and doors. Commercial and industrial establishments in such communities will also be adversely affected, particularly given the absence of energy substitutes such as natural gas.

Review of energy program initiatives across Canada indicates that Manitoba has been pro-active in seeking to understand the structure and causes of energy poverty, and in developing remedies.

See section "D.2 Bill Affordability and Energy Poverty".

For Macroeconomics Aspects:

8. Given your findings with respect to demand responses by various customer classes and sectors of the economy to electricity price increases, review, assess and provide analysis on the potential or probable implications for the Manitoba economy as a whole.

Market economies have experienced major energy price increases. The dramatic oil price shocks of the 1970s which were largely unanticipated, led to economic contractions of half a per cent or less. The cumulative impact on U.S. GDP of the oil price shock in the late 1970s is estimated to be about 3%. These past experiences are helpful in bounding the likely effects of significant electricity price increases in Manitoba. See section *"E.1 Energy Price Shocks".*

The projected electricity rate increases are not of the same magnitude as the oil price shocks of the 1970s. However, given that in the short-term, demand for electricity is highly price-inelastic, the steepness of the projected rate increases will impose a significant burden, particularly on households, businesses and institutions that do not have access to natural gas. In some locations, especially those which are heavily dependent on an industry that is sensitive to electricity prices, there could be large local impacts on employment, incomes and output. See sections *"C.2 Price Elasticities", "C.3 GDP Elasticities, and Energy and Electricity Intensities", "D.2 Bill Affordability and Energy Poverty"* and *"E.1 Energy Price Shocks".*

The Manitoba economy is significantly affected by wide and difficult-to-predict fluctuations in other key variables, such as exchange rates and commodity prices. Notwithstanding wide variations in these variables, the Manitoba economy has continued to thrive. See sections *"E.2 Exchange Rates"* and *"E.3 Commodity Prices"*

The net effect on GDP may eventually be modest, keeping in mind that the electricity cost shares for major sectors of the economy (e.g., the service sector which comprises 71% of GDP) are low. However, in the interim, there are likely to be significant adjustment costs. See sections *"B.1 Economic Setting" and "D.4 Electricity Intensity Varies Widely Across Some Sectors of the Manitoba Economy".*

9. In the context of the proposed Manitoba Hydro rate increases, with the benefit of the latest Statistics Canada input-output tables for Manitoba (and/or other relevant sources), identify

and provide comment on the "electricity intensive" sectors of the Manitoba economy, including the following:

a. Whether the province would be at risk of losing major electricity-consuming firms to other North American jurisdictions;
b. In light of the heavily export-oriented nature of key sectors of the Manitoba economy, what the implications would be for producers.
c. Place these issues in some quantitative perspective, both in terms of the aggregate provincial GDP and income distribution effects by key sectors and customer classes.

Certain industries will be significantly affected if the projected rate increases are realized. In the manufacturing sector, the most vulnerable industries appear to be 'basic chemicals' and 'pulp and paper' where electricity comprises high shares of costs. Iron and steel mills, foundries, non-ferrous metal production, fertilizer and pesticide, and various equipment manufacturing industries also have significant electricity cost shares.

In the agricultural sector, 'greenhouses' and 'animal production' have significant electricity cost shares. In the mining sector, 'support activities for oil and gas production' and extraction of metals also have significant electricity cost shares.

While the consequences of high electricity rates in some of these industries will be quite significant, they need to be understood from the perspective of overall price variation and uncertainty associated with other key variables which affect them, such as exchange rates and commodity prices.

See sections *"B.1 Economic Setting", "E.1 Energy Price Shocks", "E.2 Exchange Rates", "E.3 Commodity Prices", "E.4 Electricity Intensity Varies Widely Across Some Sectors of the Manitoba Economy"* and *"Appendix 5: Manitoba Electricity Cost Shares by Sub-Sector".*

10. Provide a report on the Microeconomic Aspects and Macroeconomic Aspects to be placed on the public record that provides your findings and supporting information.

Appendix 2: Curriculum Vitae – Adonis Yatchew

Professor of Economics, University of Toronto
Editor-in-Chief, The Energy Journal
Senior Consultant, Charles River Associates

Department of Economics, University of Toronto

150 St. George Street, Toronto, Canada M5S 3G7

(416) 978-7128

adonis.yatchew@utoronto.ca
http://www.economics.utoronto.ca/yatchew/

Ph.D. Economics 1980
Harvard University

M.A. Economics 1975
University of Toronto

B.A. Mathematics and
Economics 1974
University of Toronto

Adonis Yatchew's research focuses on econometrics, energy and regulatory economics. Since completing his Ph.D. at Harvard University, he has taught at the University of Toronto. He has also held visiting appointments at Trinity College, Cambridge University and the University of Chicago, among others. He has written a graduate level text on semiparametric regression techniques published by Cambridge University Press. He has served in various editorial capacities at The Energy Journal since 1995 and is currently the Editor-in-Chief. He has advised public and private sector companies on energy, regulatory and other matters for over 25 years and has provided testimony in numerous regulatory and litigation procedures. Adonis Yatchew currently teaches undergraduate and graduate courses in energy economics, graduate courses in econometrics and 'Big Ideas' courses on energy and the environment with colleagues in physics and classics.

ACADEMIC EXPERIENCE

Current Position	Professor of Economics, University of Toronto
2008	Visiting academic, Department of Mathematics and Statistics, University of Melbourne
2008	Visiting academic, School of Economics and Finance, Queensland University of Technology
2008	Visitor, National Center for Econometric Research, Queensland University of Technology
2005	Visiting Fellow, ARC Center of Excellence for Mathematics and Statistics of Complex Systems, Mathematical Sciences Institute, Australian National University
2001	Visiting Fellow, School of Mathematical Sciences, Australian National University

1986 to 2004	Associate Professor, Economics, University of Toronto
1989, 1990, 1991	Visiting Research Associate, Harvard University
1986	Visiting Fellow Commoner, Trinity College, Cambridge U.K.
1980 to 1986	Assistant Professor, Economics, University of Toronto
1984	Visiting Research Associate, National Bureau of Economic Research, Cambridge, Massachusetts
1982 to 1984	Visiting Assistant Professor, University of Chicago
1976	Lecturer, University of Toronto, Scarborough College

EDITORIAL AND PROFESSIONAL ACTIVITIES

Current

Editor-in-Chief, The Energy Journal (2006-present)
Member, Board of Editors, Economics of Energy and Environmental Policy
Member, Editorial Board, Foundations and Trends in Econometrics
Member, Council, International Association for Energy Economics
Member, National Center for Econometric Research, Econometrics of Energy and the Environment, Australia

Past

Editor, The Energy Journal, (2006)
Joint Editor, The Energy Journal (1995-2005)
Associate Chair for Graduate Studies, University of Toronto, 2006-2009
Joint Editor 1997, Distributed Generation, special issue of the Energy Journal
Advisory Editor, Economics Letters (1985-1997)
Member, Advisory Board, *Eurasia Foundation*, 1995-2007

AWARDS AND DISTINCTIONS

USAEE Senior Fellow Award, June 2014

SELECTED PRESENTATIONS

May 2016, Montebello Quebec: presentation entitled “Rational Carbon Policy and Regulation”, Canadian Energy Law Forum.

March 2016, Paris: Keynote Address “Subsidiarity and Separation”, 4th International Symposium on Energy and Finance Issues.

November 2015, Panelist, “Outlook on Oil”, University of Toronto Energy Network, University of Toronto.

June 2015, Milan: “Discerning Trends in Commodity Prices”, Invited presentation, Fondazione Eni Enrico Mattei, International Workshop on Recent Evolutions of Oil and Commodity prices.
April 2015, Bank of Canada, Workshop on Commodity Super-Cycles, “Discerning Trends in Commodity Prices.

September 2014, Beijing: Keynote address entitled “The Economics of Energy, Big Ideas for the Non-Economist”, Chinese Academy of Sciences, International Association for Energy Economics 4th IAEE Asian Conference.

June 2014, Hong Kong: Invited presentation entitled “Renewable Energy”, Hong Kong’s Electricity Future: Balancing Reliability, Environment and Cost, Hong Kong Baptist University.

July 2012, Hong Kong: Invited Speaker on “Climate Change and Electricity Generation”, Hong Kong Baptist University.

December 2010, Hong Kong: Invited paper on renewable energy, Fourth Asian Energy Conference.

October 2010, Berlin: Invited paper on quantile regression, Workshop on Quantile Regression Methods, Humboldt University.

October 2008, Gold Coast, Queensland: Keynote speaker, Australian Conference of Economists. Title of presentation: “Economics, Econometrics and Regulation”.

August 2007, Lisbon: Keynote speaker, Cemapre Conference on Advances in Semiparametric Methods and Applications. Title of presentation: “Data on Derivatives, Nonparametric Regression and the Curse of Dimensionality”.

BOOKS, EDITED VOLUMES

Yatchew, A., 2003, Semiparametric Regression for the Applied Econometrician, 213 pages, Themes in Modern Econometrics, Cambridge University Press.

Chinese Energy Economics, Special Issue of The Energy Journal, Edited by Ying Fan and Adonis Yatchew, 2016.

REFEREED PUBLICATIONS

Dimitropoulos, D. and A. Yatchew 2017, "Discerning Trends in Commodity Prices", Macroeconomic Dynamics, 1-19, doi:10.1017/S1365100516000511.

Y.S. Cheng, K.H. Cao, C.K. Woo and A. Yatchew 2017, "Residential willingness to pay for deep decarbonization of electricity supply: Contingent valuation evidence from Hong Kong", Energy Policy 109, 218–227.

Dimitropoulos, D. and A. Yatchew 2017, "Is Productivity Growth in Electricity Distribution Negative? An Empirical Analysis Using Ontario Data", The Energy Journal, 38:2,175-200.

Rivard, B. and A. Yatchew 2016, "Integration of Renewables into the Ontario Electricity System", The Energy Journal, vol 37, Special Issue 2, 221-242.

Yatchew, A. 2016, "Rational vs. 'Feel-Good' Carbon Policy – Transferability, Subsidiarity and Separation" Energy Regulation Quarterly, 4:3, 31-40, http://www.energyregulationquarterly.ca/articles/rational-vs-feel-good-carbon-policy-transferability-subsidiarity-and-separation#sthash.u6jtvAJI.dpbs.

John Colton, Kenneth Corscadden, Stewart Fast, Monica Gattinger, Joel Gehman, Martha Hall Findlay, Dylan Morgan, Judith Sayers, Jennifer Winter, Adonis Yatchew 2016, Energy Projects, Public Acceptance and Regulatory Systems in Canada: A White Paper

Yatchew, A. 2014: "Energy, Markets and Their Failures", Bulletin of the Chinese Academy of Sciences, vol. 28, no. 4, pp. 304-305, http://english.cas.cn/bcas/2014_4/201411/P020141121529033572162.pdf.

Yatchew, A. 2014: "Economics of Energy: Big Ideas for the Non-Economist", Energy Research and Social Science, 1(1), 74-82, http://dx.doi.org/10.1016/j.erss.2014.03.004 .

Green, R. and A. Yatchew 2012:"Support Schemes for Renewable Energy: An Economic Analysis", Economics of Energy & Environmental Policy, 1, 83-98.

Yatchew, A. and A. Baziliauskas 2011: "Ontario Feed-In Tariff Programs", Energy Policy, 39, 3885-3893.

Hall, Peter and A. Yatchew 2010: "Nonparametric Least Squares in Derivative Families", Journal of Econometrics, 157, 362-374.

Yatchew, A. 2008: "Perspectives on Nonparametric and Semiparametric Modeling", The Energy Journal, Special Issue to Acknowledge the Contribution of G. Campbell Watkins to Energy Economics, 17-30.

Hall, Peter and A. Yatchew 2007: “Nonparametric Estimation When Data on Derivatives are Available”, Annals of Statistics, 35:1, 300-323.

McCaig, B. and A. Yatchew 2007: “International Welfare Comparisons and Nonparametric Testing of Multivariate Stochastic Dominance”, Journal of Applied Econometrics, 22:5, 951-969.

Ricciuto, L., V. Tarasuk and A. Yatchew 2006: “Socio-demographic Influences on Food Purchasing Among Canadian Households”, European Journal of Clinical Nutrition, 60:6, 778-790.

Yatchew, A. and W. Haerdle 2006: “Nonparametric State Price Density Estimation Using Constrained Least Squares and the Bootstrap”, Journal of Econometrics, 133:2, 579-599.

Hall, Peter and A. Yatchew, 2005: “Unified Approach to Testing Functional Hypotheses in Semiparametric Contexts”, Journal of Econometrics, 127, 225-252.

Yatchew, A.,Y. Sun and C. Deri, 2003: “ Efficient Estimation of Semi-parametric Equivalence Scales With Evidence From South Africa”, Journal of Business and Economic Statistics, 21, 247-257.

Yatchew, A. and J.A. No, 2001: “Household Gasoline Demand in Canada”, Econometrica, 1697-1710.

Yatchew, A., 2000, “Scale Economies in Electricity Distribution: A Semiparametric Analysis”, Journal of Applied Econometrics, 15, 187-210.

Yatchew, A., 1999, “An Elementary Nonparametric Differencing Test of Equality of Regression Functions”, Economics Letters, 271-8.

Yatchew, A. 1998, “Nonparametric Regression Techniques in Economics”, Journal of Economic Literature, 36, 669-721.

Yatchew, A. and L. Bos 1997, “Nonparametric Regression and Testing in Economic Models”, Journal of Quantitative Economics, 13, 81-131, www.chass.utoronto.ca/~yatchew.

Yatchew, A. 1997, “An Elementary Estimator of the Partial Linear Model”, Economics Letters, Vol. 57, pp.135-43. Vol. 59, 1998 403-5.

Waverman, L. and A. Yatchew 1994, "The Regulation of Electricity in Canada", in International Comparisons of Electricity Regulation, R. Gilbert and E. Kahn, editors, Cambridge University Press, 366-405.

Yatchew, A., 1992, "Nonparametric Regression Tests Based on Least Squares", Econometric Theory, Vol. 8, 435-451.

Yatchew, A., 1988, "Some Tests of Nonparametric Regression Models", in Dynamic Econometric Modelling, Proceedings of the Third International Symposium on Economic Theory, W. Barnett, E. Berndt, H.White (eds.), Cambridge University Press, 121-135.

Yatchew, A., 1986, "Comment" on Frontier Production Functions, Econometric Reviews, Vol. 4(2), 345-352.

Yatchew, A. "Multivariate Distributions Involving Ratios of Normal Variables", 1986, Communications in Statistics, Vol. A15, Number 6, Theory and Methods, 1905-26.

Yatchew, A., 1985, "A Note on Nonparametric Tests of Consumer Behaviour", Economics Letters, Vol. 18, 45-48.

Yatchew, A., and Griliches, Z., 1985, "Specification Error in Probit Models", Review of Economics and Statistics, 134-139.

Epstein, L., and A. Yatchew, 1985, "Nonparametric Hypothesis Testing Procedures and Application to Demand Analysis", Journal of Econometrics, Vol. 30, 149-169.

Epstein, L., and A. Yatchew, 1985, "The Empirical Determination of Technology and Expectations: A Simplified Procedure:, Journal of Econometrics, Vol. 27, 235-258.

Bird, R., M. Bucovetsky and A. Yatchew, 1985, "Tax Incentives for Film Production: The Canadian Experience", Public Finance Quarterly, Vol. 13, 396-421.

Yatchew, A. 1984, “Generalizing the Composite Commodity Theorem”, Economics Letters, 16, 15-21.

Yatchew, A. 1984, “Applied Welfare Analysis With Discrete Choice Models”, Economics Letters, 18, 13-16.

Yatchew, A., 1981, "Further Evidence on 'Estimation of a Disequilibrium Aggregate Labor Market'", Review of Economics and Statistics, 142-144.

Griliches, Z. and A. Yatchew, 1981, “Sample Selection Bias and Endogeneity in the Estimation of the Wage Equation: An Alternative Specification, Annales de l’Insee, 43, 35-46.

Pesando, J., and Yatchew, A., 1977, "Real vs. Nominal Interest Rates and the Demand for Consumer Durables in Canada", Journal of Money, Credit, and Banking, 28-436.

OTHER PAPERS / STUDIES

Yatchew, A. 1995, "The Distribution of Electricity on Ontario: Restructuring Issues, Costs and Regulation", Ontario Hydro at the Millenium, University of Toronto Press, 327-342,353-354.

Yatchew, A. 1995, "Comments on The Regulation of Trade in Electricity: A Canadian Perspective", Ontario Hydro at the Millenium, University of Toronto Press, 165-7.

Yatchew, A. 2001: "Incentive Regulation of Distributing Utilities Using Yardstick Competition", Electricity Journal, Jan/Feb, 56-60.

Littlechild, Stephen and A. Yatchew, 2002: "Hydro One Transmission and Distribution: Should They Remain Combined or be Separated", www.chass.utoronto.ca/~yatchew .

Yatchew, A., 1999, "Differencing Methods in Nonparametric Regression: Simple Techniques for the Applied Econometrician", 86 manuscript pages.

RECENT RESEARCH GRANTS

2011-2016 SSHRC grant "Nonparametric regression when data on derivatives are available".

2007-2011 SSHRC grant "Nonparametric and semiparametric estimation when data on derivatives are available".

2004-2007 SSHRC grant "Semiparametric demand modeling and testing".

CURRENT AND RECENT SUPERVISIONS

Ph.D.

Dhruv Sinha (2017): Essays in Energy

Dimitrios Dimitropoulos (2015): Three Essays in Energy Economics and Industrial Organization, Thesis Supervisor.

Adam Found (2014): Essays in Municipal Finance, Thesis Supervisor.

M.A.

Daniel Edgel (2017-2017): Fulbright Scholar, M.A. Economics

Nathan Warkentin (2015-2016): Masters of Science in Sustainability Management. “Integration of Renewable Wind Energy Sources in Ontario”

Sean Lemon (2013): M.Sc.Pl., Planning Program, Geography. An Evaluation of Ontario’s Global Adjustment Mechanism (GAM). Thesis Committee.

Undergraduate

Wei, Max (2016-2017) Engineering Science. Undergraduate thesis: “Wind Energy Intermittency, Diversity and Interconnections in Ontario”. Thesis Supervisor.

Shaker, Youssef (2016-2017) Engineering Science. Undergraduate thesis: “Analyzing the Effectiveness of Conservation Programs in Ontario”. Thesis Supervisor.

Wilbur Li, (2012) Engineering Science. Undergraduate thesis: “Ontario’s Feed-In-Tariff Program. Analysis of PV Solar Feed-In-Tariff Rates”. Thesis Supervisor.

OTHER PROFESSIONAL EXPERIENCE:

(2017) Prepared expert testimony on regulatory costing of railway transportation services, filed before the *Canadian Transportation Agency*.

(2017) Prepared analyses on the degree of integration of natural gas hub prices in a major North American acquisition of pipeline and storage facilities.

(2016) Prepared analyses on price determination in West Coast gasoline and diesel markets as part of an asset acquisition evaluation.

(2016) Prepared statistical analyses of market power in the acquisition of MTS by Bell Canada.

(2016) Testified before the *Ontario Energy Board* on behalf of EPCOR Utilities Inc. in a proceeding relating to natural gas expansion in Ontario, EB-2016-04.

(2016) Conducted ‘extent of the market’ and market power analyses for a major hydrocarbon company seeking to acquire additional refining capacity.

(2015) Conducted analyses of utility benchmarking for a large electricity distributor as part of a regulatory rate proceeding before the *Ontario Energy Board*.

(2015) Co-authored study of integration of renewables for the *Alberta Market Surveillance Administrator.*

(2014) Conducted econometrics analyses of spot and forward prices in Alberta electricity markets in a major electricity acquisition evaluation.

(2013) Testified before the *Ontario Energy Board* on behalf of the Electricity Distributors Association on electricity rates and incentive regulation.

(2012) Prepared expert damages testimony in *Oracle America Inc. v. Micron Technology, Inc., U.S. District Court, Northern District of California, Oakland Division*.

(2011) Coauthored study for the *Alberta Market Surveillance Administrator* on electricity market transparency and bidding.

(2011) Prepared Ontario electricity sector review for the Electricity Distributors Association.

(2011) Appointed sole representative of a major Canadian electrical utility in infrastructure pricing negotiations with an incumbent telecom carrier.

(2011) Prepared testimony on behalf of Toronto Hydro on the pricing of attachment space for wireless facilities on joint-use-poles, filed before the *Ontario Energy Board*.

(2010) Prepared testimony on behalf of Noranda Aluminum, Inc. Filed before the *Public Service Commission of the State of Missouri*.

(2009) Prepared study for major generating company on sufficient competition tests for boundary entities in the Ontario electricity market.

(2009) Prepared testimony on worldwide paraxylene markets *Interquisa Canada L.P. and Parachem Chemicals L.P.*, International Court of Arbitration of the International Chamber of Commerce.

(2008) Prepared analysis of incentive regulation of capital and operating c osts and productivity growth for electricity distributors. Filed before the *Ontario Energy Board*.

(2007) Prepared analysis of distributor benchmarking of capital and operating costs on behalf of the Electricity Distributors Association. Filed before the *Ontario Energy Board*.

(2007) Prepared evidence on market power in Ontario electricity markets.

(2005-2007) Prepared analyses of pricing of investor communications services.

(2007) Prepared testimony on behalf of the Electricity Distributors Association on utility benchmarking of capital and operating costs. Filed before the Ontario Energy Board.

(2004-2007) Prepared various analyses in a class action and settlement proceeding involving billing of natural gas. Participated in settlement proceedings.

(2004, 2005, 2006) Prepared odds of winning prizes in promotions by a leading U.S.-based international fast-food chain.

(2006) Prepared testimony on incentive regulation. Filed before the *Ontario Energy Board*.

(2006) Prepared testimony on cost-sharing of capital and operating costs of joint-use power poles. Filed before the *New Brunswick Board of Commissioners of Public Utilities.*
(2005) Prepared testimony on cost-sharing of power poles by cable companies on behalf of Thunder Bay Hydro.

(2004) Prepared testimony on cost-sharing of capital costs of power poles by cable companies. Filed before the *Ontario Energy Board*.

(2003) Prepared testimony on behalf of large Ontario electricity distributors on distributor service area amendments. Filed before the *Ontario Energy Board*.

(2003) Prepared testimony on behalf of J.D. Irving Ltd. on rates of return, performance based regulation and benchmarking. Filed before the *New Brunswick Board of Commissioners of Public Utilities*.

(1982-1994) Participated in numerous Ontario Hydro rate hearings before the *Ontario Energy Board* on behalf of Ontario electricity distributors.

(1989-1991) Filed testimony before the *Ontario Environmental Assessment Board* in connection with the Ontario Hydro long-term demand supply plan.

Appendix 3: References on Elasticities[95]

Ahmed, R., Stater, K. J., & Stater, M. (2013). The Effect of Poverty Status and Public Housing Residency on Residential Energy Consumption in the US. Energy Studies Review, 20(1).

Al-Sahlawi, M.A., 1989. The demand for natural gas: a survey of price and income elasticities. Energy J. 10 (1), 77-90.

Alberini, A., W. Gans, D. Velez-Lopez, Residential consumption of gas and electricity in the U.S.: The role of prices and income, Energy Economics, Volume 33, Issue 5, 2011, 870-881.

Azadeh, A., Jafari-Marandi, R., Abdollahi, M., & Roudi, E. (2017). A novel benchmark methodology for estimating industrial electricity demand considering unsteady socio-economic conditions. International Journal of Business Performance Management, 18(2), 196-215.

Azevedo, I. M. L., Morgan, M. G., & Lave, L. (2011). Residential and Regional Electricity Consumption in the US and EU: How Much Will Higher Prices Reduce CO2 Emissions? The Electricity Journal, 24(1), 21-29.

Baek, Y. (2011). Responsiveness of residential electricity demand to changes in price, information, and policy (Doctoral dissertation, Georgia Institute of Technology).

Barnett, W.A., Lee Y.W., 1985. The global properties of the Minflex Laurent, Generalized Leontief, and Translog flexible functional forms. Econometrica 53, 1421-1437.

Berndt, E.R., Christensen, L.R., 1973. The translog function and the substitution of equipment, structures, and labor in US manufacturing 1929-68. J. Econom. 1 (1), 81-113.

Berndt, E.R., Wood, D.O., 1975. Technology, prices, and the derived demand for energy. Rev. Econ. Stat. 57 (3), 259-268.

Berndt, E.R., 1976. Reconciling alternative estimates of the elasticity of substitution. Rev. Econ. Stat. 58 (1), 59-68.

Berndt, E.R., Wood, D.O., 1979. Engineering and econometric interpretations of energy-capital complementarity. Am. Econ. Rev. 69 (3), 342-354.

Berndt, E.R., 1991. The Practice of Econometrics: Structural and Time Series Approaches. Addison Wesley, New York.

Bernstein, M.A., Griffin, J., 2005. Regional Differences in the Price-elasticity of Demand for Energy. National Renewable Energy Laboratory, Santa Monica, California. Available at: <http://RAND.org/pubs/technical_reports/2005/RAND_TR292.pdf> (9 October 2007)

[95] These references do not include numerous papers on electricity and energy demand in developing countries.

Bjørner, T. B., Togeby, M., & Jensen, H. H. (2001). Industrial companies' demand for electricity: evidence from a micropanel. Energy Economics, 23(5), 595-617.

Bohi, D., Zimmerman, M.E., 1984. An update on econometric studies of energy demand behavior. Annu. Rev. Energy 9, 105-54.

Bohi, D., 2013 Analyzing demand behavior: a study of energy elasticities, Resources for the Future.

Boogen, N., Datta, S., & Filippini, M. (2017). Dynamic models of residential electricity demand: Evidence from Switzerland. Energy Strategy Reviews, 18, 85-92.

Carter, A., Craigwell, R., & Moore, W. (2012). Price reform and household demand for electricity. Journal of Policy Modeling, 34(2), 242-252.

Caves, D.W., Christensen, L.R., Herriges, J.A., 1984. Consistency of residential customer response in time-of-use electricity pricing experiments. J. Econom. 26 (1), 179-203.

Caves, D.W., Christensen, L.R., Herriges, J.A., 1987. The neoclassical model of consumer demand with identically priced commodities: an application to time-of-use electricity pricing. RAND J. Econ. 18 (4), 564-580.

Cebula, R. J. (2012). Recent evidence on determinants of per residential customer electricity consumption in the US: 2001-2005. Journal of Economics and Finance, 36(4), 925-936.

Çetinkaya, M., Başaran, A. A., & Bağdadioğlu, N. (2015). Electricity reform, tariff and household elasticity in Turkey. Utilities Policy, 37, 79-85.

Cho, S. H., Kim, T., Kim, H. J., Park, K., & Roberts, R. K. (2015). Regionally-varying and regionally-uniform electricity pricing policies compared across four usage categories. Energy Economics, 49, 182-191.

Christensen, L.R., Jorgenson, D.W., Lau, L.J., 1975. Transcendental logarithmic utility functions. Am. Econ. Rev. 65 (3), 367-383.

Contreras, S., Smith, W., & Fullerton Jr, T. M. (2010). US commercial electricity consumption.

Dahl, C., 1993. A Survey of Energy Demand Elasticities in Support of the Development of the NEMS. Available at: <https://mpra.ub.uni-muenchen.de/72229/8/MPRA_paper_72229.pdf> (19 July 2017)

Dahl, C., Roman C., 2004. Energy Demand Elasticities – Fact or Fiction: A Survey. Working Paper, Colorado School of Mines.

Deaton, A., Muellauer J., 1980. An almost ideal demand system. Am. Econ. Rev. 70, 312-326.

Denton, F. T., Mountain, D. C., & Spencer, B. G. (2003). Energy demand with declining rate schedules: an econometric model for the US commercial sector. Land Economics, 79(1), 86-105.

Dergiades, T., & Tsoulfidis, L. (2008). Estimating residential demand for electricity in the United States, 1965–2006. Energy Economics, 30(5), 2722-2730.

Dubin, J.A., McFadden, D.L., 1984. An econometric analysis of residential electric appliance holdings and consumption. Econometrica, 52 (2), 345-362.

EPA, 2005. Electricity Demand Response to Changes in Price in EPA's Power Sector Model. U.S. Environmental Protection Agency, Washington D.C.

Espey, J. A., Espey, M., 2004. Turning on the lights: a meta-analysis of residential electricity demand elasticities. J. Agric. Appl. Econ. 36, 65-81.

Eskeland, G. S., & Mideksa, T. K. (2010). Electricity demand in a changing climate. Mitigation and Adaptation Strategies for Global Change, 15(8), 877-897.

Faruqui, A., Malko, J.R., 1983. The residential demand for electricity by time-of-use: a survey of twelve experiments with peak load pricing. Energy 8 (10), 781-796.

Faruqui, A., Palmer, J., 2012. The Discovery of Price Responsiveness – A Survey of Experiments Involving Dynamic Pricing of Electricity. Available at: <http://papers.ssrn.com/sol3/papers.cfm?abstract_id=2020587>

Fell, H., Li, S., & Paul, A. (2014). A new look at residential electricity demand using household expenditure data. International Journal of Industrial Organization, 33, 37-47.

FERC, 2008. Assessment of Demand Response & Advanced Metering, Staff Report, Federal Energy Regulatory Commission, Washington D.C. Available at: <http://www.ferc.gov/legal/staff-reports/12-08-demand-response.pdf>

Filippini, M., Hirl, B., & Masiero, G. (2016). Rational habits in residential electricity demand.

Fisher, F.M., Fox-Penner, P.S., Greenwood, J.E., Moss, W.G., Phillips, A., 1992. Due diligence and the demand for electricity: a cautionary tale. Rev. Ind. Organ. 7 (2), 117-149.

Fullerton, T. M., Juarez, D. A., & Walke, A. G. (2012). Residential electricity consumption in Seattle. Energy Economics, 34(5), 1693-1699.

Fullerton, T. M., Resendez, I. M., & Walke, A. G. (2015). Upward Sloping Demand for a Normal Good? Residential Electricity in Arkansas. International Journal of Energy Economics and Policy, 5(4).

Fullerton Jr, T. M., Macias, D. R., & Walke, A. G. (2016). Residential Electricity Demand in El Paso. Journal of Regional Analysis & Policy, 46(2), 154.

Garen, J., Jepsen, C., & Saunoris, J. (2011). The relationship between electricity prices and electricity demand, economic growth, and employment.

Genc, T. S. (2016). Measuring demand responses to wholesale electricity prices using market power indices. Energy Economics, 56, 247-260.

Gillingham, K., Newell, R.G., Palmer, K., 2009. Energy efficiency economics and policy. Annu. Rev. Resour. Econ. 1 (1), 597-620.

Goodwin, P.B., 1992. A review of new demand elasticities with special reference to short and long run effects of price changes. J. Transp. Econ. Policy 26, 155–169.

Hartman, R.S., 1979. Frontiers in energy demand modeling. Annu. Rev. Energy 4, 433-466.
Joskow, P.L., Wolfram, C.D., 2012. Dynamic pricing of electricity. Am. Econ. Rev. 102 (3), 381–385.

Hosoe, N., & Akiyama, S. I. (2009). Regional electric power demand elasticities of Japan's industrial and commercial sectors. Energy Policy, 37(11), 4313-4319.

Hung, M. F., & Huang, T. H. (2015). Dynamic demand for residential electricity in Taiwan under seasonality and increasing-block pricing. Energy Economics, 48, 168-177.

Jamil, F., & Ahmad, E. (2011). Income and price elasticities of electricity demand: Aggregate and sector-wise analyses. Energy Policy, 39(9), 5519-5527.

Karney, D. H. (2017). Uncovering state-level heterogeneity: The case of US residential electricity demand.

Kussel, G., & Frondel, M. (2016). Switching Response to Power Prices: Evidence from German Households.

Kamerschen, D. R., & Porter, D. V. (2004). The demand for residential, industrial and total electricity, 1973–1998. Energy Economics, 26(1), 87-100.

Khanna, M., & Rao, N. D. (2009). Supply and demand of electricity in the developing world. Annu. Rev. Resour. Econ., 1(1), 567-596.

Kouris, G., 1983. Energy demand elasticities in industrialized countries: a survey. Energy J. 4, 73–94.

Krishnamurthy, C. K. B., & Kriström, B. (2015). A cross-country analysis of residential electricity demand in 11 OECD-countries. Resource and Energy Economics, 39, 68-88.

Labandeira, X., Labeaga, J. M., & López-Otero, X. (2012). Estimation of elasticity price of electricity with incomplete information. Energy Economics, 34(3), 627-633.

Labandeira, X., Labeaga, J.M., López-Otero, X., 2017. A meta-analysis on the price elasticity of energy demand. Energy Policy 102, 549-568.

Lijesen, M. G. (2007). The real-time price elasticity of electricity. Energy economics, 29(2), 249-258.

Lim, H. B., & Jenkins, G. P. (2000). Electricity Demand and Electricity Value. Development Discussion Paper, 1.

Liu, T. (2013). Demand for electricity: A case in South Korea. University of Illinois at Urbana-Champaign.

Mendez-Carrillo, E. C. (2014). A long-and short-run analysis of electricity demand in Ciudad Juarez. The University of Texas at El Paso.

Metghalchi, M., & Hoppes, D. (2012). Short-Run Residential Electricity Demand in Houston. Southwestern Economic Proceedings, 28, 79-84.

Moshiri, A. and Duah N. (2016), Changes in Energy Intensity in Canada. The Energy Journal, 37 (4), 315-342.

Nakajima, T., & Hamori, S. (2010). Change in consumer sensitivity to electricity prices in response to retail deregulation: a panel empirical analysis of the residential demand for electricity in the United States. Energy policy, 38(5), 2470-2476.

Newsham, G.R., Bowker, B.G., 2010. The effect of utility time-varying pricing and load control strategies on residential summer peak electricity use: a review. Energy Policy 38, 3289-3296.

Olmstead, D. E. (2012). Public policy and economic efficiency in Ontario's electricity market: 2002-2011. Doctoral thesis, Carleton University, Ottawa, Canada.

Parks, R.W., Weitzel, D., 1984. Measuring the consumer welfare effects of time-differentiated electricity prices. J. Econom. 26 (1), 35-64.

Qiu, Y. (2014). Do energy efficient technologies still save energy after rebound effects? An econometric analysis of electricity demand in the commercial building sector. Environmental and Resource Economics.

Reiss, P. C., & White, M. W. (2005). Household electricity demand, revisited. The Review of Economic Studies, 72(3), 853-883.

Ryan, D. & Plourde, A. (2009). "Empirical Modeling of Energy Demand", in International Handbook on the Economics of Energy, eds. Joanne Evans and Lester Hunt, Edward Elgar.

Ryan, D. and Razek, N.A. (2012). "The Likely Effect of Carbon Pricing on Energy Consumption in Canada", Sustainable Prosperity, Background Paper.

Stanley, T.D., Jarrell, S.B., 1989. Meta-regression analysis: a quantitative method of literature surveys. J. Econ. Surv. 3, 161–170.

Statzu, V., & Strazzera, E. (2008). A panel data analysis of electric consumptions in the residential sector.

Suganthia, L., Samuel, A.A., 2012. Energy models for demand forecasting – a review. Renew. Sustain. Energy Rev. 16, 1223–1240.

Sweeney, J. 2016 Energy Efficiency: Building a Clean, Secure Economy, Hoover Institution Press, Stanford University.

Tan, J. J. E. (2013). Do price shocks change electricity consumption? Evidence from New Zealand industrial users (Doctoral dissertation).

Taylor, L., 1975. The demand for electricity: a survey. Rand J. Econ. 6 (1), 74-110.
Taylor, L. D. (2012). Telecommunications demand in theory and practice. Springer Science & Business Media.

Vaage, K. (2000). Heating technology and energy use: a discrete/continuous choice approach to Norwegian household energy demand. Energy Economics, 22(6), 649-666.

Wade, S.H., 2003. Price Responsiveness in the AEO2003 NEMS Residential and Commercial Building Sector Models. Department of Energy, Washington D.C.

Weron, R., 2006. Modeling and Forecasting Electricity Loads and Prices: A Statistical Approach. John Wiley & Sons, New York.

Weron, R., 2014. Electricity price forecasting: a review of the state-of-the-art with a look into the future. Int. J. Forecast. 30 (4), 1030-1081.

Xiao, N., Zarnikau, J., Damien, P., 2007. Testing functional forms in energy modeling: an application of the Bayesian approach to US electricity demand. Energy Econ. 29 (2), 158-166.

Yatchew, A., 2003, Semiparametric Regression for the Applied Econometrician, 213 pages, Themes in Modern Econometrics, Cambridge University Press.

Yatchew, A. and J.A. No, 2001: “Household Gasoline Demand in Canada”, Econometrica, 1697-1710.

Yoo, S. H., Lee, J. S., & Kwak, S. J. (2007). Estimation of residential electricity demand function in Seoul by correction for sample selection bias. Energy Policy, 35(11), 5702-5707.

Zarnikau, J., 2003. Functional forms in energy demand modeling. Energy Econ. 25 (6), 603-613.

Zarnikau, J., Hallett, I., 2008. Aggregate industrial energy consumer response to wholesale prices in the restructured Texas electricity market. Energy Econ. 30 (4), 1798-1808.

Zee, S. M., & Burford, R. L. (2008). Explorations in Estimation Methodologies for a Simplified Model of Residential Demand for Electricity with Systematically Varying Coefficients. International Journal of Economic Perspectives, 2(2), 94.

Appendix 4: Manitoba Electricity Cost Shares by Sub-Sector

Source: CANSIM Tables 381-0033 Supply and Use, Manitoba 2013.

Manufacturing	
Fruit and vegetable preserving and specialty food manufacturing [BS311400]	1.55%
Bakeries and tortilla manufacturing [BS311800]	1.01%
Textile and textile product mills [BS31A000]	1.28%
Sawmills and wood preservation [BS321100]	1.16%
Veneer, plywood and engineered wood product manufacturing [BS321200]	1.86%
Pulp, paper and paperboard mills [BS322100]	6.98%
Basic chemical manufacturing [BS325100]	18.10%
Pesticide, fertilizer and other agricultural chemical manufacturing [BS325300]	1.63%
Soap, cleaning compound and toilet preparation manufacturing [BS325600]	1.29%
Plastic product manufacturing [BS326100]	1.04%
Non-metallic mineral product manufacturing (except cement and concrete products) [BS327A00]	1.72%
Iron and steel mills and ferro-alloy manufacturing [BS331100]	3.33%
Non-ferrous metal (except aluminum) production and processing [BS331400]	2.51%
Foundries [BS331500]	3.04%
Forging and stamping [BS332100]	1.00%
Hardware manufacturing [BS332500]	1.11%
Coating, engraving, heat treating and allied activities [BS332800]	1.14%
Engine, turbine and power transmission equipment manufacturing [BS333600]	1.98%
Electric lighting equipment manufacturing [BS335100]	1.88%
Motor vehicle electrical and electronic equipment manufacturing [BS336320]	1.60%
Mining	
Gold and silver ore mining [BS212220]	2.76%
Copper, nickel, lead and zinc ore mining [BS212230]	1.97%
Other metal ore mining [BS212290]	3.40%
Stone mining and quarrying [BS212310]	0.37%
Sand, gravel, clay, and ceramic and refractory minerals mining and quarrying [BS212320]	0.75%
Other non-metallic mineral mining and quarrying (except diamond and potash) [BS21239A]	0.71%
Support activities for oil and gas extraction [BS21311A]	6.30%
Support activities for mining [BS21311B]	0.03%
Agriculture	
Crop production (except greenhouse, nursery and floriculture production) [BS111A00]	0.86%
Greenhouse, nursery and floriculture production [BS111400]	2.78%
Animal production (except aquaculture) [BS112A00]	1.93%
Forestry and logging [BS113000]	1.09%

Fishing, hunting and trapping [BS114000]	0.44%
Support activities for crop and animal production [BS115A00]	0.20%
Support activities for forestry [BS115300]	0.04%
Services	
Furniture and home furnishings stores [BS442000]	1.08%
Building material and garden equipment and supplies dealers [BS444000]	1.03%
Gasoline stations [BS447000]	1.20%
Miscellaneous store retailers [BS453000]	1.05%
Non-store retailers [BS454000]	1.91%
Crude oil and other pipeline transportation [BS486A00]	2.06%
Radio and television broadcasting [BS515100]	1.02%
Non-depository credit intermediation [BS522200]	1.06%
Lessors of real estate [BS531100]	2.26%
Lessors of non-financial intangible assets (except copyrighted works) [BS533000]	1.27%
Educational services [BS610000]	2.12%
Offices of dentists [BS621200]	1.43%
Miscellaneous ambulatory health care services [BS621A00]	1.07%
Nursing and residential care facilities [BS623000]	1.83%
Social assistance [BS624000]	6.09%
Amusement and recreation industries [BS713A00]	1.18%
Traveller accommodation [BS721100]	1.45%
RV (recreational vehicle) parks, recreational camps, and rooming and boarding houses [BS721A00]	2.57%
Automotive repair and maintenance [BS811100]	2.42%
Repair and maintenance (except automotive) [BS811A00]	1.35%
Personal care services and other personal services [BS812A00]	1.27%
Dry cleaning and laundry services [BS812300]	4.48%
Professional and similar organizations [BS813000]	5.36%
Educational services [NP610000]	6.07%
Arts, entertainment and recreation [NP710000]	2.11%
Religious organizations [NP813100]	3.23%
Grant-making, civic, and professional and similar organizations [NP813A00]	2.60%
Other non-profit institutions serving households [NP999999]	1.18%
Community colleges and C.E.G.E.P.s [GS611200]	2.57%
Universities [GS611300]	1.17%
Other educational services [GS611A00]	4.36%
Other municipal government services [GS913000]	2.96%
Other aboriginal government services [GS914000]	1.93%
Utilities	
Natural gas distribution [BS221200]	0.12%
Water, sewage and other systems [BS221300]	0.61%

Construction	
Residential building construction [BS23A000]	0.04%
Non-residential building construction [BS23B000]	0.03%
Transportation engineering construction [BS23C100]	0.02%
Oil and gas engineering construction [BS23C200]	0.02%
Electric power engineering construction [BS23C300]	0.12%
Communication engineering construction [BS23C400]	0.25%
Other engineering construction [BS23C500]	0.10%
Repair construction [BS23D000]	0.04%
Other activities of the construction industry [BS23E000]	0.35%

1

Tab 63

CONFIDENTIAL

INDEPENDENT EXPERT CONSULTANT REPORT: LOAD FORECAST REVIEW

NOVEMBER 15, 2017

PREPARED FOR

Manitoba Public Utilities Board

PREPARED BY

Daymark Energy Advisors

DAYMARK ENERGY ADVISORS
370 MAIN STREET, SUITE 325 | WORCESTER, MA 01608
TEL: (617) 778-5515 | DAYMARKEA.COM

TABLE OF CONTENTS

Executive Summary 1

I. Introduction 7

A. General Rate Application Process and Independent Expert Consultants 7

B. Organization of this Report 7

II. Load Forecasting Methodology 9

A. General Overview 9

B. Key Sectors 10

1. Residential Methodology 10

2. Mass Market 14

3. Top Consumers 17

C. Transmission and Distribution Losses 19

D. Gross Firm Energy and Peak Demand 20

III. Comparison of MH Methodologies with Industry Practice 24

A. Econometric and End-Use Forecasting 24

B. Economic Assumptions 25

1. GDP Forecasts 26

2. Population Forecasts 30

C. Price Elasticity and Implication of Rate Increase 32

1. Price Elasticity 32

2. Fuel Switching Not Considered 37

D. Alternative Load Forecast 37

1. Sensitivity and Scenario Analysis 38

2. Risk and Uncertainty 39

E. Reliability of Load Forecast 40

1. Historical Performance of Load Forecasting Methods 40

2. Accuracy of the Load Forecast 45

F. Weather Normalization 46

G. Incorporation of DSM Savings in Load Forecast 48
IV. Load Forecast Changes (2014 to 2017) 50
A. Residential Load Forecast Methodology 51
B. General Service Mass Market Methodology 53
C. Top Consumers Load Forecast Methodology 54
D. Other Aspects of Load Forecast 56
E. Assumptions 57
V. Summary and Conclusions 60

LIST OF APPENDICIES

APPENDIX A Daymark Energy Advisors' Scope of Work

APPENDIX B Documents Relied Upon

LIST OF TABLES

Table ES1: Key Summary Findings of MH Load Forecast Analysis 5
Table 1: MH Estimated Price, Income, and GDP Elasticities 33
Table 2: Estimates of Stepwise Regression Models of Residential Average Usage Model 35
Table 3: Variance Inflation Factor (VIF) of Residential Average Usage Model 35
Table 4: Estimates of Stepwise Regression of GS Small and Medium Average Usage Model 36
Table 5: Estimates of Stepwise Regression of GSMM Large Customers 36
Table 6: Sensitivity of Load Forecast to an Assumption Change 38
Table 7: Evaluation of Extreme Events 39
Table 8: Comparison of MH Estimated Price, Income, and GDP Elasticities in 2014 and 2017 58
Table 9: Key Summary Findings of MH Load Forecast Analysis 63

LIST OF FIGURES

Figure 1. Components of Gross Firm Energy 10
Figure 2: Annual Average Usage and Customer Count for the Residential Sector 12
Figure 3: Annual Average Usage and Customer Count for the General Service Mass Market Sector, Small and Medium Customer Category 15
Figure 4: Annual Average Usage and Customer Count for General Service Mass Market Sector, Large Customer Category 16
Figure 5: Short- and Long-Term Load Forecasts for the General Service Top Consumers Sector 18
Figure 6: Gross Firm Energy and Sector-Level Load Forecasts 21
Figure 7: Monthly Peak Load (MW) for 2017/18 Fiscal Year 22
Figure 8: Annual Peak Demand for MH Service Territory 23
Figure 9: Annual Manitoba GDP (2007 $M) used in MH's Load Forecast 29
Figure 10: Average N-year Ahead Error Forecast, Population and Residential Customer Count 31
Figure 11: Annual Real Electricity Price, Residential Sector (2016/17 = 100) 32
Figure 12: Comparison of Historical Weather Adjusted Gross Firm Energy (GWh) with Multiple Forecast Vintages of Gross Firm Energy 41
Figure 13: Comparison of Historical Weather Adjusted Residential Sales (GWh) with Multiple Forecast Vintages of Residential Sales 42
Figure 14: Comparison of Historical Weather Adjusted General Service Mass Market Sales (GWh) with Multiple Forecast Vintages of GSMM Sales 43
Figure 15: Comparison of Actual General Service Top Consumers Sales (GWh) with Multiple Forecast Vintages of Top Consumers Sales 44
Figure 16: Comparing Actual and Weather Adjusted Gross Firm Energy with the Annual Heating Degree Days 47
Figure 17: Annual Gross Firm Energy (GWh) Forecast Comparison 50
Figure 18: Annual Gross Total Peak (MW) Forecast Comparison 51
Figure 19: Residential Sales (GWh) Comparison between 2014 and 2017 Load Forecasts 52
Figure 20: General Service Mass Market Sales (GWh) Comparison between 2014 and 2017 Load Forecasts 54
Figure 21: General Service Top Consumers Sales (GWh) Comparison between 2014 and 2017 Load Forecasts 56

LIST OF ACRONYMS

AAGR	annual average growth rate
C&S	Codes & Standards
CBC	Conference Board of Canada
CDD	cooling degree days
CSE	Centre for Spatial Economics
GDP	Gross Domestic Product
GRA	General Rate Application (2017/18 & 2018/19)
GSMM	General Service Mass Market
GWh	gigawatt-hours
HDD	heating degree days
HVDC	High Voltage Direct Current
kWh	kilowatt-hours
LSE	Load Serving Entities
MH	Manitoba Hydro
MW	megawatts
PLIL	Potential Large Industrial Loads
PUB	Manitoba Public Utilities Board
T&D	transmission and distribution
VIF	variance inflation factor

EXECUTIVE SUMMARY

Manitoba Hydro's (MH) 2017 Load Forecast Report summarizes its approach to developing a long-term forecast of energy and peak demand for its system, which it accomplishes by building up its forecast by sector based on historical econometric relationships. Daymark Energy Advisors (Daymark) was engaged by the Manitoba Public Utilities Board (PUB) to provide an independent review of MH's load forecast. This report details that review and presents our findings.

Daymark's scope of work is attached to this report – we were commissioned to gather sufficient information from available documents, meetings with MH staff, and research into and knowledge of current forecasting practices to evaluate the reasonableness of MH's load forecast methodologies. In addition, a comparison of the 2017 load forecast to the 2014 load forecast was included in our scope.

MH 2017 Load Forecasting Methodology

Overall, the methodologies employed by MH to develop its projections of future energy and demand are reflective of industry practice, but are not on the leading edge of forecasting approaches. MH's sector-level, regression-model-based load forecast is consistent with industry practices. Many Load Serving Entities (LSE) typically divide load forecast analyses into residential, commercial, and industrial sectors and then estimate the average electricity usage per customer and number of customers in each sector. The independent variables, or predictors, used in the regression models that MH developed are similar to the variables used in load forecasts in the industry. MH explicitly addresses weather impacts on load, savings from DSM and codes and standards, and load changes associated with electric vehicle adoption, but the company does not address potential fuel substitution during a time of anticipated large electricity price increases. MH relies on econometric approaches to a great extent; in this report we offer several areas of improvement and modification to enhance both the forecast and the documentation of the company's process and results.

A key shortcoming of the approach taken by MH is the reliance on a forecast that has a probability of being accurate 50% of the time – for a business with high capital costs and long project lead times, a forecast that is expected to address 90% of the potential futures is typically preferred. In addition, because of the uncertainty and change prevalent in the energy industry, MH should investigate a diversity of alternative futures in order to better understand the implications of a range of potential futures in their long-term planning process.

Key Findings

Table ES1 provides Daymark's assessment of key topics where improvement in the methodologies may improve the approach and have an impact on the load forecast used by MH. Moreover, this table also summarizes MH's methodology for addressing these key topics, along with Daymark's conclusions. We summarize those recommendations here and provide greater detail throughout this report.

The top consumers forecast relies on a conservative approach to forecasting – MH uses short-term knowledge of the MH account executives for particular accounts, which is useful for the near term, but the long-term sector projections should rely on all historical trends and not single out only those accounts with a consistent history of business and consumption in the province for the duration of the historical data period. In addition, the changes in methodology between the 2014 and 2017 forecasts for this sector result in significant forecast differences over the twenty-year period. The 2017 Potential Large Industrial Load (PLIL) method used a conservative approach by only considering the total load of top consumer companies that have been in the MH service territory since 1983/84, thus excluding the historical load of three companies that are currently in the top consumers sector. Daymark estimated that the conservative PLIL method used in 2017 forecasted 523 GWh less load than would have been forecasted using the 2014 methodology over the forecast period from 2017/18 to 2036/37.

The price elasticities of all three sectors (residential, general service mass market, and top consumers) reported by MH may be incorrectly estimated. The econometric model used for estimating residential price elasticity exhibits a multicollinearity issue. Similarly, the use of trend and dummy variables in the average usage models of both the residential and general service mass market sectors have suppressed the impact of electricity price elasticity. In our investigation of the modeling, the regression models used by MH produced higher price elasticity coefficients before the use of trend or dummy variables in the sector-level forecasts. Moreover, the price elasticity estimated for top consumers through the above-mentioned conservative PLIL method is lower than if it was estimated using the PLIL method used in the 2014 load forecast. Although this is an area of concern, based on the regression parameters, overall R-square and other statistics, the overall load forecast of each sector is appropriate in total, the key concern is in the interpretation of the elasticity coefficients.

The load forecast report provided by MH should include greater attention to the theoretical basis for their selection of the predictor variables as well as full disclosure

and discussion of the potential statistical concerns identified in the analysis so that one can review the total impact of their decisions as they move to the final forecast.

Price elasticity is included in the regressions used to forecast future energy, therefore response to price changes are embedded in the modeling. However, the magnitude of the electricity price increases anticipated are not of the level that have been seen during the historical period and MH may see greater elasticity impacts than presented in its 2017 load forecast report. Coupled with the multicollinearity issues observed with regard to the price variable coefficients and the trend and dummy variable impacts, the forecast could be lower than it is currently predicted by taking a higher price elasticity coefficient into account.

Finally, MH has historically under-forecasted population trends, a predictive variable that underlies the residential and general service mass market forecasts of customer count. The use of lower customer count forecasts will result in a lower residential load forecast and a lower general service mass market load forecast.

The possibility of switching to an alternative fuel type or fuel source, driven by increases in the price of electricity, is not explicitly considered in the MH load forecast analysis. It is important to consider the potential magnitude of energy source switching that the proposed MH rate hikes may induce, since electricity prices are requested to increase by 65% in the year 2025 as compared to 2018 rates.[1] Similarly, the recent trend of low natural gas prices and a projected decrease in solar costs may make these alternatives more economically attractive considering the proposed electricity price changes. It must also be recognized that a substitution effect will be offset by natural inertia, that is the consumer effort necessary to change fuels may delay or reduce the potential for substitution.

Based on our analysis, Daymark has developed the following recommendations for improving Manitoba Hydro's current load forecasting methodology:

- The load forecast analysis should consider scenario analysis by developing alternative load forecasts in addition to the base load forecast. These scenarios would help create alternative future settings that represent the different possible trends of several key input variables that are used in generating the base load forecast. Such scenarios could consider key uncertainties by

[1] "2017 GCR AT 2017 RATES" excel file provided by MH.

representing different assumptions for economic and population growth, electricity and fuel commodity prices, and CO_2 prices.

- MH should evaluate the inherent characteristics of fundamental variables using stochastic risk assessments. Currently, Manitoba Hydro's method of evaluating load uncertainty at p10 and p90 levels is based on considering the overall impact of key input variables on the load variation. Using a stochastic risk assessment method would allow for the estimating of potential outcomes by incorporating random variation in the key input variables. Probabilities are assigned to different values of key uncertain variables that have been identified as such through sensitivity analysis.

- MH may generate a better estimate of weather-dependent load by using more than two years of monthly energy and degree day data to estimate the weather-dependent relationship. Currently, the company uses two years of data to estimate the weather-dependent load relationship and 25 years of data to define the "normal" weather year. It is unclear at this stage whether this two-year-based coefficient is more extreme than that developed through a reliance on greater data points, nor is it clear whether the then-normalized loads are higher or lower than they should be – but these new normalized loads are the dependent variables on which the forecast econometric equations are based. MH should provide greater analysis and information in its next forecast, providing the rationale for the use of a two-year coefficient for normalization. Also, Manitoba Hydro could improve its weather normalization method by using a shorter period to calculate the "normal" year weather variables.

- MH should consider testing its econometric models for a variety of statistical concerns. For example, the average electricity usage regression models contain multicollinearity issues. Similarly, MH should consider the economic reasoning before introducing any new predictor variables into its regression models in addition to checking the statistical significance, and potential implications for its price elasticities.

Table ES1: Key Summary Findings of MH Load Forecast Analysis

TOPIC	MH METHOD	COMMENT/REMARKS	IMPACT ON LOAD FORECAST
Top Consumers PLIL model	The PLIL accounts for the long-term load growth of the top consumers sector by evaluating historical shifts in the energy usage of top consumers as a group rather than as individuals.	The 2017 PLIL method was conservative because it only considers the total load of top consumer companies that have been in the MH service territory since 1983/84, thus excluding the historical load of three companies that are currently in the top consumer sector.	The conservative PLIL method used in 2017 forecasted 523 GWh less load than using the 2014 method and 2017 data over the 20-year forecast period.
Electricity Price Elasticity	The load forecasting methodology uses price elasticity with the help of econometric regression models at the sector-level.	The price elasticities of all three sectors may be incorrectly estimated. The econometric model used for estimating residential price elasticity exhibits a multicollinearity issue. Similarly, the use of trend and dummy variables in the average usage models of both the residential and general service mass market sectors have suppressed the impact of electricity price elasticity. Moreover, the price elasticity estimated for top consumers through the conservative PLIL method discussed just above is lower than if it were estimated using the PLIL method used in 2014 load forecast.	The incorrectly estimated price elasticity will not provide the actual impact of proposed rate increases on each sector's electricity demand.
Population Forecast	MH uses population forecasts from an external institution in its load forecasting methodology.	The evaluation of historical population and residential values along with the forecast used by MH show that MH has under-forecasted the population and residential customer count.	Lower customer forecast will result in a lower residential load forecast and a lower general service mass market load forecast.
Scenarios and Sensitivity	MH evaluated the impact of changes in its key econometric analysis variables.	The load forecast analysis did not consider scenario analysis, which would help create alternative future settings that represent the different plausible trends of key input variables used in the base load forecast and provide broader information on potential system implications than the current approach.	Scenario analysis would have provided further insight of the impact of future alternative scenarios on MH's load forecast.
Risk and Uncertainty	MH evaluated load uncertainty at p10 and p90 levels on the base load forecast.	A more robust approach to consider uncertainty on load would be to evaluate the inherent characteristics of each fundamental variable with the help of probabilistic (i.e., stochastic) risk assessments.	
Fuel Switching Consideration in the Analysis	The possibility of switching to an alternative fuel type or fuel source due to the increase in electricity price is not explicitly considered in the MH load forecast analysis.	It is important to consider energy source switching, since electricity prices are requested to increase by 65% in 2025 as compared to 2018 rates. Similarly, the recent trend of low natural gas prices and a steady decrease in solar costs may make these alternatives more economically attractive considering the proposed electricity price changes.	Load forecast may change without considering potential alternative energy source substitution due to the proposed rate increase.

Load Forecast Methodology Comparison Between 2014 and 2017

Daymark also compared the 2014 and 2017 load forecast methodologies and assumptions for the various sectors defined by Manitoba Hydro. Overall, the 2017 methods generated a lower long-term forecast than the analysis conducted in 2014. Moreover, the annual average growth rate of gross firm energy forecasted in 2017 is lower than the annual average growth rate forecasted in 2014. The annual average growth rate of gross firm energy is estimated by using first and tenth year forecast from both 2014 and 2017 reports. Additionally, the annual growth rate using the ten-year gross firm energy forecast was higher in 2014 at 1.46% compared to 0.81% in the 2017 forecast. The key differences between the 2014 and 2017 load forecast methodologies are in the models used for forecasting general service mass market (GSMM) customer count, the PLIL method used for capturing long-term forecasts for the top consumers category, and economic and population assumptions used in the analysis.

In order to estimate the customer count for the GSMM sector, the 2017 forecast estimated customer count directly, while the 2014 forecast modeled the percentage change in the number of customer types. As noted earlier, the 2017 PLIL method used a conservative approach by only considering the total load of top consumers companies that have been in MH's service territory since 1983/84, the start year of MH's modeling period. In contrast, the 2014 PLIL methodology considered the load of all companies included in the top consumers sector.

I. INTRODUCTION

A. General Rate Application Process and Independent Expert Consultants

On May 5, 2017, Manitoba Hydro (MH) filed its 2017/18 & 2018/19 General Rate Application (GRA). The application has many facets that include interim rate relief and financial evidence to determine the requested rate increases. A key component in the financial information provided by Manitoba Hydro is its load forecast.

The Manitoba Public Utilities Board (PUB) retained Daymark Energy Advisors (Daymark) to review and provide an expert opinion on Manitoba Hydro's export price and revenue forecasts and electricity load forecasts. This report provides our expert opinion on electricity load forecasts; Daymark's expert opinion on export price and revenue forecasts is provided separately.

Beyond our two expert reports on the above-mentioned topics, the PUB has also engaged independent expert consultants to examine and provide opinions on:

1. Updated costs of Manitoba Hydro's major generation and transmission projects currently under development or construction;
2. The economic impacts to the Province of Manitoba of proposed electricity rate increases; and,
3. Capital Projects.

While our report comprehensively addresses the specific aspects of our scope of work, our review should be considered alongside the other studies and analyses commissioned by the PUB in connection with Manitoba Hydro's application.

B. Organization of this Report

This report is organized such that it aligns with our scope of work, which is available on the PUB's website[2] and is attached to this report as Appendix A, for ease of reference.

- Part II, ***Load Forecasting Methodology***, provides our assessment of Manitoba Hydro's load forecasting methods, including how they compare to industry practices;

[2] Access available at the following link. http://www.pubmanitoba.ca/v1/proceedings-decisions/appl-current/pubs/2017%20mh%20gra/daymark%20iecs%20scope%20of%20work.pdf

- Part III, ***Comparison of MH Methodologies with Industry Practices***, discusses Manitoba Hydro's load forecasting methodologies on key topics and compares with industry-practices;
- Part IV, ***Load Forecast Changes (2014 to 2017)***, provides our review of Manitoba Hydro's 2017 Load Forecast and our findings related to how the 2017 forecast compares to the 2014 forecast used in Manitoba Hydro's NFAT application; and,
- Part V, ***Summary and Conclusions***, bring everything together and describes our team's key findings and recommendations.

II. LOAD FORECASTING METHODOLOGY

A. General Overview

Manitoba Hydro developed sector-level forecasts to generate its total annual load forecasts. The key sectors that were modeled separately for generating the overall load forecast are residential, general service mass market, and general service top consumers; these sectors form the total consumer sales[3].

The total consumer sales, also referred to as general consumer sales, include the energy supplied to all of Manitoba Hydro's individually-billed customers. During the 2016/17 fiscal year,[4] MH averaged 570,712 general consumer sales customers, who consumed a total of 22,025 GWh[5] of energy. The common bus is the total load metered at all the substations in the province that supply MH's non-diesel customers. In addition to the total consumer sales, the common bus includes distribution losses and construction power. MH reported common bus load to be 23,115 GWh in 2016/17. The common bus is 1,090 GWh or 4.9% greater than the total consumer sales discussed above.[6]

MH adds transmission losses and station service load to the common bus load to calculate the gross firm energy – the total load that needs to be generated for domestic firm load requirements on the integrated system, excluding diesel customers. MH reported gross firm energy of 25,227 GWh for 2016/17. This is 3,202 GWh or 14.5% greater than the total consumer sales. Figure 1 graphically depicts MH's methodology for generating the forecast for gross firm energy.

Gross firm energy is then adjusted for DSM-related energy savings by subtracting forecasted annual program-based DSM savings. The DSM-adjusted annual load forecast becomes the basis for financial analysis to forecast revenue.

[3] "There are four remaining groups of customers. Seasonal customers are those billed twice a year rather than on a monthly basis. Diesel customers are from four remote communities not connected to the integrated grid system. Also included are Flat Rate Water Heating and Area and Roadway Lighting and over 50,000 of these services do not count as customers. The electricity use of these four groups totals 226 GWh or 1.0% of Total Sales." (Source: Page 2, 2017 Load Forecast Report)

[4] The MH fiscal year starts on April 1st of a typical year to March 31st of the following year. For example, 2016/17 represents the period from April 1, 2016 to March 31, 2017.

[5] Page 2, 2017 Load Forecast Report.

[6] Ibid.

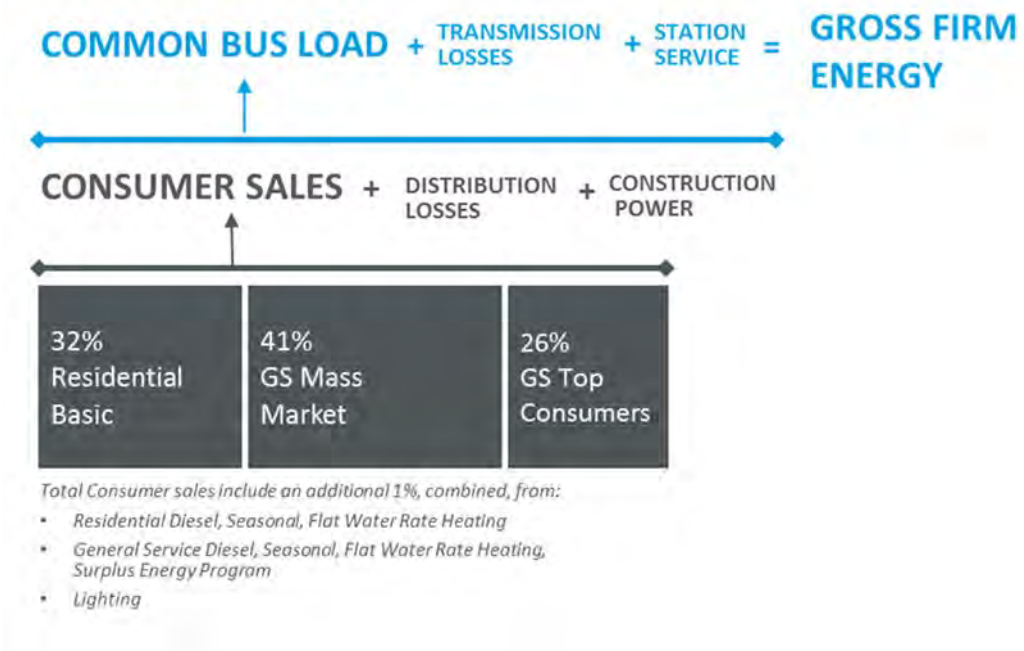


Figure 1. Components of Gross Firm Energy

B. Key Sectors

1. Residential Methodology

MH's residential sector includes a total of 480,365 customers that were responsible for 32.5% of total consumer sales in 2016/17. The residential sector is comprised mostly of residential structures that include single-family dwellings, multi-family dwellings, and individually-metered apartment units. MH uses a primary econometric approach to forecast load for this sector, which is then compared to a secondary approach to support the reasonableness of the primary approach. Each are described here.

MH's primary residential forecast methodology, first, estimates two key components: (1) number of residential customers or dwellings, and (2) the average usage per residential customer. The customer forecast relies on several third-party Manitoba population forecasts and a ratio of total population to total residential customers estimated by MH. The key assumptions used by the third-party population forecasts are summarized in the *Economic Assumptions* section of this report.

To forecast the average annual usage per residential customer, MH uses an econometric model with assumptions that include electricity prices[7], annual disposable income, and the annual ratio of the number of electric heat customers to total customers. The model also features a trend variable that, as MH indicates, captures increases in electric use and house size.[8] The average electricity usage, which is the dependent variable in the regression model, also included both program-based Codes and Standards DSM savings and weather adjustments to actual load. ~~**[CONFIDENTIAL BEGIN]**~~ Figure 2 shows the annual residential customer average usage and residential customer count for both historical and forecast periods. The average usage shown in the figure is adjusted for the change in usage due to weather variation. MH estimates that the average residential customer usage will decrease slightly for the next few years. The residential customer count is estimated to increase at a consistent rate during the forecast period.

[7] The electricity price variable was lagged by 2.5 years.

[8] Manitoba Hydro, "2016 Electric Load Forecast", Market Forecast June 2017, p.62

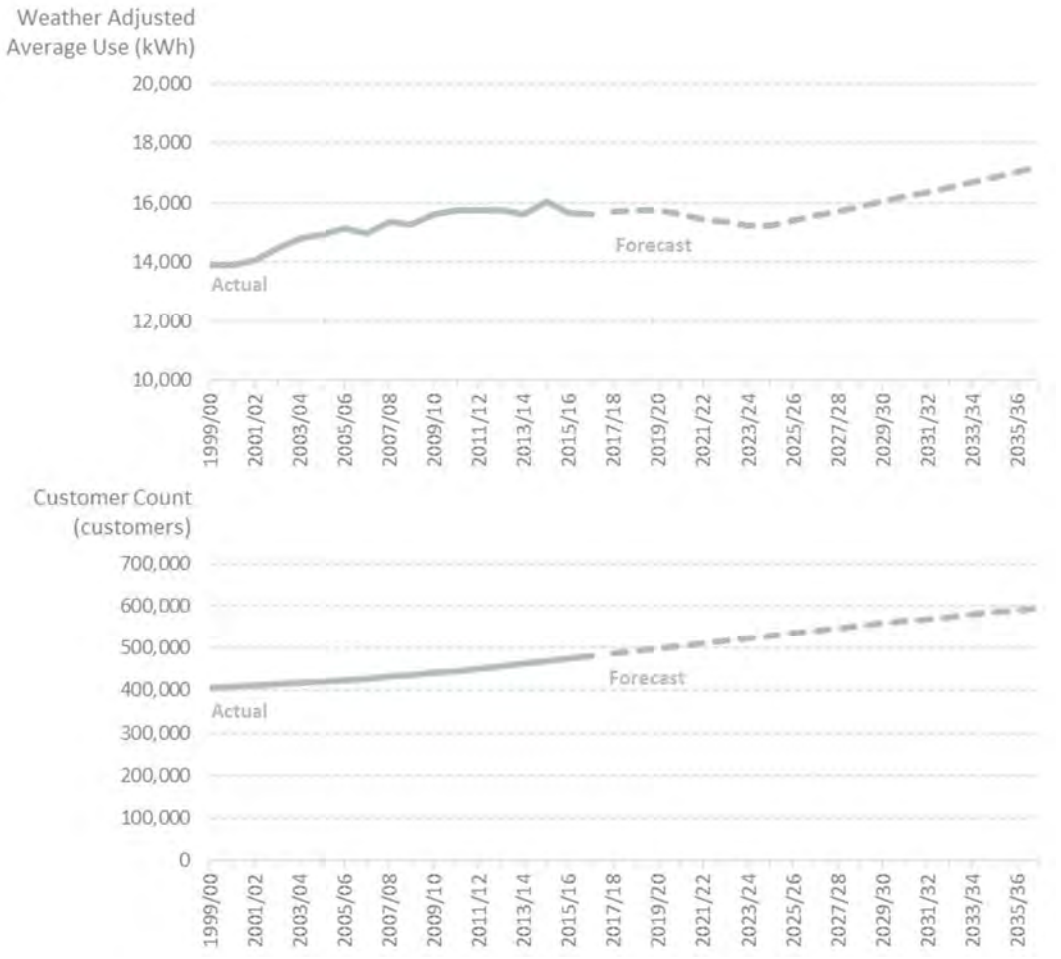


Figure 2: Annual Average Usage and Customer Count for the Residential Sector

~~[CONFIDENTIAL END]~~

To produce the residential energy forecast, the forecasted number of residential customers is multiplied by the forecasted overall average usage per customer. In addition, the projected energy savings associated with LED adoption is subtracted from the forecast and any increase in electricity usage due to future adoption of electric vehicles is added to the forecast. MH indicated that these phenomena are not adequately addressed in the baseline methodology. Similarly, the future energy savings associated with Codes and Standards, outlined in Manitoba Hydro's Power Smart Plan and DSM initiatives, are subtracted from the annual load forecast at this point in the analysis.

MH indicates that it also employed an end-use forecasting methodology as a secondary approach to its residential energy forecast. Most of the data to develop these end-use forecasts came from the 2017 Economic Outlook and 2014 MH Residential Energy Use Survey[9]. The end-use methodology developed different estimates of the number of both existing and new dwellings, and the saturation of space and water heating in these dwellings. The number of space heating systems were forecasted separately in existing and new dwellings. Specifically, the forecast of space heating systems in new buildings used econometric models to estimate the number of electric space heating systems in new single detached and multi-unit dwellings by region. Separate estimates for space heating in existing dwellings and water heating systems were developed to forecast the number of annual replacements using a Weibull distribution[10] based on the average age of the system. Regarding the forecast of water heating systems, MH estimated electric and natural gas water heater saturations and average age by considering annual replacements, fuel switching, and saving estimates from the Heating Fuel Choice initiative[11]. Moreover, the end-use forecasting methodology also included the forecast of electricity usage for other major appliances including central air conditioning, major appliances, televisions, and lighting by dwelling type.

The total load forecast estimated by this alternative end-use method, along with additional information from MH's 2014 Residential Survey, was balanced against the load estimated by the primary econometric modeling to ensure that the primary modeling was reasonable. During discussions with MH, staff indicated that the secondary modeling confirmed the primary approach and thus no modifications to the primary approach were needed. However, there was no specific documentation that described the "balancing" considerations in the load forecast report, nor did it explain what MH would have done if the load estimated by the primary regression method and the secondary end-use method were different. Based on its review, Daymark found that the secondary end-use forecasting results were limited in their use by MH, despite the effort that went into their development and maintenance. Besides balancing, the secondary end-use method is also relied upon to estimate the ratio of electric heat customers to total customers, which is one of the predictors in the primary residential average usage regression model. However, as discussed later in this report, the use of a

[9] MH develops both the Economic Outlook and the Residential End Use Survey and updates them periodically.

[10] Weibull distribution is a continuous probability function that is a versatile distribution that can take on the characteristics of other types of distributions, based on the value of the shape parameter.

[11] 2017 Load Forecasting Methodology, Page 61.

"saturation" variable in the primary average usage regression model causes a multicollinearity issue.

2. Mass Market

The general service mass market (GSMM) sector of MH's service territory is comprised of 67,676 customers and was responsible for 42% of total consumer sales in 2016/17. Of the total GSMM customers, 85% were commercial customers, and the remaining customers were industrial sector accounts. The 2017 GSMM forecasting methodology used two different models: one to forecast customer count and the second to forecast average annual usage, an approach that is similar to the residential modeling methodology. The GSMM customers were divided into two categories – grouping small and medium customers in one forecast group and then modeling the larger customers in a second group.

The method used to forecast GSMM customer counts leveraged econometric models with assumptions relative to Gross Domestic Product (GDP) and year-end residential customer counts. The small and medium customer model used year-end residential customer data and Manitoba real GDP from 1985/86 to 2016/17. Similarly, the model that forecasted large customers used the same year-end residential customer count and a blended GDP variable that MH created by combining Manitoba, Canada, and U.S. GDPs.[12]

The GSMM average use forecast followed a similar regression method for forecasting customer count. The average use forecast model for the small and medium customer category used an econometric model with assumptions related to electricity price, Manitoba GDP, and a dummy variable, to account for changes in the MH billing system in 2005/06. Similarly, the average use forecast model for the large customer category used an econometric model with assumptions related to electricity price, the Manitoba/Canada/U.S. blended GDP, and a dummy variable.[13] Both models used historical annual data from 1989/90 to 2016/17. The use of a lagging time frame with

[12] $Blended\ GDP\ = (Manitoba\ GDP\ in\ m\$)^a * (Canada\ GDP\ in\ B\$)^b * (US\ GDP\ in\ B\$)^c$ where a, b, and c are weights given to different GDP values and the sum of a, b, and c equals to 1. The weights vary by modeled sector. For example, in the regression models used to estimate customer number and average usage for the large GSMM sector, MH used the GDP weights of 30% (a), 35% (b), and 35% (c) for Manitoba, Canada, and US GDP, respectively.

[13] The dummy variable from 1999/00 to 2005/06 is included to reflect the average use of the 750V – 30 kV group being higher for during those years by 250,000 kWh. The average usage of large GSMM customers from 1999/00 to 2005/06 is 7,237,157 kWh. The dummy variable used to account for higher usage by 250,000 kWh is just 3.5% of the average usage during that period.

the electricity price is inconsistent between the two groups of GSMM categories. The large customer category relies on an electricity price variable that is lagged by 2 years, whereas the small and medium customer category regression selected did not lag the electricity price variable[14].

~~[CONFIDENTIAL BEGIN]~~ Figure 3 shows the annual average usage (kWh) and customer count for the small and medium customer category within the GSMM sector. The MH load forecast analysis projects both average usage and customer count to grow slightly during the forecast period.

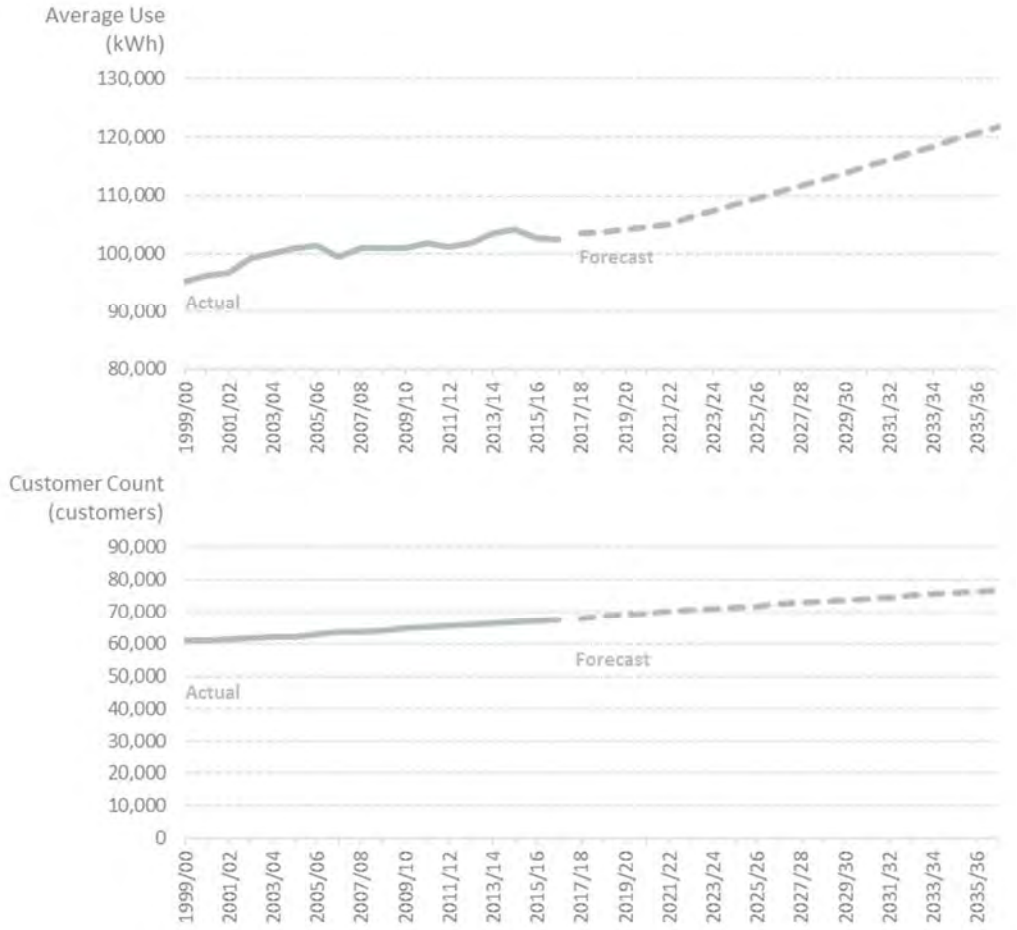


Figure 3: Annual Average Usage and Customer Count for the General Service Mass Market Sector, Small and Medium Customer Category

[14] The use of a lagged variable reduces the number of observations used in the regression model. In the load forecast analysis, MH used historical annual data from 1986/87 to 2016/17 resulting in 33 observations. The use of two-year lag in the large customer category excluded the first three observations resulting in the use of only 28 observations in the analysis.

Similarly, Figure 4 includes the annual average usage and customer count for the large customer category within the GSMM sector, for both historical and forecast periods. The average usage for the GSMM large customer category is projected to decrease within the 2017/18 to 2023/24 period. The decrease in average usage for large customers is mainly due to the proposed rate increase, and its impact on consumption. The number of customers in this category is estimated to increase consistently during the forecast period.

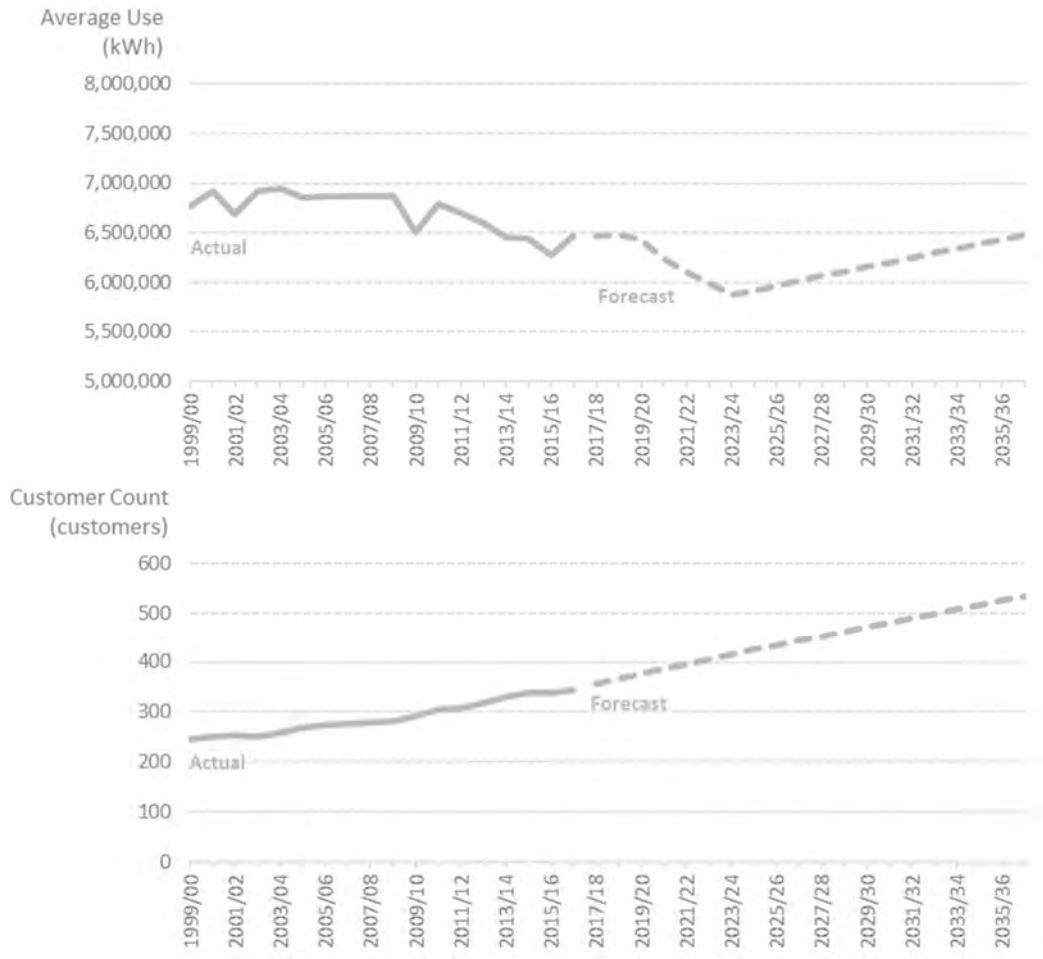


Figure 4: Annual Average Usage and Customer Count for General Service Mass Market Sector, Large Customer Category

~~[CONFIDENTIAL END]~~

The final step in forecasting the GSMM total load requires multiplying the forecasted number of customers in each rate class by the forecasted average use. Similar to the residential sector, the future use of electric vehicles in the general service mass market sector was added to this forecast and the energy savings from the codes and standards, as outlined in Manitoba Hydro's Power Smart Plan, were subtracted from the forecast.

3. Top Consumers

The General Service Top Consumers sector of MH's service territory includes 10 companies with 26 separate accounts that represent 26% of total consumer sales in 2016/2017. ~~[CONFIDENTIAL BEGIN]~~ The 10 companies belong to four industry sectors: primary metals, chemicals, petro/oil/natural gas, and pulp/paper. MH recently moved seven companies from its top consumers category to the GSMM category, citing that these companies have smaller annual usage and the usages are consistent over the future years. [redacted] [CONFIDENTIAL END] The load forecast methodology for the top consumers sector involved creating short-term forecasts for each customer and long-term forecasts for the sector as a whole.

The short-term forecasts were created for each individual customer using information about the individual companies' ~~[CONFIDENTIAL BEGINS]~~ operating plans, short-term expansion or contraction plans as shared in the news and in publications, company prospectuses, and through information gathered by MH's key account representatives. The company-level short-term forecasts generated the load forecast for the first five years. The individual company-level forecasts are then held constant beyond year 5 and a long-term forecast is considered to account for any changes in the load in the top consumer sector as a whole. MH defines this long-term forecast as Potential Large Industrial Loads (PLIL).

MH mentioned that the PLIL allows MH to account for the evaluation of historic shifts in the energy usage of top consumers as a group, rather than as individuals, thus accounting for unexpected load changes for the "current" companies included in the top consumers sector. The PLIL method uses an econometric model that fits a regression model of historical load of the ten top consumer companies with the annual electricity price and a blended Canadian and U.S.-based GDP assumption.

Figure 5 presents both short- and long-term load forecasts for the Top Consumers sector. As mentioned before, the short-term forecast covers the first five year of the forecast.

The industry-specific short-term, along with total short-term load, are presented from 2017/18 to 2022/23 in the following figure. Beyond 2022/23, in addition to the short-term forecast, the figure includes the additional load forecast generated using the PLIL method.

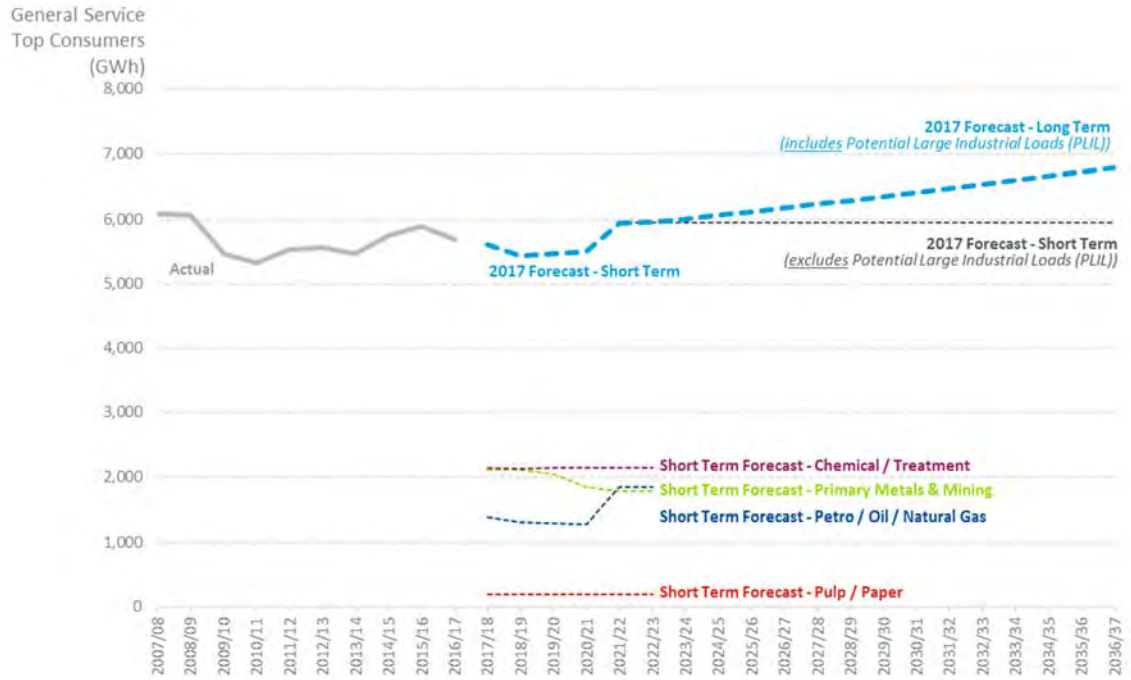


Figure 5: Short- and Long-Term Load Forecasts for the General Service Top Consumers Sector

The 2017 PLIL method used a conservative approach by only considering the total load of top consumers companies that have been in the MH service territory since 1983/84, the start year of MH's modeling period. The 2017 PLIL method excluded the historical load of three companies that are currently in the top consumers sector because they became part of the category after 1983/84. By excluding the historical load of these companies, the 2017 PLIL method did not consider the possibility of additional load from two sources: (1) future new customers that may be joining the MHs service area, nor (2) additional growth from the three companies that were not part of the group for the entire historical period. Unlike the 2017 method, the method used in 2014 for forecasting PLIL load considered the total historical load of the top consumers sector.

Daymark re-ran MH's 2017 PLIL model using the method used by MH in 2014, considering the historical annual load of all companies that are now part of the top

consumers sector.[15] The exclusion from the 2017 PLIL model of the load of three companies that became part of the top consumer sector after 1983/84 has at least two implications. The load forecast estimated for PLIL in 2017 is lower that it would have been if the method used was consistent with the method used in 2014. For example, the load forecast associated with PLIL using the 2017 method is 840 GWh in 2036/37 and the load at the same year using the 2014 methodology is 1,363 GWh. The conservative PLIL method used in 2017 forecasted 523 GWh less load than the method used in 2014 over the forecast period, a difference of 62%.

Moreover, the electricity price elasticity estimated using the more conservative 2017 methodology is lower by 41% than the price elasticity estimated by using the 2014 methodology[16]. MH reported the price elasticity impact of -0.37 in its 2017 Load Forecast report. Using MH's 2014 PLIL methodology, Daymark estimated that the price elasticity for the top consumers would be -0.53. ~~[CONFIDENTIAL END]~~

C. Transmission and Distribution Losses

MH calculated distribution losses by comparing the energy measured at the distribution centers and the energy measured at combined customers' meters.[17] The annual distribution losses for MH in the last twenty years has been between 3.5% to 5.5% of total consumer sales[18]. MH used distribution losses of 4.6% of total consumer sales in its load forecast analysis.[19]

In addition to distribution losses, MH incorporates transmission losses in its load forecast. MH defined transmission losses as the percentage of power (in terms of total consumer sales) lost during the transfer of power from generation stations to the distribution station, collectively known as common bus. The annual transmission losses for MH have been in the range of 8.8% to 10.5% of total consumer sales in the last 20

[15] Daymark's "*Average Use and PLIL stepwise regression summary*" spreadsheet.

[16] The price elasticity reported in the 2017 Load Forecast Report for Top Consumers is -0.3736. Whereas, Daymark estimated the price elasticity of -0.5280 when the 2014 methodology was used with 2017 data. The difference between the two price elasticities is 41.3% using the calculation:

$$\frac{\left(-0.3746-(-0.5280)\right)}{-0.3746}*100\%$$

[17] MH mentioned that besides technical power lost during transfer, other factors that contributed to losses include the offset tween billing cycle and calendar month, customer accounting adjustments, inaccuracies associated with estimated billing, metered but unbilled consumption of Manitoba Hydro offices, and energy theft (Page 31, 2017 Load Forecast Report).

[18] Table 22, Page 31, 2017 Load Forecast Report.

[19] Ibid.

years[20]. In its 2017 Load Forecast Report, MH attributed the transmission losses to the High Voltage Direct Current (HVDC) lines and the distance over which transmission of power generated must travel from northern-located generation to the southern distribution points. MH used an estimate of 9.1% of total consumer sales to account for the future transmission loss in its forecast analysis.[21] This is the average of the last five years' actual transmission losses in the MH territory.

MH's load forecast analysis then incorporates 13.7% of total consumer sales for its transmission and distribution (T&D) losses. The percentage of losses considered for T&D losses is higher than the national averages in Canada and in the U.S. Data from the World Bank suggests that the average transmission and distribution losses in Canada in the last ten years is around 8.5%.[22] Similarly, the U.S. Energy Information Administration reports that average transmission and distribution losses in the U.S. for 2015 were around 4.7%.[23]

D. Gross Firm Energy and Peak Demand

MH uses its sector-level load forecasts along with distribution losses to estimate the common bus load forecast. Specifically, the common bus forecast is the sum of total consumer sales, distribution losses, and construction power. MH adds annual transmission losses and station service load to the common bus energy to forecast the gross firm energy. Figure 6 presents the annual forecast of gross firm energy along with the sector-level load forecasts presented in the 2017 Load Forecast Report.

[20] 2017 Load Forecast Report, page 34, Table 25.

[21] Ibid.

[22] World Bank, accessed October 24, 2017, available at: https://data.worldbank.org/indicator/EG.ELC.LOSS.ZS?locations=CA

[23] US Energy Information Administration, accessed October 24, 2017, available at: https://www.eia.gov/tools/faqs/faq.php?id=105&t=3

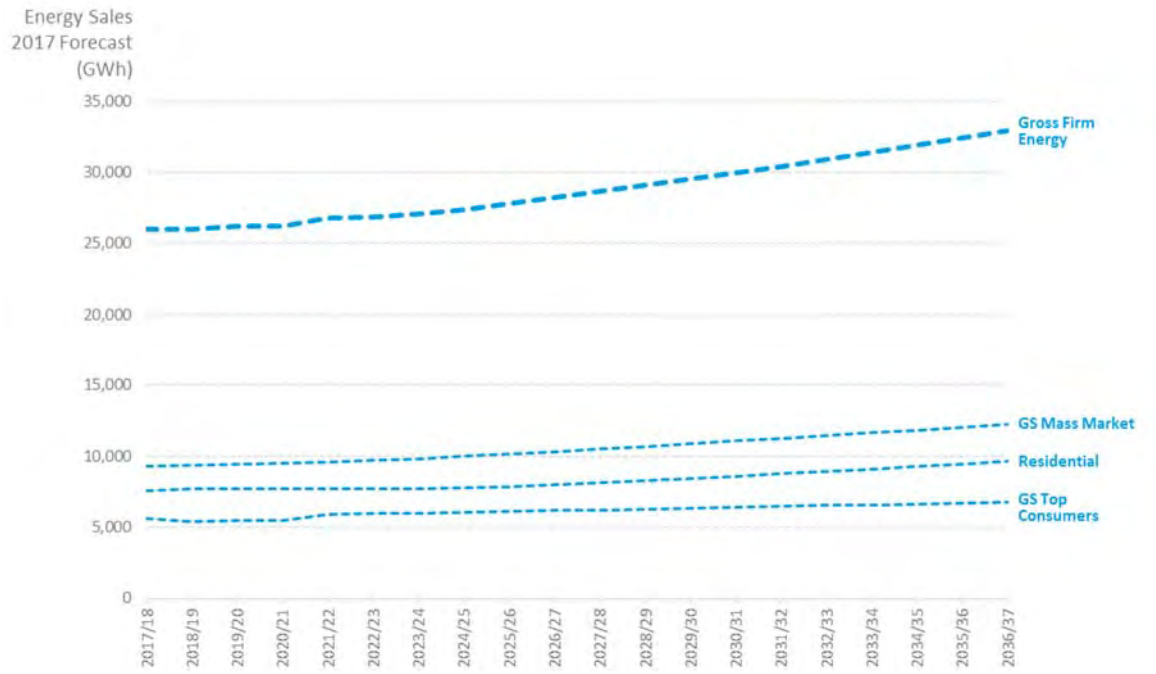


Figure 6: Gross Firm Energy and Sector-Level Load Forecasts

To forecast peak loads, MH breaks the annual energy forecasts into monthly energy forecasts and applies load factors. To forecast monthly gross firm energy, MH uses annual Common Bus load forecasts and the average of historical monthly Common Bus percentages as compared with the annual load. The monthly percentage estimated is based on the 5-year monthly percentage of Common Bus to annual Common Bus load. As shown earlier in Figure 1, the Common Bus is the sum of total consumer sales, distribution losses, and construction power. The monthly transmission losses and station service are added to monthly Common Bus to calculate the monthly gross firm energy.

MH then calculated the monthly total peak demand using the monthly gross firm energy and monthly load factor. Load factor is the ratio of average hourly energy usage to the peak hourly load. The load factors, and eventually the monthly peak load, are calculated separately for the Top Consumers sector since the average hourly usage for Top Consumers is higher relative to their peak value than in the residential of General Service Mass Market sectors. Top Consumers peak loads are calculated by applying a 92% load factor to that sector's monthly energy usage. Alternatively, for the residential and General Service Mass Market customers, a ten-year historical average load factor along with the monthly forecasted energy is used to forecast the monthly peak load.

Figure 7 shows the monthly peak demand (in MW) for the 2017/18 fiscal year. Please note that the 2017/18 fiscal year is from April 2017 to March 2018.



Figure 7: Monthly Peak Load (MW) for 2017/18 Fiscal Year

MH has a winter peaking system and, so it estimates the annual peak demand using the monthly peak demand of three winter months – December, January, and February. MH also applies a ratio using the January peak to estimate the annual peak demand.[24] Figure 8 shows the annual peak demand (MW) of the MH service territory for both historical and forecast periods.

[24] Page 69, 2017 Load Forecast Report.

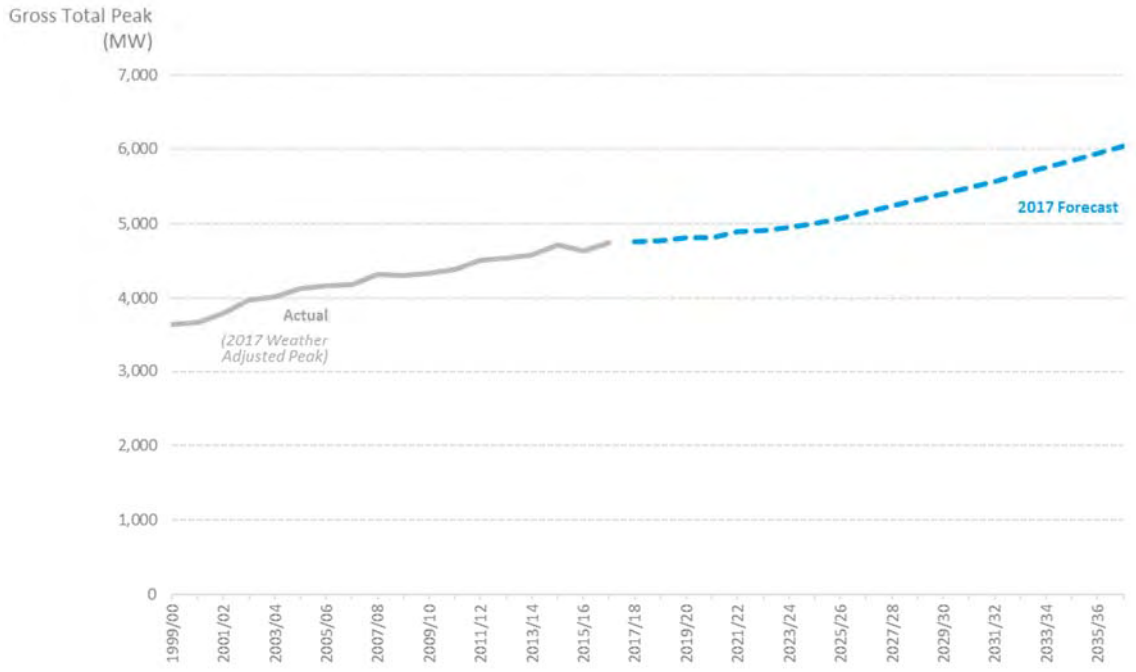


Figure 8: Annual Peak Demand for MH Service Territory

As discussed above, MH uses monthly gross firm energy and monthly load factors to forecast monthly peaks. While this concept is used by other utilities, it is less popular compared to other approaches used for forecasting peak load. According to a 2010 survey of utility companies' forecasting methods conducted by Itron, only 8% of utilities used this method. The same study found that 59% of surveyed companies were using econometric modeling and 26% used load shapes to develop the monthly peaks.[25]

[25] Itron "PGE Forecast Review Summary" (April 2015), p.26

III. COMPARISON OF MH METHODOLOGIES WITH INDUSTRY PRACTICE

A. Econometric and End-Use Forecasting

As discussed in the *Load Forecasting Methodology* section, MH performed forecasts at the sector-level by dividing its customers into three groups – Residential, General Service Mass Market, and Top Consumers. MH used econometric regression models to forecast Residential and GSMM sectors' average usage per customer and number of customers. For its Top Consumers category, MH used company-specific short-term forecasts along with an MH-developed, regression-based long-term forecast known as the PLIL method.

MH's sector-level, regression model based load forecast is consistent with industry practices. Load serving entities (LSE) typically divide the load forecast analysis into residential, commercial, and industrial groups to estimate the average usage and number of customers in each group. The independent variables or predictors used in MH's developed regression models are also similar to the variables used in other load forecasts in the industry.

One of the key predictor variables used in all the sector-level forecasts is electricity price, which allows the utility to account for the potential change in electricity usage with projected changes in electricity price. Besides electricity price, the regression models used by MH contained a variable to account for the change in electricity demand with the change in income or economic health. The Residential sector forecast included real disposable income per capita, whereas the GSMM sector included a GDP variable. However, MH did not include any variable to account for fuel substitution, such as natural gas prices. In light of the electricity price increases due to MH's proposed rate increases and the current low natural gas prices, this type of variable should have been considered.

MH used different approaches for forecasting customer counts for its residential and GSMM sectors. The customer count forecast for the residential sector is based on a third-party population forecast and the ratio of residential customers to population derived from historical data. Alternatively, the GSMM customer count forecast used regression models with residential customer count and GDP as predictor variables. As mentioned, the population and economic forecasts utilized by MH are based on external organization's forecasts. We discuss the key assumptions of the external third-party forecasts in the *Economic Assumptions* section of this report.

MH also relied on end-use forecasting in its residential sector load forecast. As discussed earlier, the use of the end-use forecasting results was limited, despite the effort used to develop and maintain the method. The average customer usage derived from the end-use method was used only to compare with the average usage estimated from MH's econometric method for "reasonableness." The end-use method also estimates "heating saturation", or the ratio of heating customers to total customers, which is used as one of the independent variables in the primary regression model that estimates average usage of residential customers.

Besides the econometric-based method, utilities have used other modeling approaches to forecast load, such as time-series analyses, engineering-based "bottom-up" forecasting approaches, and statistically-adjusted end-use modeling.[26] The time-series models typically use historical sales and weather variables to predict future electricity load. The econometric regression method, such as the one utilized by MH, can use many predictor variables including demographic variables, customer usage information, economy-related variables, monthly and seasonal-fixed effects, electricity and other fuel prices, and weather variables. The engineering-based "bottoms-up" approach is an end-use based model where the load forecast is estimated by disaggregating the usages of key end-uses such as space and water heating, refrigerator, and other appliances or equipment energy consumption. Statistically-adjusted end-use models are a hybrid structure combining components of the engineering end-use technology models with structural econometric equations. In practice, this type of approach mostly considers three different components: appliance ownership via a saturation component, energy usage intensity trends of the appliances or equipment, and consumer's usage behavior.[27]

B. Economic Assumptions

Economic and population variables are used extensively in the econometric modeling used to forecast both customer counts and average usage per customer. For example, the GDP variable is used as one of the predictors for estimating both the number of customers[28] and the average usage for the GSMM sector. Moreover, the PLIL method that is used to account for the long-term load forecast of the Top Consumers sector also

[26] Carvallo, Juan Pablo and *et. al.* Load Forecasting in Electric Utility Integrated Resource Planning. Ernest Orlando Lawrence Berkley National Laboratory, October 2016.

[27] Ibid.

[28] The other predictor used for estimating GSMM customer count is the Residential customer count. And the forecast of Residential customer count is based on the population forecast. Thus, the population forecast has an indirect effect on the GSMM customer count forecast as well.

relies on a combination of the Canada and US GDP as the predictor variable. Similarly, the load forecast for residential customers is based on the population forecast.

The GDP and population data used in the load forecast models are based on a survey of forecasts from various financial and consulting institutions. MH used GDP forecasts of Manitoba, Canada, and United States in its load forecasting methodology by calculating the simple averages of multiple third-party forecasts. MH has used multiple sources for its short-term forecast, but relied on only a few for its long-term GDP and population forecasts. There are many institutions forecasting near-term GDP, whereas there are only a few institutions that generate a long-term forecast.[29]

1. GDP Forecasts

~~**[CONFIDENTIAL BEGIN] [*Labeling this section as confidential as we relied on information provided by MH. To confirm with MH]***~~

The long-term GDP forecast used by MH is the average forecast of three organizations – Conference Board of Canada, IHS Economics, and the Centre for Spatial Economics. Daymark reviewed the method and assumptions used by these three organizations to generate the long-term GDP forecasts.

The Conference Board of Canada (CBC) provided projections of economic and population growth for both Canada and Manitoba. At the national level, the CBC expected the Canadian economy to grow 1.9% in 2017. However, this projected growth rate is much less than the average increase of 3.2% in the decade before the 2008-2009 recession. The CBC did not expect any acceleration in real GDP growth going into 2018 because of low business investment levels and slowing growth in the labor force tied to an aging population. Uncertainty pertaining to the rise of U.S. trade protectionism could also affect forecasted growth. In the long-term, economic growth in Canada is estimated to average 1.8% from 2019 to 2040. While continued anemic business investment levels will continue to hamper growth, the aging of Canada's population[30] will be the main reason behind slackening economic growth.[31]

[29] For example, in order to calculate the Manitoba GDP forecast for 2017 and 2018, MH used the average of Manitoba GDP forecast's estimated by CIBC, Desjardins, Laurentian, National Bank, BMO Nesbitt Burns, Royal Bank, Scotiabank, and TD Bank.

[30] Population aging in Canada will slow down growth in both the population and the labor force and significantly effect income and spending patterns. The rate of retirement for baby boomers is expected to increase over time, which will likely cause labor shortages that will compel companies to increase investment in equipment, machinery, technology, and efficient production methods and workforces.

[31] Confidential – Provincial Source Forecasts, pp. 78-79.

For the province of Manitoba, the CBC pointed out that the province has experienced the second-strongest growth of any province over the last 10 years. Manitoba experienced average annual real GDP growth of 2.5% over the past two decades. However, CBC argued that the lack of investment in important capital stock will lead to a decrease in growth in the future years. CBC believes that the province's capital stock will grow more slowly than most of the other provinces in Canada during the forecast period.[32] CBC expects Manitoba's real GDP growth to average 1.8% annually from 2016 to 2040.

IHS Economics provided a short-term look at the overall Canadian economy and a medium-term analysis of Manitoba's population and GDP. The short-term forecast for real GDP growth in Canada was 2.5% for 2017. However, like the CBC analysis, IHS sees the slowdown in the Canadian labor market and changing trade relations with the U.S. as potentially affecting economic growth.[33] In terms of the U.S. economy, IHS expects the U.S. economy to grow 2.2% in 2017.[34]

Regarding Manitoba, the economy of the province grew 2.4% in 2016. This growth was attributed to growth in goods-producing industries, as well as gains in construction, manufacturing, and agricultural industries. Growth in construction was greatly helped by Manitoba Hydro's construction projects such as the Keeyask power generation station and Bipole III transmission line. There has also been consistent growth of around 2% in the output in the service sector over the past several years. Because of the closing of the Thompson nickel mine in October 2017, the output of the goods-producing industry may experience some contractionary pressures. Therefore, output growth in this sector could decrease to 2.1%. In all, Manitoba is expected to experience around 2.2% growth this year and for the next four years.

The Centre for Spatial Economics (CSE) provides forecasts for economic and population growth in the U.S., Canada, and Manitoba. For the U.S., real GDP growth is expected to average 2.1% and 2.3% for the 2017-2021 and 2022-2028 periods, respectively.

[32] The rising debt levels of Manitoba Hydro will lessen the utility's investment for new projects once the current megaprojects are completed. While mining exploration endures, there have been few greenfield investments announced. Private investment in equipment and machinery will not be enough to support capital stock growth in the province.

[33] Canada's aging population and the growing transition from permanent full-time positions to part-time jobs is influencing the nature of job creation. The trade protectionist policies espoused by President Trump could have economic ramifications for Canada, especially with regard to the value of the Canadian dollar. The announcement of US duties on softwood lumber has led to the Canadian dollar dropping in value relative to the US dollar.

[34] Ibid., pp. 233-234.

However, the CSE acknowledged that there is much uncertainty regarding economic growth globally because of the change in the U.S. administration.[35]

The economic forecast for Canada has the country's real GDP growing on average 1.9% annually for 2017-2021 and 1.7% for 2022-2026. The CSE cited an expected slow recovery for most commodity prices as an important factor influencing growth since these prices impact all aspects of aggregate demand. Similar to the CBC's forecast, the CSE saw a slowing in business investment, especially in the long term when the investment cycle winds down and major projects are finished.[36] The investment and spending rates are expected to increase in the long term because of deficit elimination and the health and social service demands of an aging population. The labor force is estimated to grow by an average of 0.7% over the medium term. However, this rate will decrease to 0.6% during the long term as the participation rate declines and the country's labor force ages. Lastly, the country's population growth is expected to average 1.0% from 2017-2021 and 0.9% from 2022-2028.[37]

Manitoba is expected to see a strong rebound in its manufacturing industry, which will support its economic growth over the forecast period. The province will see an average growth in real GDP of 1.8% in the medium term, with continued investment and project completion in the utility industry helping to bolster this growth during this period.[38] On average, real GDP is estimated to grow 1.2% in the long term.

As discussed earlier, MH calculated the simple average of different third-party GDP forecasts for Manitoba, Canada, and U.S. regions. Figure 9 shows the annual GDP of the Manitoba region used in MH's load forecasting analysis for both historical and forecast

[35] It is expected that machinery and equipment investment will be strong over the medium term with an average of 5.6%. Residential expenditures are estimated to average 5.4% over the medium term and motor vehicle expenditures will average less than 0.5% over the entire forecast period. Ibid., p.362

[36] Residential investment is also expected to remain low because of the general decrease in housing. Consumer expenditure is estimated to be weakened in the middle of the forecast because of rising interest rates but rising to an average of 2.3% in the long term. Government investment is expected to grow by 1.1% while real current spending will grow by 1.3% in the medium term thanks to the federal's government's plan to invest $120 billion in infrastructure over the next ten years.

[37] Ibid., pp. 357-361.

[38] Residential investment is expected to grow by 3.7% annually in the medium-term due to increases in housing starts. Consumer expenditures will average 2.2% over the medium term while government investment will average 1.8% during that period. Employment growth will average a little over 1% in the medium term. Regarding the long term, residential investment will decline to an annual average of 1.3%, while consumer expenditures will also decline to an average of 2%. Government spending will be consistent in the long term at around 1% in the long term, with spending needs increasing due to population aging. The labor force will grow at 1% per year due to slower population growth and a weaker economy towards the end of the forecast time period. Manufacturing will increase in the later years while a reduction in major project investment is expected, which is similar to what the CBC anticipated.

periods. The Manitoba GDP, expressed in millions of 2007 dollars, is estimated to grow consistently during the entire load forecast period.

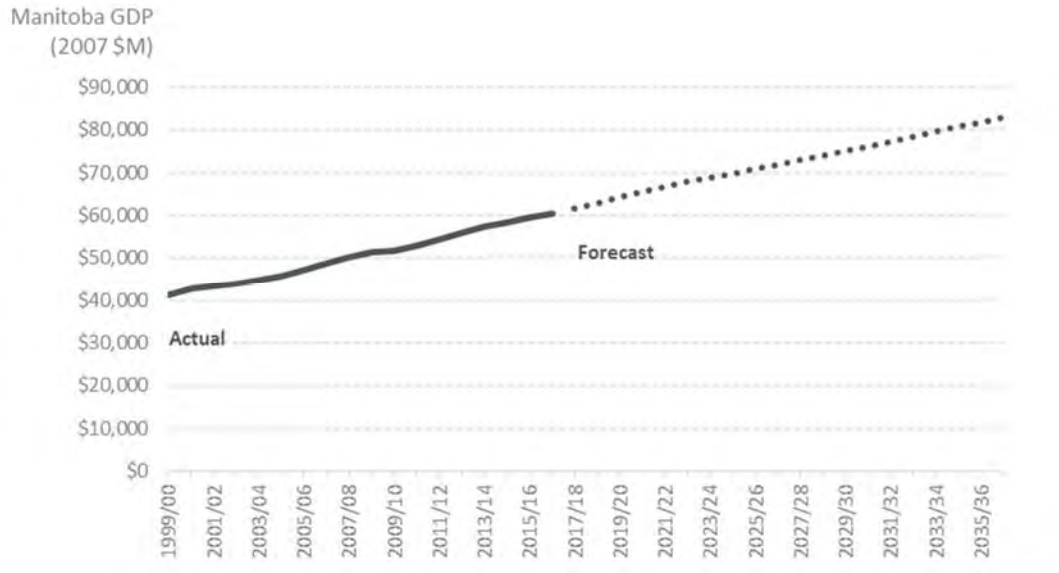


Figure 9: Annual Manitoba GDP (2007 $M) used in MH's Load Forecast

~~**[CONFIDENTIAL END]**~~

MH uses a single GDP variable, defined as a blended GDP, in its load forecast models created by geometrically combining Manitoba, Canada, and U.S. GDPs.[39] The weights assigned to each jurisdiction differ based on the sector modeled.[40] There are a couple of issues with the way the blended GDP is created and used in the analysis. First, the GDP units used for creating a combined GDP for the three sectors are not consistent. MH used Manitoba's GDP in millions of dollars ($), whereas Canada and U.S. GDP are considered in billions of ($). Even though the results (regression coefficients) would not have changed using the same units for three different GDP, the use of a blended GDP also has an interpretability issue, especially with the real GDP elasticity. For instance, the real GDP elasticity estimated for large customers within the GSMM sector is 0.29[41] and

[39] $Blended\ GDP\ = (Manitoba\ GDP\ in\ m\$)^a * (Canada\ GDP\ in\ B\$)^b * (US\ GDP\ in\ B\$)^c$ where a, b, and c are weights given to the different GDPs and the sum of a, b, and c equals to 1. The weights vary by modeled sector. For example, in the regression models used to estimate customer number and average usage for the Large GSMM sector, MH used the GDP weights of 30% (a), 35% (b), and 35% (c) for Manitoba, Canada, and US GDP, respectively.

[40] The Small, Medium category assigned 100% weight to Manitoba GDP. In the models used for the Large GSMM sector, MH used the GDP weights of 30% (a), 35% (b), and 35% (c) for Manitoba, Canada, and US GDP, respectively. Similarly, the PLIL model assigned equal weights of 50% for Canada and US GDPs.

[41] 2017 Load Forecast Report, Page 57.

interpreting this number is challenging until the geometric combination is used to track back to the individual GDP relationship.

2. Population Forecasts

~~[CONFIDENTIAL BEGIN] [*Labeling this section as confidential as we relied on information provided by MH. To confirm with MH]*~~

With regard to demographics, the load forecasting methodology used by MH relies on long-term population forecasts from CBC, Spatial Economics, and IHS. CBC concluded that Manitoba's population is expected to age over the next two decades but at a slower pace than most other Canadian provinces. A higher birth rate is expected for Manitoba, which will bolster natural population increases during the forecast period. Additionally, population growth will be supported by higher levels of international immigration into the province.

While growth in the labor force is expected to slow down over time in Manitoba, its forecasted 1% average annual compound growth will be larger than that of any other province.[42] The IHS report mentioned that Manitoba experienced a multi-decadal record increase in population in 2016 at 1.7%, which would boost domestic demand and labor force growth. Population growth is forecasted by IHS to generally hover around 1.2% for the next four years.[43] Similarly, the forecast created by Spatial Economics predicts that the population of the province will grow on average by 1.3% annually in the medium term while in the long term the growth rate will slow to around 1%. Spatial Economics expects the increase in net international migration of recent years will decline in the medium term, but will be offset somewhat by increases in net interprovincial migration.[44]

The population forecast forms the basis of both the residential and GSMM sector-level customer count forecasts. Historically, MH's evaluation of population and residential customer forecasts shows that MH has typically under-forecasted the population values. Figure 10 shows the average N-year ahead population and residential customer forecast errors. MH estimates the forecast errors using their population forecast and the actual historical numbers. For example, a 5-year ahead error forecast is the percentage difference between actual population and the forecast for population created 5 years in

[42] Ibid., pp. 96-97.
[43] Ibid., pp. 310, 313
[44] Ibid., pp. 376-377

advance. The figure shows that the average percentage error varies, on average, from 0.033% in 1-year ahead comparisons to 2.01% in 10-year ahead forecasts.[45] The positive error percentages denote that the actual population is higher than the forecasted population. Similarly, the average error percentage on forecasts for residential customer counts varies from 0.35% in 1-year ahead forecasts to 4.5% in the 10-year ahead forecasts.[46] Since the load forecast for the residential sector is the product of the customer count forecast and the average usage forecast, the use of a lower-than-actual customer count forecast will result in a lower residential load forecast. Moreover, since residential customer count is one of the predictor variables for forecasting the number of GSMM customers, the use of under-forecasted residential customer numbers results in lower-than-actual GSMM customer counts, which in turn produces a lower GSMM load forecast.

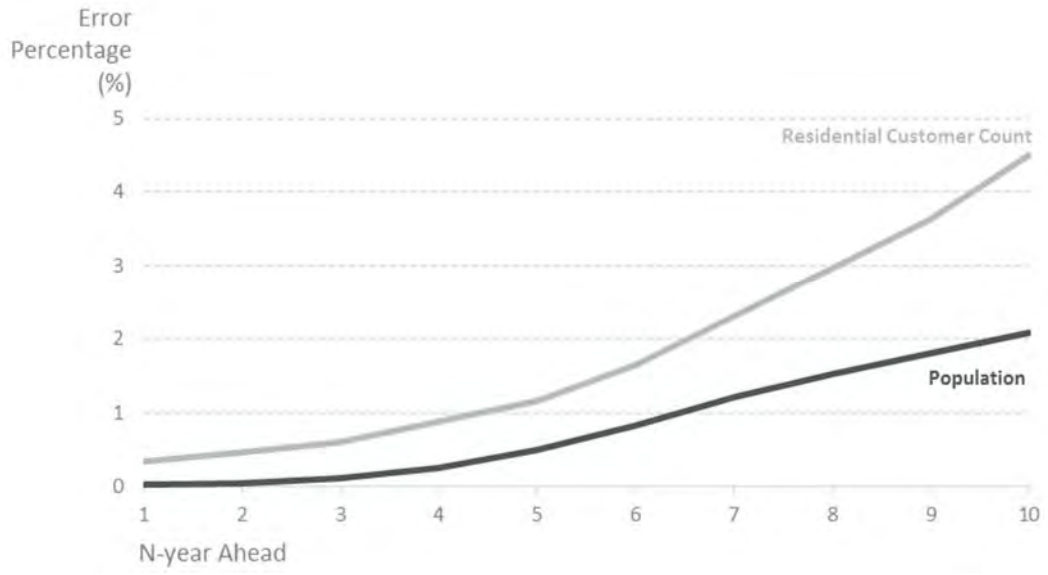


Figure 10: Average N-year Ahead Error Forecast, Population and Residential Customer Count

~~**[CONFIDENTIAL END]**~~

[45] Source: Row 68, "Population Fcst" tab in "Error Evaluation – Manitoba Population 2016" excel file

[46] The error percentage for residential customers only uses data after 2004 as MH reported a structural change in its Residential customer forecast in 2004.

C. Price Elasticity and Implication of Rate Increase

1. Price Elasticity

MH has estimated different elasticities by sector to measure and project the economic effects of electricity price, income, and GDP in the demand for electricity[47]. The price, income, and GDP elasticities were estimated from econometric modeling in the sector-level load forecasts. It is important to estimate the impact of electricity price on MH customers' electricity demand because the proposed rate increase is considerable. Figure 11 shows the real annual electricity price for residential customers.

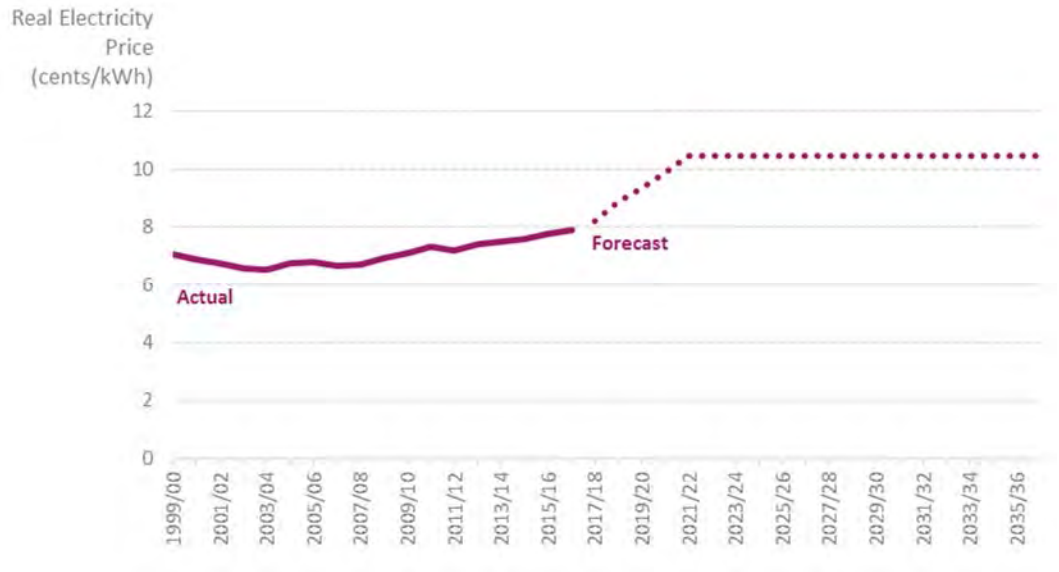


Figure 11: Annual Real Electricity Price, Residential Sector (2016/17 = 100)

Table 1 presents the elasticities estimated and reported by MH in its load forecast report. Using the price elasticity of gross firm energy from the table, MH estimated that a one percent increase in electricity price reduces the gross firm energy by 0.27%. The elasticities estimated are then used – along with the future electricity price, income, and GDP variables – to consider their impact on the load forecast.

[47] Price elasticity estimates the impact of a one percent change in electricity demand with a one percent change in electricity price.

Table 1: MH Estimated Price, Income, and GDP Elasticities [48]

	PRICE ELASTICITY	REAL INCOME ELASTICITY	REAL GDP ELASTICITY
Residential Basic	-0.28	0.30	
GS Mass Market Small/Medium	-0.13		0.55
GS Mass Market Large	-0.46		0.29
GS Top Consumers	-0.37		0.62
Gross Firm Energy	**-0.27**	**0.10**	**0.36**

Daymark found that some of the elasticities reported by MH may be incorrectly estimated for different reasons. The econometric model used for the energy forecast includes a variable that estimates the price elasticity of residential customers and that coefficient exhibits a multicollinearity issue. MH reported the price elasticity of -0.28 using the model with the multicollinearity issue. The regression model used for estimating average usage per customer has multicollinearity issues mainly due to the use of highly correlated independent variables - the log transformation income, saturation, and trend variables are highly correlated with each other. Daymark calculated the variance inflation factor (VIF) of the independent variables used in MH's residential regression model, which assesses how much the variance of an estimated regression coefficient increases if the predictors are correlated. A VIF value of 5 or greater indicates a reason to be concerned about multicollinearity[49]. As presented in Table 3, The VIF values of the independent variables of income, saturation, and trend variables are greater than 25 indicating that multicollinearity exists in the model.

Daymark estimated residential price elasticity to be -0.34 when the variables causing the multicollinearity were removed from the equation. Although multicollinearity doesn't affect the overall fit of the model, or result in bad forecasts of the dependent variable, it does produce unreliable coefficient estimates. As a result of the multicollinearity in MH's residential average usage model, the coefficients associated with electricity price and income, which are interpreted as price elasticity and income elasticity, may be incorrectly estimated[50].

Similarly, the price elasticity estimated for the top consumers sector, through the conservative PLIL method, is lower than it would be if it were estimated using the PLIL

[48] 2017 Load Forecast Report, Page 57.

[49] http://blog.minitab.com/blog/adventures-in-statistics-2/what-are-the-effects-of-multicollinearity-and-when-can-i-ignore-them

[50] Ibid.

method from the 2014 load forecast. MH reported the price elasticity of -0.37 for its top consumer sector in 2017. However, Daymark found that the price elasticity for top consumers would be -0.53 if MH had used the method used in the 2014 Load Forecast Report.

Moreover, the use of trend and dummy variables in the average usage models may have suppressed the impact of electricity price elasticity. MH used a trend variable in the average usage regression model featured in their residential forecast. MH mentioned in their load forecast methodology that the trend variable was intended to capture increases in both electric use and house size. A trend variable is typically added to a regression in order to control for a common trend among the variables[51]. In the case of the residential average usage model, a simple positive (1, 2, 3, 4, etc.) trend variable was added to control for the effects of increasing electric use and house size on the other regression variables over time. Even though including the trend variable in the average usage model of residential customer may be justifiable, we found that the residential price elasticity coefficient, decreases after adding the trend variable.

In order to understand the impacts on price elasticity of the trend and dummy variables MH used, Daymark performed stepwise regressions by adding independent variables incrementally to the average usage regressions of residential and GSMM sectors. Table 2 shows the results of the stepwise regression analysis of residential average usage. The values outside the parentheses are the estimated coefficients while the values inside the parentheses are the associated t-values.[52] The data in the last column (Model 4) present the results reported by MH in its 2017 Load Forecast Report[53]. The values of the coefficient for electricity price, or the price elasticity of electricity, across different models becomes smaller in magnitude after the trend variable is included in the regression equation. The price elasticity decreases from 0.46 (Model 3) to 0.28 (Model 4) once the trend variable is included.

[51] For example, regressing a stock price for one company on the stock price of another company may show that they are correlated simply because they were trending in the same direction. By adding a trend variable to the equation, the trend is accounted for and therefore the true nature of the relationship between the two variables is more clearly revealed.

[52] A t-value measures the extremeness of a statistical estimate. It is calculated by subtracting the hypothesized value from the statistical estimate and dividing the resulting value by the estimated standard error. The greater the absolute magnitude of the t-value from zero, the greater the evidence of statistical significance or difference.

[53] 2017 Load Forecast Report, Page 62.

Table 2: Estimates of Stepwise Regression Models of Residential Average Usage Model

RESIDENTIAL BASIC, AVERAGE USAGE MODEL				
	Model 1	Model 2	Model 3	Model 4
Electricity Price	-0.20 (-0.38)	-0.34 (-3.28)	-0.46 (-6.82)	-0.28 (-4.43)
Income	-	0.99 (24.26)	0.23 (1.79)	0.30 (3.19)
Saturation	-	-	3.42 (6.04)	1.31 (2.12)
Trend	-	-	-	0.01 (4.53)
Adjusted R-Squared	-0.03713	0.9609	0.985	0.9922

Table 3 presents the variance inflation factor (VIF), which assesses how much the variance of an estimated regression coefficient increases if the predictors are correlated. The VIF values associated with the income, saturation, and trend variables in MH's residential average usage model show that these three variables created the multicollinearity issue.

Table 3: Variance Inflation Factor (VIF) of Residential Average Usage Model

RESIDENTIAL BASIC, AVERAGE USAGE MODEL - VIF				
	Model 1	Model 2	Model 3	Model 4
Electricity Price	-	1	1.09	1.84
Income	-	1	25.93	26.63
Saturation	-	-	26.19	60.41
Trend	-	-	-	26.05

Moreover, our analysis shows that the inclusion of dummy variables in GSMM average usage regressions also reduces the price elasticity. MH included dummy variables in their forecast models for average usage of GSMM small non-demand, small demand, and medium, and large customers.

- The dummy variable in the GSMM small and medium customer average usage model represents a billing system change that resulted in a reclassification of customers in 2006/07.
- The dummy variable in the GSMM large customer average usage model reflects the average use of the 750V-30kV group being higher by about 250,000 kWh for the years from 1999/00 to 2005/06.

Dummy variables are often added to regressions in order to represent the measurement value of a variable that cannot be easily measured on a numeric ratio scale.[54] .

However, the coefficients for electricity price (also price elasticities of electricity) in the GSMM small, medium, and large customer average usage models decrease in magnitude once the dummy variables are added to each of the regressions. Table 4 presents the stepwise regression results developed by MH for small and medium customers within the GSMM sector.

Table 4: Estimates of Stepwise Regression of GS Small and Medium Average Usage Model

GSMM SMALL AND MEDIUM CLASS AVERAGE USAGE MODEL COEFFICIENTS			
	Model 1	Model 2	Model 3
Electricity Price	-0.85 (4.17)	-0.17 (4.13)	-0.13 (3.61)
Real GDP	-	0.46 (29.06)	0.55 (21.57)
Dummy	-	-	0.03 (3.79)
Adjusted R-Squared	**0.3779**	**0.9814**	**0.9879**

Similarly, Table 5 includes the stepwise regression results for large customers within the GSMM sector, which were produced by Daymark using the data provided by MH for the same time period. The decrease in price elasticity shows that including a trend or dummy variable in the regression equation reduced the forecasted impact of a price increase compared to when there were no trend or dummy variables used. While the inclusion of both the trend and dummy variables in MH's average usage models may be justified, our analysis shows that the price elasticities reported by MH are underestimated.

Table 5: Estimates of Stepwise Regression of GSMM Large Customers

GSMM LARGE CUSTOMER AVERAGE USAGE MODEL COEFFICIENTS			
	Model 1	Model 2	Model 3
Electricity Price	-1.07 (12.89)	-0.66 (5.86)	-0.46 (5.55)
Real GDP	-	0.22 (4.35)	0.28 (8.05)
Dummy	-	-	0.06 (5.63)
Adjusted R-Squared	**0.8595**	**0.9169**	**0.9627**

[54] Econometrics, Samuel Cameron, p. 173

2. Fuel Switching Not Considered

The load forecasting methodology developed by MH does not consider the effect of electricity price increase completely, particularly the potential substitution effect of electricity price increases. Increases in electricity price impacts customers in two different ways. With the increase in the price of electricity, the budget allocated for electricity can now only buy fewer units than the consumer could afford before. Similarly, the increase in electricity price makes the relative price of other substitute goods cheaper and can reduce the demand for the higher-priced product (electricity) as the consumer switches to a lower-cost substitute product.

The possibility of switching to an alternative fuel type or source due to the increase in electricity price is not explicitly considered in the MH load forecast analysis. For example, as the price of electricity increases and the price of natural gas decreases, or even remains constant, it can be expected that electric load will decrease due to consumers switching to natural gas as a rational response to the price changes. It is important to consider the potential magnitude of fuel or source switching that the proposed rate hike may induce, since electricity prices are requested to increase by 65% in 2025 as compared to 2018 rates.[55] Similarly, the recent trends of low natural gas prices and a steady decrease in solar costs may make these alternatives more economically attractive considering the proposed electricity price. It must also be recognized that a substitution effect will be offset by natural inertia, that is the effort to change fuels may delay or reduce the potential for substitution.

D. Alternative Load Forecast

The method for developing alternatives or ranges around the base load forecast is an important step in the forecast analysis because it considers a wider range of future conditions including alternative trends for the key input variables. A simple point forecast provides a single view of the future – investigating the potential differences that could occur using alternatives, or ranges, affords the utility the ability to plan more effectively by understanding the uncertainties involved.

Investigating alternative load forecast in addition to the base forecast helps to quantify the additional cost (or benefit) that might be realized if the future load pattern follows the path specified in the alternative load forecast rather than the base forecast. Thus, considering these alternative forecasts allows one to understand the magnitude of risk and uncertainty of different likely future load growth scenarios. The alternative load

[55] "2017 GCR AT 2017 RATES" excel file provided by MH.

forecasts are mainly developed using economic models based on scenarios or a statistical (percentile or distribution) approach based on a stochastic approach. Alternative load forecasts are also developed using percentiles or deviations from the base forecast as their alternatives. Besides developing alternative load forecast scenarios, utilities have also evaluated the impact on the base load forecast by varying key input variables individually which is known as sensitivity analysis.

1. Sensitivity and Scenario Analysis

MH's load forecast only considered sensitivity analysis by varying the key input variables of the load forecast analysis. Specifically, MH calculated the impact of a 0.1% annual change in population, income, GDP, and electricity price, on gross firm energy and peak demand over the 20-year forecast period. Table 6 presents these sensitivity results. For example, MH estimated that a 0.1% higher population growth than forecasted by MH in their base or reference forecast will increase the energy forecast in by 293 GWh and the peak load forecast by 54 MW over the next 20 years. The changes in the key input variables considered in the sensitivity analysis were not based on well-defined future economic or technology trends.

Table 6: Sensitivity of Load Forecast to an Assumption Change

CHANGE IN 20 YEAR AVERAGE ANNUAL GROWTH RATE	ENERGY (GWh)	PEAK (MW)
0.1% Increase/Decrease in Population	± 293	± 54
0.1% Increase/Decrease in Income	± 49	± 9
0.1% Increase/Decrease in GDP	± 178	± 33
0.1% Increase/Decrease in Electricity Price	∓ 134	∓ 25
Climate Change per Degree Celsius Warmer	+ 20	- 49

MH also evaluated the impact of a few extreme events on its future energy load. MH considered the effect of extreme events such as a 100 percent conversion of natural gas use to electricity, potential changes in load from a very large industrial customer, an increase in online shopping, high adoption of electric vehicles, and an illustrated effect of grid parity.[56] Table 7 presents the impact of extreme events on the base load forecast as estimated by MH.

[56] Grid parity is when a customer will have an economic option to provide some or all of their electricity need via an alternative energy source. The illustrated example of grid parity used by MH evaluated the load impact due to solar panel installation by 100,000 residential (2 kW system) and 10,000 commercial (50 kW system) customers. (Page 55, 2017 Load Forecast Report)

Table 7: Evaluation of Extreme Events

	ENERGY (GWh)	PEAK (MW)
All Natural Gas in Manitoba to Electricity	+ 16,000	+ 7,000
Increase/Decrease of One Very Large Industrial Customer	± 1,500	± 180
Maximum Potential Effect of Increased Online Shopping	– 775	– 143
Additional Load if 100% Electric Vehicle Saturation Rate	+ 12,015	+ 1,502
Illustrated Effect of Grid Parity (e.g., Solar Panels)	– 857	– 78

Even though MH evaluated the impact of changes in its key econometric analysis variables, its load forecast analysis did not consider scenario analysis by developing alternative load forecasts in addition to the base load forecast. Scenarios help create alternative future values for key variables that represent the different plausible trends that could occur. For example, scenarios may consider key uncertainties by representing different assumptions for economic and population growth, electricity and fuel commodity prices, and CO_2 prices. MH has the ability to develop comprehensive future forecast values that reflect the interactions of several different fundamental variables identified from its sensitivity analysis. Moreover, the different trends of key input variables considered in the scenarios account for the joint impact in the load forecast and, thus, can be an improved alternative to individual variable's impacts considered in the sensitivity analysis.

2. Risk and Uncertainty

MH's load forecast was created by developing various assumptions and different analysis methods to estimate Manitoba's future energy requirement. The underlying variations in the fundamental variables such as population and economic outlook, Top Consumer customers, and overall usage pattern gives rise to uncertainty inherent in MH's load forecast, as it does in any projection. MH created a P50 load forecast, meaning there is an expectation of a 50% chance that the actual growth will be higher than the forecast, and a 50% chance that the actual growth will be lower than the forecasted growth. In order to evaluate the potential load variation, MH then created two different load growth scenarios by considering a P10 and P90 of the base load forecast.[57] The P90 load forecast denotes the level of annual electricity load that is forecasted to be exceeded 90% of the year. The P10 and P90 load forecasts estimated by MH considered the variability due to long-term economic effects and did not include variability due to

[57] High (Low) Load = Base Forecast +/- 1.28*Standard Deviation

weather.[58] The load forecast variability estimated at p10 and p90 are not utilized further in the load forecast analysis.

MH's method of evaluating load uncertainty at p10 and p90 levels relied on considering the overall impact of key input variables such as population, economy, and other effects on the load variation. Utilities have also utilized a more robust approach by evaluating the inherent characteristics of each fundamental variable with the help of probabilistic (i.e., stochastic) risk assessments. This method provides a tool for estimating potential outcomes by allowing random variations in one or more key input variables. Probabilities are assigned to different values of the key uncertain variables, preferably identified through sensitivity analysis. The random variations can be based on fluctuations observed in historical data using standard time-series techniques.[59] Outcomes are then identified that are associated with different values of the key factors in combination. Since the probabilistic method involves generating multiple outcomes by varying key input variables, the final results often include the expected outcome and a probability distribution for these key factors.

E. Reliability of Load Forecast

Daymark compared MH's load forecast from previous years with the actual load to assess the reliability of the load forecast created by MH. Daymark also reviewed MH's method of calculating the accuracy of its load forecast by comparing actual weather adjusted load with the forecasts created five- and ten-years in advance.

1. Historical Performance of Load Forecasting Methods

Daymark gathered forecasts of gross firm energy and sector-level loads created in 2011, 2014, 2015, and 2016 with the goal of comparing these forecasts with the actual observed load.[60] Specifically, we compared the historical actual gross firm energy, residential load, GSMM load, and top consumer load to the corresponding forecasts conducted by Manitoba Hydro through the years. Additionally, weather adjusted values were compared to actual energy values; these are also shown in the coming figures.

[58] The 2017 Load Forecast Report mentioned that the standard deviation of weather variation has been found to be approximately 2% of both energy and peak. Annual weather variations tend to be independent of the economy, so the variance due to weather can be added to the economic variance to derive an overall combined variance. (Source: 2017 Load Forecast Report, Page 44).

[59] The random variations of the input variables are then used to generate a distribution of potential outcomes from a large number of simulations.

[60] "Electric Load Forecast 2011", "Electric Load Forecast 2014", "Electric Load Forecast 2015", "Electric Load Forecast 2016".

Figure 12 compares historical weather adjusted gross firm energy to different forecast vintages of gross firm energy. Comparing the 2011, 2014, and 2015 forecast values of the gross firm energy with the weather adjusted actual gross firm energy, this figure demonstrates that the forecasted load was greater than the actual load for all years. In particular, the 2011 forecast has the highest estimated deviations, followed by the 2015 and the 2014 forecasts. Only one historical data point exists for the 2016 forecast.



Figure 12: Comparison of Historical Weather Adjusted Gross Firm Energy (GWh) with Multiple Forecast Vintages of Gross Firm Energy

Figure 13 displays the estimated residential sales load values from the various forecasts conducted by MH. The 2011 forecast has consistently higher values than the actual historical adjusted values. The 2015 forecast also estimated higher values than those in 2017 in the later years shown in the figure. The figure shows that the Residential forecast created in 2014 estimated lower load than actual for the first two years of the forecast.

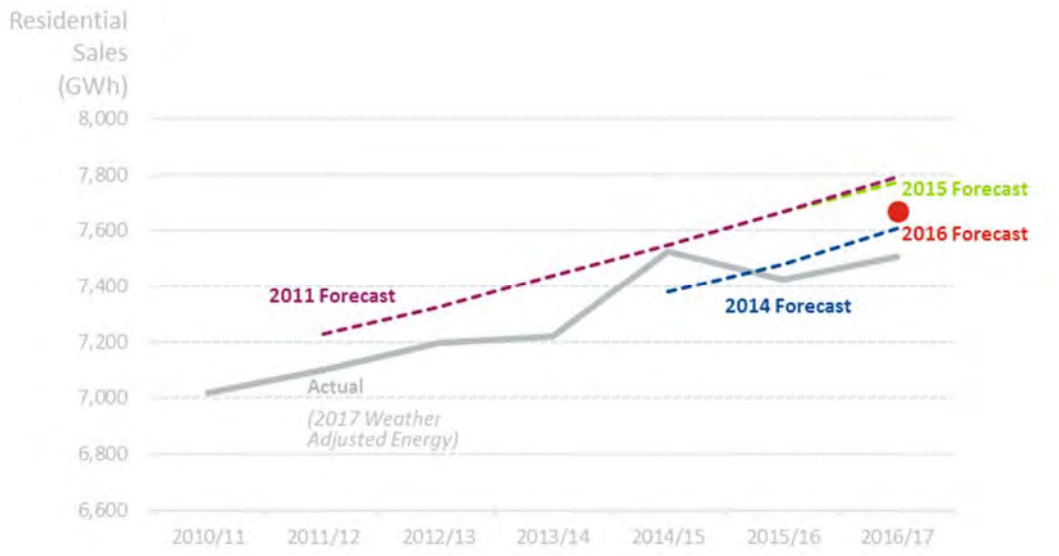


Figure 13: Comparison of Historical Weather Adjusted Residential Sales (GWh) with Multiple Forecast Vintages of Residential Sales

Figure 14 shows the estimated GSMM load values from the different forecast years. Overall, each forecast estimated load values that were higher than actual adjusted energy values. The only exception was the 2016/17 value from the 2015 forecast, which was slightly lower than the actual forecast.

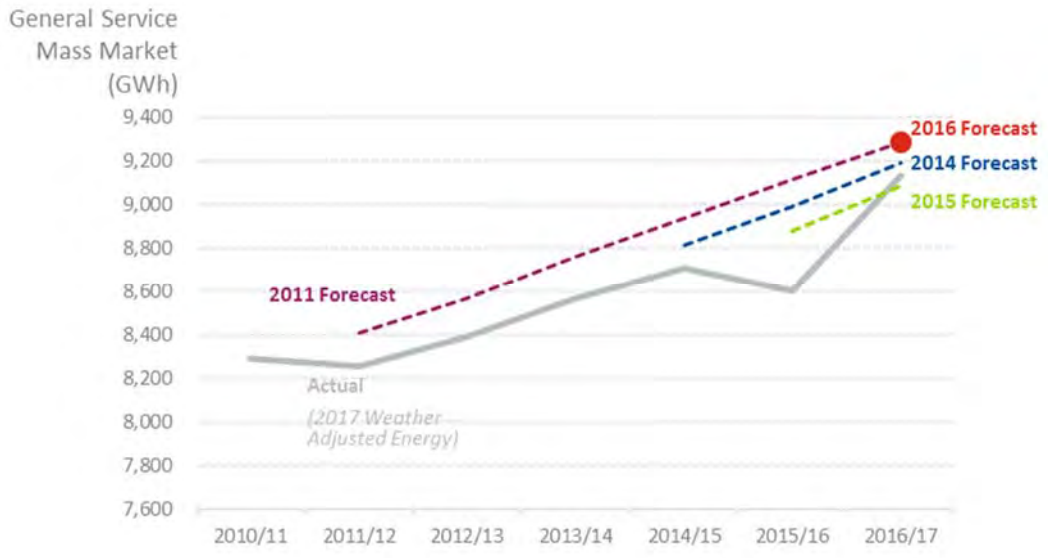


Figure 14: Comparison of Historical Weather Adjusted General Service Mass Market Sales (GWh) with Multiple Forecast Vintages of GSMM Sales

Figure 15 displays the estimated GS top consumer load from different MH forecasts. While all the previous forecasts have load values that were higher than actual historical consumption, there is significant variability in different years' forecasts from 2015/2016. While the 2015 forecast value is lower than both the 2011 and 2014 forecast value in 2015/16, it exceeds both the 2011 and 2014 values by 2016/17. The 2014 forecast value rises to more or less equal the 2011 forecast value in 2015/16 but falls below the 2014 forecast again by 2016/17.

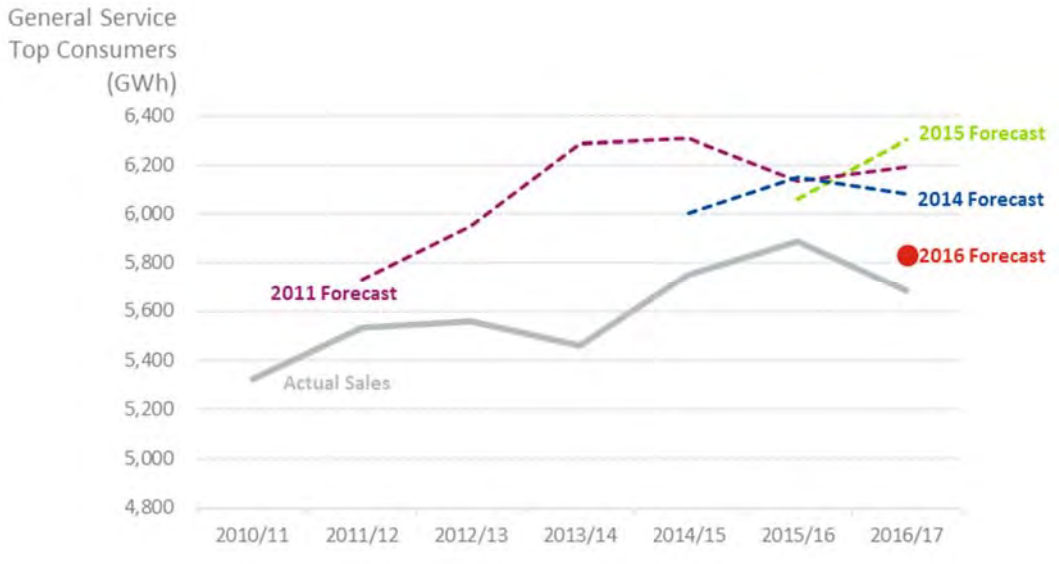


Figure 15: Comparison of Actual General Service Top Consumers Sales (GWh) with Multiple Forecast Vintages of Top Consumers Sales

2. Accuracy of the Load Forecast

MH calculates the accuracy[61] of its previous forecast by comparing the actual load with the forecasts created five- and ten-years in advance. Manitoba Hydro acknowledged that only a certain degree of accuracy is possible regarding the load forecasts due to load variation caused by both population and economic growth.[62] The Company estimates that there is only an 80% chance that a 5-year energy forecast will fall within 3.2% of the actual and an 80% chance that a 10-year forecast will be within 4.3% of the actual due to economic variability alone. The Company tracks historic forecast variation because of these forecast uncertainties[63].

The accuracy calculation method used by MH depends on weather normalization and on adjustments that are made to the forecast by subtracting program-based DSM savings. First, the actual, observed load is weather adjusted. Second, the forecasted program-based DSM savings are subtracted from the accuracy calculation. There is no analysis with regard to how forecasted program-based DSM savings compares with the actual savings. Thus, weather normalization and handling of program-based DSM affects the load forecast accuracy that MH is estimating.

MH can use additional methods to analyze its load forecast accuracies. For example, the sum of errors and annual average growth rate (AAGR) can be alternative metrics to compare forecasts with actual load.[64] The sum of errors is the ratio of the difference between forecasted and actual load to the actual load for any given year. The annual average growth rate[65] compares the load growth rate between two years of actual and forecasted load.

[61] Accuracy at five-year prior: $Accuracy_t = (Forecast_{t-5} - Actual_t)/Actual_t$ where $Actual_t$ is observed load ± weather adjustment – cumulative program-based DSM savings of five years.

[62] 2017 Load Forecast Report, Page 47.

[63] Ibid.

[64] Hyndman, R., 2006. Another Look at Forecast Accuracy Metrics for Intermittent Demand. Foresight Int. J. Appl. Forecast. 43–46.
http://citeseerx.ist.psu.edu/viewdoc/download?doi=10.1.1.218.7816&rep=rep1&type=pdf

[65] $Y_{t+n} = Y_t * (1 + AAGR)^n$

F. Weather Normalization

MH assumes that its load forecast is adjusted to reflect what is considered to be normal weather. The historical annual loads are adjusted to account for weather variability within its load forecasting process. MH adjusts actual load for any weather-dependent usage due to actual differences in weather patterns in the current year as compared to a 'normal' weather pattern year. MH defined the 'normal' weather by using a 25-year rolling average monthly temperature. This process, commonly known as weather normalization, adjusts consumption for the weather-dependent load overserved in the actual load data. A common method in weather normalization, also used by MH, is to first quantify the electricity demand that is dependent on weather being colder or hotter than normal temperature days.[66]

MH's weather normalization regression models used the monthly energy usage, actual heating degree days (HDD), and cooling degree days (CDD) for the same month for the previous two years (24 data points). MH then used the resulting regression coefficients with 'normal' CDD and HDD data to calculate the weather-dependent energy usage for that year. The 'normal' degree days are based on the 25-year rolling temperature average of the Manitoba region.

Figure 16 compares the actual historical gross firm energy with weather adjusted gross firm energy along with the annual HDDs[67] during the same period. The weather adjusted annual gross firm energy is lower than actual gross firm energy since actual annual HDDs are lower than the normal HDD. Similarly, the weather adjusted load is greater than actual gross firm energy when the annual HDDs are higher than normal HDDs.

[66] The parameters used to measure weather-related electricity consumption are degree days. The degree days assume that consumers use more or less energy when the temperature is above or below a certain base temperature. MH has used a base temperature of 14˚C to calculate the heating degree days (HDD) and used the base temperature of 18˚C to calculate the cooling degree days (CDD).

[67] The annual HDDs were calculated using monthly Common Bus HDDs used by MH in its weather normalization. The HDDs are expressed in terms of fiscal year. For example, annual HDDs of 2016/17 includes total monthly HDDs from April 2016 to March 2017.

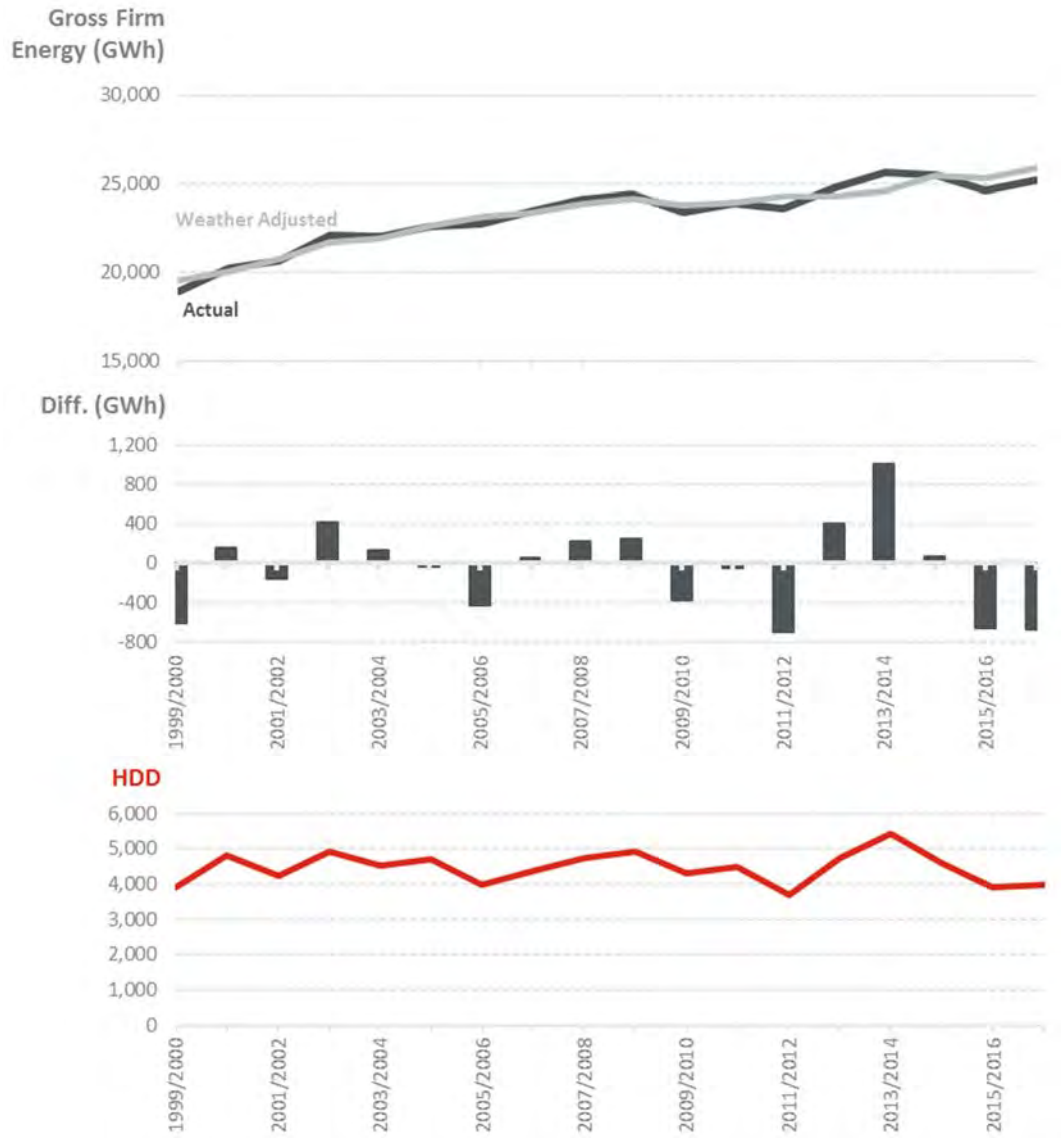


Figure 16: Comparing Actual and Weather Adjusted Gross Firm Energy with the Annual Heating Degree Days

MH may get better estimates of weather-dependent load by relying on more than two-years of monthly energy and degree days to estimate the weather-dependent relationship.[68] Regression models usually produce robust estimates when more data points are used. Since there is wide variation in recent weather patterns, the use of more monthly observation in the weather normalization model will help improve the

[68] Introduction to Regression Analysis, Nonlinear Regression and Curve Fitting: http://www.nlreg.com/intro.htm

robustness of weather dependent estimates. Daymark re-produced the regression results by using the previous ten years of monthly energy usage and weather data using the same weather normalization modeling parameters used by MH. The use of 10-year monthly usage and weather data for residential usage produced lower CDD and HDD coefficients than the coefficients estimated by MH's use of two years of data.[69]

MH could also improve its weather normalization by using a shorter-period to calculate the "normal" year weather variables. As mentioned earlier, MH used a 25-year rolling average to get normal year weather parameters for CDD and HDD. Many utilities are moving to the use of shorter time-periods to create normal weather temperature profiles. For example, BC Hydro uses a ten-year rolling average of monthly heating and cooling degree days.[70] With the climate change debate, it may make sense to use a shorter time-frame if in fact electricity use is becoming more weather-dependent. However, MH has not provided evidence to demonstrate why one approach is superior to the other.

G. Incorporation of DSM Savings in Load Forecast

MH considered two potential DSM-based savings programs in the load forecast analysis: savings based on the implementation of Codes and Standards (C&S) and utility program-based DSM savings. The annual historical average electricity usage also included both program-based and C&S-based energy savings. Essentially, MH added back historic DSM savings to the actual measured energy use prior to estimating its average use per customer for residential, GSMM, and top consumers[71] sectors.

The logic for including these DSM savings with actual measured MH load is that MH would have to serve this additional load if the DSM measures were not in place as part of C&S or utility-sponsored DSM programs. However, it is not clear why MH would add DSM savings related with C&S savings. The C&S DSM savings are based on set rules and these rules may have the same requirements going forward if they are not replaced by more stringent rules. Even though MH excludes the future C&S savings once the forecasts are created, the use of historical C&S DSM savings in the average usage regression model estimates different future average usage values than the average

[69] Using the same regression model used by MH with 10-year data. Data provided by MH in excel workbook: "WeatherNormalizationUpdated2-Daymark.xlsx"

[70] BC Hydro, Fiscal 2017 to Fiscal 2019 Revenue Requirements Application, Chapter 3-Load and Revenue Forecast, Page 3-6.

[71] The DSM savings are adjusted via PLIL model for Top Consumer category.

usage regression model used by MH by considering both C&S and program-based DSM savings.

Comparing MH's DSM forecasting method to those used by other utilities, a 2013 survey of utility forecasting methods found that 38% of utilities surveyed subtract DSM savings from their forecast.[72] Like the method used by Manitoba Hydro, this method assumes that current DSM program impacts are already accounted for in the forecast in the historical data and future DSM programs are not included and therefore are subtracted. Around 22% of utilities surveyed estimate a model with historical DSM and then subtract past and future DSM savings, while 11% of those surveyed capture DSM impacts through the SAE model specification.

[72] Itron "2013 Forecasting Benchmark Survey" p.20

IV. LOAD FORECAST CHANGES (2014 TO 2017)

Daymark carried out a comparison of the 2014 and 2017 load forecast methodologies and assumptions for the various customer groups defined by Manitoba Hydro. These customer group methodologies included the residential basic methodology, the general service mass market methodology, and the general service top consumer methodology. Similarly, we also compared the economic and population assumptions used in generating both the 2014 and 2017 load forecasts.

Overall, the methods used in 2017 produced lower long-term forecasts than the analyses performed in 2014. Figure 17 shows the gross firm energy forecasts created during 2014 and 2017. The 10-year historical growth rate of gross firm energy is 0.85%. The gross firm energy forecasted during 2017 is lower as compared with the gross firm energy forecasted during 2014. The annual growth rate using ten-year gross firm energy forecasted in 2014 is 1.46%. Whereas, the annual growth rate using the 10-year forecast from the 2017 methodology is 0.81.

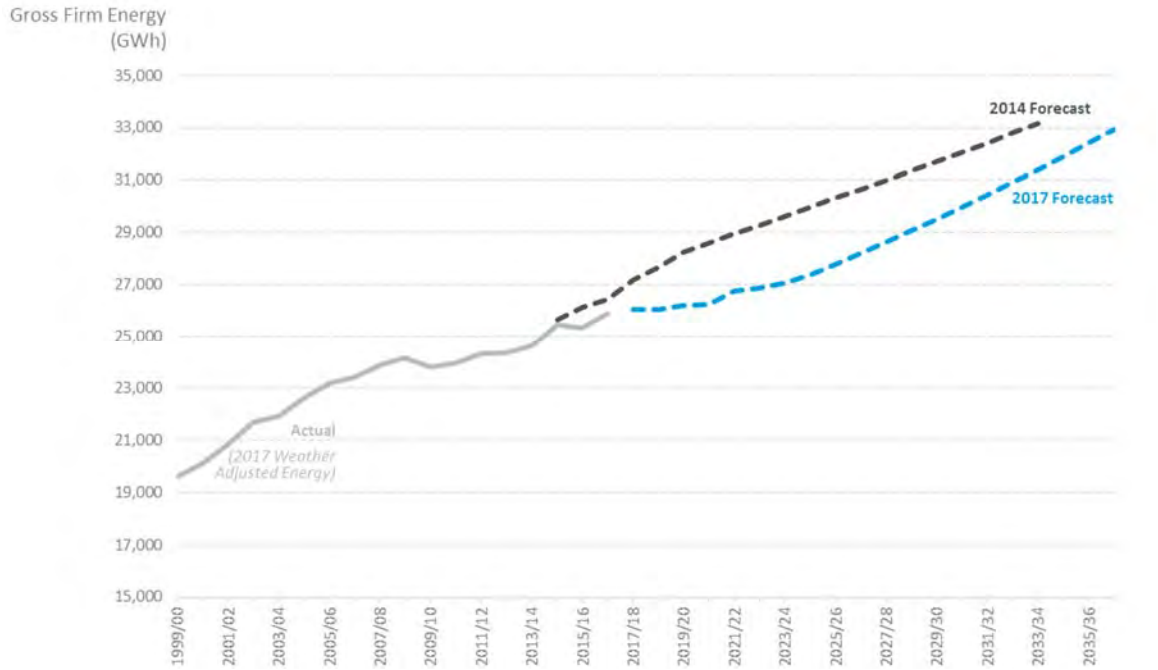


Figure 17: Annual Gross Firm Energy (GWh) Forecast Comparison

Similarly, Figure 18 shows the comparison of MH's 2014 and 2017 peak load forecasts. Consistent with the gross firm energy trend, the MH forecast of peak load in 2017 is lower than the peak load forecasted in 2014.

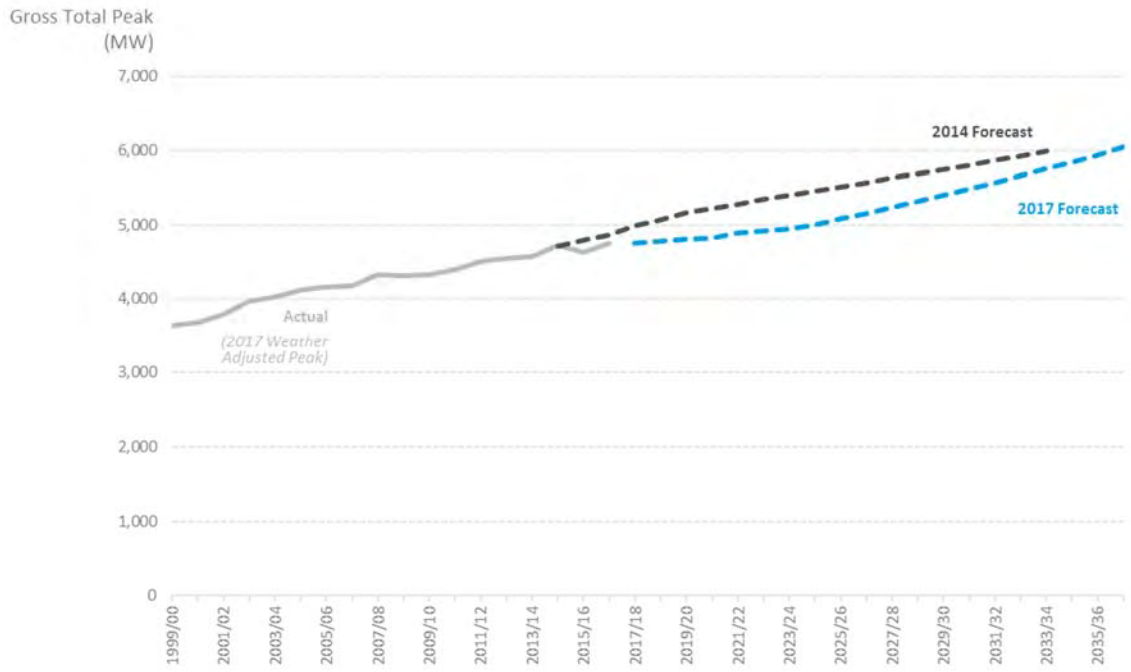


Figure 18: Annual Gross Total Peak (MW) Forecast Comparison

A. Residential Load Forecast Methodology

An econometric forecast of the average annual electricity use per customer of the residential basic sector was featured in both the 2014 and the 2017 methodologies. Although both the 2014 and 2017 forecasts used trend variables in their models, the trend variable used in the 2017 forecast was specifically defined as capturing increases in electric use and house size.[73] Lastly, the forecasted number of dwellings, multiplied by the overall average customer usage determined the GWh forecast in both 2014 and in 2017. However, the 2014 forecast mentions that annual savings estimates from the Heating Fuel Choice Initiative were subtracted whereas the 2017 forecast subtracted energy savings tied to the higher-adoption of LED lights.

Figure 19 shows the annual residential load forecasts estimated in 2014 and 2017. The residential load forecast is quite comparable between 2014 and 2017, although MH

[73] Manitoba Hydro, "2017 Electric Load Forecast", Market Forecast June 2016.p. 62.

estimated a slightly lower forecast for the residential sector customers in 2017 than in 2014, perhaps as a result of the elasticity response to anticipated electricity price increases among other factors.

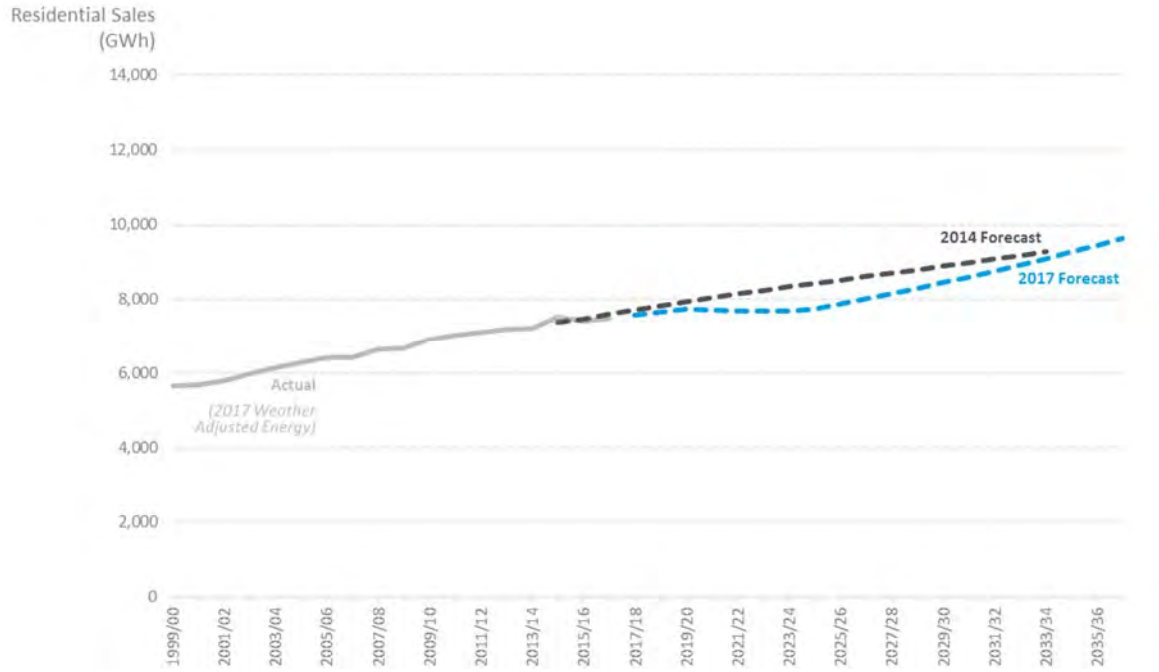


Figure 19: Residential Sales (GWh) Comparison between 2014 and 2017 Load Forecasts

In addition to the econometric model for average usage, the residential load forecast included end-use forecasting in both 2014 and 2017. However, it is not clear how end-use forecasting methodology is further used in both year's load forecasts, besides its use in estimating the ratio of electric heat customers to total customers, which is used in the average usage regression model.[74] The information used for the end-use forecasting model used information provided by the residential energy use survey. The 2014 methodology used the 2009 residential energy use survey while the 2017 methodology used the residential survey completed in 2014. The end-use forecasting methodologies used in 2014 and 2017 varied in forecasting the number of existing residential

[74] The ratio is expressed as a "Saturation" variable in the 2017 Load Forecast report. The 2017 report also mentioned the use of end-use forecasting results to check the reasonableness of total usage estimated from the average usage regression model. However, it is not clear how MH would adjust the average usage model if the results from the regression and end use models provided different results.

dwellings[75], space heating systems in the new dwellings[76], assumptions used for existing heating system in 2014, and heating choice method for 2017[77] .

B. General Service Mass Market Methodology

The general service mass market methodology in both 2014 and 2017 used two forecasts: a customer count forecast, and an average customer usage forecast. The customer count forecast model uses econometric regressions in both years. However, there are some differences between how this analysis was carried out in 2014 as compared to 2017. The percentage change in the number of customers was modeled in 2014 while the 2017 forecast estimated the customer count directly. Furthermore, the variable for Manitoba GDP is explained as being lagged[78] in the 2014 analysis but not in the 2017 analysis. Depending on the customer class, the GDP and customer variables used in the model equations for GSMM large customers differ between 2014 and 2017. The 2017 methodology uses a blended GDP variable created by blending Manitoba, Canada, U.S. real GDPs to forecast the year-end number of GSMM large customers. We discussed the implication of using a blended variable in detail in the *GDP Forecasts* section of this report.

The general service mass market average usage forecast calculated the historical average use per general service customer. The 2014 model does not lag electric price while the 2017 model lags electric price by two years. Unlike the 2014 model, the 2017 model incorporates dummy variables. The 2017 model also used a blended real GDP and holds the average use of each rate group constant. Finally, the 2017 model adjusted the number of customers in each group. The general service mass market sales forecast for 2014 and 2017 both project total GWh by multiplying the forecasted number of

[75] The forecast for existing dwellings differed between the 2014 and 2017 residential basic methodologies since the 2017 methodology specifically mentions that customer space heating fuel switches were taken into consideration for the forecast. The treatment of historical space heating systems by dwelling did not differ between the two methodologies, both involving the division of historical dwellings by type and region into nine space heating systems.

[76] The regions featured in the forecast were “Winnipeg” and “South Gas” in 2014 while the 2017 regions included “Winnipeg” and “Gas Available.” The regressions in the 2017 forecasts used a natural gas price trend variable, which was absent in the 2014 regressions. The weighted average and lag-years used in the regressions differ between 2014 and 2017. It seemed that choice of lag variables and assigned weighting is mainly driven with the goal of getting optimum statistical results rather than economic sense.

[77] The 2014 forecast methodology mentions that the former heating systems of dwellings were determined from billing system notes and inventory, while the 2017 forecast methodology makes no mention of this technique. The utilization of saving estimates from the Heating Fuel Choice initiative was also mentioned in the 2017 methodology for the forecast of water heating systems in new and existing dwellings but missing in the 2014 methodology.

[78] The lagged independent variable (Manitoba GDP) allows the regression to account for the impact of past value of the independent variable on the current dependent variable.

customers in each rate class by the forecasted average usage within those same rate classes. The future use of electric vehicles in the mass market sector was added to this forecast Figure 20 presents the general service mass market annual load forecast from 2014 and 2017. The 2017 load forecast is slightly lower than the 2014 load forecast; however, the annual load estimated in 2017 is projected to be higher than the load estimated in 2014 in the year 2027/28.

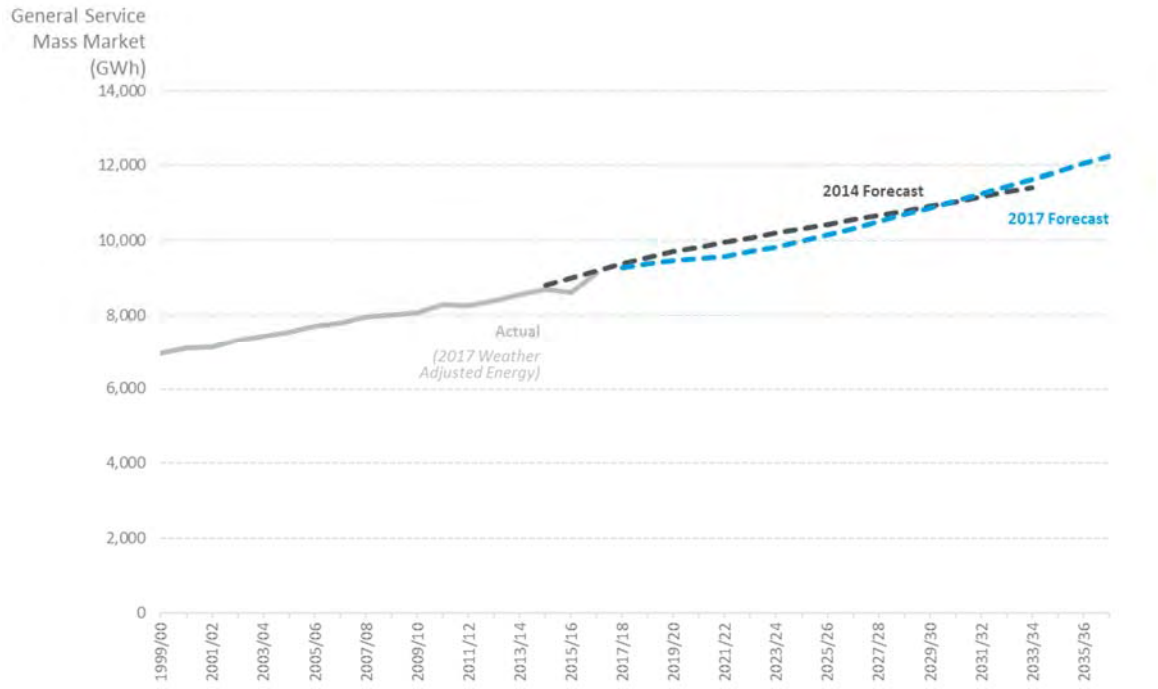


Figure 20: General Service Mass Market Sales (GWh) Comparison between 2014 and 2017 Load Forecasts

C. Top Consumers Load Forecast Methodology

The 2014 and 2017 general service top consumers methodologies both revolved around creating short-term and long-term growth forecasts among the company's top-consuming customers. Short-term forecasts are created for each individual customer using information on individual operating plans. The resulting calculations are five-year short-term forecasts for committed projects. To estimate long-term forecasts for the top consumers sector, the PLIL category, introduced earlier, was created. This allows for the evaluation of historic shifts in the energy consumption of top consumers as a group,

rather than simply as individuals. The differences between the 2014 and 2017 methods dealt with the number of companies included in the individual short-term forecasts. The 2014 method relied on 17 individual company forecasts while the 2017 method relies on just 10 individual company forecasts. This is because the 7 other companies moved to the general service mass market category. [CONFIDENTIAL BEGIN] [redacted] [CONFIDENTIAL END]

The long-term PLIL forecast used the same econometric model in both 2014 and 2017. However, the 2017 PLIL method used a conservative approach by only considering the total load of top consumer companies that have been in MH's service territory since 1983/84, the start year of MH's modeling period. The detailed discussion regarding the impact of PLIL method change in 2017 on MH load forecast is presented in the earlier *Top Consumers* section of this report. Figure 21 shows the load forecast comparison between 2014 and 2017 for the top consumers sector. Besides the short-term load forecast differences (number of companies included in top consumer category), the decrease in 2017 load forecast is also a result of the change in the PLIL long-term forecasting method in the 2017 load forecast.

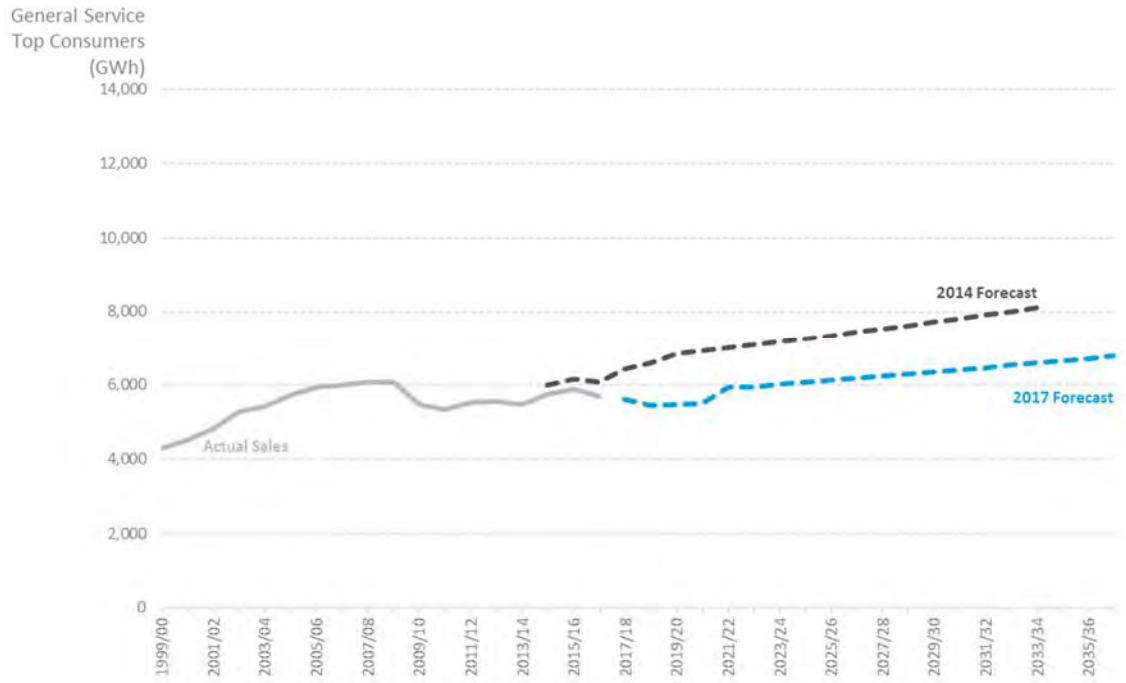


Figure 21: General Service Top Consumers Sales (GWh) Comparison between 2014 and 2017 Load Forecasts

D. Other Aspects of Load Forecast

The methodology for forecasting electric vehicles was the same in both 2014 and 2017. This forecast relied on historical automobile registrations per year in Manitoba to aid in estimating future trends.

The 2014 and 2017 methodologies for forecasting the individual communities that were supplied by diesel generation were also the same. In order to forecast monthly gross firm energy, the 2014 and 2017 methodologies averaged both the monthly percentages of customer growth through the year and the GWh for the month of the year for a specific time period. This time-period was three to five years in the 2014 methodology and five years in the 2017 methodology.

The calculation of monthly and annual gross firm energy and gross total peak in 2014 and 2017 were the same except for a few aspects. The 2014 method added top consumer peaks using a 95% load factor applied to the top consumer monthly energy while the 2017 method used a 92% load factor. While both the 2014 and 2017 methodologies used a three-month winter load factor for the winter months of

December, January, and February to calculate the annual gross total peak, the 2017 method applied a ratio from the January peak for use as the annual peak.

E. Assumptions

The economic assumptions that went into the 2014 and 2017 load forecast were taken from Manitoba Hydro's economic outlook and energy price outlook for those respective years. The number of residential basic customers in Manitoba was forecasted to increase by 1.3% (5,802 units) in 2014/2015 with averages of 1.0% per year throughout the forecast period. The historical average increase in 2014 was 1.0% per year over the last ten years. In 2017, the forecast of the number of residential basic customers estimated a 1.2 % increase in 2017/18 with an annual average of 1.1% per year during the forecast period. For 2017, the historical average increase in customers was 1.2% per year over the last ten years.

The electricity price forecast in both 2014 and 2017 is based on the Consumer Price Index and rate increase projections from the integrated financial forecast. In 2014, the real electricity price was forecasted to increase by 2.2% in 2014/15, increase between 1.9% and 2.1% from 2015/16 to 2018/19, and increase by 1.9% annually for the remainder of the forecast period[79]. In 2017, the price was forecasted to increase 3.36% in 2018, 7.9% annually from 2019 to 2024, and 4.54% in 2025.[80] In addition, MH also included a 2% price increase beyond 2025 to adjust for inflation.

In 2014, the real Manitoba disposable income annual growth was 1.2% for the previous 10 years and 0.8 % for the previous 20 years. The rate was forecasted to grow at 1.0% annually for the following 10 years and 1.2% annually for the next 20 years. These values changed in 2017, with the disposable income per residential customer growing on average by 1.4% during the past 20 years and 1.7% over the past 10 years. The disposable income is forecasted to grow 0.6% annually for the next 20 years and was used in the residential basic forecast in both 2014 and 2017.

Forecast information on the real economic growth (GDP) in Manitoba is used in the general service mass market and general service top consumers forecasts. The 2014 forecast expected estimated economic growth to be 2.2% in 2014/15, with 2.7% expected growth by 2016/17. Growth was then estimated to drop to 1.6% by 2020/21, staying level for the rest of the forecast period. In the 2017 methodology, the real economic growth expectations for Manitoba, Canada, and the U.S. that were used in the

[79] 2014 Load Forecast Report, Page 56

[80] MH-provided Excel workpaper. "2017 GCR AT 2017 Rates"

analysis were different than the numbers used in 2014. The real Manitoba GDP is expected to grow 2.0% in 2017/2018 and an average of 1.6% annually for the next 20 years. GDP in Canada is forecasted to grow 2.1% in 2017/18 and an average of 1.8% annually over the next 20 years. The GDP for the U.S. is estimated to grow 2.3% in 2017/18 and an average of 2.1% annually for the next 20 years.

The elasticities of price, real income, and real GDP were estimated using econometric modeling in the 2014 and 2017 forecasts. Price elasticities were determined for residential basic customers, general service mass market small and medium customers, general service mass market large customers, general service top consumers customers, and gross firm energy. Real income elasticities were calculated for residential basic and gross firm energy categories. Lastly, real GDP elasticities were estimated for all general service customer categories. Table 8 presents the price, income, and GDP elasticities estimated by MH in its 2014 and 2017 Load Forecast report. The elasticities estimated are very similar in both years.

Table 8: Comparison of MH Estimated Price, Income, and GDP Elasticities in 2014[81] and 2017[82]

2014 Load Forecast Methodology

	PRICE ELASTICITY	REAL INCOME ELASTICITY	REAL GDP ELASTICITY
Residential Basic	-0.26	0.27	
GS Mass Market Small/Medium	-0.12		0.55
GS Mass Market Large	-0.46		0.29
GS Top Consumers	-0.43		0.86
Gross Firm Energy	**-0.25**	**0.51**	
		(Income + GDP Combined)	

2017 Load Forecast Methodology

	PRICE ELASTICITY	REAL INCOME ELASTICITY	REAL GDP ELASTICITY
Residential Basic	-0.28	0.3	
GS Mass Market Small/Medium	-0.13		0.55
GS Mass Market Large	-0.46		0.29
GS Top Consumers	-0.37		0.62
Gross Firm Energy	**-0.27**	**0.1**	**0.36**

[81] 2014 Load Forecast Report, Page 58.

Both the 2014 and 2017 forecasts reflected future DSM savings that were tied to existing provincial building codes and improved equipment efficiency standards (codes and standards). These DSM-associated savings from programs are included in the historical data used in the forecast. It is explained in the 2014 forecast that codes and standards were treated as a supply-side resource and are accounted for in Manitoba Hydro's power smart plan and not in the forecast. The 2017 forecast mentions that future DSM savings from future power smart offerings above the current level and incremental to the codes and standards were subtracted from the load forecast.

The normal weather assumptions for both 2014 and 2017 are based on degree days used to measure weather for the forecast. The temperatures used are from Winnipeg and are expressed in Heating Degree Days (HDD) and Cooling Degree Days (CDD), respectively. The HDD are the number of average degrees colder than 14 degrees C each day, whereas the CDD are the number of average degrees warmer than 18 degrees C each day. The forecast assumes normal weather, which is determined from a 25-year average of HDD and CDD in Winnipeg. This 25-year period was April 1989 to March 2014 for the 2014 forecast and April 1992 to March 2017 in the 2017 forecast.

V. SUMMARY AND CONCLUSIONS

Manitoba Hydro uses several different sector-level forecasts to estimate its total annual load. These sectors, which are modeled separately, include residential, general service mass market, and general service top consumers. In total, the load forecast of these sectors represents the total consumer sales.

The company's residential forecast methodology estimates the number of residential customers or dwellings and the average usage of residential customers. The customer forecast relies on different third-party Manitoba forecasts and a ratio of total population to total residential customers estimated by Manitoba Hydro. An econometric model is used to forecast the average annual usage per customer. This model regresses average electricity usage, which includes historical DSM savings, on electricity price, annual disposable income, and the annual ratio of the number of electric heat customers to total customers. The model also features a trend variable to capture increases in electric use and house size. Manitoba Hydro estimated a slight decrease in average residential customer usage over the next few years and an increase in residential customer count at a consistent rate during the forecast period.

The residential energy forecast is created by multiplying the forecasted number of residential customers by the forecasted overall average usage per customer. Projected energy savings tied to LED adoption and increases in energy usage connected to the future adoption of electric vehicles are also added to the forecast. Future energy savings linked to C&S outlined in MH's Power Smart Plan and DSM initiatives were excluded from the annual load forecast.

The general service mass market 2017 methodology forecasted customer count and average annual usage for both small and medium customers and large customers. The customer count forecasts used econometric models featuring GDP and year-end residential customer counts as predictor variables. The average usage forecast for large customers also used electricity price and a dummy variable, but used a blended GDP variable based on trajectories for Manitoba, Canada, and the U.S. Both the annual average usage and customer count projections are expected to grow slightly during the forecast period for the small and medium customer group. For the large customer group, the annual average usage is expected to decrease from 2017/18 to 2023/24, which is primarily due to the proposed rate increases. The number of customers in the large category is projected to increase consistently during the forecast period.

The load forecast methodology for the top consumers sector featured the development of short-term forecasts for each customer and a long-term forecast for the whole sector. This sector includes 10 companies and 26 separate accounts that represent 26% of total consumer sales in 2016/2017. The company-level short-term forecasts estimated the load forecast for the first five years, and then was held constant beyond year 5 where a long-term forecast is introduced to account for load changes for the entire top consumers sector. This long-term forecast, called the Potential Large Industrial Loads or PLIL, relies on an econometric model that fits a regression model of historical load of the ten top consumer companies with the annual energy price and a blended Canadian and U.S. GDP assumption. The PLIL method used in 2017 was conservative in that it only included the total load of top consumers companies that have been in the MH service territory since 1983/84. ~~[CONFIDENTIAL BEGINS]~~ This resulted in the exclusion of the historical load of three companies from the forecast. ~~[CONFIDENTIAL ENDS]~~ This methodology also resulted in the 2017 PLIL forecast estimating 523 GWh less load than would have been estimated using MH's 2014 forecast methodology, which considered the total historical load of the top consumers sector. Furthermore, the 2017 methodology estimated an electricity price elasticity that is 41% lower than the price elasticity estimated using the 2014 methodology.

After reviewing Manitoba Hydro's 2017 load forecast methodologies, Daymark identified several issues worthy of further discussion. Table 9 presents the key summary findings where improvement in methodology may enhance the approach and impact the load forecast. We discuss these below in more detail than in Table 9.

The price elasticities of all three sectors (residential, general service mass market, and top consumers) reported by MH may be incorrectly estimated. The econometric model used for estimating residential price elasticity exhibits a multicollinearity issue. Similarly, the use of trend and dummy variables in the average usage models of the residential and general service mass market sectors have suppressed the impact of electricity price elasticity. In our investigation of the modeling, the regression models used by MH produced higher price elasticity coefficients before the use of trend or dummy variables in the sector-level forecasts. Moreover, the price elasticity estimated for top consumers through the conservative PLIL method is lower than if it was estimated using the PLIL method used in the 2014 load forecast.

MH has historically under forecasted population trends, a predictive variable that underlies the residential and general service mass market forecasts of customer counts. The use of a lower customer forecast will result in a lower residential load forecast and a

lower general service mass market load forecast. Moreover, the company's use of a blended GDP variable presents several issues. The magnitude of the GDP monetary units used to create the blended GDP for the three sectors are not consistent across the Manitoba, Canada, and the U.S. While the regression coefficients would not have changed if the same units were used for the blended GDP variable for the three sectors, the use of a bended GDP has interpretability issues, particularly with regard to the real GDP elasticity.

Manitoba Hydro does not explicitly consider, in its load forecast analysis, the possibility of switching to an alternative energy source, which could reasonably occur as a result of increases in electricity prices. Since electricity prices are requested to increase by 65% in 2025 as compared to 2018 rates, it is important to recognize the amount of energy source switching that may occur. The recent trends in low natural gas prices as well as the consistent decrease in solar costs could make these alternatives more economically attractive based on the proposed electricity price. It is also important to recognize that a substitution effect will offset by the natural inertia, that is, the effort to change fuels may delay or reduce the potential for substitution.

Table 9: Key Summary Findings of MH Load Forecast Analysis

TOPIC	MH METHOD	COMMENT/REMARKS	IMPACT ON LOAD FORECAST
Top Consumers PLIL model	The PLIL accounts for the long-term load growth of the top consumers sector by evaluating historical shifts in the energy usage of top consumers as a group rather than as individuals.	The 2017 PLIL method was conservative because it only considers the total load of top consumer companies that have been in the MH service territory since 1983/84, thus excluding the historical load of three companies that are currently in the top consumer sector.	The conservative PLIL method used in 2017 forecasted 523 GWh less load than using the 2014 method and 2017 data over the 20-year forecast period.
Electricity Price Elasticity	The load forecasting methodology uses price elasticity with the help of econometric regression models at the sector-level.	The price elasticities of all three sectors may be incorrectly estimated. The econometric model used for estimating Residential price elasticity exhibits a multicollinearity issue. Similarly, the use of trend and dummy variables in the average usage models of both the residential and general service mass market sectors have suppressed the impact of electricity price elasticity. Moreover, the price elasticity estimated for top consumers through the conservative PLIL method discussed just above is lower than if it were estimated using the PLIL method used in 2014 load forecast.	The incorrectly estimated price elasticity will not provide the actual impact of proposed rate increases on each sector's electricity demand.
Population Forecast	MH uses population forecasts from an external institution in its load forecasting methodology.	The evaluation of historical population and residential values along with the forecast used by MH show that MH has under-forecasted the population and residential customer count.	Lower customer forecast will result in a lower residential load forecast and a lower general service mass market load forecast.
Scenarios and Sensitivity	MH evaluated the impact of changes in its key econometric analysis variables.	The load forecast analysis did not consider scenario analysis, which would help create alternative future settings that represent the different plausible trends of key input variables used in the base load forecast and provide broader information on potential system implications than the current approach.	Scenario analysis would have provided further insight of the impact of future alternative scenarios on MH's load forecast.
Risk and Uncertainty	MH evaluated load uncertainty at p10 and p90 levels on the base load forecast.	A more robust approach to consider uncertainty on load would be to evaluate the inherent characteristics of each fundamental variable with the help of probabilistic (i.e., stochastic) risk assessments.	
Fuel Switching Consideration in the Analysis	The possibility of switching to an alternative fuel type or fuel source due to the increase in electricity price is not explicitly considered in the MH load forecast analysis.	It is important to consider energy source switching, since electricity prices are requested to increase by 65% in 2025 as compared to 2018 rates. Similarly, the recent trend of low natural gas prices and a steady decrease in solar costs may make these alternatives more economically attractive considering the proposed electricity price changes.	Load forecast may change without considering potential alternative energy source substitution due to the proposed rate increase.

Based on our analysis, Daymark has developed the following recommendations for improving Manitoba Hydro's current load forecasting methodology:

- The load forecast analysis should consider scenario analysis by developing alternative load forecasts in addition to the base load forecast. These scenarios would help create alternative future settings that represent the different possible trends of several key input variables that are used in generating the base load forecast. Such scenarios could consider key uncertainties by representing different assumptions for economic and population growth, electricity and fuel commodity prices, and CO_2 prices.
- MH should evaluate the inherent characteristics of fundamental variables using stochastic risk assessments. Currently, Manitoba Hydro's method of evaluating load uncertainty at p10 and p90 levels is based on considering the overall impact of key input variables on the load variation. Using a stochastic risk assessment method would allow for the estimating of potential outcomes by allowing random variation in key input variables. Probabilities are assigned to different values of key uncertain variables which have optimally been identified through sensitivity analysis.
- MH may generate a better estimate of weather-dependent load by using more than two years of monthly energy and degree day data to estimate the weather-dependent relationship. Currently, the company uses two years of data to estimate the weather-dependent load relationship and 25 years of data to define the "normal" weather year. Also, Manitoba Hydro could improve its weather normalization method by using a shorter period to calculate the "normal" year weather variables.
- MH should consider testing its econometric models of different statistical issues. For example, the average usage regression models contain multicollinearity issues. Similarly, MH should consider the economic reasoning before introducing any new predictor variables in its regression models in addition to checking the statistical significance.

Daymark also compared the 2014 and 2017 load forecast methodologies and assumptions for the various customer groups defined by Manitoba Hydro. Overall, the 2017 methods generated a lower long-term forecast than the analysis conducted in 2014 with the 10-year historical growth rate of gross frim energy forecasted in 2017 being

lower than the 2014 forecasted gross firm energy. Additionally, the annual growth rate using ten-year gross firm energy forecast was higher in 2014 at 1.46% compared to 0.81% in the 2017 forecast. The key differences between 2014 and 2017 load forecast methodologies are in the models used for forecasting mass market customer (GSMM) count, PLIL method used for capturing long-term forecast for top consumer category, and economic and population assumptions used in the analysis.

In order to estimate the customer count for GSMM category, the 2017 forecast estimated customer count directly while the 2014 forecast modeled the percentage change in the number of customer types. The 2017 PLIL method used a conservative approach by only considering the total load of top consumer companies that have been in MH's service territory since 1983/84, the start year of MH's modeling period. Whereas, 2014 PLIL methodology considered load of all companies included in the top consumer category.

APPENDIX A

Daymark Energy Advisors

Scope of Work

DAYMARK ENERGY ADVISORS

Scope of Work

Export Pricing and Revenues Review

1. Review Manitoba Hydro's electricity export price forecast and third party consultant forecasts, including the low and high case forecasts, in the context of current MISO market conditions and factors influencing future MISO prices. The third party consultant forecasts are to be taken as a "given" and are to be assumed to be reasonable and accurate with respect to the other tasks in this Scope of Work. Notwithstanding that the third party consultant forecasts are to be accepted for the purposes of this review, if the IEC identifies significant issues or inconsistencies with the third party consultant forecasts in the course of its general review, those issues or inconsistencies are to be identified in the IEC's reports.

2. Review and assess Manitoba Hydro's forecast of exportable surplus energy and capacity by on-peak and off-peak period, taking into account expected inflow conditions, reservoir levels, and tie line capacities.

3. Review Manitoba Hydro's forecast for export revenues and fuel & power purchases for the next twenty years and assess whether the forecast of net extraprovincial revenue is reasonable. As an independent review of the extraprovincial revenues arising from contracted energy and capacity sales was undertaken at the 2014 NFAT (Exhibit LCA-5 in response to CSI Undertaking UT-34), a review of Manitoba Hydro's export contracts and estimation by the IEC of firm energy revenues and capacity revenues is not required for any contracts that were contemplated and assessed at the NFAT. Manitoba Hydro's updated export revenues, volumes, and unit prices by contract and by year will be provided as part of PUB MFR-84. The firm energy and capacity revenues in PUB MFR-84, for those contracts evaluated by the IEC at the NFAT, are to be taken as "given", so long as the firm energy and capacity revenues are aligned with the independent analysis from the NFAT after adjusting for changes in forecast exchange rates and escalation.

4. Assess the reasonableness of changes in Manitoba Hydro's forecasting methodology that eliminates the assumed premiums for surplus dependable energy and capacity sales.

5. Provide comments on the factors influencing the MISO market and trends that are affecting market prices, including but not limited to:

   (a) state and federal policies on electricity generation and emissions;

   (b) existing generation mix;

   (c) expected new generation to be installed in the next 20 years;

   (d) forecasted generation retirements in the next 20 years;

   (e) supply and demand balance in the northern MISO region; and

   (f) factors that may affect Manitoba Hydro's ability to export energy and capacity into the MISO market.

6. Provide a report to be placed on the public record that provides the Consultant's findings, opinions, and non-commercially sensitive supporting information.

7. Provide a non-public report to the PUB that provides commercially sensitive information and additional calculations supporting the findings.

Public and Commercially Sensitive Load Forecast Review

8. Review Manitoba Hydro's 2017 Load Forecast and assess the changes with respect to the 2014 Load Forecast.

9. Assess Manitoba Hydro's load forecasting methods for Residential, Mass Market, and Top Consumers segments and compare to industry best practices with respect to:

   (a) the econometric and end-use forecasting methodology;

   (b) the elasticity methodology used to evaluate how Manitoba Hydro evaluates the implications of rate increases and new technology on electricity demand.

   (c) Manitoba Hydro's economic assumptions including population growth, GDP growth, and price elasticity;

   (d) the reliability of the short and long-term domestic load forecast modelling;

(e) the extent to which Manitoba Hydro has used appropriate scenario planning to examine the potential impact of changes in the industry, the Manitoba and Canadian economies, available technology (generation and loads) and energy efficiency measures (costs and cost effectiveness);

(f) the appropriate use of probability analysis of projected load forecasts;

(g) the extent to which retrospective load analysis provides confidence in the load forecast;

(h) the reasonableness of peak demand and energy trends including seasonal variations in load forecasting; and

(i) impacts on load forecasts resulting from potential fuel switching, particularly in light of recent trends in the cost of natural gas and potential carbon taxes.

10. Assess other aspects of the load forecasting methodology including transmission and distribution losses.

11. Evaluate the historical performance of Manitoba Hydro's load forecasting methodologies for Residential, Mass Market, and Top Consumers segments.

12. Review the commercially sensitive load forecast for Top Consumers and assess the reasonableness of the forecasting methods and forecast.

13. Coordinate with other IECs who are reviewing price elasticity impacts on electricity demand in order to minimize duplication of analysis.

14. Provide a report to be placed on the public record that provides the Consultant's findings, opinions, and non-commercially sensitive supporting information.

15. Provide a non-public report to the PUB that provides commercially sensitive information and additional calculations supporting the findings.

APPENDIX B

Daymark Energy Advisors

Documents Relied Upon

Consistent with the agreement between Daymark Energy Advisors and the Manitoba Public Utilities Board, the following appendix provides a reference to the documents that were relied upon to develop this Independent Expert Consultant Report.

This appendix is organized into two sections. The first is a list of the documents relied upon that are already part of the record in this docket. The second is an annotated bibliography of additional documents relied upon that are not already part of the record in this docket.

Documents in the Record

Document Name:	Confidential or Non-Confidential:
Manitoba Hydro, "*2017 Electric Load Forecast*", Market Forecast June 2017.	Non-Confidential

Annotated Bibliography of Additional Documents

Document or File Name:	Confidential or Non-Confidential:
Publicly-Sourced Documents	
BC Hydro Power Smart, "*Fiscal 2017 to Fiscal 2019 Revenue Requirements Application*", ERRATA, August 17, 2016.	Non-Confidential
Ernest Orlando Lawrence Berkeley National Laboratory "*Load Forecasting in Electric Utility Integrated Resource Planning*", October 2016.	Non-Confidential
Cameron, "*Making Regression Analysis More Useful, II: Dummies and Trends*", Chapter 7.	Non-Confidential
Itron, "*PGE Forecast Review Summary*", April 2015.	Non-Confidential
Itron, "*2013 Forecasting Benchmarking Study*", August 29, 2013.	Non-Confidential
Wilkerson, Jordan, et al., "*Survey of Western U.S. electric utility resource plans*", December 13, 2013.	Non-Confidential
Public Documents from Manitoba Hydro	
Manitoba Hydro, "*2016 Electric Load Forecast*", Market Forecast June 2016.	Non-Confidential
Manitoba Hydro, "*2011 Electric Load Forecast (For External Use)*", Market Forecast May 2011, Approved July 2011, Revised May 2012.	Non-Confidential
Confidential Document from Manitoba Hydro	
BMO Capital Markets, "*Provincial Monitor*", Spring 2017	Confidential
IFF16 Update with Interim Projected Retail Rates	Confidential
"Error Eval – Manitoba Pop 2016.xlsx"	Confidential
CAC/CENTRA I-10a	Confidential
CAC/CENTRA I-13	Confidential
Christian Associates Energy Consulting, "*Review of Forecast Methods Underlying the 2015 Energy Forecast for Manitoba Hydro*", October 6, 2015.	Confidential
Navius Research Inc., "*Review of Forecasting Methods Used by Manitoba Hydro's Economic Analysis Department (EAD)*", February 28, 2014.	Confidential
"Elec Heat Market Share 2017_Daymark.xlsx"	Confidential

Document or File Name:	Confidential or Non-Confidential:
Manitoba Hydro, "2014 Electric Load Forecast (For Internal Use Only)", Market Forecast, August 2014.	Confidential
Manitoba Hydro, "*2015 Electric Load Forecast (For Internal Use Only)*", Market Forecast June 2015.	Confidential
"Electric Vehicles 2017_Daymark.xlsx"	Confidential
"Error Evaluation – Interest Rates 2015.xlsx"	Confidential
"Error Evaluation – Manitoba Population 2016.xlsx"	Confidential
"Gen2017-Daymark.xlsx"	Confidential
"GeneralConsumersAndManitobaFirm.xlsx"	Confidential
Manitoba Hydro, "*GS Average Use Model, The AUTOREG Procedure*".	Confidential
"GS Large Cust 2017.xlsx"	Confidential
"GS Mass Market 2017 – May 1st_Daymark.xlsx"	Confidential
Manitoba Hydro, "*GS Small and Medium Cust Model, The AUTOREG Procedure*".	Confidential
"GSTop_10_2017_Daymark.xlsx"	Confidential
"GSTop_2014_Daymark.xlsx"	Confidential
"GSTop_2015_Daymark.xlsx"	Confidential
"GSTop_2016_Daymark.xlsx"	Confidential
Manitoba Hydro, "*Manitoba Hydro Weather Normalization, Model Sharing Session, Itron Annual Energy Forecasting Meeting*."	Confidential
"Load Forecast Data – Formulas.xlsx"	Confidential
"MB RGDP exercise.xlsx"	Confidential
"MHResCustForecast.xlsx"	Confidential
Manitoba Hydro, "*Top Consumers PLIL Model, The AUTOREG Procedure*".	Confidential
"PopulationForecast2017.xlsx"	Confidential
PUB MFR 97-Top Consumers LF 2017 – CONFIDENTIAL	Confidential
Manitoba Hydro, "*Res Average Use Model, The AUTOREG Procedure*."	Confidential

Document or File Name:	Confidential or Non-Confidential:
"Res AveUse Model 2017_Daymark.xlsx"	Confidential
"Res End Use 2017_electric_final_Daymark.xlsx"	Confidential
"SurveyOfForecasters2017.xlsx"	Confidential
"Top Consumer PLIL 2017_Daymark.xlsx"	Confidential
"WeatherNormalization-Daymark.xlsx"	Confidential
"WeatherNormalizationUpdated2-Daymark.xlsx"	Confidential
"WeatherNormalizationUpeated-Daymark.xlsx"	Confidential

IEC LOAD FORECAST REPORT - ADDITIONAL REFERENCES

The following table provides detailed references for the footnotes used in Section III.B "Economic Assumptions" of the Daymark IEC Report: Load Forecast Review. The source for many of the footnotes used in the "Economic Assumptions" section of the Report is confidential documents included in a file titled "Provincial Source Forecasts PDF[1]." This is an electronic file provided confidentially by MH in response to Daymark's questions during the site visit regarding provincial economic and population forecasts used by MH to develop their load forecast.

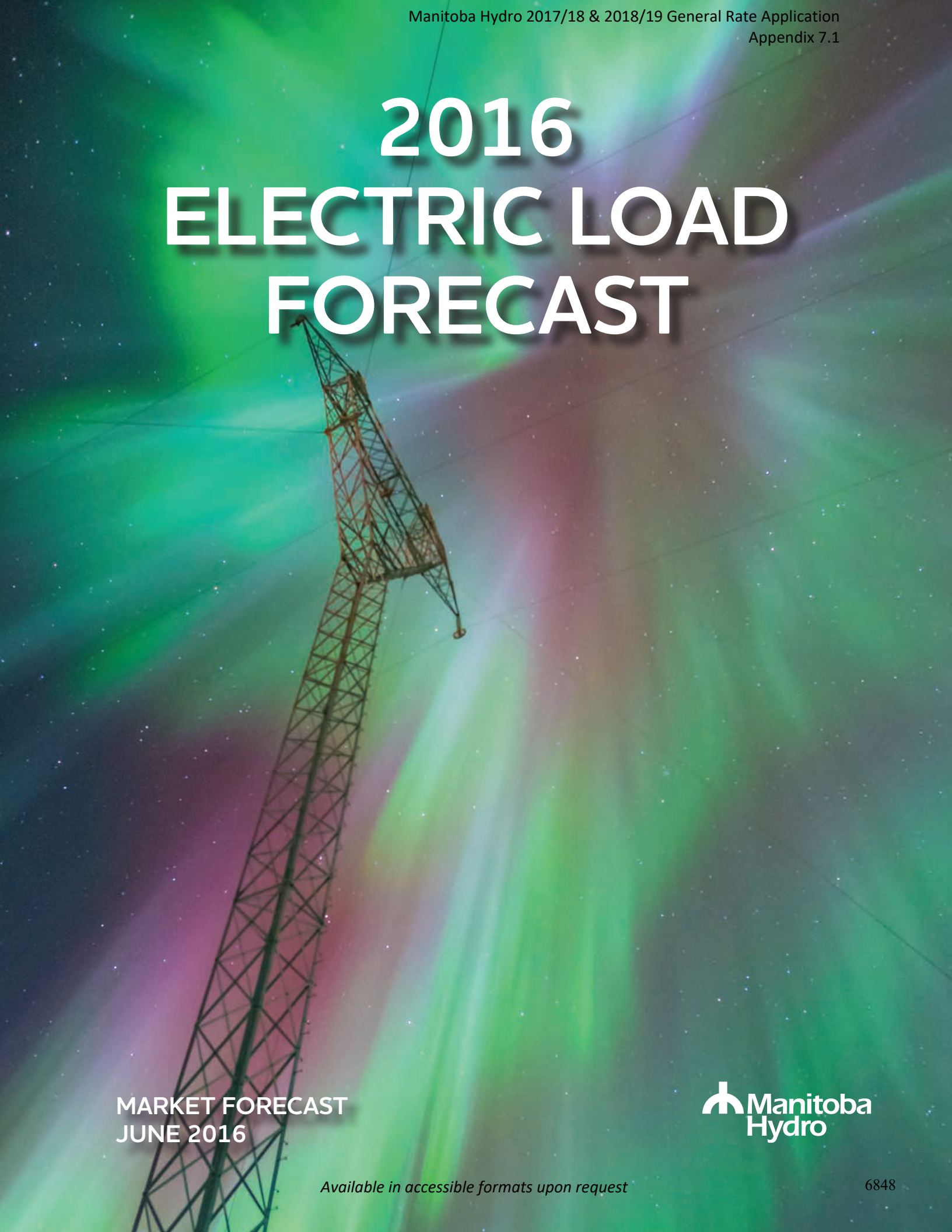
Footnote	Report Page Number	Referenced in the Report filed November 15, 2017	Source of Footnotes	Detailed Reference if Source is from "Confidential - Provincial Source Forecasts" pdf Document
30	26	No	Confidential – Provincial Source Forecasts, Pdf page 78-79.	Conference Board Report, Outlook Long-Term Economic Forecast Manitoba—2017, pages ii-iii.
31	26	Yes	Confidential – Provincial Source Forecasts, Pdf page 78-79.	Conference Board Report, Outlook Long-Term Economic Forecast Manitoba—2017, pages ii-iii.
32	27	No	Confidential – Provincial Source Forecasts, Pdf Page 81, 90, 91, 96.	Conference Board Report, Outlook Long-Term Economic Forecast Manitoba—2017, pages v, xiv, xv and 20
33	27	No	Confidential – Provincial Source Forecasts, Pdf Page 234.	IHS Economics Report "Canada Provincial Forecast and Analysis", May 2017, page 8.
34	27	Yes	Confidential – Provincial Source Forecasts, Pdf page 233-234.	IHS Economics Report "Canada provincial Forecast and Analysis", May 2017, page 7-8.
35	28	Yes	Confidential – Provincial Source Forecasts, Pdf page 362.	Centre for Spatial Economics, The C4SE Provincial Economic Forecast, January 2017, page 3.1.

[1] Document provided by MH indicates that the document is "for the exclusive use of Anitha Brar, abrar@hydro.mb.ca, Manitoba Hydro.

36	28	No	Confidential – Provincial Source Forecasts, Pdf Page 357-358.	Centre for Spatial Economics, The C4SE Provincial Economic Forecast, January 2017, pages 2.1 - 2.2.
37	28	Yes	Confidential – Provincial Source Forecasts, Pdf page 357-361.	IHS Economics Report, The C4SE Provincial Economic Forecast, January 2017, pages 2.1 - 2.4.
38	28	No	Confidential – Provincial Source Forecasts, Pdf Page 376-377.	Centre for Spatial Economics, The C4SE Provincial Economic Forecast, January 2017, pages 7.1 - 7.2.
39	29	No	MH provided Excel Workbook: "GS Mass Market 2017 - May 1st_Daymark"	
40	29	No	MH provided Excel Workbook: "GS Mass Market 2017 - May 1st_Daymark"	
41	29	Yes	2017 Load Forecast Report, Page 57.	
42	30	Yes	Confidential – Provincial Source Forecasts, Pdf Page 96-97.	The Conference Board of Canada Report provincial Outlook Long-Term Economic Forecast Manitoba—2017, Page 20-21.
43	30	Yes	Confidential – Provincial Source Forecasts, Pdf Page 310, 313.	IHS Economics Report "Canada provincial Forecast and Analysis", May 2017, page 80, 83.
44	30	Yes	Confidential – Provincial Source Forecasts, Pdf Page 376-377.	Centre for Spatial Economics, The C4SE Provincial Economic Forecast, January 2017, pages 7.1 - 7.2.
45	31	Yes	Row 68, “Population Fcst” tab in “Error Evaluation – Manitoba Population 2016”	

Tab 64

2016 ELECTRIC LOAD FORECAST



MARKET FORECAST
JUNE 2016

Manitoba Hydro

Available in accessible formats upon request

IMPORTANT:

THIS MATERIAL IS THE EXCLUSIVE PROPERTY OF MANITOBA HYDRO AND ALL RIGHTS ARE RESERVED. ANY RELEASE, REPRODUCTION OR OTHER USE THEREOF WITHOUT THE EXPRESS WRITTEN CONSENT OF MANITOBA HYDRO IS STRICTLY PROHIBITED.

Cover: Gillam Northern Lights (Photo courtesy of Tony Loewen, Operating / Electrical Technician Trainee, Lower Nelson River Maintenance Department)

EXECUTIVE SUMMARY

Overview

The Gross Firm Energy in Manitoba is forecast to grow from a weather adjusted value of 25,355 GWh in 2015/16 to 29,110 GWh in 2025/26. This average growth is 375 GWh or 1.4% per year for 10 years. By 2035/36, Gross Firm Energy is forecast to be 34,193 GWh, a twenty-year growth rate of 442 GWh or 1.5% per year.

Gross Total Peak is forecast to grow at about the same pace, from an adjusted value of 4,634 MW in 2015/16, growing 71 MW or 1.4% a year for the next 10 years, and 81 MW or 1.5% a year for the next 20 years. By 2035/36, the peak is forecast to be 6,250 MW.

Growth is expected in all sectors. The 20 year growth rates in the Residential Basic, General Service Mass Market and General Service Top Consumers sectors are forecast to be 1.2%, 2.1% and 1.1% respectively. During the last 10 years, Gross Firm Energy has grown 215 GWh or 0.9% per year. This ten year period includes the 2009 economic downturn that slowed growth and also reflects the influence of Manitoba Hydro's Demand Side Management activities.

The primary driver of growth in Manitoba is the population, with the secondary driver being the economy. The population of Manitoba has grown from 1,180,000 people in 2005/06 to 1,297,000 people in 2015/16, averaging 1.0% growth per year. Manitoba's population is forecast to grow to 1,562,000 by 2035/36, averaging 0.9% per year. Real Manitoba Gross Domestic Product (GDP) is expected to grow 2.1% in 2016/17 and average 1.8% annually for the next 20 years. Combined Canada and US GDP is forecast to grow 2.0% in 2016/17 and average 2.1% annually for the next 20 years.

Three main components represent the majority of Manitoba's electricity use:

1. **Residential Basic** customer growth is expected to mimic population growth, growing 0.9% per year over the next 20 years. An increase in average use per customer adds 0.3% to the growth and is primarily due to increased use of electric space and electric water heating in dwellings.

2. **General Service Mass Market** is forecast to grow at an average 2.1% per year, which is higher than the historic growth of 1.1% per year over the past ten years. The growth is

primarily due to expected continued growth in GDP and the transfer of seven Top Consumers into the Mass Market sector starting in 2016/17.

3. **General Service Top Consumers** is forecast to grow at 1.1% per year. This is higher than the 0.1% reduction per year during the past ten years which included the loss of a customer and an economic downturn. But it is less than the 4.0% growth per year during the prior ten years. The 20 year historical growth of the Top Consumers has been 1.8% per year.

Change Between the 2015 and 2016 Forecast

The Gross Firm Energy forecast starts 406 GWh (1.5%) lower in 2016/17 and by 2034/35 is 1,479 GWh (4.2%) lower than the 2015 forecast. This is a reduction of just over 3 years of load growth by 2034/35. (1 year = approximately 442 GWh). The difference in 2016/17 is mainly attributable to a lower starting point in the Residential and General Service Mass Market sector, along with changes in the Top Consumers short term plans. By 2034/35, the difference is primarily attributable to the Top Consumers sector (-1,065 GWh) and a lower population forecast lowering the Residential and General Service Mass Market sectors.

Consistent with the reduction in Gross Firm Energy, the Gross Total Peak is 210 MW lower in 2034/35 than presented under the 2015 Forecast, which is a reduction of 2½ years of load growth. (1 year = approximately 80 MW).

Forecast Variability

By 2035/36, the Load Forecast has an 80% probability of being accurate to within ±1,737 GWh or ±5.1%. Due to the inherent variability of the load, this is the best level of accuracy possible.

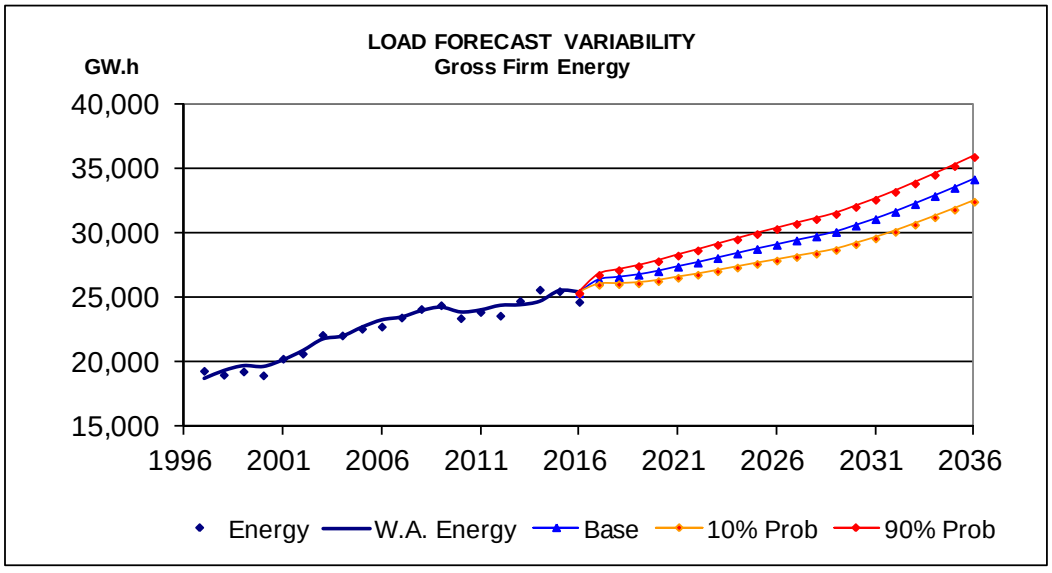


Table 1 - Gross Energy and Peak

GROSS FIRM ENERGY AND GROSS TOTAL PEAK
History and Forecast
2005/06 - 2035/36

Fiscal Year	Gross Firm Energy (GWh)	Growth (%)	Gross Total Peak (MW)	Growth (%)	Load Factor (%)
2005/06	22,757		4,085		63.6%
2006/07	23,464	3.1%	4,208	3.0%	63.7%
2007/08	24,122	2.8%	4,304	2.3%	64.0%
2008/09	24,417	1.2%	4,509	4.8%	61.8%
2009/10	23,412	-4.1%	4,393	-2.6%	60.8%
2010/11	23,892	2.1%	4,286	-2.4%	63.6%
2011/12	23,605	-1.2%	4,367	1.9%	61.7%
2012/13	24,750	4.9%	4,559	4.4%	62.0%
2013/14	25,625	3.5%	4,743	4.0%	61.7%
2014/15	25,505	-0.5%	4,713	-0.6%	61.8%
2015/16	24,673	-3.3%	4,479	-5.0%	62.9%
2015/16 Wadj	25,355	2.8%	4,634	3.5%	62.5%
10 Year Avg Gr.	215	0.9%	47	1.1%	
2016/17	26,385	4.1%	4,850	4.7%	62.1%
2017/18	26,596	0.8%	4,885	0.7%	62.1%
2018/19	26,785	0.7%	4,928	0.9%	62.0%
2019/20	27,060	1.0%	4,971	0.9%	62.1%
2020/21	27,410	1.3%	5,033	1.2%	62.2%
2021/22	27,729	1.2%	5,089	1.1%	62.2%
2022/23	28,082	1.3%	5,154	1.3%	62.2%
2023/24	28,435	1.3%	5,218	1.3%	62.2%
2024/25	28,785	1.2%	5,282	1.2%	62.2%
2025/26	29,110	1.1%	5,341	1.1%	62.2%
10 Year Avg Gr.	375	1.4%	71	1.4%	
2026/27	29,447	1.2%	5,402	1.1%	62.2%
2027/28	29,762	1.1%	5,458	1.0%	62.2%
2028/29	30,106	1.2%	5,520	1.1%	62.3%
2029/30	30,602	1.6%	5,608	1.6%	62.3%
2030/31	31,108	1.7%	5,696	1.6%	62.3%
2031/32	31,666	1.8%	5,796	1.7%	62.4%
2032/33	32,273	1.9%	5,905	1.9%	62.4%
2033/34	32,896	1.9%	6,017	1.9%	62.4%
2034/35	33,532	1.9%	6,131	1.9%	62.4%
2035/36	34,193	2.0%	6,250	1.9%	62.5%
20 Year Avg Gr.	442	1.5%	81	1.5%	

***Note: History and historic growth rates include program-based DSM initiatives.**
Forecast and forecasted growth rates exclude program-based DSM initiatives.

Table 2 - Change in Energy and Peak

GROSS FIRM ENERGY AND GROSS TOTAL PEAK
Change from Previous Forecast
2016/17 - 2035/36

Fiscal Year	Gross Firm Energy			Gross Total Peak		
	2016 Forecast (GWh)	2015 Forecast (GWh)	Change (GWh)	2016 Forecast (MW)	2015 Forecast (MW)	Change (MW)
2015/16 Act	24,673			4,479		
Weather Adj.	682			155		
2015/16 Wadj	25,355	26,145	(790)	4,634	4,829	(195)
2016/17	26,385	26,792	(406)	4,850	4,936	(86)
2017/18	26,596	27,126	(530)	4,885	5,000	(115)
2018/19	26,785	27,486	(701)	4,928	5,063	(135)
2019/20	27,060	27,600	(539)	4,971	5,086	(115)
2020/21	27,410	28,449	(1,039)	5,033	5,210	(178)
2021/22	27,729	28,786	(1,057)	5,089	5,267	(179)
2022/23	28,082	29,197	(1,115)	5,154	5,337	(184)
2023/24	28,435	29,590	(1,155)	5,218	5,406	(187)
2024/25	28,785	29,999	(1,214)	5,282	5,476	(194)
2025/26	29,110	30,408	(1,299)	5,341	5,547	(206)
10 Year	375	426		71	72	
Avg Gr.	1.4%	1.5%		1.4%	1.4%	
2026/27	29,447	30,823	(1,376)	5,402	5,619	(217)
2027/28	29,762	31,243	(1,481)	5,458	5,692	(234)
2028/29	30,106	31,664	(1,559)	5,520	5,765	(245)
2029/30	30,602	32,094	(1,492)	5,608	5,840	(232)
2030/31	31,108	32,531	(1,423)	5,696	5,915	(219)
2031/32	31,666	33,101	(1,435)	5,796	6,012	(217)
2032/33	32,273	33,684	(1,411)	5,905	6,112	(207)
2033/34	32,896	34,317	(1,421)	6,017	6,220	(204)
2034/35	33,532	35,011	(1,479)	6,131	6,341	(210)
19 Year	430	467	(36)	79	80	-1
Avg Gr.	1.5%	1.5%	-0.1%	1.5%	1.4%	0.0%

*Note: History includes program-based DSM initiatives.
Forecast and forecasted growth rates exclude program-based DSM initiatives.

TABLE OF CONTENTS

EXECUTIVE SUMMARY ..... **I**

TABLE OF CONTENTS ..... **V**

LIST OF TABLES AND FIGURES ..... **VI**

INTRODUCTION **1**

FORECAST OVERVIEW **4**

General Consumers Customer Forecast 4
General Consumers Sales Forecast 6
Manitoba Energy Forecast 8
Comparison of the 2015 Forecast to Actuals 10
Change between the 2015 and 2016 Forecasts 12

FORECAST DETAILS **17**

Residential Basic 17
Residential Diesel, Seasonal, and Flat Rate Water Heating 19
General Service Mass Market 20
General Service Top Consumers 21
General Service Diesel, Seasonal, and Flat Rate Water Heat 23
General Service Surplus Energy Program 23
Plug-In Electric Vehicles 24
Area & Roadway Lighting 27
Total General Consumers Sales 29
Diesel Sales 30
Distribution Losses 31
Construction Power 32
Manitoba Load at Common Bus 33
Transmission Losses 34
Station Service 35
Gross Firm Energy 37
Gross Total Peak 39

VARIABILITY AND ACCURACY **42**

Weather Effect and Weather Adjustment 42
Effect of Extreme Weather 43
Load Variability 44
5 and 10 Year Forecast Accuracy 47

LOAD SENSITIVITES AND EXTREME EVENTS **50**

ASSUMPTIONS **56**

Economic Assumptions 56
Price / Income / GDP Elasticity 57
Demand Side Management (DSM) in the Forecast 57
Normal Weather Assumptions 58

METHODOLOGY **59**

GLOSSARY OF TERMS **70**

LIST OF TABLES AND FIGURES

TABLE 1 - GROSS ENERGY AND PEAK III
TABLE 2 - CHANGE IN ENERGY AND PEAK IV
TABLE 3 - COMPONENTS OF MANITOBA ELECTRICITY USE 3
TABLE 4 - GENERAL CONSUMERS SALES CUSTOMERS 5
TABLE 5 - GENERAL CONSUMERS SALES ENERGY 7
TABLE 6 - COMPONENTS OF MANITOBA ENERGY 9
TABLE 7 - 2015/16 FORECAST TO ACTUAL 11
FIGURE 1 - CHANGE OF RES BASIC FORECAST 12
TABLE 8 - CHANGE OF RES BASIC FORECAST 12
FIGURE 2 - CHANGE OF GS MASS MARKET FORECAST 13
TABLE 9 - CHANGE OF GS MASS MARKET FORECAST 13
FIGURE 3 - CHANGE OF GS TOP CONSUMER FORECAST 14
TABLE 10 - CHANGE OF GS TOP CONSUMER FORECAST 14
FIGURE 4 - CHANGE OF ENERGY FORECAST 15
TABLE 11 - CHANGE OF ENERGY FORECAST 15
FIGURE 5 - CHANGE OF PEAK FORECAST 16
TABLE 12 - CHANGE OF PEAK FORECAST 16
FIGURE 6- RESIDENTIAL BASIC SALES 17
TABLE 13 - RESIDENTIAL SALES 17
TABLE 14 - RESIDENTIAL BASIC SALES 18
FIGURE 7 - GENERAL SERVICE MASS MARKET 20
TABLE 15 - GENERAL SERVICE MASS MARKET 20
FIGURE 8 - GENERAL SERVICE TOP CONSUMERS 21
TABLE 16 - GENERAL SERVICE TOP CONSUMERS 21
TABLE 17 - PLUG-IN ELECTRIC VEHICLES 26
FIGURE 10 - AREA & ROADWAY LIGHTING 27
TABLE 18 - AREA & ROADWAY LIGHTING 27
TABLE 19 - AREA & ROADWAY LIGHTING 28
FIGURE 11 - GENERAL CONSUMERS SALES 29
TABLE 20 - GENERAL CONSUMERS SALES 29
FIGURE 12 - DIESEL SALES 30
TABLE 21 - DIESEL SALES 30
FIGURE 13 - DISTRIBUTION LOSSES 31
TABLE 22 - DISTRIBUTION LOSSES 31
FIGURE 14 - CONSTRUCTION POWER 32
TABLE 23 - CONSTRUCTION POWER 32
FIGURE 15 - MANITOBA LOAD AT COMMON BUS 33
TABLE 24 - MANITOBA LOAD AT COMMON BUS 33
FIGURE 16 - TRANSMISSION LOSSES 34
TABLE 25 - TRANSMISSION LOSSES 34
FIGURE 17 - STATION SERVICE 35
TABLE 26 - STATION SERVICE 35
TABLE 27 - MONTHLY STATION SERVICE ENERGY 36
TABLE 28 - MONTHLY STATION SERVICE PEAK 36
FIGURE 18 - GROSS FIRM ENERGY 37

TABLE 29 - GROSS FIRM ENERGY 37
TABLE 30 - MONTHLY GROSS FIRM ENERGY 38
FIGURE 19 - GROSS TOTAL PEAK 39
TABLE 31 – GROSS TOTAL PEAK 39
TABLE 32 - MONTHLY GROSS TOTAL PEAK 39
FIGURE 20 - ENERGY VARIABILITY 45
TABLE 33 – ENERGY VARIABILITY 45
FIGURE 21 - PEAK VARIABILITY 46
TABLE 34 – PEAK VARIABILITY 46
FIGURE 22 - ENERGY ACCURACY 48
TABLE 35 - ENERGY ACCURACY 48
FIGURE 23 - PEAK ACCURACY 49
TABLE 36 - PEAK ACCURACY 49

INTRODUCTION

This document is prepared annually as Manitoba Hydro's forecast of its future load requirements for its service area. The service area consists of all of Manitoba (99.85% of sales), as well as two resale customers that supply energy to Creighton, Sask. (0.12% of sales) and the Northwest Angle, Minn. (0.03% of sales). Exports of power to other utilities are not included.

This information is provided for several purposes. Short term forecasts of sales by billing month within rate groups are needed to forecast revenue for rate design and accounting. Short term forecasts of energy and peak is needed for system operations. Long term forecasts of energy and peak is required by power planning to determine long term supply requirements.

A "customer" in this document refers to a metered electrical service. Unmetered services, such as flat rate water heating and sentinel rentals do not count as customers, and street lights group a number of services as one customer. A customer is not the same as a building. One building can have multiple electric services and may count as more than one customer, or multiple buildings may have only one service and may count as only one customer. A customer in this document is also not the same as a customer on the billing system. The latter is a person or organization that Manitoba Hydro serves. One billing customer may pay the bill for multiple services and thus count as multiple customers in this document.

Electric consumption is read from a customer's meter in units of kilowatt-hours (kWh). A typical residential dwelling not using electricity for heating uses approximately 10,000 kWh per year. This document reports electric use in terms of gigawatt-hours (GWh). One GWh equals one million kWh, which is approximately the energy of 100 typical residential dwellings not using electricity for heating.

The highest load requirement for a time period is known as the peak load. It is given in terms of megawatts (MW). One MW equals one thousand kilowatts (kW). A typical residential dwelling not using electricity for heating would use a maximum of about 2.5 kW sometime during the year. However, dwellings will not all be at their maximum use at the same hour. The use of all dwellings at any specific hour is known as the coincident load. The coincident peak is the load at the hour of Manitoba's system peak. A typical dwelling not using electricity for heating would use about 1.6 kW at the coincident peak. Therefore 1 MW is approximately the coincident peak requirement of 600 typical dwellings not using electricity for heating.

Components of Manitoba's Electricity Use – 2015/16

General Consumers Sales (also referred to as Total Sales) includes the energy supplied to all of Manitoba Hydro's individually billed customers. During the 2015/16 fiscal year, Manitoba Hydro averaged 564,643 General Consumers Sales customers who consumed 21,654 GWh.

The major groups include

(1) Residential Basic, with 474,153 customers who used 7,074 GWh or 32.7% of Sales. These are mostly residential structures that include single-family dwellings, multi-family dwellings and individual apartment suites.
(2) General Service Mass Market, with 67,395 customers who used 8,442 GWh or 39.0% of Sales. These are small to large Commercial and Industrial customers.
(3) General Service Top Consumers, with 32 customers who used 5,886 GWh or 27.2% of sales. These are 17 high-usage companies (some count as multiple customers) that are forecast individually.

The remaining customers include Seasonal customers (billed twice a year rather than monthly), Diesel customers (four remote towns not connected to the integrated grid system), Flat Rate Water Heating and Area and Roadway Lighting. Their electricity use totals only 252 GWh or 1.2% of Total Sales. Over 50,000 of these services do not count as customers.

Manitoba Load at Common Bus is the total load metered at all the substations in the province that supplies Manitoba Hydro's non-Diesel customers and includes Distribution Losses and Construction Power. In 2015/16, Common Bus was 22,460 GWh or about 3.7% more than Total Sales.

Gross Firm Energy is the total load needed to be generated for domestic firm load requirements on the Integrated System (excludes diesel). It includes Transmission Losses and Station Service. Some customers are on non-firm contracts (Surplus Energy Program), and their load is not included as part of Manitoba Hydro's generation requirement. In 2015/16, Gross Firm Energy was 24,673 GWh or about 13.9% more than Total Sales.

Table 3 - Components of Manitoba Electricity Use

COMPONENTS OF MANITOBA ELECTRICITY USE 2015/16 (Customers, Actual Consumption and Average Use)				
Forecast Group	**Cust/Serv**	**GWh**	**% of Sales**	**kWh/cust**
Residential Basic	474,153	7,074	32.7%	14,920
Residential Diesel	583	8	0.0%	13,945
Residential Seasonal	20,176	81	0.4%	3,991
Residential Flat Rate Water Heating	3,454	18	0.1%	5,083
Total Residential	494,912	7,181	33.2%	
GS Mass Market	67,395	8,442	39.0%	125,260
GS Top Consumers	32	5,886	27.2%	186,357,969
GS Diesel	184	6	0.0%	30,496
GS Seasonal	882	5	0.0%	6,115
GS Flat Rate Water Heat	359	6	0.0%	16,286
GS Surplus Energy Program	30	25	0.1%	821,015
Total General Service	68,522	14,369	66.4%	
Sentinal Flat Rate	20,643	12	0.1%	567
Sentinal Rental	25,960	-	0.0%	-
Street Lighting	1,208	92	0.4%	76,517
Total Lighting	1,208	104	0.5%	
Total General Consumer Sales	564,643	21,654	100.0%	
Less Diesel Sales		(14)	-0.1%	
Distribution Losses		791	3.7%	
Construction Power		28	0.1%	
Manitoba Load at Common Bus		22,460	103.7%	
Transmission Losses		2,116	9.8%	
Less Non-Firm Energy		(25)	-0.1%	
Station Service		123	0.6%	
Gross Firm Energy		24,673	113.9%	
* flat rate and rental services are shown in yellow, which do not count as customers				

FORECAST OVERVIEW

General Consumers Customer Forecast

In 2015/16, Manitoba Hydro had an average of 564,643 General Consumer Sales customers. These were made up of 474,153 Residential Basic customers, 67,395 General Service Mass Market customers, 32 General Service Top Consumers customers and 30 SEP (Surplus Energy Program, i.e. non-firm) customers, with the remaining being Diesel, Seasonal and Area and Roadway Lighting.

During the last 10 years, Residential Basic customers have grown at an average of 5,041 (1.1%) per year. Manitoba Hydro's 2016 Economic Outlook provides the forecast of Residential Basic customers, and this document uses that forecast. Residential Basic customers are forecast to grow 5,318 (1.1%) customers per year over the next ten years and 4,951 (1.0%) customers per year over the next 20 years.

General Service Mass Market customers have grown 590 (0.9%) per year over the last 10 years. The sector is forecast to grow 474 (0.7%) per year over the next ten years and 477 (0.7%) per year over the next 20 years. Starting in 2016/17, seven of the smallest Top Consumers were moved to General Service Mass Market for forecasting purposes and the 2015/16 customers are adjusted to reflect the change in both the General Service Mass Market and Top Consumers sectors.

Residential Seasonal customers, mainly cottages with lower usage, are growing at a slower rate than Residential Basic. Seasonal customer growth has averaged 3 (0.0%) customers per year over the last 10 years. The sector is forecast to decrease at 142 (0.7%) customers annually over the next 10 years and 131 (0.7%) customers annually over the next 20 years due to the continued transfer of higher usage seasonal customers to Residential Basic.

Area and Roadway Lighting customers were re-grouped in 2006 when Manitoba Hydro changed its billing system, resulting in a change in lighting customer counts. Area and Roadway Lighting is expected to grow at 5 (0.4%) customers annually over the next 10 years and 5 (0.4%) customers annually over the next 20 years.

Table 4 - General Consumers Sales Customers

GENERAL CONSUMERS SALES (Average Customers)
History and Forecast
2005/06 - 2035/36

Fiscal	Residential			General Service					Lighting	Total
Year	Basic	Diesel	Seas	Mass Mkt	Top Cons	Diesel	Seas	SEP		Custs
2005/06	423,742	519	20,145	61,491	26	168	814	29	793	507,727
2006/07	427,886	525	20,312	63,596	26	169	783	28	1129	514,455
2007/08	432,144	531	20,437	63,855	26	175	798	27	1142	519,135
2008/09	437,263	540	20,648	64,140	26	178	818	24	1175	524,811
2009/10	441,710	539	20,839	64,758	26	177	830	24	1191	530,095
2010/11	445,882	550	20,950	65,193	26	176	842	24	1184	534,828
2011/12	450,748	568	20,844	65,546	32	174	847	26	1155	539,939
2012/13	456,130	577	20,731	65,974	31	175	850	28	1164	545,660
2013/14	462,274	583	20,757	66,569	31	179	861	28	1157	552,438
2014/15	468,499	583	20,626	67,042	30	183	872	28	1196	559,060
2015/16	474,153	583	20,176	67,395	32	184	882	30	1208	564,643
10 Year	5,041	6	3	590	1	2	7	0	42	5,692
Avg Gr.	1.1%	1.2%	0.0%	0.9%	2.0%	0.9%	0.8%	0.5%	4.3%	1.1%
2015/16 adj				67,402	25					
2016/17	479,962	589	19,837	67,854	24	185	904	30	1,216	570,601
2017/18	485,421	598	19,717	68,362	24	187	909	31	1,221	576,469
2018/19	490,910	605	19,597	68,857	24	189	914	31	1,226	582,352
2019/20	496,389	612	19,477	69,339	24	191	919	31	1,231	588,211
2020/21	501,758	619	19,357	69,804	24	193	924	31	1,236	593,945
2021/22	506,994	626	19,237	70,259	24	194	929	31	1,241	599,535
2022/23	512,155	634	19,117	70,724	24	196	934	31	1,246	605,060
2023/24	517,259	641	18,997	71,196	24	198	939	31	1,251	610,535
2024/25	522,306	648	18,877	71,669	24	199	944	31	1,256	615,954
2025/26	527,329	655	18,757	72,145	24	201	949	31	1,261	621,352
10 Year	5,318	7	-142	474	-1	2	7	0	5	5,671
Avg Gr.	1.1%	1.2%	-0.7%	0.7%	-0.2%	0.9%	0.7%	0.3%	0.4%	1.0%
2026/27	532,344	663	18,637	72,625	24	203	954	31	1,266	626,745
2027/28	537,341	670	18,517	73,108	24	204	959	31	1,271	632,125
2028/29	542,294	677	18,397	73,594	24	206	964	31	1,276	637,462
2029/30	547,117	684	18,277	74,077	24	208	969	31	1,281	642,667
2030/31	551,749	692	18,157	74,556	24	210	974	31	1,286	647,677
2031/32	556,213	699	18,037	75,031	24	211	979	31	1,291	652,516
2032/33	560,551	706	17,917	75,505	24	213	984	31	1,296	657,226
2033/34	564,806	713	17,797	75,981	24	215	989	31	1,301	661,856
2034/35	569,018	721	17,677	76,459	24	216	994	31	1,306	666,446
2035/36	573,175	728	17,557	76,939	24	218	999	31	1,311	670,981
20 Year	4,951	7	-131	477	0	2	6	0	5	5,317
Avg Gr.	1.0%	1.1%	-0.7%	0.7%	-0.1%	0.9%	0.6%	0.2%	0.4%	0.9%

General Consumers Sales Forecast

During 2015/16, Total General Consumer Sales was 21,654 GWh. The fiscal billing year (using weather from March 16, 2015 to March 15, 2016) was significantly warmer than normal giving a weather adjustment for the year of +532 GWh. The resulting weather adjusted Total Sales value was 22,186 GWh.

Over the last 10 years, Total Sales have grown at 188 GWh (0.9%) per year. The growth was 1.5% per year in Residential Basic, 1.1% per year in General Service Mass Market, and a reduction of 0.1% in General Service Top Consumers due to the economic downturn in 2009 and the loss of one Top Consumer customer. The historical growth includes the effect of past Demand Side Management (DSM) initiatives.

Sales are forecast to grow at 337 GWh (1.4%) per year over the next 10 years and 393 GWh (1.5%) per year over the next 20 years before accounting for future market-based DSM programs.

Most of the growth is forecast to occur in General Service Mass Market, at 200 GWh (1.9%) per year over the next 20 years, followed by Residential Basic at 98 GWh (1.2%) per year and Top Consumers at 95 GWh (1.5%) per year. Starting in 2016/17, seven of the smallest Top Consumers were moved to General Service Mass Market for forecasting purposes and the 2015/16 sales, totaling 404 GWh, are adjusted to reflect the change in both the General Service Mass Market and Top Consumers sectors.

Table 5 - General Consumers Sales Energy

GENERAL CONSUMERS SALES (GWh)
History and Forecast
2005/06 - 2035/36

Fiscal	Residential				General Service						Lighting	Total
Year	Basic	Diesel	Seas	FRWH	Mass Mkt	Top Cons	Diesel	Seas	FRWH	SEP		Sales
2005/06	6,171	7	59	30	7,587	5,948	5	5	9	23	91	19,935
2006/07	6,443	7	60	29	7,839	5,989	5	4	9	23	101	20,510
2007/08	6,736	7	68	27	8,006	6,075	5	4	9	24	101	21,061
2008/09	6,847	7	74	25	8,049	6,065	5	5	8	22	102	21,210
2009/10	6,786	7	81	24	7,985	5,461	6	5	8	20	102	20,486
2010/11	6,952	8	77	23	8,258	5,324	5	5	8	24	103	20,786
2011/12	6,818	8	83	22	8,162	5,531	5	5	8	25	103	20,771
2012/13	7,223	8	81	21	8,434	5,560	5	5	7	28	103	21,477
2013/14	7,767	9	92	20	8,839	5,461	5	5	7	29	104	22,338
2014/15	7,658	9	102	19	8,771	5,750	6	6	6	27	104	22,458
2015/16	7,074	8	81	18	8,442	5,886	6	5	6	25	104	21,654
Weather Adj.	363	0	0	0	167	0	0	0	0	2	0	532
2015/16 Wadj	7,437	8	81	18	8,608	5,886	6	5	6	27	104	22,186
10 Year Wadj	101	0	2	-1	91	-6	0	0	0	0	1	188
Avg Gr.	1.5%	2.2%	3.2%	-5.4%	1.1%	-0.1%	0.9%	1.5%	-4.7%	0.9%	1.3%	0.9%
2015/16 adj					9,012	5,482						
2016/17	7,671	9	89	17	9,286	5,835	6	5	6	25	104	23,053
2017/18	7,750	9	89	16	9,471	5,748	6	5	5	26	104	23,229
2018/19	7,834	9	89	15	9,639	5,675	6	5	5	26	105	23,407
2019/20	7,931	9	89	14	9,779	5,746	6	6	5	26	105	23,715
2020/21	8,017	9	89	14	9,931	5,818	6	6	5	26	105	24,024
2021/22	8,108	9	89	13	10,084	5,890	6	6	4	26	105	24,339
2022/23	8,194	9	88	12	10,241	5,958	6	6	4	26	105	24,650
2023/24	8,277	10	88	12	10,400	6,028	6	6	4	26	105	24,961
2024/25	8,355	10	88	11	10,560	6,100	6	6	4	26	105	25,271
2025/26	8,429	10	88	11	10,701	6,172	6	6	4	26	106	25,557
10 Year	99	0	1	-1	169	69	0	0	0	0	0	337
Avg Gr.	1.3%	2.0%	0.9%	-5.0%	1.7%	1.2%	1.0%	0.5%	-5.0%	-0.5%	0.1%	1.4%
2026/27	8,488	10	88	10	10,866	6,247	6	6	3	26	106	25,855
2027/28	8,525	10	88	9	11,034	6,322	6	6	3	26	106	26,134
2028/29	8,581	10	88	9	11,203	6,400	6	6	3	26	106	26,438
2029/30	8,648	10	88	9	11,446	6,532	6	6	3	26	106	26,879
2030/31	8,714	11	88	8	11,694	6,667	6	6	3	26	106	27,328
2031/32	8,820	11	88	8	11,945	6,805	7	6	3	26	106	27,823
2032/33	8,958	11	87	7	12,202	6,946	7	6	2	26	106	28,359
2033/34	9,103	11	87	7	12,465	7,090	7	6	2	26	107	28,910
2034/35	9,248	11	87	7	12,735	7,237	7	6	2	26	107	29,472
2035/36	9,404	11	87	6	13,013	7,387	7	6	2	26	107	30,055
20 Year	98	0	0	-1	200	95	0	0	0	0	0	393
Avg Gr.	1.2%	1.7%	0.4%	-5.0%	1.9%	1.5%	0.9%	0.5%	-5.0%	-0.2%	0.1%	1.5%

Manitoba Energy Forecast

The weather adjusted actual Gross Firm Energy was 25,355 GWh in 2015/16. Gross Firm Energy has grown 215 GWh (0.9%) per year for the past 10 years. This historical growth reflects the effect of past Demand Side Management (DSM) initiatives. Gross Firm energy is forecast to grow to 34,193 GWh by 2035/36 at an average growth of 442 GWh or 1.5% per year. This is before accounting for future market-based DSM programs.

Distribution Losses, which is the difference between Manitoba Hydro's substations and the customers' meters, has a wide variance from year to year and has ranged between 3.5% and 5.5% of Total Sales. It is forecast to be between 4.4% and 4.5% of Sales for the entire forecast.

Transmission Losses which is the difference between the generators and the substations is forecast to be between 9.1% and 9.2% of Total Sales for the entire forecast period.

Distribution Losses and Transmission Losses, totaling almost 14%, need to be added to Total Sales to estimate Gross Firm Energy. The 14% value should generally be used to estimate load at generation when only load at the customer's meter is known. For example, to convert Power Smart program savings from the customer meter to generation. The exception is for large General Service customers who own their own transformation and incur minimal Distribution Losses. For these customers, a 10% value should be used.

Table 6 - Components of Manitoba Energy

MANITOBA FIRM ENERGY (GWh)
History and Forecast
2005/06 - 2035/36

Fiscal Year	General Consumer Sales less Diesel	Dist. Losses	Dist. Loss %	Const. Power	Manitoba Load at Common Bus	Trans. Losses	Trans. Loss %	Less Non Firm Energy	Station Service	Gross Firm Energy
2005/06	19,923	797	4.0%	42	20,761	1,860	9.3%	23	158	22,757
2006/07	20,497	900	4.4%	45	21,442	1,885	9.2%	22	159	23,464
2007/08	21,049	940	4.5%	47	22,036	1,949	9.3%	24	161	24,122
2008/09	21,198	1,052	5.0%	56	22,305	1,979	9.3%	22	154	24,417
2009/10	20,473	813	4.0%	75	21,361	1,934	9.4%	20	137	23,412
2010/11	20,773	947	4.6%	85	21,806	1,977	9.5%	25	134	23,892
2011/12	20,757	736	3.5%	67	21,560	1,939	9.3%	25	131	23,605
2012/13	21,463	1,184	5.5%	59	22,706	1,936	9.0%	28	136	24,750
2013/14	22,324	1,205	5.4%	12	23,541	1,969	8.8%	29	144	25,625
2014/15	22,443	992	4.4%	15	23,450	1,949	8.7%	26	132	25,505
2015/16	21,640	791	3.7%	28	22,460	2,116	9.8%	25	123	24,673
Weather Adj.	532	94		0	625	59		2	0	682
2015/16 Wadj	22,172	885	4.0%	28	23,085	2,175	9.8%	27	123	25,355
10 Year Wadj	188	5		-1	191	32		0	-4	215
Avg Gr.	0.9%	0.6%		-3.9%	0.9%	1.6%		1.5%	-2.5%	0.9%
2016/17	23,038	1,014	4.4%	116	24,168	2,109	9.2%	25	133	26,385
2017/18	23,214	1,028	4.4%	120	24,363	2,126	9.2%	26	133	26,596
2018/19	23,392	1,042	4.5%	103	24,537	2,141	9.2%	26	133	26,785
2019/20	23,700	1,055	4.4%	35	24,789	2,163	9.1%	26	133	27,060
2020/21	24,009	1,067	4.4%	35	25,111	2,192	9.1%	26	133	27,410
2021/22	24,323	1,081	4.4%	0	25,404	2,217	9.1%	26	133	27,729
2022/23	24,634	1,094	4.4%	0	25,728	2,246	9.1%	26	133	28,082
2023/24	24,946	1,107	4.4%	0	26,053	2,274	9.1%	26	133	28,435
2024/25	25,255	1,121	4.4%	0	26,375	2,302	9.1%	26	133	28,785
2025/26	25,541	1,133	4.4%	0	26,674	2,328	9.1%	26	133	29,110
10 Year	337	25		-3	359	15		0	1	375
Avg Gr.	1.4%	2.5%		-100.0%	1.5%	0.7%		-0.5%	0.8%	1.4%
2026/27	25,839	1,145	4.4%	0	26,984	2,355	9.1%	26	133	29,447
2027/28	26,118	1,156	4.4%	0	27,274	2,381	9.1%	26	133	29,762
2028/29	26,421	1,168	4.4%	0	27,590	2,408	9.1%	26	133	30,106
2029/30	26,862	1,184	4.4%	0	28,046	2,448	9.1%	26	133	30,602
2030/31	27,311	1,200	4.4%	0	28,511	2,489	9.1%	26	133	31,108
2031/32	27,805	1,220	4.4%	0	29,025	2,534	9.1%	26	133	31,666
2032/33	28,341	1,241	4.4%	0	29,583	2,583	9.1%	26	133	32,273
2033/34	28,892	1,264	4.4%	0	30,156	2,633	9.1%	26	133	32,896
2034/35	29,454	1,287	4.4%	0	30,741	2,684	9.1%	26	133	33,532
2035/36	30,037	1,311	4.4%	0	31,348	2,737	9.1%	26	133	34,193
20 Year	393	21		-1	413	28		0	1	442
Avg Gr.	1.5%	2.0%		-100.0%	1.5%	1.2%		-0.3%	0.4%	1.5%

Comparison of the 2015 Forecast to Actuals

Comparison of the 2015 Forecast to the 2015/16 Weather Adjusted Actuals

The weather adjusted General Consumer Sales for 2015/16 was 22,186 GWh which was 565 GWh lower than the 2015 Forecast of 22,681 GWh after removing the Demand Side Management (DSM) program savings achieved in 2015/16.

The weather adjusted Residential Basic sector was 210 GWh lower than the 2015 Forecast and the weather adjusted General Service Mass Market sector for was 142 GWh lower than forecast.

In 2015/16, the Top Consumers sector consumed 5,886 GWh which was 141 GWh lower than the 2015 Forecast of 6,021 GWh. The difference is primarily due to production and project deferral.

Distribution losses were 149 GWh lower than forecast and Transmission losses were 120 GWh greater than forecast.

Overall, the weather adjusted Gross Firm Energy for 2015/16 was 25,355 GWh which was 565 GWh lower than the 2015 Forecast of 25,920 GWh.

The normalized Gross Total Peak for 2015/16 was 4,634 MW which was 155 MW lower than the 2015 Forecast of 4,789 MW.

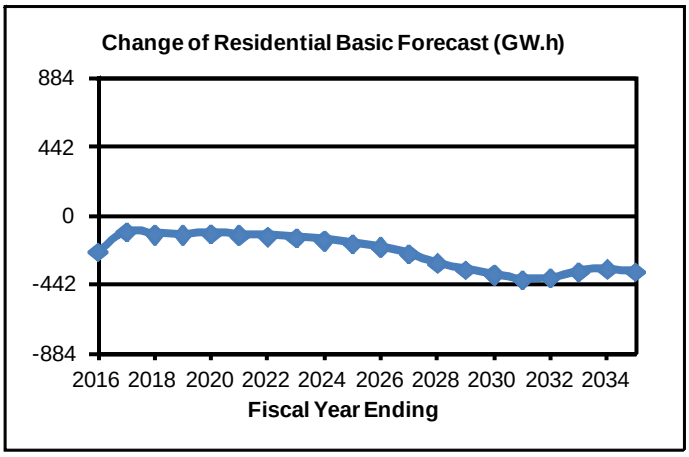
Table 7 - 2015/16 Forecast to Actual

2015 FORECAST COMPARED TO WEATHER ADJUSTED ACTUALS 2015/16 Energy (GWh) and Peak (MW)					
Forecast Group	Actuals	Weather Adjustment	Wthr Adj Actuals	2015 Forecast less DSM	WA Actuals less Forecast
Residential Basic	7,074	363	7,437	7,629	(191)
Residential Diesel	8	-	8	9	(1)
Residential Seasonal	81	-	81	98	(18)
Residential Flat Rate Water Heating	18	-	18	18	(0)
Total Residential	7,181	363	7,544	7,753	(210)
GS Mass Market	8,442	167	8,608	8,750	(142)
GS Top Consumers	5,886	-	5,886	6,027	(141)
GS Diesel	6	-	6	6	(0)
GS Seasonal	5	-	5	6	(0)
GS Flat Rate Water Heat	6	-	6	6	(0)
GS Surplus Energy Program	25	2	27	29	(2)
Total General Service	14,369	169	14,538	14,823	(285)
Sentinal Flat Rate	12	-	12	12	(0)
Sentinal Rental	-	-	-	-	-
Street Lighting	92	-	92	93	(0)
Total Lighting	104	-	104	104	(0)
Total General Consumer Sales	21,654	532	22,186	22,681	(495)
Less Diesel Sales	(14)	-	(14)	(14)	1
Distribution Losses	791	94	885	1,034	(149)
Construction Power	28	-	28	56	(28)
Manitoba Load at Common Bus	22,460	625	23,085	23,756	(672)
Transmission Losses	2,116	59	2,175	2,055	120
Less Non-Firm Energy	(25)	(2)	(27)	(29)	2
Station Service	123	-	123	137	(15)
Gross Firm Energy (GWh)	24,673	682	25,355	25,920	(565)
Gross Total Peak (MW)	4,479	155	4,634	4,789	(155)

Change between the 2015 and 2016 Forecasts

Change Between the 2015 and 2016 Residential Basic Forecast

Figure 1 - Change of Res Basic Forecast



The 2016 Residential Basic forecast starts in 2016/17 101 GWh lower from the 2015 forecast primarily due to the 2015/16 weather adjusted actual energy use being lower than forecast. The difference lessens to 101 GWh in 2016/17 and grows to 359 GWh by the end of the forecast period. 359 GWh represents less than one year of Manitoba system load growth (1 year = approximately 442 GWh).

Major changes and their effect in 2034/35:

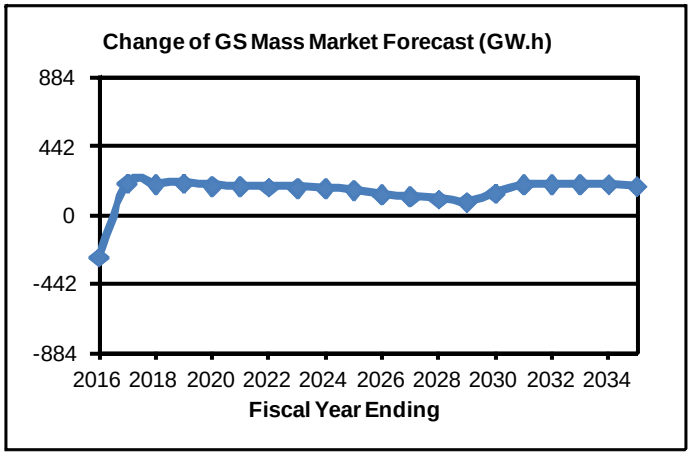
1. Decrease in the customer forecast by 17,752 customers (-220 GWh).
2. Changes in the average use forecast (-47 GWh), primarily due to:
   a. Increase in the forecast of real income: +116 GWh
   b. Changes to model and parameter estimates: -147 GWh
3. Change in the starting point (-230 GWh, which includes 39 GWh of achieved DSM)
4. Decrease in the forecast of Codes and Standards (+135 GWh)

Table 8 - Change of Res Basic Forecast

CHANGE OF RESIDENTIAL BASIC FORECAST (GWh) Comparison of 2015 to 2016 forecast										
Fiscal Year	2015 Fcst	2016 Fcst	Change	%		Fiscal Year	2015 Fcst	2016 Fcst	Change	%
2015/16	7,668	7,437	(230)	-3.0%		2025/26	8,632	8,429	(203)	-2.4%
2016/17	7,773	7,671	(101)	-1.3%		2026/27	8,732	8,488	(244)	-2.8%
2017/18	7,870	7,750	(120)	-1.5%		2027/28	8,830	8,525	(306)	-3.5%
2018/19	7,956	7,834	(122)	-1.5%		2028/29	8,926	8,581	(345)	-3.9%
2019/20	8,047	7,931	(115)	-1.4%		2029/30	9,024	8,648	(376)	-4.2%
2020/21	8,142	8,017	(125)	-1.5%		2030/31	9,122	8,714	(408)	-4.5%
2021/22	8,240	8,108	(132)	-1.6%		2031/32	9,218	8,820	(399)	-4.3%
2022/23	8,337	8,194	(143)	-1.7%		2032/33	9,316	8,958	(357)	-3.8%
2023/24	8,434	8,277	(157)	-1.9%		2033/34	9,445	9,103	(343)	-3.6%
2024/25	8,534	8,355	(179)	-2.1%		2034/35	9,607	9,248	(359)	-3.7%

Change Between the 2015 and 2016 General Service Mass Market Forecast

Figure 2 - Change of GS Mass Market Forecast



The 2016 General Service Mass Market (GSMM) forecast starts in 2016/17 204 GWh higher from the 2015 forecast primarily due to the transfer of seven Top Consumers into the Mass Market sector starting in 2016/17. The difference remains steady throughout the forecast, and by 2034/35, the Mass Market forecast is up 187 GWh, representing about a half a year of load growth.

Major changes and their effect in 2034/35:

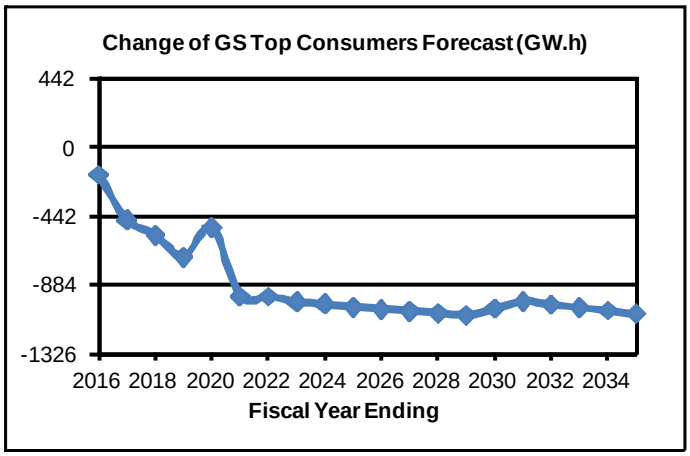
1. Seven Top Consumers transferred to the Mass Market as of 2016/17 (+449 GWh)
2. Change in the starting point (-269 GWh, which includes 128 GWh of achieved DSM)
3. Other model and economic differences (-210 GWh)
4. Decrease in the forecast of Codes & Standards (+217 GWh)

Table 9 - Change of GS Mass Market Forecast

CHANGE OF GS MASS MARKET FORECAST (GWh) Comparison of 2015 to 2016 forecast										
Fiscal Year	2015 Fcst	2016 Fcst	Change	%		Fiscal Year	2015 Fcst	2016 Fcst	Change	%
2015/16	8,878	8,608	(269)	-3.0%		2025/26	10,571	10,701	130	1.2%
2016/17	9,082	9,286	204	2.3%		2026/27	10,749	10,866	118	1.1%
2017/18	9,272	9,471	199	2.1%		2027/28	10,931	11,034	103	0.9%
2018/19	9,433	9,639	205	2.2%		2028/29	11,116	11,203	87	0.8%
2019/20	9,590	9,779	189	2.0%		2029/30	11,306	11,446	140	1.2%
2020/21	9,746	9,931	185	1.9%		2030/31	11,499	11,694	195	1.7%
2021/22	9,903	10,084	181	1.8%		2031/32	11,748	11,945	197	1.7%
2022/23	10,064	10,241	177	1.8%		2032/33	12,004	12,202	198	1.7%
2023/24	10,228	10,400	172	1.7%		2033/34	12,267	12,465	198	1.6%
2024/25	10,397	10,560	163	1.6%		2034/35	12,549	12,735	187	1.5%

Change Between the 2015 and 2016 GS Top Consumers Forecast

Figure 3 - Change of GS Top Consumer Forecast



The General Service Top Consumers forecast is 1,065 GWh lower from the 2015 forecast. Seven customers were moved from Top Consumers to the GS Mass Market sector. The short term (3 year) individual customer forecasts were down from 2015, primarily due to the advancement of an expected customer reduction. All longer term growth is now considered to be included within the Potential Large Industrial Load forecast (PLIL), including expansions and contractions expected to arise from committed plans in the Petro/Oil/Natural Gas and Mining Sectors. The 1,065 GWh reduction represents 2½ years of load growth.

Major changes and their effect in 2034/35:

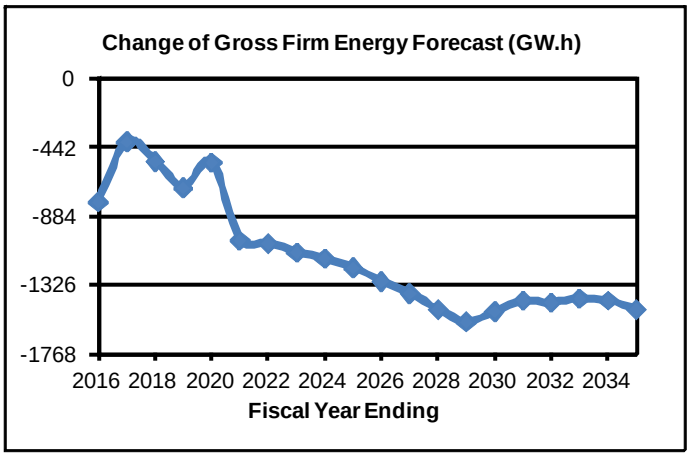
1. Seven Top Consumers moved to the Mass Market sector as of 2016/17 (-449 GWh)
2. Reassessment of short term customer planned projects. (-166 GWh)
3. Change in approach to longer term growth (PLIL) forecasts (-251 GWh)
4. The Potential Large Industrial Loads (PLIL) forecast begins in the fourth year of the forecast resulting in 16 years of PLIL in the 2016 forecast compared with 17 years of PLIL in the 2015 forecast. (-86 GWh)
5. Changes to PLIL forecast from updated model parameters and economic forecast (-113 GWh)

Table 10 - Change of GS Top Consumer Forecast

CHANGE OF GS TOP CONSUMERS FORECAST (GWh) Comparison of 2015 to 2016 forecast										
Fiscal Year	2015 Fcst	2016 Fcst	Change	%		Fiscal Year	2015 Fcst	2016 Fcst	Change	%
2015/16	6,058	5,886	(172)	-2.8%		2025/26	7,209	6,172	(1,037)	-14.4%
2016/17	6,299	5,835	(464)	-7.4%		2026/27	7,296	6,247	(1,049)	-14.4%
2017/18	6,308	5,748	(560)	-8.9%		2027/28	7,383	6,322	(1,061)	-14.4%
2018/19	6,376	5,675	(701)	-11.0%		2028/29	7,472	6,400	(1,072)	-14.3%
2019/20	6,257	5,746	(511)	-8.2%		2029/30	7,562	6,532	(1,030)	-13.6%
2020/21	6,771	5,818	(953)	-14.1%		2030/31	7,653	6,667	(986)	-12.9%
2021/22	6,845	5,890	(955)	-13.9%		2031/32	7,810	6,805	(1,005)	-12.9%
2022/23	6,948	5,958	(990)	-14.2%		2032/33	7,971	6,946	(1,025)	-12.9%
2023/24	7,031	6,028	(1,003)	-14.3%		2033/34	8,135	7,090	(1,045)	-12.8%
2024/25	7,122	6,100	(1,022)	-14.3%		2034/35	8,302	7,237	(1,065)	-12.8%

Change Between the 2015 and 2016 Gross Firm Energy Forecast

Figure 4 - Change of Energy Forecast



The Gross Firm Energy forecast starts 406 GWh (1.5%) lower in 2016/17 and by 2034/35 is down 1,479 GWh (4.2%) from the 2015 forecast. This is a reduction of just over 3 years of load growth. (1 year = approximately 442 GWh).

Summary of changes made in each sector and their effect in 2034/35:

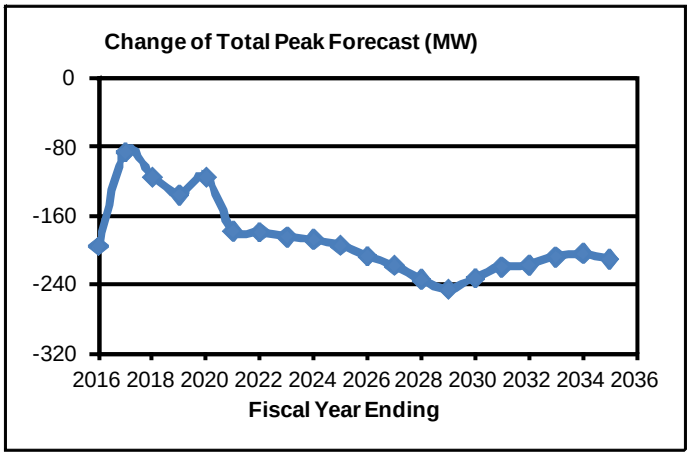
1. Residential Basic forecast is lower primarily due to a reduced customer forecast and starting point (-359 GWh)
2. General Service Mass Market forecast is lower primarily due to a lower starting point. (+187 GWh)
3. General Service Top Consumers forecast is lower due to adjustments in customer short term plans and changes to the longer term growth forecast (PLIL). (-1,065 GWh)
4. Other Sales and Losses. (-242 GWh)

Table 11 - Change of Energy Forecast

GROSS FIRM ENERGY (GWh) Comparison of 2015 to 2016 forecast										
Fiscal Year	2015 Fcst	2016 Fcst	Change	%		Fiscal Year	2015 Fcst	2016 Fcst	Change	%
2015/16	26,145	25,355	(790)	-3.0%		2025/26	30,408	29,110	(1,299)	-4.3%
2016/17	26,792	26,385	(406)	-1.5%		2026/27	30,823	29,447	(1,376)	-4.5%
2017/18	27,126	26,596	(530)	-2.0%		2027/28	31,243	29,762	(1,481)	-4.7%
2018/19	27,486	26,785	(701)	-2.5%		2028/29	31,664	30,106	(1,559)	-4.9%
2019/20	27,600	27,060	(539)	-2.0%		2029/30	32,094	30,602	(1,492)	-4.6%
2020/21	28,449	27,410	(1,039)	-3.7%		2030/31	32,531	31,108	(1,423)	-4.4%
2021/22	28,786	27,729	(1,057)	-3.7%		2031/32	33,101	31,666	(1,435)	-4.3%
2022/23	29,197	28,082	(1,115)	-3.8%		2032/33	33,684	32,273	(1,411)	-4.2%
2023/24	29,590	28,435	(1,155)	-3.9%		2033/34	34,317	32,896	(1,421)	-4.1%
2024/25	29,999	28,785	(1,214)	-4.0%		2034/35	35,011	33,532	(1,479)	-4.2%

Change Between the 2015 and 2016 Gross Total Peak Forecast

Figure 5 - Change of Peak Forecast



The Gross Total Peak Forecast is down 210 MW (3.3%) by 2034/35 from the 2015 Forecast. The peak forecast very closely follows the energy forecast with the reasons for increase in peak being similar to those for energy.

Partially offsetting the energy reduction is a 0.5% decrease of the peak load factor forecast in 2034/35. The load factor is decreasing from 63.0% in the 2015 forecast to 62.5% in the 2016 forecast. The load factor decrease is due to the reduction of the energy forecast of the Top Consumers sector which has a high load factor of 91%.

The decrease in peak in 2034/35 amounts to 210 MW, which is a reduction of 2½ years of load growth. (1 year = approximately 80 MW).

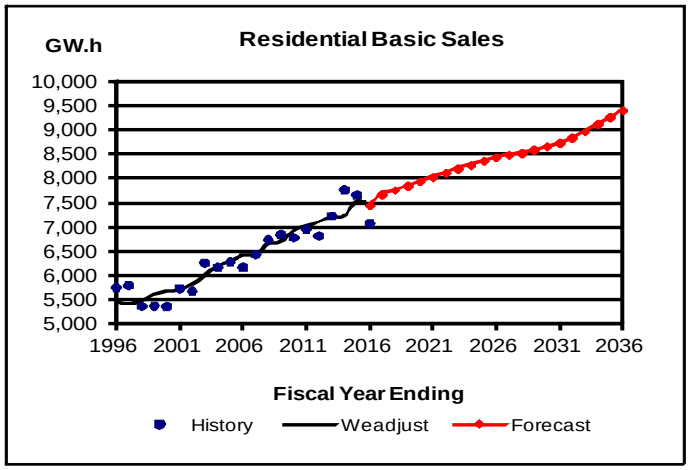
Table 12 - Change of Peak Forecast

GROSS TOTAL PEAK (MW) Comparison of 2015 to 2016 forecast										
Fiscal Year	2015 Fcst	2016 Fcst	Change	%		Fiscal Year	2015 Fcst	2016 Fcst	Change	%
2015/16	4,829	4,634	(195)	-4.0%		2025/26	5,547	5,341	(206)	-3.7%
2016/17	4,936	4,850	(86)	-1.7%		2026/27	5,619	5,402	(217)	-3.9%
2017/18	5,000	4,885	(115)	-2.3%		2027/28	5,692	5,458	(234)	-4.1%
2018/19	5,063	4,928	(135)	-2.7%		2028/29	5,765	5,520	(245)	-4.2%
2019/20	5,086	4,971	(115)	-2.3%		2029/30	5,840	5,608	(232)	-4.0%
2020/21	5,210	5,033	(178)	-3.4%		2030/31	5,915	5,696	(219)	-3.7%
2021/22	5,267	5,089	(179)	-3.4%		2031/32	6,012	5,796	(217)	-3.6%
2022/23	5,337	5,154	(184)	-3.4%		2032/33	6,112	5,905	(207)	-3.4%
2023/24	5,406	5,218	(187)	-3.5%		2033/34	6,220	6,017	(204)	-3.3%
2024/25	5,476	5,282	(194)	-3.5%		2034/35	6,341	6,131	(210)	-3.3%

FORECAST DETAILS

Residential Basic

Figure 6- Residential Basic Sales



In 2015/16, there were 474,153 Residential Basic customers. 78% are single detached, 9% multi attached, and 13% individually metered apartment suites. 54% are in Winnipeg where natural gas is available, 29% in natural gas available areas outside Winnipeg, and 17% do not have natural gas available.

Residential Basic has grown 107 GWh (1.7%) per year for the past 20 years and 101 GWh per year (1.5%) for the past 10 years which reflects the effect of past Demand Side Management (DSM) initiatives. It is forecast to grow 99 GWh (1.3%) per year for the next 10 years and 96 GWh (1.2%) per year for the next 20 years before program-based DSM initiatives.

The primary driver of Residential Basic growth is the population, which is forecast to grow 0.9% per year over the next 20 years.

Table 13 - Residential Sales

RESIDENTIAL BASIC (GWh) HISTORICAL/WEATHER ADJUSTMENT/FORECAST					
Fiscal Year	Sales	Weather Adjust	Adjusted Sales	Fiscal Year	Forecast Sales
1996/97	5,797	-389	5,408	2016/17	7,671
1997/98	5,370	106	5,476	2017/18	7,750
1998/99	5,384	207	5,590	2018/19	7,834
1999/00	5,364	309	5,672	2019/20	7,931
2000/01	5,737	-36	5,701	2020/21	8,017
2001/02	5,674	131	5,805	2021/22	8,108
2002/03	6,266	-263	6,003	2022/23	8,194
2003/04	6,170	1	6,171	2023/24	8,277
2004/05	6,275	13	6,288	2024/25	8,355
2005/06	6,171	254	6,425	2025/26	8,429
2006/07	6,443	-18	6,425	2026/27	8,488
2007/08	6,736	-78	6,657	2027/28	8,525
2008/09	6,847	-154	6,693	2028/29	8,581
2009/10	6,786	134	6,920	2029/30	8,648
2010/11	6,952	78	7,030	2030/31	8,714
2011/12	6,818	296	7,114	2031/32	8,820
2012/13	7,223	-17	7,207	2032/33	8,958
2013/14	7,767	-540	7,228	2033/34	9,103
2014/15	7,658	-120	7,538	2034/35	9,248
2015/16	7,074	363	7,437	2035/36	9,404

Table 14 - Residential Basic Sales

RESIDENTIAL BASIC SALES
History and Forecast
2015/16 - 2035/36

Fiscal	Electric Heat Billed			Non Electric Heat Billed			Total Basic			% Elec Space	% Elec Water
Year	Custs	GWh	kWh/cust	Custs	GWh	kWh/cust	Custs	GWh	kWh/cust	Heat	Heat
2015/16	183,851	4,159	22,621	290,302	2,916	10,043	474,153	7,074	14,920	38.8%	52.3%
2016/17	187,210	4,540	24,253	292,752	3,131	10,695	479,962	7,671	15,983	39.0%	52.9%
2017/18	190,134	4,584	24,110	295,288	3,166	10,722	485,421	7,750	15,966	39.2%	53.5%
2018/19	192,944	4,627	23,983	297,967	3,207	10,762	490,910	7,834	15,958	39.3%	53.9%
2019/20	195,625	4,673	23,886	300,764	3,258	10,834	496,389	7,931	15,978	39.4%	54.1%
2020/21	198,142	4,712	23,782	303,616	3,305	10,885	501,758	8,017	15,978	39.5%	54.3%
2021/22	200,492	4,752	23,700	306,502	3,356	10,949	506,994	8,108	15,991	39.5%	54.4%
2022/23	202,726	4,789	23,621	309,429	3,406	11,007	512,155	8,194	16,000	39.6%	54.4%
2023/24	204,868	4,823	23,544	312,390	3,453	11,055	517,259	8,277	16,002	39.6%	54.4%
2024/25	206,956	4,857	23,467	315,350	3,499	11,094	522,306	8,355	15,997	39.6%	54.4%
2025/26	209,008	4,888	23,387	318,321	3,541	11,123	527,329	8,429	15,984	39.6%	54.4%
2026/27	211,030	4,915	23,291	321,314	3,572	11,118	532,344	8,488	15,944	39.6%	54.4%
2027/28	213,028	4,936	23,169	324,313	3,589	11,066	537,341	8,525	15,864	39.6%	54.3%
2028/29	214,987	4,962	23,078	327,307	3,620	11,059	542,294	8,581	15,824	39.6%	54.3%
2029/30	216,888	4,990	23,006	330,229	3,658	11,077	547,117	8,648	15,806	39.6%	54.3%
2030/31	218,705	5,018	22,942	333,044	3,696	11,099	551,749	8,714	15,793	39.6%	54.2%
2031/32	220,453	5,056	22,936	335,760	3,763	11,208	556,213	8,820	15,857	39.6%	54.2%
2032/33	222,147	5,104	22,977	338,403	3,854	11,389	560,551	8,958	15,981	39.6%	54.1%
2033/34	223,803	5,154	23,027	341,003	3,949	11,581	564,806	9,103	16,116	39.6%	54.1%
2034/35	225,434	5,203	23,080	343,584	4,045	11,772	569,018	9,248	16,252	39.6%	54.0%
2035/36	227,027	5,255	23,148	346,148	4,149	11,985	573,175	9,404	16,407	39.6%	53.9%

Electric Heat Billed: Customers who have electric space heating included with their electric bill.
Non Electric Heat Billed: Customers who do not have electric space heating included with their electric bill.
% Electric Space Heat: The proportion of Total Basic customers who are Electric Heat Billed.
% Electric Water Heat: The proportion of Total Basic customers who have Electric Water Heaters.
2015/16: GWh and kWh/cust are not weather adjusted.

The average use (kWh/customer) for Electric Heat Billed customers is decreasing as individually metered apartment suites are making up a higher proportion of the growth. The average use for Non Electric Heat Billed customers is increasing mainly due to larger new homes, ventilation requirements in new dwellings and an increase in miscellaneous end uses.

Residential Diesel, Seasonal, and Flat Rate Water Heating

Residential Diesel

There were 583 Residential Diesel customers that used 8 GWh in 2015/16 with an average annual use of 13,945 kWh per customer. They have 60 amp service that does not allow for electric space heating. Space heating in the four diesel communities is mainly provided by fuel oil. The number of customers is expected to grow to 728 and usage is expected to increase 1.7% a year to 11 GWh by 2035/36 under the assumption that the communities continue to be separate from the Integrated System.

Residential Seasonal

There were 20,176 Residential Seasonal customers that used 81 GWh in 2015/16 with an average annual use of 3,991 kWh per customer. The number of customers is expected decrease to 17,557 customers by 2035/36 due to transfers of higher usage seasonal customers to Residential Basic. Seasonal customers are billed only twice a year either due to low usage (being a seasonal residence or cottage) or because of a location that makes it difficult to access for more frequent meter readings. The usage of Residential Seasonal customers is expected to increase 0.4% a year to 87 GWh in 2035/36.

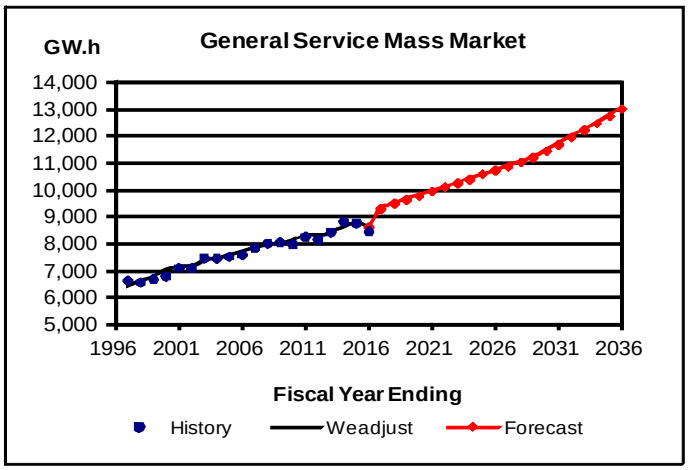
Residential Flat Rate Water Heating

Residential Water Heating is a flat rate unmetered service. This service has not been available to new customers since November 12, 1969. There were 3,454 remaining services in 2015/16. The number of services and usage is expected to decrease 5% per year throughout the forecast period. Usage was 18 GWh in 2015/16 and that will decrease to 6 GWh by 2035/36.

General Service Mass Market

General Service Mass Market includes all Commercial and Industrial customers, excluding the General Service Top Consumers. There were 67,395 General Service Mass Market customers in 2015/16. Approximately 15% are Industrial and the others are Commercial.

Figure 7 - General Service Mass Market



GS Mass Market has grown 114 GWh (1.5%) per year for the past 20 years and 91 GWh per year (1.1%) for the past 10 years. This historical growth reflects the effect of past Demand Side Management (DSM) initiatives. Starting 2016/17, seven Top Consumers totaling 404 GWh in 2015/16 were moved into the Mass Market sector for forecasting purposes which account for approximately 60% of the increase in 2016/17. The Mass Market Sector is forecast to grow 169 GWh (1.7%) per year for the next 10 years and 200 GWh (1.9%) per year for the next 20 years before program-based DSM initiatives.

The primary drivers for growth in the GS Mass Market are the population and the economy. Changes in residential customers and the Manitoba Gross Domestic Product (GDP) are reflected in the GS Mass Market's electricity use.

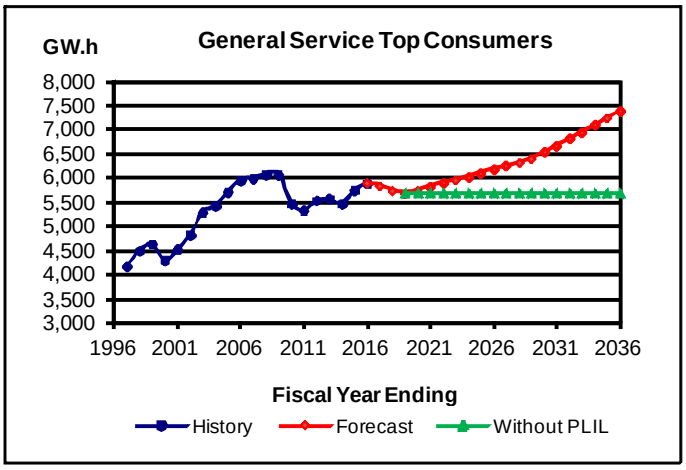
Table 15 - General Service Mass Market

GENERAL SERVICE MASS MARKET (GWh) HISTORICAL/WEATHER ADJUSTMENT/FORECAST					
Fiscal Year	Sales	Weather Adjust	Adjusted Sales	Fiscal Year	Forecast Sales
1996/97	6,627	-193	6,434	2016/17	9,286
1997/98	6,562	53	6,615	2017/18	9,471
1998/99	6,668	108	6,776	2018/19	9,639
1999/00	6,796	187	6,983	2019/20	9,779
2000/01	7,110	5	7,114	2020/21	9,931
2001/02	7,084	50	7,135	2021/22	10,084
2002/03	7,467	-137	7,330	2022/23	10,241
2003/04	7,460	-17	7,443	2023/24	10,400
2004/05	7,516	40	7,556	2024/25	10,560
2005/06	7,587	115	7,702	2025/26	10,701
2006/07	7,839	-40	7,799	2026/27	10,866
2007/08	8,006	-48	7,958	2027/28	11,034
2008/09	8,049	-46	8,003	2028/29	11,203
2009/10	7,985	93	8,078	2029/30	11,446
2010/11	8,258	42	8,299	2030/31	11,694
2011/12	8,162	103	8,265	2031/32	11,945
2012/13	8,434	-39	8,395	2032/33	12,202
2013/14	8,839	-264	8,575	2033/34	12,465
2014/15	8,771	-56	8,715	2034/35	12,735
2015/16	8,442	167	8,608	2035/36	13,013

General Service Top Consumers

General Service Top Consumers represent the top energy consuming businesses in Manitoba and account for 27% of all General Consumers Sales. GS Top Consumers include 10 distinct companies that count as 23 customers in the Primary Metals, Chemicals, Petrol/Oil/Natural Gas and Pulp/Paper sectors.

Figure 8 - General Service Top Consumers



GS Top Consumers increased 90 GWh (1.8%) per year over the past 20 years but decreased 6 GWh per year (-0.1%) over the past 10 years. The decrease was due to the economic downturn experienced from 2008 to 2011 and the loss of one Top Consumer. Starting in 2016/17, seven of the smallest Top Consumers, totaling 404 GWh in 2015/16, were moved to the General Service Mass Market Sector for forecasting purposes. Restated Top Consumers sales for 2015/16 would become 5,482 GWh, with expected growth of 319 GWh in 2016/17.

The Top Consumers sector is now forecast to grow an average of 69 GWh (1.2%) per year for the next 10 years and an average of 95 GWh (1.5%) per year for the next 20 years. Short term increases are expected in the Petro/Oil/Natural Gas sector. These are offset by reductions in the Primary Metals sector. Long term growth is forecast to be steady based on an expectation of good economic growth into the future.

Table 16 - General Service Top Consumers

GENERAL SERVICE TOP CONSUMERS (GWh) HISTORICAL/FORECAST WITH PLIL					
Fiscal Year	Sales	Fiscal Year	Individual	PLIL	Total
1996/97	4,173	2016/17	5,835	0	5,835
1997/98	4,493	2017/18	5,748	0	5,748
1998/99	4,632	2018/19	5,675	0	5,675
1999/00	4,299	2019/20	5,675	71	5,746
2000/01	4,515	2020/21	5,675	143	5,818
2001/02	4,818	2021/22	5,675	215	5,890
2002/03	5,282	2022/23	5,675	283	5,958
2003/04	5,423	2023/24	5,675	353	6,028
2004/05	5,714	2024/25	5,675	425	6,100
2005/06	5,948	2025/26	5,675	497	6,172
2006/07	5,989	2026/27	5,675	572	6,247
2007/08	6,075	2027/28	5,675	647	6,322
2008/09	6,065	2028/29	5,675	725	6,400
2009/10	5,461	2029/30	5,675	857	6,532
2010/11	5,324	2030/31	5,675	992	6,667
2011/12	5,531	2031/32	5,675	1,130	6,805
2012/13	5,560	2032/33	5,675	1,271	6,946
2013/14	5,461	2033/34	5,675	1,415	7,090
2014/15	5,750	2034/35	5,675	1,562	7,237
2015/16	5,886	2035/36	5,675	1,712	7,387

For the short term, General Service Top Consumers are forecast individually. Expected increases and decreases from customer's current and upcoming operating and expansion plans are compiled for the first three years of the forecast but exclude longer term plans that are uncommitted and subject to change.

For the long term, the growth of all Top Consumers is forecast together econometrically. The econometric long term Top Consumer forecast is referred to as Potential Large Industrial Loads (PLIL). PLIL is based on the historic growth of the ten companies that now comprise Top Consumers as well as one former Top Consumers customer that closed in 2009. These are large companies that both drive and define the national economy. The historical data used for modeling PLIL includes company expansions, cutbacks and shutdowns, new startups of companies that then were added to the Top Consumers classification, and the incremental growth of the individual Top Consumers. Therefore, the forecast implicitly includes the same expectations.

Historical growth of the Top Consumer sector is modeled using Gross Domestic Product (GDP) and electricity price as independent variables. The historic correlation between GDP, price and Top Consumer growth has been very strong and is expected to continue to be strong in the future. Future projections of GDP and price are used to forecast the future increase in Top Consumer growth starting from the fourth year of the forecast.

The sum of the individual company forecasts (less the seven Top Consumers moved to General Service Mass Market) is expected to grow from 5,482 GWh in 2015/16 to 5,675 GWh in 2018/19. After 2018/19, the individual forecasts for these customers are held constant. Longer term growth is considered to be included in PLIL, including growth and contractions expected to arise from committed plans in the Petro/Oil/Natural Gas and Mining sectors beyond year three.

PLIL is added starting in year four of the forecast. The econometric forecast for PLIL is based on an expected annual Canada/U.S. real GDP growth rate of 2.1%, leading to a forecast growth of 1.5% annually. When the historic real GDP growth rate over the past 20 years was 2.4%, the Top Consumers sector growth averaged 1.8% annually.

The Top Consumers sector is expected to grow 193 GWh in the first three years based on individual customer short term plans, and another 1,712 GWh in years 4 to 20 for PLIL.

General Service Diesel, Seasonal, and Flat Rate Water Heat

General Service Diesel

In 2015/16, there were 184 General Service Diesel Full Cost customers using 6 GWh. The General Service Diesel sector is forecast to use 7 GWh by 2035/36.

General Service Seasonal

In 2015/16, there were 882 General Service Seasonal customers using 5 GWh. The General Service Seasonal sector is expected to grow to 6 GWh by 2035/36.

General Service Flat Rate Water Heating

General Service Water Heating is a flat rate unmetered service that has not been available to new customers since November 12, 1969. There were 359 remaining services in 2015/16. The number of services is expected to decrease 5% per year throughout the forecast period. Consumption was 6 GWh in 2015/16 and that is forecast to decrease to 2 GWh by 2034/35.

General Service Surplus Energy Program

Participants in the Surplus Energy Program (SEP) used 27 GWh in 2015/16 and are expected to to use 25 GWh in 2016/17 and for the remainder of the forecast period. This energy is considered to be “interruptible” and thus “non-firm”. The energy used by these customers is included in Sales, but it is excluded from the Gross Firm Energy forecast.

Plug-In Electric Vehicles

This forecast includes an estimate of the future adoption of Plug-In Electric Vehicles in the Manitoba Hydro service area. This is made up of two types:

(1) Plug-In Hybrid Electric Vehicles (PHEVs) run on an electric battery but use an internal combustion engine (ICE) or gasoline powered generator to extend the driving range when the battery charge runs low. An example is the Chevrolet Volt. As of March 1, 2016 there were 65 PHEVs registered in Manitoba.

(2) Plug-in Electric Vehicles (PEVs) run only on electric battery power. Pure electric plug-in vehicles include the Nissan Leaf, the Tesla, Mitsubishi MiEV, and New Flyer Xcelsior transit bus. As of March 1, 2016 there were 75 PEVs registered in Manitoba.

The forecast of electric vehicles does not include non-plug-in Hybrid Electric Vehicles (HEVs). These vehicles, such as the non-plug-in Toyota Prius, have an internal combustion engine as well as a battery and electric motor to drive the wheels. The HEV battery is charged with power from the ICE and through regenerative breaking. It is not charged by plugging in and therefore does not affect electricity consumption in Manitoba. As of March 1, 2016 and after 15 years in the market, there were only 4,650 HEVs registered in Manitoba, representing 0.5% of all registered road motor vehicles.

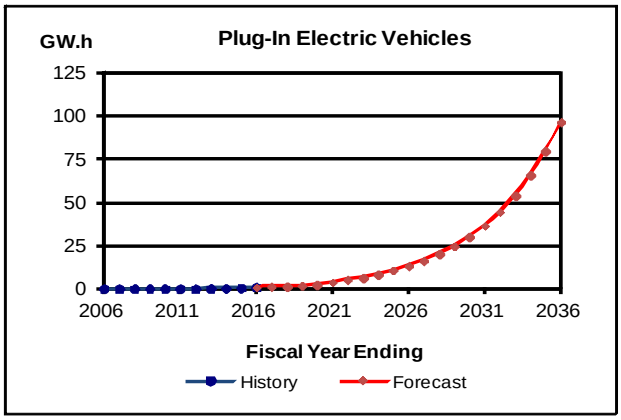
According to EV-Volumes, an EV sales database and consulting group, there were 540,000 plug-in vehicles sold worldwide in 2015, making up 0.6% of new vehicle sales in the last year. Total worldwide number of electric plug-in vehicles surpassed the one million mark in September of 2015. Out of the total global vehicle count of just over one billion, electric plug-in vehicles represent 0.1% of the total. The United States accounts for 406,000 of total electric plug-in vehicle sales to date or approximately 40% of all electric vehicles sales worldwide. In Canada, 18,451 plug-in electric vehicles were registered as of December 31, 2015 according to FleetCarma. Plug-in vehicles make up 0.08% of total road motor vehicle registrations in Canada. In Manitoba, as of fiscal year ending 2016, there were 140 plug-in vehicles out of a total of 870,589 making up 0.02% of total road motor vehicle registrations (Table 17).

On March 31, 2016, Tesla Motors unveiled its most affordable EV, the Model 3 and opened it up for preorders. The Model 3 price starts at US $35,000. By May 19, 2016, 373,000 potential

customers reserved the Model 3 with a $1,000 down payment. Cancellations are allowed up until 2020. Delivery of the first Model 3's is anticipated for late 2017, early 2018. Deliveries will first go to California, and then to the American East Coast. Tesla Motors has sold almost 125,000 electric cars worldwide since delivery of its first Tesla Roadster in 2008. Based on the 20 Tesla vehicles registered in Manitoba, the number of Model 3s on preorder from Manitoba is estimated at 60. Model 3's will probably be arriving in Manitoba in 2019 or even 2020.

The Electric Vehicle Forecast

Figure 9 - Plug-In Electric Vehicles



As of March 1st, 2016, there were a total of 140 plug-in electric vehicles, including four electric buses, registered in Manitoba with the Manitoba Public Insurance Corporation. Last year's 2015 Load Forecast predicted a total of 137 plug-in vehicles to be registered in Manitoba at fiscal year ending 2016. The latest electric vehicle forecast is adjusted to incorporate the slightly higher actual registrations recorded in fiscal year ending 2016. The Table 17 details the Manitoba actual and forecasted number of new vehicles per year, the total number of vehicles each year, as well as the corresponding numbers for Plug-In Electric Vehicles. The forecast incorporates passenger as well as commercial category vehicles such as Sport Utility Vehicles (SUVs), light and heavy duty trucks, and transit buses. Pull-trailers, farm equipment, motor boats and motor cycles are not included in the count. A passenger PEV consumes approximately 3,500 kWh annually, the equivalent use of one residential, electric hot water tank. An electric transit bus consumes 87,500 kWh annually. That is the equivalent use of three electrically heated single detached dwellings. The number of new PEVs is expected to slowly increase until it reaches about 0.71% of new vehicle sales (481 units) in 2025/26 and 4.36% of new vehicle sales (3,399 units) in 2035/36. The total number of PEVs on the road is forecasted to be 0.21% of total vehicle registrations (2,345 units) in 2025/26 increasing to 1.37% of total vehicle registrations (18,742 units) by 2035/36.

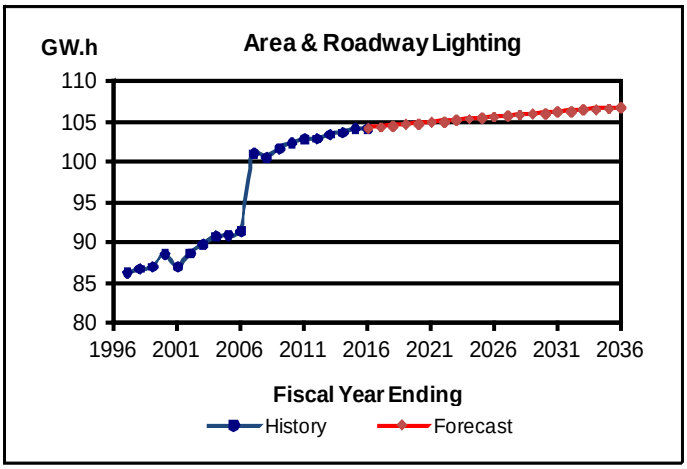
Total energy use for PEVs in Manitoba is forecasted to be 13 GWh in 2025/26 and 96 GWh by 2035/36. Peak usage coincident to Manitoba Hydro's system peak is forecasted to be 1.6 MW in 2025/26 and 12.0 MW in 2035/36. Forecasted use decreased from 2015 forecast due an adjustment in the annual consumption of electric transit buses.

Table 17 - Plug-In Electric Vehicles

PLUG-IN ELECTRIC VEHICLE FORECAST History and Forecast 2005/06 - 2035/36								
Fiscal Year	New Vehicles Purchased	New PEV Purchased	New PEV %	Total Vehicles	Total PEV	Total % PEV	Cumul Total PEV GWh	Cumul Total PEV MW
2005/06	46,127	0	0.0%	672,122	0	0.0%	0	0
2006/07	46,164	0	0.0%	686,576	0	0.0%	0	0
2007/08	47,953	0	0.0%	704,519	0	0.0%	0	0
2008/09	46,710	0	0.0%	716,963	0	0.0%	0	0
2009/10	45,355	0	0.0%	763,919	0	0.0%	0	0
2010/11	48,546	1	0.0%	780,979	1	0.0%	0	0
2011/12	52,236	8	0.0%	801,262	9	0.0%	0	0
2012/13	56,275	28	0.0%	814,569	37	0.0%	0	0
2013/14	57,783	32	0.1%	828,252	69	0.0%	0	0
2014/15	58,882	30	0.1%	857,029	99	0.0%	1	0
2015/16	57,809	41	0.1%	870,589	140	0.0%	1	0
2016/17	58,819	55	0.1%	891,983	195	0.0%	1	0.1
2017/18	59,829	67	0.1%	913,743	262	0.0%	1	0.2
2018/19	60,839	84	0.1%	935,872	346	0.0%	2	0.2
2019/20	61,848	120	0.2%	958,367	466	0.0%	2	0.3
2020/21	62,858	192	0.3%	981,230	658	0.1%	4	0.5
2021/22	63,868	220	0.3%	1,004,460	878	0.1%	5	0.6
2022/23	64,878	267	0.4%	1,028,057	1,145	0.1%	7	0.8
2023/24	65,888	325	0.5%	1,052,022	1,470	0.1%	8	1.0
2024/25	66,898	395	0.6%	1,076,354	1,865	0.2%	11	1.3
2025/26	67,907	481	0.7%	1,101,053	2,345	0.2%	13	1.6
2026/27	68,917	585	0.8%	1,126,120	2,930	0.3%	16	2.0
2027/28	69,927	711	1.0%	1,151,554	3,641	0.3%	20	2.5
2028/29	70,937	865	1.2%	1,177,355	4,506	0.4%	24	3.1
2029/30	71,947	1,052	1.5%	1,203,523	5,558	0.5%	30	3.7
2030/31	72,957	1,280	1.8%	1,230,059	6,837	0.6%	36	4.5
2031/32	73,966	1,556	2.1%	1,256,962	8,393	0.7%	44	5.5
2032/33	74,976	1,892	2.5%	1,284,232	10,285	0.8%	54	6.7
2033/34	75,986	2,301	3.0%	1,311,870	12,586	1.0%	65	8.2
2034/35	76,996	2,797	3.6%	1,339,875	15,383	1.1%	79	9.9
2035/36	78,006	3,399	4.4%	1,368,247	18,782	1.4%	96	12.0

Area & Roadway Lighting

Figure 10 - Area & Roadway Lighting



The Area and Roadway Lighting sector represents 0.5% of all sales within Manitoba. This sector includes electricity sales for the Sentinel Lighting and Street Lighting rate groups. Sentinel Lighting is an outdoor lighting service where units are available either as rentals to an existing metered service or on an unmetered, flat rate basis. Street Lighting includes all public roadway lighting in Manitoba. In 2006, a readjustment of the rate classes moved some flat rate General Service meters into the Lighting sector. Only Street Lights count as customers.

The Area and Roadway Lighting sector is forecast to increase from 104 GWh in 2015/16 to 107 GWh by 2035/36 at an average annual growth rate of 0.1 GWh or 0.1% per year. This does not include the effect of future Demand Side Management (DSM) initiatives in this sector.

Table 18 - Area & Roadway Lighting

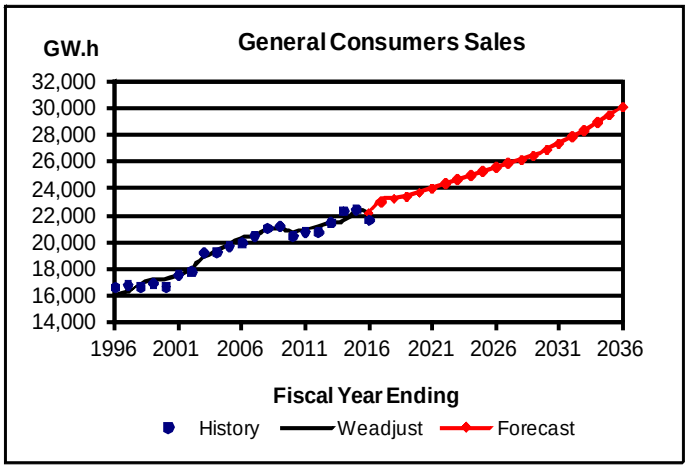
AREA & ROADWAY LIGHTING (GWh) HISTORICAL/WEATHER ADJUSTMENT/FORECAST					
Fiscal Year	Sales	Weather Adjust	Adjusted Sales	Fiscal Year	Forecast Sales
1996/97	86	0	86	2016/17	104
1997/98	87	0	87	2017/18	104
1998/99	87	0	87	2018/19	105
1999/00	89	0	89	2019/20	105
2000/01	87	0	87	2020/21	105
2001/02	89	0	89	2021/22	105
2002/03	90	0	90	2022/23	105
2003/04	91	0	91	2023/24	105
2004/05	91	0	91	2024/25	105
2005/06	91	0	91	2025/26	106
2006/07	101	0	101	2026/27	106
2007/08	101	0	101	2027/28	106
2008/09	102	0	102	2028/29	106
2009/10	102	0	102	2029/30	106
2010/11	103	0	103	2030/31	106
2011/12	103	0	103	2031/32	106
2012/13	103	0	103	2032/33	106
2013/14	104	0	104	2033/34	107
2014/15	104	0	104	2034/35	107
2015/16	104	0	104	2035/36	107

Table 19 - Area & Roadway Lighting

AREA AND ROADWAY LIGHTING History and Forecast 2005/06 - 2035/36								
Fiscal	Sentinal Flat Rates		Sentinal Rentals		Street Lighting		Total Lighting	
Year	(Services)	(GWh)	(Services)	(GWh)	(Custs)	(GWh)	(Custs)	(GWh)
2005/06	19,652	10	7,826	0	793	81	793	91
2006/07	18,669	11	23,994	0	1,129	90	1,129	101
2007/08	18,947	11	24,272	0	1,142	90	1,142	101
2008/09	19,228	11	24,542	0	1,175	91	1,175	102
2009/10	19,539	11	24,886	0	1,191	91	1,191	102
2010/11	19,835	11	25,216	0	1,184	92	1,184	103
2011/12	20,033	11	25,427	0	1,155	91	1,155	103
2012/13	20,238	12	25,613	0	1,164	92	1,164	103
2013/14	20,399	12	25,764	0	1,157	92	1,157	104
2014/15	20,495	12	25,853	0	1,196	92	1,196	104
2015/16	20,643	12	25,960	0	1,208	92	1,208	104
2016/17	20,834	12	26,138	0	1,216	93	1,216	104
2017/18	20,969	12	26,287	0	1,221	93	1,221	104
2018/19	21,104	12	26,436	0	1,226	93	1,226	105
2019/20	21,239	12	26,585	0	1,231	93	1,231	105
2020/21	21,374	12	26,734	0	1,236	93	1,236	105
2021/22	21,509	12	26,883	0	1,241	93	1,241	105
2022/23	21,644	12	27,032	0	1,246	93	1,246	105
2023/24	21,779	12	27,181	0	1,251	93	1,251	105
2024/25	21,914	12	27,330	0	1,256	93	1,256	105
2025/26	22,049	12	27,479	0	1,261	93	1,261	106
2026/27	22,184	13	27,628	0	1,266	93	1,266	106
2027/28	22,319	13	27,777	0	1,271	93	1,271	106
2028/29	22,454	13	27,926	0	1,276	93	1,276	106
2029/30	22,589	13	28,075	0	1,281	93	1,281	106
2030/31	22,724	13	28,224	0	1,286	93	1,286	106
2031/32	22,859	13	28,373	0	1,291	93	1,291	106
2032/33	22,994	13	28,522	0	1,296	93	1,296	106
2033/34	23,129	13	28,671	0	1,301	93	1,301	107
2034/35	23,264	13	28,820	0	1,306	93	1,306	107
2035/36	23,399	13	28,969	0	1,311	94	1,311	107

Total General Consumers Sales

Figure 11 - General Consumers Sales



General Consumers Sales includes sales to all of Manitoba Hydro's individually billed customers, but excludes export sales. This includes the total of all sales from the Residential, General Service and Lighting sectors. The General Service sector makes up about two-thirds, the Residential sector makes up about one-third and the Lighting group is only 0.5% of all sales.

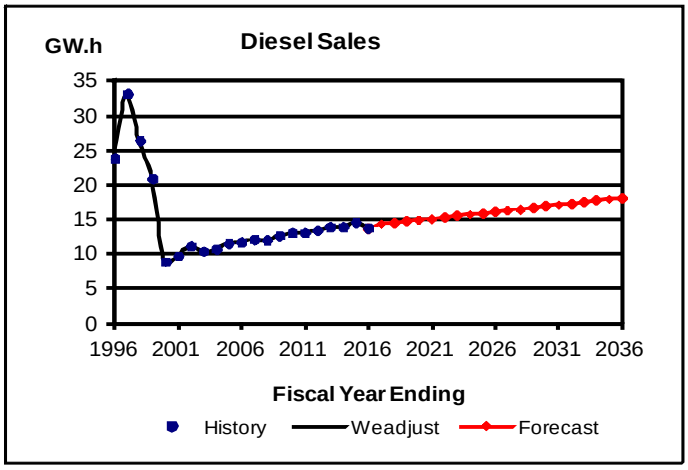
Weather adjusted General Consumers Sales has grown 311 GWh (1.6%) per year for the past 20 years and 188 GWh (0.9%) per year over the past 10 years. This historical growth includes the effect of past Demand Side Management (DSM) initiatives. Sales are forecast to grow 337 GWh (1.4%) per year for the next 10 years and 393 GWh (1.5%) per year for the next 20 years before program-based DSM initiatives.

Table 20 - General Consumers Sales

GENERAL CONSUMERS SALES (GWh) HISTORICAL/WEATHER ADJUSTMENT/FORECAST					
Fiscal Year	Sales	Weather Adjust	Adjusted Sales	Fiscal Year	Forecast Sales
1996/97	16,851	-583	16,268	2016/17	23,053
1997/98	16,681	159	16,840	2017/18	23,229
1998/99	16,929	316	17,245	2018/19	23,407
1999/00	16,696	497	17,193	2019/20	23,715
2000/01	17,590	-32	17,558	2020/21	24,024
2001/02	17,805	183	17,988	2021/22	24,339
2002/03	19,246	-401	18,846	2022/23	24,650
2003/04	19,280	-15	19,265	2023/24	24,961
2004/05	19,735	52	19,788	2024/25	25,271
2005/06	19,935	371	20,306	2025/26	25,557
2006/07	20,510	-58	20,452	2026/27	25,855
2007/08	21,061	-127	20,934	2027/28	26,134
2008/09	21,210	-201	21,009	2028/29	26,438
2009/10	20,486	227	20,713	2029/30	26,879
2010/11	20,786	120	20,906	2030/31	27,328
2011/12	20,771	401	21,172	2031/32	27,823
2012/13	21,477	-55	21,422	2032/33	28,359
2013/14	22,338	-807	21,531	2033/34	28,910
2014/15	22,458	-176	22,281	2034/35	29,472
2015/16	21,654	532	22,186	2035/36	30,055

Diesel Sales

Figure 12 - Diesel Sales



There are four communities served by diesel generation in Manitoba: Brochet, Lac Brochet, Tadoule Lake and Shamattawa. Sales within these communities are included in General Consumers Sales, but are not part of the Integrated System, and are thus not part of Common Bus or Gross Firm Load.

Between 1997 and 1999, eleven communities previously served by diesel generation were connected to the Integrated System resulting in the drop in overall diesel sales. The four sites that were to remain diesel were converted from 15 amp service to 60 amp service between 1991 and 2001 causing the increase in those years.

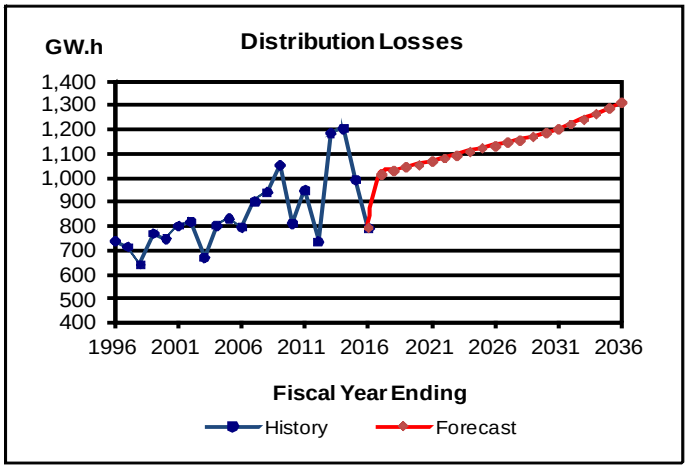
Diesel customers do not have electric heat, which requires a minimum 200 amp service, therefore there is no weather effect.

Table 21 - Diesel Sales

DIESEL SALES (GWh) HISTORICAL/WEATHER ADJUSTMENT/FORECAST					
Fiscal Year	Sales	Weather Adjust	Adjusted Sales	Fiscal Year	Forecast Sales
1996/97	33	0	33	2016/17	14
1997/98	26	0	26	2017/18	15
1998/99	21	0	21	2018/19	15
1999/00	9	0	9	2019/20	15
2000/01	10	0	10	2020/21	15
2001/02	11	0	11	2021/22	15
2002/03	10	0	10	2022/23	16
2003/04	11	0	11	2023/24	16
2004/05	12	0	12	2024/25	16
2005/06	12	0	12	2025/26	16
2006/07	12	0	12	2026/27	16
2007/08	12	0	12	2027/28	16
2008/09	13	0	13	2028/29	17
2009/10	13	0	13	2029/30	17
2010/11	13	0	13	2030/31	17
2011/12	13	0	13	2031/32	17
2012/13	14	0	14	2032/33	17
2013/14	14	0	14	2033/34	18
2014/15	15	0	15	2034/35	18
2015/16	14	0	14	2035/36	18

Distribution Losses

Figure 13 - Distribution Losses



Distribution Losses are made up of the power loss between the distribution substation (Manitoba Load at Common Bus less Construction) and the customer's meter (General Consumers Sales less Diesel), as well as all other differences between what was billed and what was metered. The other differences include:

1. The offset between cycle billing (General Consumers Sales) and actual calendar month usage (Common Bus).
2. Customer Accounting adjustments,
3. Inaccuracies associated with estimated billing (including flat rate estimates),
4. The metered but unbilled consumption of Manitoba Hydro offices, and
5. Energy lost due to theft.

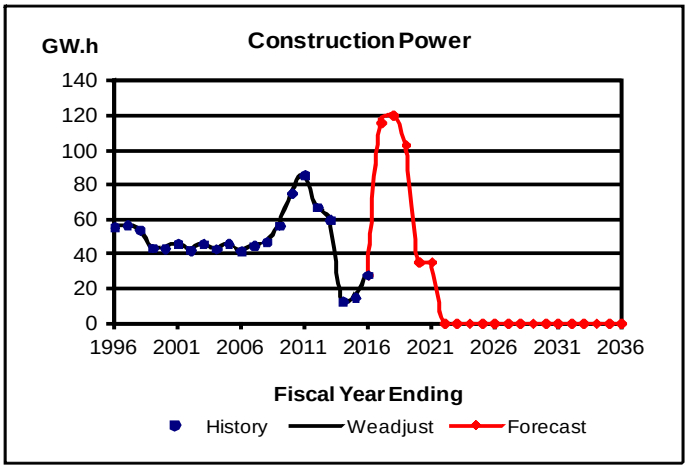
Distribution Losses are forecast in 2016/17 to be 4.4% of the General Consumers Sales less Diesel and remain between 4.4% and 4.5% throughout the forecast.

Table 22 - Distribution Losses

DISTRIBUTION LOSSES (GWh) HISTORICAL / PERCENT OF SALES / FORECAST							
Fiscal Year	Losses	Sales less Diesel	% Losses	Fiscal Year	Forecast Losses	Sales less Diesel	% Losses
1996/97	715	16,818	4.3%	2016/17	1,014	23,038	4.4%
1997/98	641	16,655	3.9%	2017/18	1,028	23,214	4.4%
1998/99	771	16,908	4.6%	2018/19	1,042	23,392	4.5%
1999/00	749	16,687	4.5%	2019/20	1,055	23,700	4.4%
2000/01	802	17,580	4.6%	2020/21	1,067	24,009	4.4%
2001/02	819	17,793	4.6%	2021/22	1,081	24,323	4.4%
2002/03	671	19,236	3.5%	2022/23	1,094	24,634	4.4%
2003/04	804	19,269	4.2%	2023/24	1,107	24,946	4.4%
2004/05	830	19,724	4.2%	2024/25	1,121	25,255	4.4%
2005/06	797	19,923	4.0%	2025/26	1,133	25,541	4.4%
2006/07	900	20,497	4.4%	2026/27	1,145	25,839	4.4%
2007/08	940	21,049	4.5%	2027/28	1,156	26,118	4.4%
2008/09	1,052	21,198	5.0%	2028/29	1,168	26,421	4.4%
2009/10	813	20,473	4.0%	2029/30	1,184	26,862	4.4%
2010/11	947	20,773	4.6%	2030/31	1,200	27,311	4.4%
2011/12	736	20,757	3.5%	2031/32	1,220	27,805	4.4%
2012/13	1,184	21,463	5.5%	2032/33	1,241	28,341	4.4%
2013/14	1,205	22,324	5.4%	2033/34	1,264	28,892	4.4%
2014/15	992	22,443	4.4%	2034/35	1,287	29,454	4.4%
2015/16	791	21,640	3.7%	2035/36	1,311	30,037	4.4%

Construction Power

Figure 14 - Construction Power



Construction Power represents the energy used by Manitoba Hydro and its contractors in the construction of major capital works such as generating stations, converter stations and major transmission lines. Construction Power also includes Station Service until a plant is commissioned. Until 2013, about 48 GWh of heating load at the Gillam, Limestone and Kettle town sites was included in Construction Power. This energy is now included in Distribution Losses.

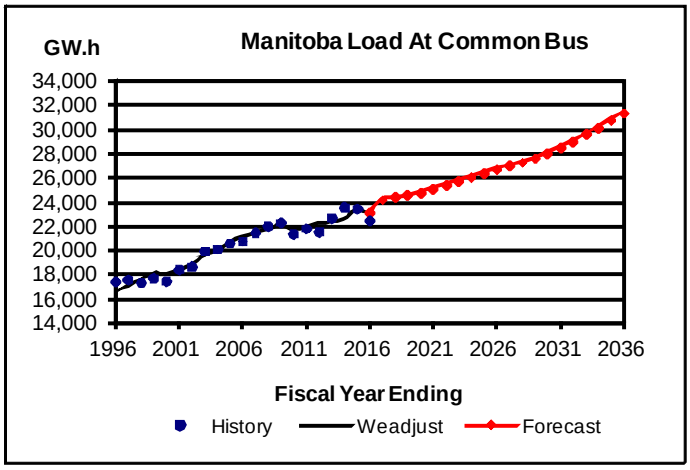
The Construction Power forecast includes: (1) the Keeyask Generating Station, (2) the Keewatinoow Converter Station, started in January 2012 with expected completion in the Fall of 2018 and (3) the Riel Converter Station with an expected completion date of 2019.

Table 23 - Construction Power

CONSTRUCTION POWER (GWh) HISTORICAL/WEATHER ADJUSTMENT/FORECAST					
Fiscal Year	Usage	Weather Adjust	Adjusted Usage	Fiscal Year	Forecast Usage
1996/97	56	0	56	2016/17	116
1997/98	54	0	54	2017/18	120
1998/99	43	0	43	2018/19	103
1999/00	43	0	43	2019/20	35
2000/01	46	0	46	2020/21	35
2001/02	42	0	42	2021/22	0
2002/03	46	0	46	2022/23	0
2003/04	43	0	43	2023/24	0
2004/05	46	0	46	2024/25	0
2005/06	42	0	42	2025/26	0
2006/07	45	0	45	2026/27	0
2007/08	47	0	47	2027/28	0
2008/09	56	0	56	2028/29	0
2009/10	75	0	75	2029/30	0
2010/11	85	0	85	2030/31	0
2011/12	67	0	67	2031/32	0
2012/13	59	0	59	2032/33	0
2013/14	12	0	12	2033/34	0
2014/15	15	0	15	2034/35	0
2015/16	28	0	28	2035/36	0

Manitoba Load at Common Bus

Figure 15 - Manitoba Load at Common Bus



Manitoba Load at Common Bus is the total load measured from all the distribution points (i.e. substations) within Manitoba. It includes all energy supplied to General Consumers Sales customers, Construction Power plus associated Distribution Losses, but excludes Diesel customers, Transmission Losses and Station Service.

Common Bus is metered and totaled to correspond exactly to each calendar month. Weather adjustment is done on a calendar month basis.

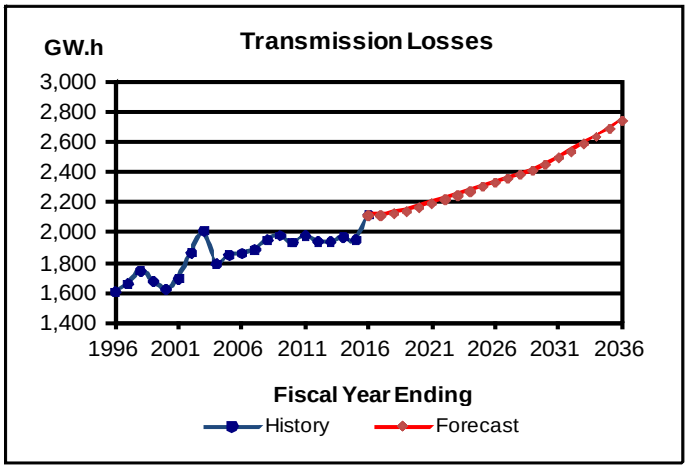
Weather adjusted Common Bus has grown 320 GWh (1.6%) per year for the past 20 years and 191 GWh (0.9%) per year during the past 10 years reflecting the recent economic downturn. This historical growth also includes the effect of past Demand Side Management (DSM) initiatives. Common Bus is forecast to grow 359 GWh (1.5%) per year for the next 10 years and 413 GWh (1.5%) per year for the next 20 years before program-based DSM initiatives.

Table 24 - Manitoba Load at Common Bus

MANITOBA LOAD AT COMMON BUS (GWh) HISTORICAL/WEATHER ADJUSTMENT/FORECAST					
Fiscal Year	Energy	Weather Adjust	Adjusted Energy	Fiscal Year	Forecast Energy
1996/97	17,590	-594	16,996	2016/17	24,168
1997/98	17,350	248	17,598	2017/18	24,363
1998/99	17,722	355	18,077	2018/19	24,537
1999/00	17,479	573	18,051	2019/20	24,789
2000/01	18,428	-135	18,293	2020/21	25,111
2001/02	18,655	159	18,813	2021/22	25,404
2002/03	19,953	-359	19,594	2022/23	25,728
2003/04	20,116	-108	20,007	2023/24	26,053
2004/05	20,600	47	20,647	2024/25	26,375
2005/06	20,761	409	21,170	2025/26	26,674
2006/07	21,442	-38	21,404	2026/27	26,984
2007/08	22,036	-197	21,839	2027/28	27,274
2008/09	22,305	-219	22,086	2028/29	27,590
2009/10	21,361	363	21,724	2029/30	28,046
2010/11	21,806	64	21,869	2030/31	28,511
2011/12	21,560	660	22,220	2031/32	29,025
2012/13	22,706	-352	22,354	2032/33	29,583
2013/14	23,541	-921	22,620	2033/34	30,156
2014/15	23,450	-41	23,408	2034/35	30,741
2015/16	22,460	625	23,085	2035/36	31,348

Transmission Losses

Figure 16 - Transmission Losses



Transmission Losses are the amount of energy lost while delivering power from the generation stations to all of the distribution substations that make up Common Bus. Transmission Losses only contains losses associated with supplying Manitoba customers. Losses attributable to exports and the gains attributable to imports are excluded. Transmission Losses are mostly losses on the High Voltage Direct Current (HVDC) lines, and are substantial because of the distance of transmission from northern generation to southern distribution points, but are much less than what AC losses would be over that distance. Transmission Losses vary year to year depending on water conditions, system configuration, outages and the magnitude of the load. High losses experienced in 2002/03 were due to two HVDC transformer failures.

Transmission Losses are forecast to be 9.1% to 9.2% of the General Consumers Sales less Diesel Sales.

Table 25 - Transmission Losses

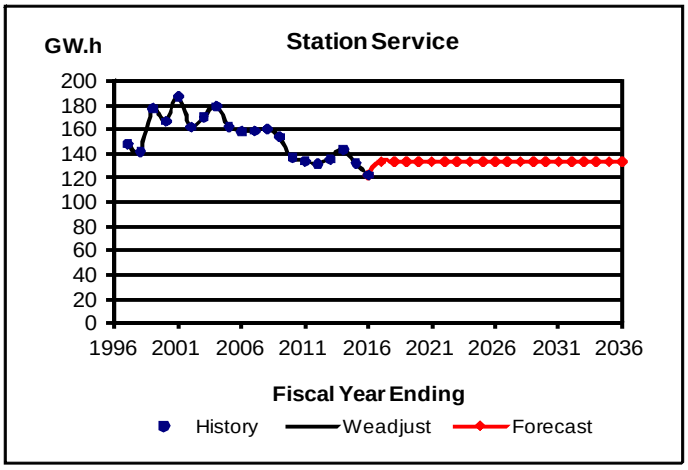
TRANSMISSION LOSSES (GWh) HISTORICAL / PERCENT OF SALES / FORECAST							
Fiscal Year	Losses	Sales less Diesel	% Losses	Fiscal Year	Forecast Losses	Sales less Diesel	% Losses
1996/97	1,660	16,818	9.9%	2016/17	2,109	23,038	9.2%
1997/98	1,745	16,655	10.5%	2017/18	2,126	23,214	9.2%
1998/99	1,675	16,908	9.9%	2018/19	2,141	23,392	9.2%
1999/00	1,623	16,687	9.7%	2019/20	2,163	23,700	9.1%
2000/01	1,696	17,580	9.6%	2020/21	2,192	24,009	9.1%
2001/02	1,864	17,793	10.5%	2021/22	2,217	24,323	9.1%
2002/03	2,012	19,236	10.5%	2022/23	2,246	24,634	9.1%
2003/04	1,792	19,269	9.3%	2023/24	2,274	24,946	9.1%
2004/05	1,852	19,724	9.4%	2024/25	2,302	25,255	9.1%
2005/06	1,860	19,923	9.3%	2025/26	2,328	25,541	9.1%
2006/07	1,885	20,497	9.2%	2026/27	2,355	25,839	9.1%
2007/08	1,949	21,049	9.3%	2027/28	2,381	26,118	9.1%
2008/09	1,979	21,198	9.3%	2028/29	2,408	26,421	9.1%
2009/10	1,934	20,473	9.4%	2029/30	2,448	26,862	9.1%
2010/11	1,977	20,773	9.5%	2030/31	2,489	27,311	9.1%
2011/12	1,939	20,757	9.3%	2031/32	2,534	27,805	9.1%
2012/13	1,936	21,463	9.0%	2032/33	2,583	28,341	9.1%
2013/14	1,969	22,324	8.8%	2033/34	2,633	28,892	9.1%
2014/15	1,949	22,443	8.7%	2034/35	2,684	29,454	9.1%
2015/16	2,116	21,640	9.8%	2035/36	2,737	30,037	9.1%

Station Service

Figure 17 - Station Service

Station Service is the energy used by power plants to generate power and service their own load. Manitoba energy or peak without Station Service is referred to as “Net”, and with Station Service as “Gross”.

Station Service energy is forecast to be 133 GWh and Station Service peak is forecast to be 23 MW from 2016/17 to 2035/36.



Station Service for Keeyask and for future non-committed plants is excluded from this forecast.

Table 26 - Station Service

STATION SERVICE (GWh) HISTORICAL/WEATHER ADJUSTMENT/FORECAST					
Fiscal Year	Usage	Weather Adjust	Adjusted Usage	Fiscal Year	Forecast Usage
1996/97	148	0	148	2016/17	133
1997/98	142	0	142	2017/18	133
1998/99	177	0	177	2018/19	133
1999/00	167	0	167	2019/20	133
2000/01	187	0	187	2020/21	133
2001/02	162	0	162	2021/22	133
2002/03	170	0	170	2022/23	133
2003/04	179	0	179	2023/24	133
2004/05	163	0	163	2024/25	133
2005/06	158	0	158	2025/26	133
2006/07	159	0	159	2026/27	133
2007/08	161	0	161	2027/28	133
2008/09	154	0	154	2028/29	133
2009/10	137	0	137	2029/30	133
2010/11	134	0	134	2030/31	133
2011/12	131	0	131	2031/32	133
2012/13	136	0	136	2032/33	133
2013/14	144	0	144	2033/34	133
2014/15	132	0	132	2034/35	133
2015/16	123	0	123	2035/36	133

Table 27 - Monthly Station Service Energy

MONTHLY STATION SERVICE ENERGY (GWh)
History and Forecast

Fiscal Year	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Total
2005/06	12.6	11.0	10.0	11.1	10.1	9.6	11.8	15.2	18.4	16.7	17.0	14.9	158.3
2006/07	10.2	8.9	8.4	10.3	9.3	8.6	13.4	16.1	16.7	18.6	19.7	18.7	158.8
2007/08	15.7	12.1	9.1	8.2	8.4	7.3	8.7	14.7	19.2	18.6	19.7	18.8	160.5
2008/09	13.8	9.4	7.5	9.5	10.4	7.1	10.6	15.1	20.1	20.4	14.9	15.5	154.2
2009/10	11.8	10.3	7.9	7.2	7.4	7.2	10.8	14.2	18.8	15.5	13.3	12.7	137.1
2010/11	10.2	9.9	7.3	6.7	7.2	7.4	9.5	12.9	16.4	17.1	14.4	15.0	134.1
2011/12	12.0	9.9	7.5	7.1	7.3	6.7	9.5	13.1	15.1	16.0	13.8	13.1	131.3
2012/13	11.0	9.4	7.7	7.0	6.7	6.4	11.4	14.3	16.2	16.6	13.7	15.2	135.5
2013/14	12.6	11.1	7.0	7.5	7.6	6.9	11.2	13.5	17.8	17.0	15.8	15.8	143.8
2014/15	12.1	9.6	7.7	7.5	7.2	7.0	8.9	13.2	14.4	16.1	15.0	13.7	132.4
2015/16	10.6	8.9	6.8	6.3	7.1	7.9	8.5	13.4	13.7	13.9	13.1	12.5	122.6
2016/17 - 2035/36	11.8	9.9	7.2	7.1	7.3	7.3	9.5	13.3	15.3	15.7	14.6	14.0	133.0

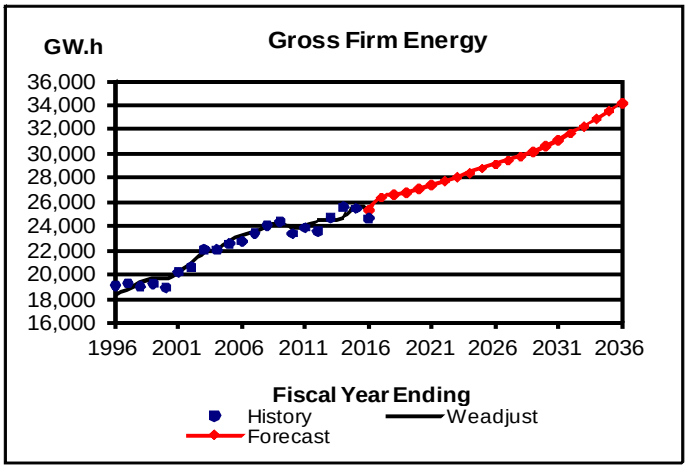
Table 28 - Monthly Station Service Peak

MONTHLY STATION SERVICE PEAK (MW)
History and Forecast

Fiscal Year	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Annual
2015/16 Actual	16	11	8	8	8	15	12	25	21	20	21	19	25
2016/17 - 2035/36	19	13	10	11	10	11	17	23	22	23	25	23	23

Gross Firm Energy

Figure 18 - Gross Firm Energy



Gross Firm Energy is the energy required to serve Manitoba Hydro's customers on the Integrated System. It excludes exports, interruptible (non-firm) loads, Diesel Sales and Station Service for Keeyask and non-committed plants.

Gross Firm Energy has grown steadily during the past twenty years, except during the economic slowdown in the 1990's and more recently in 2009.

Weather adjusted Gross Firm Energy has grown 352 GWh (1.6%) per year for the past 20 years and 215 GWh (0.9%) per year during the past 10 years reflecting the recent 2008 economic downturn. This historical growth includes the effect of past Demand Side Management (DSM) initiatives. Energy is forecast to grow 375 GWh (1.4%) per year for the next 10 years and 442 GWh (1.5%) per year for the next 20 years before program-based DSM initiatives.

Table 29 - Gross Firm Energy

GROSS FIRM ENERGY (GWh) HISTORICAL/WEATHER ADJUSTMENT/FORECAST					
Fiscal Year	Energy	Weather Adjust	Adjusted Energy	Fiscal Year	Forecast Energy
1996/97	19,321	-647	18,674	2016/17	26,385
1997/98	19,014	272	19,286	2017/18	26,596
1998/99	19,273	387	19,660	2018/19	26,785
1999/00	18,971	627	19,597	2019/20	27,060
2000/01	20,262	-143	20,119	2020/21	27,410
2001/02	20,656	174	20,830	2021/22	27,729
2002/03	22,110	-394	21,716	2022/23	28,082
2003/04	22,069	-121	21,948	2023/24	28,435
2004/05	22,589	53	22,641	2024/25	28,785
2005/06	22,757	444	23,200	2025/26	29,110
2006/07	23,464	-41	23,423	2026/27	29,447
2007/08	24,122	-212	23,910	2027/28	29,762
2008/09	24,417	-236	24,181	2028/29	30,106
2009/10	23,412	396	23,808	2029/30	30,602
2010/11	23,892	72	23,965	2030/31	31,108
2011/12	23,605	716	24,321	2031/32	31,666
2012/13	24,750	-383	24,367	2032/33	32,273
2013/14	25,625	-991	24,634	2033/34	32,896
2014/15	25,505	-44	25,461	2034/35	33,532
2015/16	24,673	682	25,355	2035/36	34,193

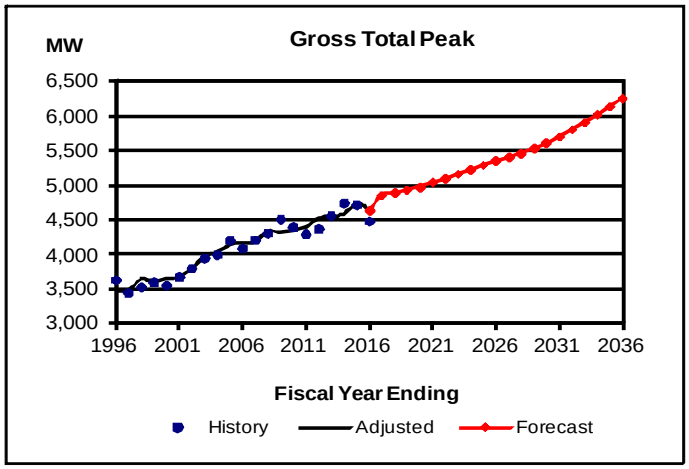
Table 30 - Monthly Gross Firm Energy

MONTHLY GROSS FIRM ENERGY (GWh)
History and Forecast
2005/06 - 2035/36

Fiscal Year	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Total
2005/06	1,727	1,698	1,660	1,735	1,649	1,610	1,781	2,045	2,301	2,240	2,171	2,139	22,757
2006/07	1,712	1,690	1,681	1,826	1,746	1,622	1,870	2,092	2,303	2,458	2,304	2,159	23,464
2007/08	1,842	1,701	1,663	1,820	1,727	1,650	1,836	2,108	2,490	2,584	2,427	2,273	24,122
2008/09	1,881	1,737	1,662	1,730	1,787	1,681	1,874	2,154	2,652	2,702	2,226	2,331	24,417
2009/10	1,861	1,744	1,671	1,667	1,644	1,672	1,888	1,935	2,560	2,524	2,213	2,032	23,412
2010/11	1,699	1,692	1,611	1,716	1,698	1,638	1,778	2,129	2,563	2,682	2,322	2,364	23,892
2011/12	1,862	1,751	1,603	1,789	1,741	1,643	1,814	2,125	2,435	2,526	2,251	2,064	23,605
2012/13	1,802	1,698	1,688	1,869	1,727	1,606	1,941	2,265	2,665	2,766	2,342	2,383	24,750
2013/14	2,041	1,754	1,650	1,766	1,725	1,657	1,914	2,258	2,884	2,895	2,553	2,527	25,625
2014/15	2,048	1,837	1,690	1,788	1,778	1,703	1,909	2,424	2,638	2,770	2,581	2,339	25,505
2015/16	1,940	1,799	1,724	1,868	1,775	1,728	1,872	2,137	2,469	2,695	2,418	2,248	24,673
15/16 Wadj	1,984	1,788	1,789	1,820	1,777	1,703	1,935	2,260	2,643	2,764	2,491	2,402	25,355
2016/17	2,017	1,875	1,801	1,891	1,833	1,761	2,021	2,365	2,807	2,959	2,556	2,500	26,385
2017/18	2,033	1,889	1,814	1,904	1,847	1,773	2,036	2,385	2,831	2,985	2,578	2,520	26,596
2018/19	2,047	1,901	1,827	1,919	1,863	1,785	2,051	2,402	2,852	3,007	2,596	2,537	26,785
2019/20	2,066	1,923	1,847	1,944	1,893	1,806	2,074	2,427	2,877	3,033	2,617	2,555	27,060
2020/21	2,093	1,947	1,869	1,973	1,928	1,833	2,098	2,453	2,910	3,069	2,650	2,587	27,410
2021/22	2,117	1,971	1,892	1,998	1,952	1,856	2,124	2,482	2,942	3,102	2,679	2,614	27,729
2022/23	2,144	1,996	1,916	2,023	1,978	1,879	2,151	2,514	2,979	3,142	2,713	2,647	28,082
2023/24	2,171	2,021	1,941	2,049	2,003	1,903	2,178	2,545	3,016	3,181	2,747	2,680	28,435
2024/25	2,198	2,046	1,965	2,074	2,027	1,927	2,205	2,577	3,053	3,219	2,780	2,713	28,785
2025/26	2,223	2,070	1,987	2,097	2,050	1,949	2,230	2,606	3,087	3,255	2,811	2,743	29,110
2026/27	2,249	2,094	2,011	2,122	2,074	1,972	2,257	2,636	3,122	3,292	2,843	2,775	29,447
2027/28	2,273	2,117	2,033	2,145	2,097	1,994	2,281	2,664	3,155	3,327	2,873	2,804	29,762
2028/29	2,299	2,142	2,057	2,170	2,121	2,017	2,308	2,694	3,191	3,364	2,906	2,836	30,106
2029/30	2,338	2,178	2,092	2,206	2,157	2,051	2,346	2,739	3,242	3,418	2,953	2,882	30,602
2030/31	2,377	2,216	2,127	2,244	2,193	2,086	2,386	2,783	3,294	3,472	3,000	2,929	31,108
2031/32	2,420	2,256	2,167	2,285	2,233	2,125	2,429	2,833	3,351	3,533	3,053	2,981	31,666
2032/33	2,467	2,300	2,209	2,329	2,276	2,166	2,476	2,887	3,414	3,599	3,111	3,038	32,273
2033/34	2,515	2,346	2,252	2,374	2,320	2,209	2,524	2,943	3,479	3,668	3,171	3,096	32,896
2034/35	2,564	2,392	2,296	2,420	2,365	2,252	2,573	3,000	3,546	3,737	3,231	3,156	33,532
2035/36	2,615	2,439	2,342	2,468	2,412	2,297	2,624	3,059	3,615	3,810	3,294	3,217	34,193

Gross Total Peak

Figure 19 - Gross Total Peak



Gross Total Peak is the maximum integrated (i.e. average) hourly load required to serve Manitoba Hydro's customers on the Integrated System. It excludes exports and Diesel Sales. It includes Station Service and Curtailable Loads.

Typically, the peak occurs on a very cold winter weekday either in the morning (often from 8 a.m. to 9 a.m.) or in the afternoon (from 5 p.m. to 6 p.m.). Electric heating is a main contributor to the peak on one of the coldest days, whereas the operation or lack thereof of large industrials often makes the difference as to the specific day and peak hour.

The adjusted Gross Total Peak has grown from 3,486 MW in 1996/97 to 4,634 MW in 2015/16 at an average growth of 60 MW or 1.5% per year. It is forecast to grow to 6,250 MW at 81 MW (1.5%) per year by 2035/36.

Table 31 – Gross Total Peak

GROSS TOTAL PEAK (MW) HISTORICAL/ADJUSTED/FORECAST					
Fiscal Year	Peak	Adjustment	Adjusted Peak	Fiscal Year	Forecast Peak
1996/97	3,444	42	3,486	2016/17	4,850
1997/98	3,525	115	3,640	2017/18	4,885
1998/99	3,596	14	3,610	2018/19	4,928
1999/00	3,555	90	3,645	2019/20	4,971
2000/01	3,672	5	3,677	2020/21	5,033
2001/02	3,797	-4	3,793	2021/22	5,089
2002/03	3,948	24	3,972	2022/23	5,154
2003/04	3,994	31	4,025	2023/24	5,218
2004/05	4,201	-72	4,129	2024/25	5,282
2005/06	4,085	84	4,169	2025/26	5,341
2006/07	4,208	-26	4,182	2026/27	5,402
2007/08	4,304	21	4,325	2027/28	5,458
2008/09	4,509	-195	4,314	2028/29	5,520
2009/10	4,393	-56	4,336	2029/30	5,608
2010/11	4,286	106	4,392	2030/31	5,696
2011/12	4,367	146	4,514	2031/32	5,796
2012/13	4,559	-13	4,547	2032/33	5,905
2013/14	4,743	-165	4,578	2033/34	6,017
2014/15	4,713	10	4,723	2034/35	6,131
2015/16	4,479	155	4,634	2035/36	6,250

Table 32 - Monthly Gross Total Peak

MONTHLY GROSS TOTAL PEAK (MW)
History and Forecast
2005/06 - 2035/36

Fiscal Year	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Annual
2005/06	2,959	2,845	3,052	3,116	3,050	2,837	2,948	3,672	3,912	3,630	4,085	3,498	4,085
2006/07	3,092	2,821	3,015	3,141	3,040	2,954	3,220	3,789	4,011	4,208	4,203	3,847	4,208
2007/08	3,494	2,736	3,042	3,294	3,033	2,777	2,979	3,996	4,078	4,304	4,289	4,095	4,304
2008/09	3,221	2,893	2,952	2,920	3,110	2,726	3,159	3,804	4,427	4,509	4,196	4,223	4,509
2009/10	3,196	2,933	3,000	2,758	2,933	2,982	3,054	3,297	4,393	4,256	4,092	4,235	4,393
2010/11	2,905	2,843	2,805	2,991	3,163	2,709	3,056	3,927	4,195	4,286	4,250	4,169	4,286
2011/12	3,183	2,886	3,056	3,278	3,189	3,045	3,129	3,756	4,095	4,367	4,270	3,608	4,367
2012/13	3,328	2,775	3,161	3,260	3,253	2,870	3,312	4,087	4,410	4,559	4,543	4,013	4,559
2013/14	3,622	3,129	3,103	3,179	3,276	3,227	3,448	4,026	4,656	4,743	4,579	4,541	4,743
2014/15	3,754	2,955	2,967	3,094	3,190	2,938	3,382	4,391	4,532	4,713	4,573	4,390	4,713
2015/16	3,447	3,000	3,114	3,351	3,314	3,427	3,134	3,858	4,021	4,479	4,424	4,247	4,479
15/16 Norm	3,468	3,028	3,137	3,238	3,244	3,043	3,318	4,101	4,374	4,572	4,483	4,390	4,634
2016/17	3,629	3,169	3,283	3,389	3,395	3,185	3,473	4,292	4,578	4,785	4,692	4,594	4,850
2017/18	3,669	3,201	3,316	3,423	3,430	3,218	3,509	4,342	4,610	4,819	4,724	4,647	4,885
2018/19	3,694	3,224	3,341	3,451	3,462	3,240	3,535	4,375	4,650	4,861	4,765	4,680	4,928
2019/20	3,728	3,259	3,378	3,495	3,514	3,277	3,574	4,419	4,692	4,904	4,804	4,711	4,971
2020/21	3,777	3,299	3,418	3,545	3,576	3,325	3,616	4,467	4,748	4,965	4,867	4,770	5,033
2021/22	3,819	3,339	3,460	3,590	3,620	3,365	3,660	4,520	4,801	5,019	4,920	4,818	5,089
2022/23	3,868	3,382	3,504	3,636	3,667	3,408	3,707	4,577	4,862	5,084	4,983	4,879	5,154
2023/24	3,916	3,425	3,549	3,682	3,714	3,452	3,753	4,634	4,923	5,147	5,046	4,940	5,218
2024/25	3,965	3,468	3,593	3,728	3,760	3,495	3,800	4,691	4,984	5,210	5,108	5,000	5,282
2025/26	4,009	3,507	3,634	3,770	3,802	3,535	3,843	4,743	5,039	5,268	5,166	5,056	5,341
2026/27	4,056	3,548	3,677	3,814	3,846	3,576	3,887	4,798	5,097	5,328	5,225	5,113	5,402
2027/28	4,099	3,587	3,717	3,855	3,888	3,615	3,929	4,848	5,150	5,384	5,280	5,167	5,458
2028/29	4,147	3,629	3,761	3,899	3,933	3,657	3,975	4,904	5,209	5,445	5,340	5,226	5,520
2029/30	4,215	3,690	3,824	3,964	3,998	3,719	4,040	4,983	5,292	5,531	5,426	5,309	5,608
2030/31	4,285	3,752	3,888	4,030	4,064	3,781	4,107	5,063	5,376	5,619	5,512	5,394	5,696
2031/32	4,362	3,821	3,959	4,103	4,137	3,850	4,181	5,153	5,470	5,717	5,609	5,489	5,796
2032/33	4,446	3,895	4,036	4,182	4,217	3,925	4,262	5,251	5,573	5,824	5,715	5,593	5,905
2033/34	4,532	3,971	4,115	4,263	4,298	4,002	4,344	5,352	5,679	5,935	5,824	5,700	6,017
2034/35	4,620	4,049	4,195	4,346	4,382	4,080	4,429	5,455	5,787	6,048	5,936	5,808	6,131
2035/36	4,711	4,130	4,279	4,432	4,468	4,161	4,516	5,562	5,899	6,165	6,051	5,922	6,250

Peak load is measured and recorded differently than energy data. The system load at every hour is calculated by System Operations as:

Hourly Gross Total Peak (t)
= Hourly Total Generation (t)
- Hourly Metered Exports (t) + Hourly Metered Imports (t)
- Losses Associated with Exports (t) + Gains Associated with Imports (t)
+ Curtailments (t)

Losses for exports and gains for imports are only known on a monthly energy basis. The hourly value is obtained by using the ratio of exports/imports for the hour to the total exports/imports for the month and applying that to the total metered loss/gain for the month. The remaining difference between the balance of the load and Common Bus is taken as the Transmission Losses associated with Manitoba load.

Curtailments for individual customers are calculated as the difference between what the customer would have used if not curtailed versus what they actually used.

Annual Peak

The forecast annual peak is higher than the maximum of the monthly peaks. This is because the peak can occur in any one of the winter months. The same characteristic is apparent in historical peaks. The average historical annual peak is higher than the maximum of the highest average monthly peaks. For studies requiring yearly data, the annual peak should be used.

16 Hour Peak

The peaks in this document are integrated hourly peaks. For some studies and analysis of avoided cost or DSM savings, an estimate of the average peak during onpeak hours (from 6 a.m. to 10 p.m.) may be desired. To convert hourly peak to 16 hour peak, multiply the hourly peak in the associated month by the following percentages:

Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
94.4%	94.9%	95.8%	96.0%	96.3%	96.0%	96.6%	95.6%	95.8%	96.6%	95.6%	95.5%	94.8%

VARIABILITY AND ACCURACY

Weather Effect and Weather Adjustment

The weather effect is determined in any sector every year by regressing the previous two years of actual monthly energies against the actual HDD and CDD for the month. This results in a GWh per HDD effect and a GWh per CDD effect for that sector for that year.

Only sectors whose major variation is due to weather can have a weather effect estimated. Sectors that vary primarily due to industrial output levels or seasonal but non-weather reasons may yield false weather effects if estimated. Weather effects are not determined for the GS Top Consumers, Seasonal, Diesel, Water Heating and Lighting sectors.

For sectors where a weather effect is calculated, this document shows energy as the reported value and as a weather adjusted value. Forecasts are based on the weather adjusted values. The calculations are:

Weather Adjustment = HDD weather effect * (HDD actual - HDD normal)
+ CDD weather effect * (CDD actual - CDD normal)

Weather Adjusted Actual = Actual - Weather Adjustment

Following are the HDD and CDD weather effect factors by sector:

Residential Basic: 0.6 GWh / HDD, 1.0 GWh / CDD
GS Mass Market: 0.3 GWh / HDD, 0.8 GWh / CDD
General Consumers Sales: 0.9 GWh / HDD, 1.8 GWh / CDD
Gross Firm Energy: 1.2 GWh / HDD, 2.9 GWh / CDD
Gross Total Peak: 49 MW / degree (at -30 degrees Celsius),
119 MW / degree (at +30 degrees Celsius)

Effect of Extreme Weather

A record cold winter will increase load 4% and a record warm winter will decrease it 4%. An additional 2% load increase is possible due to a record hot summer and a 1% decrease due to a record cool summer.

The effect of extreme weather is larger on a monthly basis, and even larger on a daily basis.

		Effect of Weather due to Winter Extremes on Gross Firm Energy							
	GWh/DDH	Normal		Record Warm			Record Cold		
	1.2	DDH	GWh	DDH	GWh	Effect	DDH	GWh	Effect
Year:	2016/17	4,540	26,385	3,678	25,378	-4%	5,439	27,437	4%
Month:	Jan 2017	945	2,959	663	2,628	-11%	1,261	3,328	12%
Day:	Jan 2017	30	95	6	67	-30%	56	125	31%

		Effect of Weather due to Summer Extremes on Gross Firm Energy							
	GWh/DDC	Normal		Record Cool Summer			Record Hot Summer		
	2.9	DDC	GWh	DDC	GWh	Effect	DDC	GWh	Effect
Year:	2016/17	179	26,385	69	26,069	-1%	364	26,915	2%
Month:	July 2016	67	1,891	6	1,716	-9%	142	2,105	11%
Day:	July 2016	2	61	0	55	-10%	14	95	56%

The effect of a change in temperature on the load at the time of peak due to a 5 degree temperature difference is 18% in the summer and 5% in the winter.

Summer	Winter	Effect of Change in Temperature on Gross Total Peak							
MW/Deg	MW/Deg	Normal		Warm Winter, Cool Summer			Cold Winter, Hot Summer		
119	49	Temp	MW	Temp	MW	Effect	Temp	MW	Effect
Summer	2016/17	30	3,389	25	2,792	-18%	35	3,986	18%
Winter:	2016/17	-30	4,850	-25	4,607	-5%	-35	5,094	5%

Load Variability

Uncertainty is an inherent characteristic of forecasting. The load will vary both year to year and long term because of underlying changes in population growth, economic growth, changes in the operations of Top Consumers, and overall use patterns. An economic recession will slow energy growth and an economic boom will increase it. Cycles cannot be predicted in advance so some appropriate midpoint must be chosen as the forecast.

This forecast was created as Manitoba Hydro's best estimate of Manitoba's future energy requirement with an expectation of a 50% chance that actual growth will be higher than the forecast, and a 50% chance that actual growth will be lower than the forecast. This can also be called the P50 (50th Percentile) or Base Forecast.

To evaluate the potential for variation, historic load variability has been analyzed using a probabilistic-based approach. Doing this provides an estimate of the magnitude of the potential load variation from the forecast due to population, economy and other effects. 10% and 90% confidence bands (-/+ 1.28 standard deviations), also known as P10 and P90, were selected to be a proxy for the Low and High Load Forecast Scenarios for use in risk analysis studies. They are calculated as follows:

Load = Base Forecast -/+ 1.28 x Standard Deviation

For other probability points, substitute for the 1.28 the following numbers:

Prob	0.1%	2.5%	10%	20%	50%	80%	90%	97.5%	99.9%
Z(Prob)	-3.09	-1.96	-1.28	-0.84	0.00	0.84	1.28	1.96	3.09

This calculation gives the variability due to long term economic effects. It does not include variability due to weather which was removed through the use of weather adjusted load. The standard deviation of the weather variation has been found to be approximately 2% of both the energy and peak. Annual weather variations tend to be independent of the economy, so if a combined variance is desired, then the variance due to weather can be added to the variance without weather to derive an overall variance that includes weather.

The following four charts and tables summarize the variability for energy and peak. By 2035/36, the Load Forecast has an 80% probability of being accurate to within ±1,737 GWh or ±5.1%. Due to the inherent variability of the load, this is the best level of accuracy possible.

The overall economic standard deviation in 2035/36 is 1,355 GWh or 4.0% of the forecast energy. Analyzed individually, the economic standard deviation of the Top Consumers sector is 1,326 GWh (17.9%), Residential is 509 GWh (5.4%) and Mass Market is also 463 GWh (3.6%), showing that the Top Consumers sector is the majority of the variance.

Figure 20 - Energy Variability

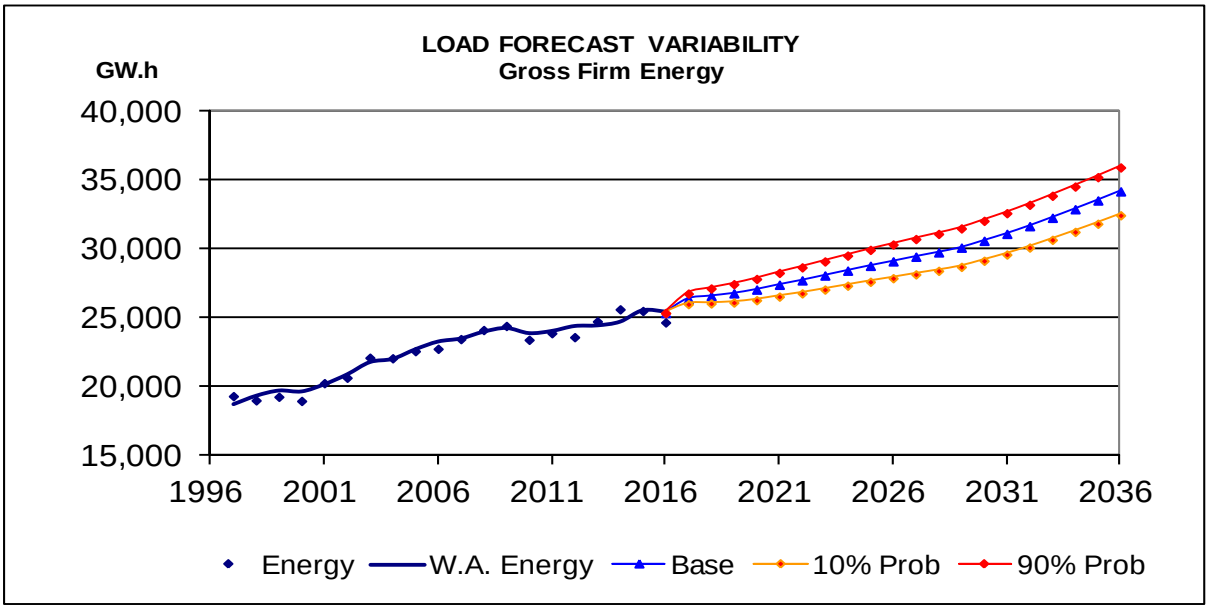


Table 33 – Energy Variability

Fiscal Year	Gross Firm Base Fcst	Long Term Economic Std Dev	10.0% Prob Point	90.0% Prob Point
2016/17	26,385	299	26,002	26,769
2017/18	26,596	424	26,053	27,139
2018/19	26,785	520	26,119	27,452
2019/20	27,060	601	26,290	27,830
2020/21	27,410	673	26,548	28,272
2021/22	27,729	737	26,784	28,674
2022/23	28,082	797	27,060	29,103
2023/24	28,435	853	27,342	29,527
2024/25	28,785	905	27,626	29,945
2025/26	29,110	954	27,887	30,333
2026/27	29,447	1,001	28,164	30,730
2027/28	29,762	1,046	28,421	31,103
2028/29	30,106	1,090	28,709	31,502
2029/30	30,602	1,131	29,152	32,052
2030/31	31,108	1,172	29,606	32,609
2031/32	31,666	1,210	30,115	33,218
2032/33	32,273	1,248	30,673	33,872
2033/34	32,896	1,285	31,249	34,543
2034/35	33,532	1,321	31,839	35,225
2035/36	34,193	1,355	32,455	35,930

Figure 21 - Peak Variability

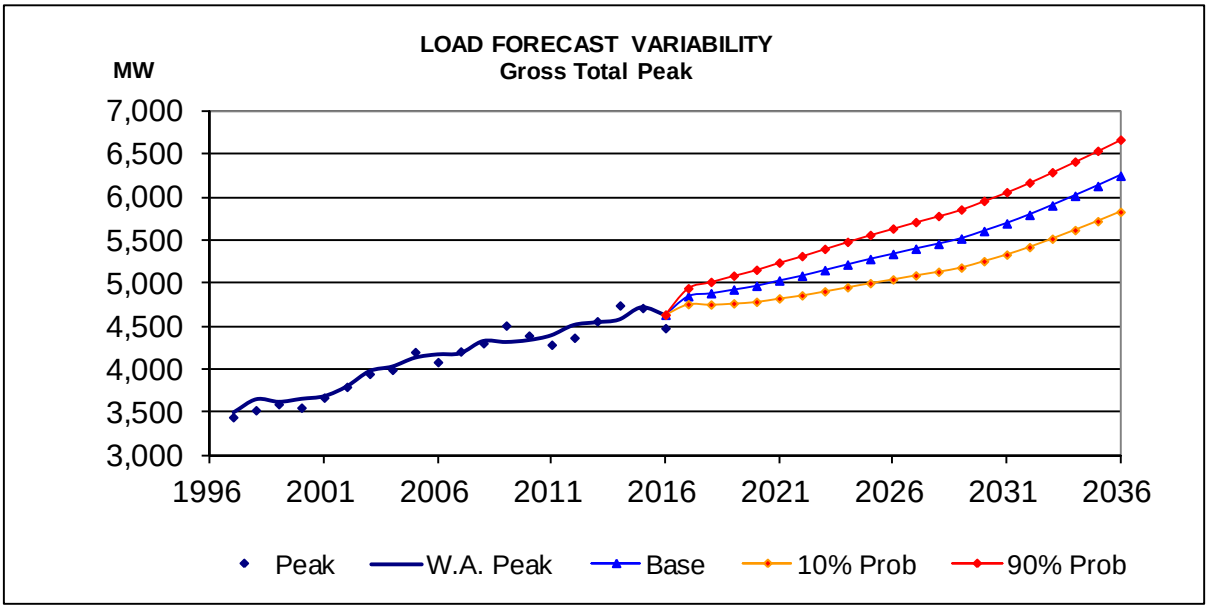


Table 34 – Peak Variability

Fiscal Year	Gross Total Peak Base Fcst	Long Term Economic Std Dev	10.0% Prob Point	90.0% Prob Point
2016/17	4,850	72	4,758	4,943
2017/18	4,885	102	4,754	5,016
2018/19	4,928	126	4,767	5,089
2019/20	4,971	145	4,785	5,158
2020/21	5,033	162	4,825	5,241
2021/22	5,089	178	4,860	5,317
2022/23	5,154	193	4,907	5,400
2023/24	5,218	206	4,954	5,482
2024/25	5,282	219	5,002	5,562
2025/26	5,341	231	5,046	5,636
2026/27	5,402	242	5,092	5,712
2027/28	5,458	253	5,134	5,782
2028/29	5,520	263	5,183	5,858
2029/30	5,608	273	5,257	5,958
2030/31	5,696	283	5,334	6,059
2031/32	5,796	292	5,421	6,170
2032/33	5,905	302	5,518	6,291
2033/34	6,017	310	5,619	6,415
2034/35	6,131	319	5,722	6,540
2035/36	6,250	327	5,830	6,670

5 and 10 Year Forecast Accuracy

Due just to the load variation caused by population growth and economic growth, there is only a certain level of accuracy possible. Using the load variability estimates of the previous section, due to economic variability alone, there is only an 80% chance that a 5 year energy forecast will be within 3.1% of the actual, and an 80% chance that a 10 year energy forecast will be within 4.2% of the actual.

Recognizing this inherent uncertainty of the forecast, historic forecast variation has been tracked. The following four figures and tables compare previous load forecasts to actual results 5 and 10 years later.

The energy savings achieved under Manitoba Hydro's market-based DSM programs between the year the forecast was prepared and the year being forecast was subtracted first from the forecast value. The remaining difference is taken as an estimate of the accuracy of the forecast.

The following figures and tables may suggest cycles in the forecast made up of alternating periods of over-forecasting and under-forecasting. These are not so much due to a bias in the forecast as they are due to unexpected periods of recession or economic growth. Once one of these unexpected periods occur, the accuracy of the previous five 5-year forecasts for 5 years, and the accuracy of the previous ten 10-year forecasts for ten years will be affected thus causing periods of over- or under-forecasting.

Compensation for these periods of over and under-forecasting cannot be applied until after the events occur and only then can they be identified and quantified. The forecast assumes average expected economic conditions. When economic conditions are abnormal, the forecast will be high or low.

The weather adjusted Gross Firm Energy is shown in two separate columns in the Energy Accuracy table (Table 35) and they vary in each year due to the difference in weather normals used in each of the respected forecasts. Weather normals differences are due to the use of a 25 year rolling average which relies on the previous 25 years of weather data while at the time the forecast is created.

Figure 22 - Energy Accuracy

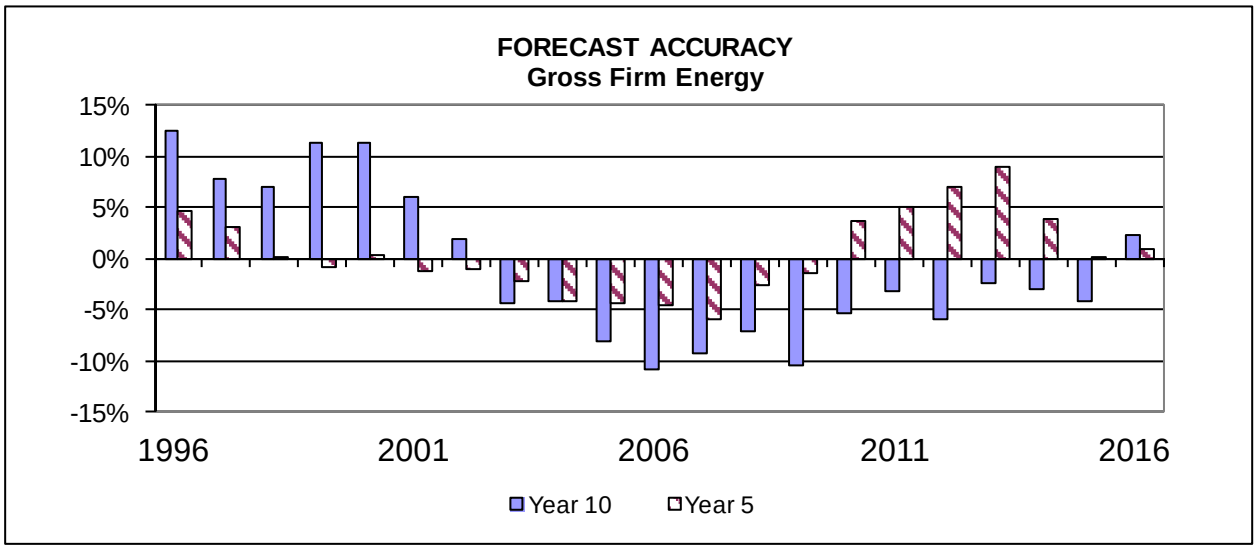


Table 35 - Energy Accuracy

Fiscal Year	Actual Gross Firm Energy	Forecast Prepared 5 Years Previous	W.A. Gross Firm Energy	5 Year Percent Accuracy	Forecast Prepared 10 Years Previous	W.A. Gross Firm Energy	10 Year Percent Accuracy
1995/96	19,148	19,179	18,318	4.7%	20,659	18,370	12.5%
1996/97	19,321	19,395	18,810	3.1%	20,174	18,716	7.8%
1997/98	19,014	19,455	19,429	0.1%	20,661	19,320	6.9%
1998/99	19,273	19,675	19,818	-0.7%	21,919	19,708	11.2%
1999/00	18,971	19,767	19,703	0.3%	21,833	19,629	11.2%
2000/01	20,262	20,018	20,241	-1.1%	21,300	20,103	6.0%
2001/02	20,656	20,783	20,980	-0.9%	21,364	20,979	1.8%
2002/03	22,110	21,395	21,861	-2.1%	20,916	21,868	-4.4%
2003/04	22,069	21,134	22,062	-4.2%	21,191	22,107	-4.1%
2004/05	22,589	21,693	22,664	-4.3%	20,870	22,714	-8.1%
2005/06	22,757	22,216	23,277	-4.6%	20,812	23,346	-10.9%
2006/07	23,464	22,107	23,489	-5.9%	21,395	23,595	-9.3%
2007/08	24,122	23,353	23,962	-2.5%	22,328	24,034	-7.1%
2008/09	24,417	23,926	24,259	-1.4%	21,756	24,320	-10.5%
2009/10	23,412	24,734	23,850	3.7%	22,611	23,892	-5.4%
2010/11	23,892	25,239	24,020	5.1%	23,299	24,071	-3.2%
2011/12	23,605	25,909	24,202	7.1%	22,924	24,376	-6.0%
2012/13	24,750	26,464	24,270	9.0%	23,844	24,433	-2.4%
2013/14	25,625	25,512	24,538	4.0%	23,938	24,696	-3.1%
2014/15	25,505	25,492	25,469	0.1%	24,456	25,508	-4.1%
2015/16	24,673	25,622	25,375	1.0%	25,990	25,414	2.3%

Figure 23 - Peak Accuracy

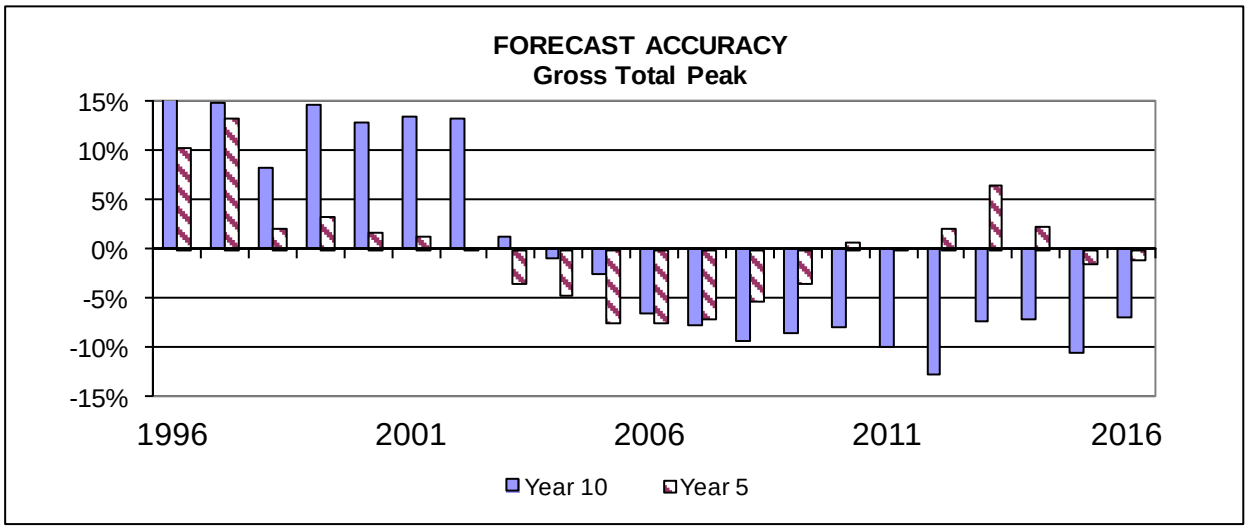


Table 36 - Peak Accuracy

Fiscal Year	Actual Gross Total Peak	Forecast Prepared 5 Years Previous	Normalized Gross Total Peak	5 Year Percent Accuracy	Forecast Prepared 10 Years Previous	Normalized Gross Total Peak	10 Year Percent Accuracy
1995/96	3,628	3,850	3,491	10.3%	4,081	3,491	16.9%
1996/97	3,444	3,906	3,450	13.2%	3,962	3,450	14.8%
1997/98	3,525	3,768	3,688	2.1%	3,990	3,688	8.2%
1998/99	3,596	3,703	3,586	3.3%	4,108	3,586	14.5%
1999/00	3,555	3,738	3,678	1.6%	4,152	3,678	12.9%
2000/01	3,672	3,758	3,711	1.3%	4,210	3,711	13.4%
2001/02	3,797	3,759	3,755	0.1%	4,251	3,755	13.2%
2002/03	3,948	3,801	3,939	-3.5%	3,989	3,939	1.3%
2003/04	3,994	3,833	4,025	-4.8%	3,990	4,025	-0.9%
2004/05	4,201	3,817	4,129	-7.6%	4,023	4,129	-2.6%
2005/06	4,085	3,860	4,169	-7.4%	3,899	4,169	-6.5%
2006/07	4,208	3,894	4,195	-7.2%	3,868	4,195	-7.8%
2007/08	4,304	4,097	4,329	-5.4%	3,927	4,329	-9.3%
2008/09	4,509	4,161	4,314	-3.6%	3,948	4,314	-8.5%
2009/10	4,393	4,371	4,337	0.8%	3,993	4,337	-7.9%
2010/11	4,286	4,398	4,392	0.1%	3,959	4,392	-9.9%
2011/12	4,367	4,606	4,513	2.1%	3,942	4,513	-12.7%
2012/13	4,559	4,705	4,421	6.4%	4,098	4,421	-7.3%
2013/14	4,743	4,524	4,423	2.3%	4,107	4,423	-7.1%
2014/15	4,713	4,661	4,736	-1.6%	4,236	4,736	-10.6%
2015/16	4,479	4,739	4,789	-1.1%	4,455	4,789	-7.0%

LOAD SENSITIVITES AND EXTREME EVENTS

Manitoba Hydro examines the effect of possible events on the load. The information presented here provides planners with an understanding of what the potential scale of these individual events may have on the system load requirements.

The individual effects of each event can be included in scenario or sensitivity analysis if the need arises. Each change in assumption can be individually applied to the forecast as required to capture the annual energy and peak effect of the desired assumption in any given year. All values are listed at Generation and include transmission and distribution losses.

The sensitivities provide an estimate of what effect a change in assumption will have on the annual energy and peak over the 20 year forecast period.

Effects are summarized below, and the details of each effect follow.

Sensitivity of the Load to an Assumption Change	Energy (GWh)	Peak (MW)
0.1% Increase/Decrease in Population	± 297	± 54
0.1% Increase/Decrease in Income	± 47	± 9
0.1% Increase/Decrease in GDP	± 199	± 36
0.1% Increase/Decrease in Electricity Price	∓ 154	∓ 28
Climate Change per Degree Celsius Warmer	+ 50	- 49

Evaluation of Extreme Events	Energy (GWh)	Peak (MW)
All Natural Gas in Manitoba to Electricity	+ 16,000	+ 7,000
Increase/Decrease of One Very Large Industrial Customer	± 1,500	± 180
Maximum Potential Effect of Increased Online Shopping	- 775	- 143
Additional Load if 100% Electric Vehicle Saturation Rate	+ 8,792	+ 1,099
Illustrated Effect of Grid Parity (e.g. Solar Panels)	- 857	- 78

For context, one year of energy growth is 442 GWh and one year of peak growth is 80 MW.

Population / Economic / Price Changes

The population, economy and prices are the most significant drivers of the load in Manitoba. These effect of each driver based on the coefficients found in the models is summarized below.

Population: A one-time 1% increase in population (12,971 people) results in a 1% increase in the number of Residential Basic customers (4,742 customers representing 71 GWh) and a 0.33% change in the number of GS Mass Market customers (224 customers representing 61 GWh). The total effect on Manitoba Gross Firm Energy would be 148 GWh (0.59%) for any given year. Assuming a 0.1% change in the annual average population growth rate over the 20 year forecast period, the total effect would be a change of 297 GWh in the 20th year of the forecast.

Income: A one-time 1% increase in real income results in a 0.29% increase in Residential average use (43 kWh per customer and 21 GWh overall). On Manitoba Gross Firm Energy it is 23 GWh (0.09%). Assuming a 0.1% change in the annual average income growth rate over the 20 year forecast period, the total effect would be a change of 47 GWh in the 20th year of the forecast.

GDP: A one-time 1% increase in Manitoba GDP results in a 0.54% increase in GS Mass Market Small and Medium average use (555 kWh per customer totaling 37 GWh). A 1% increase in Canada/US GDP results in 0.30% increase in GS Large Customer average use (18,850 kWh per customer totaling 6 GWh) and a 0.84% increase in Top Consumers use (46 GWh). The total effect of a 1% increase in GDP on Manitoba Gross Firm Energy is 100 GWh (0.39%). Assuming a 0.1% change in the annual average GDP growth rate over the 20 year forecast period, the total effect would be a change of 199 GWh in the 20th year of the forecast.

Electricity Price: A one-time 1% increase in real electricity price results in a 0.29% decrease in Residential average use (-43 kWh per customer totaling -21 GWh). It will also result in a 0.18% decrease in GS Mass Market Small and Medium average use (-185 kWh per customer totaling -12 GWh), a 0.47% decrease in GS Mass Market Large average use (-29,532 kWh per customer totaling -10 GWh) and a 0.48% decrease in GS Top Consumers use (-26 GWh). The total effect of a 1% increase in real electricity price on Manitoba Gross Firm Energy is -77 GWh (-0.30%). Assuming a 0.1% change in the annual average GDP growth rate over the 20 year forecast period, the total effect would be a change of 154 GWh in the 20th year of the forecast.

Below is a summary of the 20 year impact to the forecast should a change of 0.1% to the annual growth rate for each of the economic assumption is assumed.

	Energy (GWh)	Peak (MW)
0.1% Increase/Decrease in Population	± 297	± 54
0.1% Increase/Decrease in Income	± 47	± 9
0.1% Increase/Decrease in GDP	± 199	± 36
0.1% Increase/Decrease in Electricity Price	∓ 154	∓ 28

Climate Change

The Intergovernmental Panel on Climate Change projects an increase in global temperature as a result of rising concentrations of greenhouse gases in the atmosphere. Changes to temperature and extreme events have the potential to influence future energy demands.

In the last 100 years, the city of Winnipeg's 25-year average temperature has resulted in Heating Degree Days (HDD) in the range of 4,500 to 5,000 each year. A 25 year moving average is used for the forecast to help minimize the effects of year to year variability and to represent the long term climatology. This section quantifies the general effect caused by a 1°C increase in average daily temperature throughout the year.

In Manitoba Hydro's case, if Winnipeg experienced a uniform 1°C warming throughout the year, winter months would be subject to less heating while summer months would be subject to more cooling. Over 200 winter days, every degree Celsius of temperature rise above average conditions will result in an approximate decrease of 200 Heating Degree Days (HDD) per year, and a corresponding approximate increase of 100 Cooling Degree Days (CDD) per year over 100 summer days.

Applying the Weather effect for Manitoba Hydro at Generation gives:

Decrease of 200 HDD ➔ -240 GWh and -49 MW in the winter

Increase of 100 CDD ➔ +290 GWh and +119 MW in the summer

The resulting total effect of every one degree increase in temperature would be:

An increase of 50 GWh to annual energy and a decrease of 49 MW to system peak.

	Energy (GWh)	Peak (MW)
Climate Change per Degree Celsius Warmer	+ 50	- 49

Conversion of all Natural Gas Use to Electricity

Currently, about 275,000 Residential and General Service customers use natural gas as a fuel for space heating, water heating, cooking, etc. Given possible future green initiatives that could implement carbon taxes on fossil fuels, a scenario to consider is the conversion of all natural gas used as a fuel to electricity.

Assumptions exclude industries using natural gas as an ingredient, not as a fuel, and use a fuel efficiency averaging 82% and a load factor of 26%.

	Energy (GWh)	Peak (MW)
All Natural Gas in Manitoba to Electricity	+ 16,000	+ 7,000

Potential Changes in Load from Very Large Industrial Customers

This forecast includes an expectation that there may be new large industrial users of electricity that may come to Manitoba. GS Top Consumers includes a Potential Large Industrial Loads category that adds 1,712 GWh to GS Top Consumers by 2035/36. This is expected to be made up of increases and decreases by current top consumers, additions of new top consumers and company closures. However, this forecast does not anticipate the scenario of one customer using up the entire PLIL projection as a single startup.

Manitoba Hydro's largest customer currently uses in excess of 1,500 GWh annually and has a coincident peak load of about 180 MW. It is feasible that one or more customers of this size could decide to start up in Manitoba in the next 20 years. A single large new customer could

use the entire amount of energy that has been forecast under the Potential Large Industrial Loads projection.

Similarly, it is possible that one or more very large customers may discontinue operations in Manitoba. This could also be the equivalent of losing Manitoba Hydro's largest customer.

	Energy (GWh)	Peak (MW)
Increase/Decrease of One Very Large Industrial Customer	± 1,500	± 180

Maximum Potential Load Effect of Increased Online Shopping

Online shopping is a growing service offering by many retailers. It is possible that this trend could lead to fewer retail establishments if online shopping becomes pervasive. The potential load reduction of such a scenario will be the electricity use of about 5,800 General Service customers in the Retail sector who currently use about 680 GWh. At generation, this represents a potential total of 775 GWh and 143 MW (using a 62% load factor). This assumes that the structures used for retail are torn down or are refurbished with other businesses that would otherwise have built a new structure.

	Energy (GWh)	Peak (MW)
Maximum Potential Load Effect of Increased Online Shopping	- 775	- 143

Potential Load from High Adoption of Electric Vehicle Technology

This forecast includes the expected impact due to adoption of electric vehicles within Manitoba over the next twenty years. The specifics have been detailed in the Electric Vehicle Forecast section of this document.

It is possible that the current technological challenges will be solved, price will match those of internal combustion vehicles, and range anxiety will be alleviated. If or when these issues are resolved, It is possible that electric vehicles may eventually grow to be the dominant vehicle.

The maximum load required, if 100% of all new passenger and commercial vehicles purchased every year within the forecast period are Plug-In Electric Vehicles (PEVs), would be 8,888 GWh of energy and 1,111 MW of load. Currently, the forecast for electric vehicles load by 2035/36 is 96 GWh and 12 MW. Therefore the maximum additional load required over the current forecast for 100% saturation is 8,792 GWh (20 years of load growth) and 1,099 MW (about 14 years of peak growth).

	Energy (GWh)	Peak (MW)
Additional Load if 100% Electric Vehicle Saturation Rate	+ 8,792	+ 1,099

Illustrated Effect of Grid Parity

Grid Parity is when a customer will have an economic option to provide some or all of the electricity needs their home or business requires with an alternative energy source. Grid parity requires the self-generated kWh cost to be competitive with utility power when considering operating, maintenance costs and a reasonable amortization period for capital costs.

Solar photovoltaic installations are frequently referenced in discussions related to grid parity as costs continue to decline. Initial adoption rates may be gradual and may take years to mature. For illustrative purposes, the effect at utility generation if 100,000 residential and 10,000 commercial customers added solar panels would be:

	Energy (GWh)	Peak (MW)
Illustrated Effect of Grid Parity (e.g. Solar Panels)	- 857	- 78

ASSUMPTIONS

Economic Assumptions

Economic forecast assumptions are taken from the economic variables that become part of Manitoba Hydro's 2015 Economic Outlook and the 2015 Energy Price Outlook.

Residential Customers - The number of Residential Basic customers in Manitoba is forecast to increase by 1.2% (5,809 units) in 2016/17 and averages 1.0% per year over the forecast period. This compares to a historical average increase of 1.1% per year over the last ten years. Residential customers are used in the Residential and GS Mass Market customer forecasts.

Electricity and Natural Gas Prices - The electricity price forecast is based on the Consumer Price Index (CPI) and rate increase projections contained in the Integrated Financial Forecast. The real electricity price is forecast to increase by 2.1% in 2016/17, annually increase between 1.9% and 2.2% from 2017/18 to 2027/28 and then reduce to a 0.2% annual increase for the remaining seven years of the forecast. Manitoba Hydro views the natural gas price forecast as commercially sensitive information. Consistent with the Clean Environment Commission and Electric General Rate Application, this information will not be publicly disclosed. The ratio of prices is used in the Residential Basic forecast.

Manitoba Disposable Income - Real Manitoba disposable income per Res Basic customer grew 1.4% for the past 20 years and 1.9% for the past 10 years. It is forecast to grow 0.9% annually for the next 20 years. Manitoba disposable income is used in the Res Basic forecast.

Gross Domestic Product (GDP) - Real economic growth in Manitoba averaged 2.5% annually for the past 20 years and 2.4% annually for the past 10 years. Real Manitoba GDP is expected to grow 2.1% in 2016/17 and average 1.8% annually for the next 20 years. Manitoba GDP is used in the GS Mass Market Small and Medium forecasts.

Gross Domestic Product (Canadian and US GDP) – Combined real economic growth in Canada and US averaged 2.4% annually for the past 20 years and 1.5% annually for the past 10 years. It is forecast to grow 2.0% in 2016/17 and average 2.1% annually for the next 20 years. This is used in the GS Mass Market Large and GS Top Consumer forecasts.

Price / Income / GDP Elasticity

The economic effects of price, income and GDP have been incorporated into the 2016 forecast. The elasticity of each has been estimated from econometric modeling. See the Methodology section for more details. A summary of the elasticities found is:

	Price Elasticity	Real Income Elasticity	Real GDP Elasticity
Residential Basic	-0.29	0.29	
GS Mass Mkt Small/Medium	-0.18		0.54
GS Mass Mkt Large	-0.47		0.30
GS Top Consumers	-0.48		0.84
Gross Firm Energy	-0.32	0.10	0.41

Demand Side Management (DSM) in the Forecast

This forecast reflects future DSM savings associated with existing Provincial building codes and improved equipment efficiency standards and regulations (Codes and Standards). This is the only effect of DSM initiatives that is specifically accounted for in the forecast.

Savings due to DSM programs to date are embedded in the historical data that is the basis for this forecast. The current level of past achieved DSM savings is assumed to remain in place throughout the future. Future DSM savings arising from future Power Smart offerings and market engagement above the current level and incremental to the above mentioned Codes and Standards are not reflected in this forecast. They are accounted for separately in Manitoba Hydro's Power Smart Plan and Power Resource Plan.

As a result, historical growth rates in this document are not directly comparable to future growth rates because the history includes the effect of past program-based DSM initiatives, but the forecast does not.

For customers involved in Load Displacement and Alternative Energy initiatives, the forecast excludes the effect of the initiatives, and projects the load without the savings due to the initiatives.

Normal Weather Assumptions

Weather for forecast purposes is measured by degree days. Winnipeg temperatures are used, as Winnipeg is central to most of the weather-dependent load (Residential and General Service Mass Market) in Manitoba.

Cold weather is expressed in Heading Degree Days (HDD), which is the number of average degrees colder than 14 degrees Celsius each day. Hot weather is expressed in Cooling Degree Days (CDD), which is the number of average degrees warmer than 18 degrees Celsius each day. Daily temperature is the average of the high and low temperature for the day. The equations are:

HDD = sum (max(0, 14 - (Daily high + Daily low) / 2))

CDD = sum (max(0, (Daily high + Daily low) / 2) - 18)

The base temperature of 14 degrees for HDD is the temperature below which most buildings have their heating systems (furnaces) running.

The base temperature of 18 degrees for CDD is the temperature above which buildings start to run their space cooling systems (air-conditioning).

The forecast is prepared assuming normal weather. Normal weather for the 2016 forecast is determined from the 25 year average of Heating Degree Days and Cooling Degree Days in Winnipeg over the period April 1991 to March 2016.

The 25 year weather normals used for every year of this forecast are 4,539.7 HDD and 179.1 CDD. This is a decrease of 28.9 HDD from last year's normal of 4,568.6 HDD, and no change from last year's normal of 179.1 CDD.

The range of HDD from 1991 to 2016 was from a warm winter of 3,677.6 HDD in 2011/12 (862.1 HDD below normal) to a cold winter of 5,439.3 HDD in 1995/96 (899.6 HDD above normal).

The range of CDD from 1991 to 2016 was from a cool summer of 71.8 CDD in 2004/05 (107.3 CDD below normal) to a hot summer of 267.3 CDD in 1995/96 (88.2 CDD above normal).

METHODOLOGY

Residential Basic Methodology

Several different models and forecasts were used to determine the Residential Basic Model. These are the steps to produce the forecast:

1. **Forecast Residential Dwellings** - The forecast of Manitoba residential customers in Manitoba Hydro's 2016 Economic Outlook was used for the total number of Residential Basic customers for the 2016/17 to 2035/36 period. The customer forecast was based on the average of several Manitoba population forecasts from various external agencies multiplied by a forecast of the people per customer ratio. The customer forecast was reduced by about 0.5% to account for customers with multiple services to obtain the forecast of individual dwellings.

2. **Forecast Existing Dwellings** – Existing dwellings were broken down by dwelling type (single detached, multi attached, and Individually metered apartment suites) within each fuel region (Winnipeg, Gas Available outside Winnipeg and No Gas Available). The rate of change due to demolitions and type change (e.g. bulk apartments to individually metered) as well as customer switches of their space heating fuel were taken into account.

3. **Historical Space Heating Systems –** The number of historical dwellings by type and region were each divided into nine space heating systems: Electric Forced Air Furnace, Electric Baseboard, Electric Ground Source Heat Pump, Electric Boiler, Gas High-Efficiency Furnace, Gas Mid-Efficiency Furnace, Gas Standard-Efficiency Furnace, Gas Boiler, and Other heat that is not billed for gas or electric. Percentages of each heat type in existing dwellings were taken from the 2014 Residential Energy Use Survey.

4. **Forecast of Space Heating Systems in New Dwellings** – Econometric equations were developed to forecast the number of electric space heating systems in new single detached and multi attached dwellings in Winnipeg and South Gas regions as follows:

   Logit (Percentage of New Dwellings (t))

   = -5.45 + 2.20 * T + 2.07 * PGEFF (lag(t)) Single Detached, Winnipeg

   = -2.11 + 0.78 * T + 2.92 * PGEFF (lag(t)) Single Detached, South Gas

= -7.25 + 3.72 * T + 6.38 * PGEFF (lag(t))	Multi Attached, Winnipeg
= -3.26 + 0.39 * T + 5.82 * PGEFF (lag(t))	Multi Attached, South Gas

Logit	- A log transformation of percentages used for saturation analysis
T	- A trend variable capturing the effect of natural gas price changes
PGEFF	- Ratio of the gas to electricity price for high efficiency furnaces
lag(t)	- The weighted average (38%, 6%, 6%, 50%) of the 1, 3, 4 and 5 year lags

R-squared: 80.2%, 89.6%, 48.9%, 75.7%

T-stats:

Constant:	-10.14, -9.72, -3.34, -6.15
T:	7.53, 6.61, 3.16, 1.35
PGEFF:	2.49, 8.71, 1.90, 7.11

The 2014 Residential Energy Use Survey was used to break the forecast of new electric heat dwellings and new non-electric-heat dwellings within single detached, multi attached and individually metered apartment suites by Winnipeg, South Gas and No Gas areas into specific furnace types.

5. **Forecast of Space Heating Systems in Existing Dwellings** – The average age of heating systems in existing dwellings was determined from the 2014 Residential Energy Use Survey. The number of replacements was estimated using a Weibull distribution based on the average age of each furnace type from the survey. Switches of furnace types were estimated using survey respondents in older dwellings with newer heating systems and included saving estimates from the Heating Fuel Choice initiative. Their former heating system was verified using billing system information.

6. **Forecast of Water Heating Systems in New and Existing Dwellings –** Electric and natural gas water heater saturations and average age were estimated for dwellings with and without natural gas space heat using information from the 2014 Residential Energy Use Surveys. The number of replacements was forecast using a Weibull distribution based on the average age of water heaters and switches between fuels were taken into account when forecasting future numbers of water heaters. Saving estimates from the Heating Fuel Choice initiative were included.

7. **Other End Uses** – Other major uses of residential electricity were forecast by dwelling type, including central air conditioning, major appliances, televisions and lighting using the saturation data from the 2014 Residential Energy Use Survey.

8. **Determine Overall Average Use** – An econometric linear model was used to forecast the average annual electricity use per customer of the Residential Basic sector. The Average Use per customer without Demand Side Management (DSM) programs and Codes & Standards (C&S) savings was used as the dependent variable in the model. Historical data from 1992/93 to 2015/16 was modeled. The resulting model and parameters are:

   (Total Usage + DSM programs + C&S savings) / Customers
   = 3949 + 29645 x Saturation - 639 x Price + 0.0669 x Income + 67.2 x T(t)

   Saturation - Electric Heat Customer Count / Total Res Basic Customer Count
   Price - Manitoba Real Residential Electricity Price lagged 2.5 yrs
   Income - Manitoba Real Income per Res Basic Customer
   T - A trend variable capturing increases in electric use and house size

   R-squared: 99.4%
   T-stats:

Constant:	1.97
Saturation:	2.66
Price:	-4.40
Income:	2.80
T:	3.45

9. **Appliance Use and Balancing** – Conditional Demand Analysis using the Residential Survey data combined with customer annual use from billing data was used to derive average annual energy use by type of heating system and appliance for existing and new dwellings. These average uses were multiplied by the number of each type of system and appliance to get the total energy use. This was balanced against Step 8 results to ensure reasonableness.

10. **Determine Total GWh used** – The forecast number of dwellings multiplied by the overall average use determined the GWh forecast. The forecast of energy savings from Codes and Standards as outlined in Manitoba Hydro's Power Smart Plan were subtracted, and the

future use of Electric Vehicles in the Residential sector was added. The result was the forecast of Residential Basic customer total energy use. This excludes savings from future Demand Side Management initiatives.

General Service Mass Market Methodology

A) General Service Mass Market Customer Forecast

Econometric analysis of historical sales data was used to develop models to forecast the number of General Service Mass Market customers. Forecasts of Manitoba Gross Domestic Product (GDP) and Manitoba Hydro Residential Basic Customers were then input into the models to generate forecasts for the number of customers for each year of the forecast period.

The number of Small Non-Demand, Small Demand and Medium customers was modeled using yearend historical customer data from 1985/86 to 2015/16. The resulting model and parameters are as follows:

Number of Customers at yearend (t)

= 34087 + 0.191 x MGDP + 0.046 x RES

MGDP - Manitoba Real Gross Domestic Product
RES - Yearend number of Residential Basic Customers

R-squared: 99.6%
T-stats:

Constant:	18.16
MGDP:	7.46
RES:	6.48

General Service Mass Market customer growth was assigned to Small Non Demand, Small Demand and Medium classes by using their 3 year average growth by class and allocating the customers appropriately.

The number of General Service Large customers was modeled using yearend historical customer data from 1989/90 to 2015/16. The resulting model and parameters are as follows:

Number of GS Large Customers at yearend (t)

= -339 + 0.013 x CUGDP + 0.0013 x RES

CUGDP - Canada / U.S. Blended Real Gross Domestic Product
RES - Yearend number of Residential Basic Customers

R-squared: 98.8%
T-stats:

Constant:	-9.24
CUGDP:	2.98
RES:	10.20

B) General Service Mass Market Average Use Forecast

Historical Average Use per General Service customer was calculated after removing the effects of DSM and Codes & Standards. The average use of the combined Small Non-Demand (SND), Small Demand (SD) and Medium classes were forecast using an econometric linear regression model that included Electricity Price and Manitoba GDP. Historical data from 1989/90 to 2015/16 was used. The resulting model and parameters are as follows:

Average Use per SND, SD and Medium

= 63457 - 2740 x Elec Price + 1.24 x MGDP + 3572 x Dummy

Elec Price - SND, SD and Medium Average Real Electricity Price
MGDP - Manitoba Real Gross Domestic Product
Dummy - "1" up to 2005/06 due to a billing system change causing a reclassification of customers in 2006/07

R-squared: 99.1%
T-stats:

Constant:	11.33
Elec Price:	-5.48

MGDP:	22.12
Dummy:	4.33

The Average Use for Large Mass Market customers was modeled using historical data from 1989/90 to 2015/16. The resulting model and parameters are as follows:

Average Use per GS Large

= 7912265 - 631604 x Elec Price + 487 x CUGDP + 264846 x Dummy

Elec Price	- GS Large Average Real Electricity Price
CUGDP	- Canada / U.S. Blended Real Gross Domestic Product
Dummy	- Included from 1999/00 to 2005/06 to reflect the average use of the 750V-30kV group being higher for those years by about 250,000 kWh

R-squared: 97.7%

T-stats:

Constant:	12.77
Elec Price:	-7.08
CUGDP:	10.98
Dummy:	3.98

The GS Mass Market Small, Medium and Large groups are further subdivided into rate groups that are based on customer's usage. If usage by an individual customer increases (or decreases) sufficiently then they are re-assigned to the appropriate rate group. This action results in the average use of each group to remain relatively stable. For the forecast, the average use of each rate group is held constant. The number of customers in each group is adjusted so that both the total number of customers and overall average use forecast by these models is achieved.

C) General Service Mass Market Total Use Forecast

Total GWh for the General Service Mass Market sector was forecast by multiplying the forecast number of customers in each rate group by the forecast average use. The forecast of energy savings from Codes and Standards as outlined in Manitoba Hydro's Power Smart Plan were subtracted, and the future use of Electric Vehicles in the GS Mass Market sector was added.

General Service Top Consumers Methodology

Each company in the Top Consumers group was forecast individually. Information on individual company operating plans was collected from company specific prospectus and quarterly reports, industry news and reports, and from Manitoba Hydro's Key & Major Account advisors. This information is used in the preparation of company specific short term forecasts for committed projects. The short term plans are forecasted to occur in the first three years. In the long term, following the third year, the company specific energy forecast is held constant for the remainder of the forecast period.

To account for longer term energy requirements in this group of consumers, a special classification called Potential Large Industrial Loads (PLIL) has been created. PLIL is used instead of attempting to forecast each top consumer individually for the long term. It is based on the historical growth of the Top Consumers group and represents the natural growth or contraction of all the Top Consumers together, including unexpected major expansions, contractions, new customers, or loss of customers.

An econometric model of Top Consumers was used to forecast PLIL. The model was developed by fitting historical Top Consumers annual energy from 1983/84 to 2015/16 to the Top Consumer Electricity Price and to a blended Canadian and U.S. Real GDP.

The resulting model and parameters are as follows:

Total Load = 2854 - 508 x Top Price + 0.951 x CUGDP

Top Price - Manitoba Top Consumers Real Electricity Price
CUGDP - Canada / U.S. Blended Real Gross Domestic Product

R-squared: 95.7%
T-stats:

Constant:	2.94
Top Price:	-2.94
CUGDP:	12.70

The forecasted growth from this model was used in years 4 through 20 as PLIL.

Electric Vehicles

The methodology for forecasting Electric Vehicles used historical data, supplied by Statistics Canada and Manitoba Public Insurance, on automobile registrations per year in Manitoba to help estimate future trends. Appropriate assumptions from recent relevant literature were applied to Manitoba's situation. The forecast section on Electric Vehicles provides further details.

Other Sectors

Seasonal, Water Heating, Lighting

Most of the smaller sales sectors, including Seasonal, Flat Rate Water Heating and Area and Roadway Lighting were forecast by analysis of the changes in the number of customers or services and in changes in average use per customer or service. Growth rates were applied based on history and a best estimate as to what the future will bring.

Diesel

Each of the diesel generated supplied communities was individually forecast and included in the forecast under the assumption that these communities are not anticipated to be connected to the Integrated System during the forecast period.

Monthly Sales Allocations

Monthly percentages of customer growth through the year and GWh for each month of the year were averaged for the past three to five years. The most appropriate growths were applied to the forecasts of annual customers and kWh to get the monthly forecasts.

Monthly and Annual Gross Firm Energy and Gross Total Peak

The 5 year monthly percentage of Common Bus and Station Service are applied to their annual energy to calculate their monthly values. Transmission Losses are calculated using a 5 year average of their ratio to Common Bus. Monthly Common Bus, Transmission Losses and Station Service are added up to give the Monthly System Energy. Monthly Common Bus, Transmission Losses, Station Service and Gross Firm Energy are totaled to give the Annual Gross Firm Energy.

The Gross Total Peak is calculated from Load Factors applied to the forecast monthly Gross Total Energy. Prior to calculating the Load Factors, the Top Consumer energy and peak are subtracted because the Top Consumers have a higher average hourly energy relative to their peak value than the Residential and General Service Mass Market Customers. A 10 year historical average Load Factor is calculated for the remaining energy and is applied to the forecast monthly energy to get the peaks for the remaining energy. The Top Consumer peaks are added using a 92% Load Factor applied to the Top Consumer monthly energy.

The annual Gross Total Peak is calculated using the 3 winter months of December, January and February when the actual peak has typically occurred and applied a ratio from the January peak to be used as the annual peak.

Historical weather adjusted energy is used to calculate the annual Load Factor. The historical trend of the load factor increasing 0.08% per year is applied to the forecast in the winter months when the annual system peak occurs. The number of hours in each month is used to calculate monthly Load Factors.

Growth Rates

Annual GWh/year growth rates in this document are linear growth rates, calculated as:

GWh growth / number of years.

Annual percentage growth rates in this document are compound growth rates calculated as:

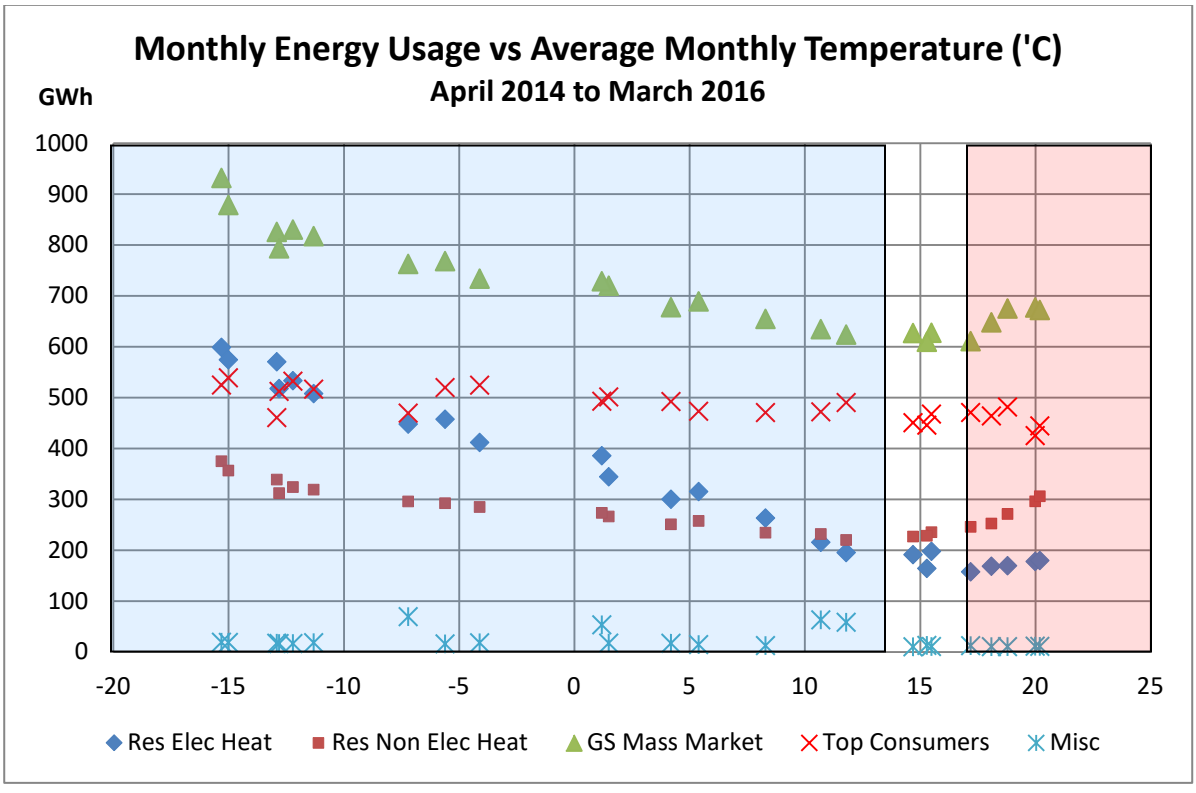
(final GWh / initial GWh) ^ (1 / number of years) – 1.

Weather Normalization Model

Historical weather adjusted actuals are the foundation of the underlying historical information used in the Residential Average Use and General Service Mass Market Average Use models. Manitoba Hydro forecasts with the assumption of normal weather. The process of adjusting annual historical usage to reflect the same weather pattern reduces the inherit variability caused by weather in the underlying data in each respective model.

The relationship of energy to weather is depicted below. The energy usage in each month is compared to the average monthly temperature. Heating Degree Days (HDD) occur in the shaded blue area where daily temperature averages are less than 14°C. Similarly, Cooling Degree Days (CDD) occur in the shaded red area where the daily temperature averages are above 18°C. Sectors with significant heating and cooling loads show an increase in energy consumption as the temperature departs from the base load. Base load temperature, where there are no significant heating or cooling loads, range between 14°C to 18°C.

The sectors that are weather adjusted are the General Service Mass Market, Residential Electric Heat and Residential Non Electric Heat.



The weather effect is determined in these sectors every year by regressing the previous two years of actual monthly energies against the actual HDD and CDD for the billing month. Due to the nature of cycle billing, the weather best associated with the billing cycle is the 16th of the previous month to the 15th of the current month. The result is a GWh/HDD coefficient and a GWh/CDD coefficient for each sector for each historical year. With each sector using the exact same two year period, the coefficients produced in each sector can be added together to form the HDD and CDD coefficients for General Consumers Sales for the given year.

The weather normalization model is also applied for Common Bus. Common Bus is metered at month end and as such, the weather used for the analysis is from the 1st of the month to the last day of the month. For the Common Bus weather normalization model, the usage attributable to the Top Consumers is removed because Top Consumers energy usage fluctuations is primarily related to production and is not weather related. The weather coefficients used at Generation are the Common Bus coefficients increased proportionately for Transmission Losses.

The weather regression model in each sector would be as follows:

GWh = h * HDD + c * CDD + Constant

h - Heating Degree Day coefficient (GWh per HDD)
c - Cooling Degree Day coefficient (GWh per CDD)
Constant - Base load portion not affected by heating or cooling (GWh)

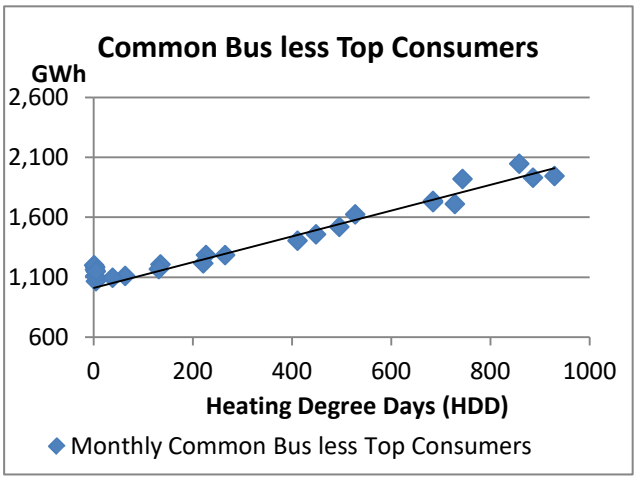
The resulting model and parameters for Common Bus calculated for April 2014 to March 2016 would be as follows:

GWh = 1009.7 + 1.074*HDD + 2.437* CDD

R-squared: 97.8%

T-stats:

Constant:	41.99
HDD:	25.45
CDD:	4.34
Standard Error:	49.6



GLOSSARY OF TERMS

Area and Roadway Lighting sector - includes electricity sales for the Sentinel Lighting and Street Lighting rate groups.

Common Bus - is the total load measured from all the distribution points (i.e. substations) within Manitoba. It includes all energy supplied to General Consumers Sales customers, Construction Power plus associated Distribution Losses, but excludes Diesel customers, Transmission Losses and Station Service.

Customer – Most metered electrical services count as a customer. Unmetered services such as flat rate water heating and sentinel rental services do not count as a customer. Street lighting counts all the services grouped as a premise as one customer.

Codes and Standards – A Demand Side Management (DSM) initiative associated with existing Provincial building codes and improved equipment efficiency standards. This is the only DSM initiative that is specifically accounted for in the forecast.

Cooling Degree Days (CDD) - CDD is a measurement designed to reflect the demand for energy needed to cool a building. CDD is the number of degrees warmer than 18 degrees Celsius each day is, based on the average of the high and low temperature of the day.

CDD = sum (max(0, (Daily high + Daily low) / 2) - 18)

Curtailable - is a load that can be curtailed on short notice. A discount is given for subscribing to this program. Curtailable loads can affect peak demand because some periods of curtailment may be at or near the system peak.

Gas Available Area – A city or town in Manitoba where customers have natural gas service available and can choose to heat their dwelling with either natural gas or electricity. Approximately 83% of Residential Basic customers, including the entire city of Winnipeg, have gas available.

General Consumers Sales - includes the energy supplied to all of Manitoba Hydro's individually billed customers. It excludes export sales.

General Service Mass Market - includes all Commercial and Industrial customers, excluding the Top Consumers group.

General Service Sector - made up of sales to Commercial and Industrial businesses served by Manitoba Hydro. This sector consists of five rate groups (Basic, Diesel, Seasonal, Flat Rate Water Heating and Surplus Energy Program).

General Service Top Consumers - is made up of the largest electricity users of Manitoba Hydro.

Gross Firm Energy - is the energy required to serve Manitoba Hydro's customers on the Integrated System. It excludes exports, interruptible (non-firm) loads and diesel customers.

Gross Total Peak - is the maximum integrated (i.e. average) hourly load required to serve Manitoba Hydro's customers on the Integrated System. It excludes exports and diesel customers. It includes curtailable loads.

GWh (gigawatt-hour) - The unit of energy primarily used in this document. One GWh equals one million kWh (kilowatt-hours), which is approximately equal to the energy of 100 typical dwellings not using electricity for heating, or 40 dwellings that use electricity for heating.

Heating Degree Days (HDD) – HDD is a measurement designed to reflect the demand for energy needed to heat a building. HDD is the number of degrees colder than 14 degrees Celsius each day is, based on the average of the high and low temperature of the day.

HDD = sum (max(0, 14 - (Daily high + Daily low) / 2))

Integrated System - is the power grid that connects Manitoba Hydro's generation sources to its customers. All Manitoba Hydro's customers except diesel are on the Integrated System.

Interruptible (Non-Firm) Energy - includes all energy sold to Manitoba customers on a non-firm basis. Currently, the only rate group for this is the Surplus Energy Program (SEP).

kWh/cust (kilowatt-hours per customer): The unit of energy primarily used in this document to represent the average use of one customer. The total usage in GWh of a group of customers is divided by the number of customers and then multiplied by one million.

Load Factor - is the ratio of the average hourly energy over a period, usually a year, divided by the energy used at a specific hour, usually the hour of system peak. A load factor of 25% means that the average energy is one-quarter of what is used at system peak. A load factor greater than 100% means that the average hourly energy is more than what is used at system peak. Given a specific energy, a lower load factor means a higher peak. The equation is:

Load Factor = (Total Energy / Hours) / (Energy over the hour of system peak)

Manitoba Load at Common Bus - is the total load measured from all the distribution points (i.e. substations) within Manitoba. It includes all energy supplied to General Consumers Sales customers plus associated Distribution Losses, but excludes diesel customers, Transmission Losses and Station Service.

MW (megawatt): The unit of peak demand primarily used in this document. One MW is a million watts. One thousand MW of peak demand for one hour equals one GWh of energy. Alternatively, one MW for a thousand hours also equals one GWh of energy.

Net Firm Energy and **Net Total Peak** - are the same as Gross Firm Energy and Gross Total Peak except they exclude Station Service. The reporting of Manitoba Load in the Load Forecast used "Net" until 2008. It presented both until 2011. Starting with the 2012 forecast, only the "Gross" is presented. Net can be calculated when needed by subtracting Station Service from the Gross.

Residential Basic – is the primary residential customer group made up of single detached and multi attached dwellings as well as individually metered apartment suites.

Residential sector - made up of sales to residential customers for non-business operations. The Residential sector is comprised of four rate groups (Basic, Diesel, Seasonal, and Flat Rate Water Heating).

Station Service - is the energy used by power plants to generate power and service their own load.

Tab 65

PUB MFR 9 (Revised)
Corporate Overview

Corporate Risk Analysis Report and Specific Risk Management Plans for all major risks including drought. [Appendix 11.7, 2015/16 GRA]

The response to PUB MFR 9 has been updated to include the redacted version of Manitoba Hydro's Corporate Risk Management Report Appendices.

Public disclosure of the response to this MFR (or portions thereof) would result in the release of information considered to be confidential and commercially sensitive. As directed by the PUB, Manitoba Hydro has filed a motion seeking confidential treatment of the redacted information contained in the attachment to this response pursuant to Rule 13.



Manitoba Hydro Corporate Risk Management Report December 2015

THIS REPORT INCORPORATES PRIVILEGED AND CONFIDENTIAL INFORMATION AND IS FOR INTERNAL REFERENCE ONLY

TABLE OF CONTENTS

1.0 INTRODUCTION **2**

2.0 HIGH CONSEQUENCE RISKS **3**
2.1 Infrastructure Risk **4**
2.2 Water Variation / Drought Risk **5**
2.3 Export Market Access Risk **6**

3.0 SIGNIFICANT AND EMERGING RISKS **7**
3.1 Infrastructure Investment **7**
3.2 Financial Strength **8**
3.3 Regulation and Licencing **11**
3.4 Indigenous Relationships **13**
3.5 Emerging Energy Technologies **15**
3.6 Human Resources **16**
3.7 Other Significant and Emerging Risks **17**

4.0 CORPORATE RISK MAP **20**

5.0 APPENDICES
A – Corporate Risk Tolerance Assessment **23**
B – Corporate Risk Profiles **38**
C – Corporate Risk Management Framework **92**

1.0 INTRODUCTION

The Corporate Risk Management Report is normally updated on an annual basis to provide Manitoba Hydro's stakeholders with information on the status of major risks facing the Corporation as it carries out its mandate. The report identifies and assesses each risk, describes activities used to manage the risk and provides estimates of the potential residual impact to the Corporation in terms of likelihood and consequence after mitigation actions have been taken. The Corporation's tolerance for each risk and an assessment of whether the risk is within or outside the desired tolerance level is also provided.

As a Crown-owned utility providing an essential and life-sustaining energy service to Manitobans, Manitoba Hydro has a relatively low tolerance for risk. However, because Manitoba Hydro is also an important economic driver for the Province, some risks are necessary in order to take advantage of opportunities to maximize value for stakeholders. These risks are managed through a systematic, proactive and integrated process which is designed to balance the objectives of:

- identifying threats that affect the achievement of the Corporation's mission and mandate;
- mitigating the consequences of negative occurrences; and
- taking advantage of opportunities to provide benefits to all stakeholders.

Most risk management efforts are focused on reducing the occurrence of negative events. However, the Corporation also has plans in place to reduce the impacts should a negative event occur. These plans are under continual assessment. In addition, all safety and reliability risks are managed through strict adherence to design, construction and operating standards and practices together with extensive public education and employee training programs. A comprehensive Emergency Response Program is also in place to ensure an effective and coordinated response to possible emergencies or disasters.

The financial and operational risks associated with the management of an integrated electricity and natural gas utility are significant. These risks include the impacts of weather on supply and demand, price and market uncertainties, interest, inflation and foreign exchange rates, skilled labour availability and costs, aging infrastructure maintenance and replacement, increasing regulatory, environmental and legal requirements, and accelerated technological change. Manitoba Hydro manages these

risks through an integrated control framework and through the maintenance of an adequate level of financial reserves through retained earnings.

Manitoba Hydro's Corporate Risk Management Report is structured to provide the following:

- A summary of the high consequence risks including:
  - Loss of major infrastructure
  - Drought
  - Loss of export markets
- An overview of significant and emerging risks and actions taken to address those risks.
- A Corporate Risk Map providing a visual depiction of Manitoba Hydro's risks categorized into high, medium and low likelihood of occurrence and the corresponding consequences.
- A Corporate Risk Tolerance Assessment of each risk.
- Corporate Risk Profiles - one page summaries of each of Manitoba Hydro's risks.

2.0 HIGH CONSEQUENCE RISKS

The most significant risks facing Manitoba Hydro are those rated as high consequence due to the potential magnitude of impact on the Corporation's ability to achieve its mandate and strategic goals and are quantified in the following table:

RISK	POTENTIAL FINANCIAL IMPACT
INFRASTRUCTURE	
Prolonged loss of supply	> $2 billion
DROUGHT	
Water Supply Variation / Drought	>$1.9 billion for a 5 year drought commencing in 2017/18 (IFF 15)
LOSS OF EXPORT MARKET ACCESS	> 30 % of electricity revenue

2.1 Infrastructure Risk (Category D)

A catastrophic infrastructure failure continues to be the most significant risk facing the Corporation and its customers. Potential impacts include prolonged loss of system supply, the inability to maintain minimum energy services, loss of life, severe environmental damage and significant costs to the Manitoba economy. Failure can be caused by a number of factors including an extreme weather event, sabotage, fire, human error, or technical malfunction.

By the nature of its business, Manitoba Hydro has an especially low tolerance for infrastructure risk. Significant efforts are expended on managing this risk in a manner that avoids the occurrence of a catastrophic event and minimizing consequences should a catastrophic event occur.

Risk Treatment

In the short term, actions are continually being taken to enhance emergency response and disaster management processes. In the longer term, major investment in renewal and expansion of the infrastructure system are underway to maintain and improve system reliability, energy security and safety. Key management plans and projects include:

- Major New Generation & Transmission projects which increase capacity and energy or provide increased reliability. These include building the Bipole III Reliability project with a planned in-service date of 2018/19 and construction of the Keeyask Generating Station with a planned in-service date of 2019/20. Manitoba Hydro is proceeding with the Manitoba-Minnesota Transmission Project, a transmission interconnection into the U.S. which supports enhanced export capability, reliability and drought risk mitigation.

- Renewal and replacement of aging electric and gas infrastructure through execution of a long term plan to improve system capacity and reliability. This includes critical distribution assets and stations, rehabilitation of existing generators, wood poles, cable and gas pipe replacement, cyber and physical security upgrades, and changes to gas distribution operations and pipelines to address emerging issues with respect to pipeline integrity and load growth. In

response to the 2014 rupture of the TransCanada main gas pipeline, the Corporation is constructing a compressed natural gas facility to help mitigate small scale outages during a natural gas supply interruption.

- Water retaining structures and flow control management, including: surveillance inspections, instrumentation monitoring, and engineering analyses of dams and dykes including emergency plans for individual facilities; systematic utilization of failure modes-based condition assessment techniques; and rehabilitation of the Pointe du Bois spillway facility.

- Continual improvement to enhance and strengthen the Corporate Emergency Management Program. In 2015, the Emergency Preparedness Policy was revised, and an Executive Emergency Management Committee was created to provide oversight of the program and to directly support the Corporate Emergency Center during an emergency event. In addition the Corporation continues to develop and maintain emergency preparedness and response management plans.

2.2 Water Supply Variation / Drought Risk (C.1 and D.2)

On average, there is a high likelihood of a drought occurring about once in every ten years. In the circumstances of an extreme drought that is more severe than the worst on record, there is a possibility of insufficient energy supplies being available to meet firm load demands. This would result in extreme financial and reputational impacts on the Corporation. The cost of a five year drought similar to the worst on record is estimated to be $1.9 billion (IFF 15) for a drought commencing in 2017/18.

Risk Treatment

There are several measures in place to manage the impacts of a drought, as follows:

- Manitoba Hydro's current generation and transmission facilities are designed and operated to ensure firm demand can be supplied given a repeat of the lowest river flows since 1912. A drought more severe than the worst on record could occur and would require non-normal operations. This may include operating reservoirs outside of the normal range for power production. Non-normal operation may also include demand reduction measures such as public appeal for conservation,

enforced conservation, or rotating reductions of non-essential load. Actions to manage drought will depend on its duration and severity and any other conditions that prevail at the time.

- Once built, the new Manitoba-Minnesota Transmission interconnection with the U.S. will provide the Corporation with increased ability to access additional amounts of energy through higher imports and through financial settlement of firm export contracts.

- Adequate financial reserves are required to protect against a repeat of the worst drought on record. At March 31, 2015 retained earnings totaled $2.8 billion. It should be noted, however, that while drought is a major quantifiable risk, an adequate level of retained earnings is required to recover from other significant risks such as a prolonged loss of supply or the loss of export market access.

2.3 Export Market Access Risk (Category A.2)

On average Manitoba Hydro derives a significant portion of its revenue from export sales to U.S. and Canadian markets. The prime impact of restricted market access would be significantly reduced net export revenues which are fundamental in keeping domestic rates low and offsetting the upfront costs of capital investments. Market access risk also includes restrictions on Manitoba Hydro's ability to import which could increase the cost of droughts, and degrade system reliability.

Risk Treatment

Manitoba Hydro continues to actively work to mitigate and manage market access uncertainties, as follows:

- In alliance with other industry participants such as the Canadian Electricity Association, and other stakeholders, Manitoba Hydro continues to lobby MISO, IESO and FERC for the development or elimination of market rules that affect electricity trade and facilitate full participation of Manitoba Hydro in US and Canadian electricity markets.

- Manitoba Hydro also engages in extensive lobbying efforts in the US to promote waterpower as a clean, reliable and renewable source of energy and to counter anti-hydro special interest group lobbying.

- The Corporation also engages with environmental, consumer and business stakeholder groups to discuss and promote its development plans.

- Market access risk is also reduced by having long term contracts and strong relationships in place with major export counterparties.

3.0 SIGNIFICANT AND EMERGING RISKS

While loss of infrastructure, drought and potential loss of export markets remain as the highest consequence risks for the Corporation, there are other significant and emerging risks that can affect the achievement of the Corporation's mission and mandate. These risks include:

3.1 Infrastructure Investment (Category D)

As noted above, Manitoba Hydro is making significant investments in a number of major new Generation and Transmission projects and initiatives in order to increase capacity and energy or provide increased reliability. These projects include construction of Bipole III and the Keeyask generating station, development of the Manitoba-Minnesota Transmission Project, replacement of aging infrastructure, and execution of new, more aggressive demand side management initiatives which target a significant increase in energy consumption savings. These plans will require the investment of approximately $17 billion (CEF 15) over the next 10 years. These projects are well into their construction cycles and any significant delays or cancellations would have significant financial, reputational and contractual consequences.

There are a number of very significant risks associated with such large initiatives that will challenge the Corporation's ability to meet Manitoba's energy needs while keeping customer rates affordable, and maintaining the Corporation's financial strength. These challenges include completing the projects on time and on budget, maintaining relationships with all stakeholders that could affect execution of these projects, and funding the investments while preserving the financial integrity of the Corporation.

Mitigation measures to address cost risks include the use of best practices in cost estimating, contracting practices and the inclusion of appropriate contingencies and management reserves. Preserving financial strength and managing stakeholder relationship issues are discussed below.

3.2 Financial Strength (B.7)

Maintaining financial strength is essential in order to make the necessary investments in infrastructure, to continue to provide safe and reliable service to customers, financially withstand the risks and uncertainties that are inherent in the Corporation's operations and to provide customers with long-term rate stability and predictability and avoid the need for large or sudden rate increases in the future.

The extensive capital investment in new and existing infrastructure will significantly weaken the Corporation's key financial ratios given that these investments will be largely funded through increased borrowing. Careful management of the Corporation's financial position is necessary in order to mitigate the risk of leaving customers exposed to sharp rate increases in the event of a prolonged drought or catastrophic outage. As well, there could be negative impacts to the credit rating of the Province if credit rating agencies were to deem Manitoba Hydro to no longer be financially self-supporting.

The Corporation has a solid plan to balance the need for investment to maintain safe and reliable service with the need to provide stable and predictable rates for customers. Key areas of focus and associated challenges are:

3.2.1 Continuing Cost Containment Measures

The Corporation continues to find and implement innovative ways to control costs without compromising the ability to deliver safe and reliable service. For example, since over 75 per cent of operating costs are comprised of wages and benefits, Manitoba Hydro has committed to reducing over 300 positions through attrition by 2016-17, resulting in annual savings of approximately $30 million. Manitoba Hydro is also targeting to limit increases in operating costs to 1% to 2021/22, excluding the impacts of accounting changes.

Other initiatives include a multi-year program to review and improve supply chain performance. The initial phase of the program has identified opportunities to reduce costs and increase operational efficiencies in materials management, fleet services and purchasing. In addition, the Corporation continues to

effectively manage costs associated with its sustaining capital investment requirements by engaging in a number of asset management strategies in order to prolong the economic life of its assets and replace assets in poor health in the most cost-effective manner.

3.2.2 Pursuing Export Sales (A.2)

Net extraprovincial revenues have enabled Manitoba Hydro to maintain low electricity rates for Manitobans and as such, the Corporation will continue to aggressively pursue a balanced portfolio of profitable export sales to provide the highest financial benefits to ratepayers and all Manitobans over the long term.

Key factors affecting the ability to increase export volumes and revenues are:

- **Export Market Prices** - In recent years export prices for electricity have been affected by the economic slowdown in the U.S. and the availability of low-cost natural gas made possible by new production techniques and wind generation. The Corporation has endeavored to reflect these factors as accurately as possible in its forecasts of future export market prices. Based on the input of external industry specialists, the Corporation is forecasting a moderate rise in export prices over the long term, restrained by the continued impact of natural gas pricing and other generation options. There is a risk that export prices could be lower than industry experts are predicting, and that would be a downside risk which could hamper the Corporation's ability to achieve forecasted export revenues. This would put pressure on financial ratios and result in the requirement for higher projected rate increases.

- **Cost of New Hydraulic Generation** – The resources currently in development are supported by a number of export agreements, including a 250-megawatt sale to Minnesota Power, a 125 MW sale to Northern States Power and a 108–megawatt sale to Wisconsin Public Service. [redacted] Should their costs exceed those forecasted, the

Corporation's ability to achieve forecasted financial targets with projected rate increases would be challenging.

- **Market Access -** The new Manitoba – Minnesota transmission interconnection will help increase export revenues by increasing export capability by 883 MW and import capability by 683 MW. These increases in transfer capability will increase the amount of firm load that can be served by the Manitoba Hydro's generating system, will enhance the value of new DSM initiatives and will result in achieving higher export prices and lower import prices. The line, while increasing export volumes, will also reduce water spillage in high water years.

3.2.3 Controlling Finance Expenses

In order to maintain business continuity in times of drought or catastrophic system outage, bridge cash flow financing will be required. Therefore, it remains critically important to maintain access to sufficient market liquidity through the use of the Corporation's short term debt credit facility, as well as ready access to the debt capital markets.

Projected finance expense is expected to double over the first ten years of the IFF15 forecast, due mainly to the borrowing requirements arising from the planned capital expenditures required to meet the growing energy needs of Manitoba and to replace aging infrastructure. In addition, the potential cumulative financial impact of a one-percent change in interest rates over the next ten years is estimated at $1.0 billion (IFF 15).

Manitoba Hydro will endeavor to manage financial expense exposure by continuing to closely monitor financial markets and take action to reduce costs where prudent and feasible. As a result of the low interest rate environment over the past several years Manitoba Hydro has been able to reduce its net weighted average interest rate by approximately 2.0% since 2006/07 and increase its weighted average term to maturity by over three years during the same period.

3.2.4 Implementing Domestic Sales Rate Increases (B.7)

Manitoba Hydro's financial forecast projects the requirement for reasonable and predictable domestic rate increases of 3.95 per cent per year over the next decade.

Implementing these rate increases to ensure ongoing safe and reliable service continues to be a significant challenge in convincing stakeholders that the projected level of rate increases are in the best long-term interests of all ratepayers. Significant efforts have, and will continue to be focused on delivering compelling and convincing arguments before the PUB to obtain the required level of rate increases going into the future. Even with the projected rate increases, it is expected that Manitoba Hydro's domestic customers will continue to have electricity rates that are affordable and competitive. As well, offering new and expanded Power Smart programs are aggressively targeting additional electricity and natural gas savings, which will aid customers in managing their overall energy costs.

3.3 Regulation and Licencing (H.1)

The Corporation requires a variety of regulatory approvals and licences to carry out its activities. Key approvals and licences include those issued under the National Energy Board Act, Water Power Act and Environment Act either to build new generation and transmission facilities or to maintain the operation of existing facilities. Failure to obtain approvals and licences on favourable terms or in a timely fashion could have significant financial, operating and water regime impacts, increasing costs, and reducing hydraulic generation, capacity and export sales. Expiration of a licence without renewal will expose the Corporation to embarrassment and loss of reputation. Although highly unlikely, cancelation of a licence could expose the Corporation to the possibility that a third party could acquire the water power rights at a location and potentially the loss of the asset.

There are two significant issues currently facing the Corporation that could have significant impact on operations and reputation if they are not addressed. These are:

3.3.1 The Listing of Lake Sturgeon under the Species at Risk Act (C.3.1)

Almost all of the Corporation's hydroelectric generating stations are located where Lake Sturgeon are found. It is possible that at most sites the Department of

Fisheries and Ocean could determine that the stations are negatively affecting the fish and/or its habitat. Due primarily to historical commercial overharvest, plus additional stressors including hydroelectric development and ongoing Indigenous domestic harvest, Lake Sturgeon populations have been severely depleted over the past 100 years and the species is currently under review for listing as endangered under SARA at most locations in Manitoba. If Lake Sturgeon is listed as "Endangered" under the SARA, the Corporation could face restrictions on current operations, structural modifications to infrastructure, delays in developing new generation due to difficulties with securing permits, and high costs of recovery measures that are potentially mandated. The Corporation continues to take significant action to minimize the need for and likelihood of listing Lake Sturgeon under SARA (see detail of risk treatment on profile C.3.1), however uncertainty remains.

3.3.2 Environmental and Social Impacts of Legacy Facilities

Many of Manitoba Hydro's legacy facilities such as Grand Rapids, Kelsey, Churchill River Diversion (CRD), Lake Winnipeg Regulation (LWR), Kettle G.S., Long Spruce G.S. and the HVDC facilities were constructed without the benefit of modern environment reviews and community and Indigenous consultations.

Manitoba Hydro is now having to deal with the impacts of these legacy projects in the context of modern societal and environmental values. This is unlike recent projects such as Wuskwatim, Bipole III and Keeyask where the impacts were studied, understood and communicated up front and consultations were held. So although legacy projects have all the necessary permits and are legally compliant, the expectations of Manitobans for legacy projects reach beyond what was legally required in the past. This gap in expectations exposes the Corporation to controversy whenever it is seeking a new licence or a change to an existing licence unless it proactively addresses all legacy issues before a licencing decision is required.

This situation arose during both the Wuskwatim and BiPole III Environment Act licencing processes where the public had opportunities to express concerns associated with the environmental and social impacts of CRD and LWR projects.

In these processes the fact their Water Power Act licences were not finalized after 30 years became a point of issue leading to the Clean Environment Commission (CEC) making a non-licencing recommendation on the need to acquire final licences.

Similarly in the BiPole III process the fact that legacy hydro projects in northern Manitoba had not undergone modern environmental reviews lead the CEC to make a non-licencing recommendation that both the Province and Manitoba Hydro conduct a Regional Cumulative Environmental Effects Assessment (RCEEA) of all Manitoba Hydro projects in the lower Nelson River sub-basin before any more projects are licenced for construction.

In the recently completed LWR Final Licence hearing the CEC went even further and recommended that all legacy hydro projects in the Province should be licenced under the Environment Act.

The issue of reviewing the environmental and social impacts from legacy projects is problematic in several ways for the Corporation. Base line data is lacking, the reviews are very costly, they take many years to complete and they can lead to delays in re-licencing existing facilities or constructing future facilities.

Over the next ten years, twelve of Manitoba Hydro's Water Power Act licences will have to be renewed. Although legally this should be a relatively simple process as prescribed under the Water Power Act regulations, public expectations, the requirement for the Province of Manitoba to consult under Section 35 of the Constitution with Indigenous peoples on all licencing decisions and the recent recommendations from the CEC on re-licencing that includes full environmental assessments and public reviews will expose Manitoba Hydro to significant costs, and potential operational restrictions. Manitoba Hydro is currently in discussions with the Province on how to proceed with re-licencing.

3.4 Indigenous Relationships and Legal (Section I)

Manitoba Hydro's relationships with Indigenous peoples and communities are complex and have been identified as one of the key areas of focus in Manitoba Hydro's Corporate Strategic Plan, where it is acknowledged that, "engaging impacted Indigenous communities in a positive way is vital to enhance working relationships."

While Manitoba Hydro has made extensive efforts to address impacts arising from its existing development, some legacy issues still remain. These issues remain a negative influence on Manitoba Hydro's ongoing relationships and engagement with communities, as well as on public perception of Manitoba Hydro's role in that relationship.

Recent judicial decisions, notably the Supreme Court of Canada decisions in the Manitoba Métis Federation and Tsilhqot'in Nation cases, provide additional complexity and have the potential to impact Manitoba Hydro's relationships with First Nation and Métis peoples in terms of the specific legal principles flowing from the decisions, and from the increased confidence communities might have to explore and assert their rights.

The recently elected federal government included the acceptance of the UN Declaration on the Rights of Indigenous Peoples (the UNDRIP) in its platform. The full adoption and implementation of UNDRIP is also included in the Truth and Reconciliation Commissions Calls to Action. The current movement towards acceptance of the UNDRIP, including its references to "Free, Prior and Informed Consent" (FPIC), has the potential to affect new project development and, potentially, changes to current operations. This may include increased process, negotiation and development costs, as well as enhanced prospects for impact benefit agreements (IBAs) on all projects (generating and transmission). How the concept of FPIC will be interpreted and approached by regulators and the courts going forward is also not known.

Risk to the Corporation from the issues noted above include the potential for strained relationships, prolonged negotiations, legal challenges, work stoppages, blockades, demonstrations and other forms of civil disobedience. Each of these in turn has the potential to impact project costs and schedule, adversely affect corporate financial strength, reduce export sales, lengthen the time and increase the cost of regulatory approvals, and damage the Corporation's reputation.

The Corporation has a number of measures in place to manage these risks. These include:

- continuing to work with Indigenous communities, groups and individuals to resolve outstanding issues and grievances to the extent possible and reasonable;

- pursuing enhanced working relationships through mutually beneficial arrangements with Indigenous groups when developing new hydro facilities;

- the development, use and/or enhancement of management systems to flag obligations and to follow up on compliance;

- where faced with legal challenges, responding with appropriate legal defences; and to this end, monitoring developments in the field of Aboriginal law to ensure ongoing awareness of evolutions in jurisprudence on Aboriginal and Treaty rights and other Aboriginal law issues;

- ongoing engagement with government to identify appropriate strategies for managing challenges in the relationships, particularly in cases where acts of civil disobedience are being used as a response to relationship impasses;

- consistent with recent Clean Environment Commission and Provincial recommendations, and the Truth and Reconciliation *Calls to Action*, shifting the corporate focus to reconciliation efforts and the development of a strategy to work with communities towards reconciliation.

3.5 Emerging Energy Technologies (J.1)

Improvements and production cost reductions are occurring in competing supply options that have set a trajectory where commercial viability of these supply sources will influence decisions of future alternative resource options. At the present time these competing options do not face the same environmental, regulatory and stakeholder challenges as constructing new hydro facilities.

Emerging technologies have also put downward pressure on export market prices and this could continue well into the future. Continued low export prices could affect the viability of new future hydro-electric generation and may also reduce a portion of existing generating facility values due to the long life spans of these facilities.

Manitoba Hydro's current resource plans indicate that no new generation is required until 2033. This requirement is based on current load forecasts that include new DSM targets that are updated annually to reflect information that is available. This time frame allows the Corporation to assess new alternative energy technologies and work towards an integrated resource plan which determines the appropriate combination of resources to meet multiple objectives (technical, environmental etc) at the lowest cost to Manitobans.

3.6 Human Resources

Attracting, developing, retaining and protecting a highly skilled and motivated workforce that reflects the demographics of Manitoba is critical to Manitoba Hydro's success. Key risks related to human resources are as follows:

3.6.1 Safety in the Workplace (E.1)

Employee safety is always a key concern to the Corporation due to the inherent nature of the operational work performed by Manitoba Hydro. To date a focus on continuous safety improvements has resulted in a steady decline in workplace accident severity and frequency rates. The Corporation is committed to continuously improving safety performance and focusing on strategies to instill a safe and health culture in all Corporate activities. Strategies include implementing a seven point safety enhancement strategy that includes annual executive site safety reviews, developing Corporate Rapid Response Teams for various issues, and moving the Corporation beyond compliance by forming a new high performance Risk Prevention Services team.

Manitoba Hydro's international operations in developing countries exposes employees and their families to increased risk of disease, crime, or injuries from political, ethnic or religious conflict. A number of measures are taken to mitigate these risks, including providing employees with medical advice and medi-vac transportation, specialized location security advice, secure accommodations and having emergency response and evacuation plans.

3.6.2 Workforce Management (E.3)

Attracting, developing and retaining a highly skilled and motivated workforce that can effectively carry out the very important, complex and new corporate initiatives are critical to the Corporation's success. Key factors that impact the ability to achieve this are the number of employees that are eligible for retirement, competition for highly skilled workers, and the ability to keep up with technological and other changes. Manitoba Hydro's contractors will also be impacted by the same competition.

The Corporation is looking at the demographic shift that is occurring in its workforce as a challenge as well as an opportunity. Nearly 900 employees are eligible for retirement in 2015. With years of accumulated experience and knowledge, many of those nearing retirement age are key contributors to the Corporation's success, and that knowledge can be lost with little notice. It is important therefore that appropriate leadership, management, succession planning, recruitment and retention activities are in place to maintain safe and reliable service and to manage the loss of valuable experience and knowledge that can result from the retirement of key contributors. Given that business needs are changing and new technologies are available, there is an opportunity to achieve efficiencies and cost reductions through attrition.

3.7 Other Significant and Emerging Risks

Other significant and emerging risks that can affect the achievement of the Corporation's mission and mandate are as follows:

3.7.1 Reputation (G.1)

The Corporation's reputation has been impacted by issues related to trust and transparency, rate increases, labour relations, and major projects (e.g. need, financial management, local reaction). Many of these challenges are likely to continue and others may emerge (e.g. new licencing requirements and Power Smart arrangements). As a result, there is a continuing need to focus on sustaining and enhancing corporate reputation. Accordingly, the Corporation will continue to take steps to enhance its reputation through all its daily actions, including comprehensive, timely communications, respectful interactions with stakeholders, and provision of safe, reliable, and affordable energy services to customers.

3.7.2 Upstream Gas Cost Uncertainty (B.5)

There is significant upward cost pressure for transportation services on the TCPL Canadian Mainline (the "Mainline"), to which Centra is currently captive in bringing natural gas to its load centre. The Mainline is significantly underutilized resulting in less revenue than that which is required to cover the Mainline's relatively high embedded cost structure. As a result, the pipeline has been seeking

regular toll increases since 2010, which costs are passed through to Manitoba natural gas ratepayers. Tolls on the Mainline also affect transportation services that Centra obtains from third parties.

This market risk is compounded by a proposal by TCPL to segment the Mainline's cost allocation and tolls post-2020 between the under-utilized Western Mainline (on which Centra moves gas) and the highly utilized Eastern Ontario Triangle, which would facilitate the avoidance of cost responsibility for under-utilized or stranded assets on the Mainline by eastern shippers at the expense of Centra and other captive shippers on the Western Mainline. Centra is the largest captive shipper on the Western Mainline. The outcome is highly uncertain at this time. The NEB has approved segmentation in principle and intends to review it and other pricing issues in future proceedings. Centra will mitigate TCPL tolls risk by actively participating in TCPL's regulatory proceedings before the NEB as appropriate in order to ensure that Manitoba natural gas consumers' interests are adequately represented.

3.7.3 Cyber Security (F.2.1)

The growth of electronic communication and automation, while delivering significant benefits, has also increased risk to the Corporation. This risk includes any cyber attack that could impact the resiliency, reliability, confidentiality, availability or the integrity of Manitoba Hydro information and operational technology assets, including the theft of personal and or business information, and or the disruption/misuse of critical operations/assets. Any computer or control system if not secured properly may be considered a potential target.

Countermeasures, management controls and processes are in place to mitigate this risk. The Corporation has implemented a series of measures to further augment cyber-security efforts consistent with recommendations of the Office of the Auditor General. Concurrently, to meet current NERC security standards Manitoba Hydro has also undertaken several projects targeted at increasing safeguards over critical cyber assets.

Ongoing assessment and enhanced mitigation strategies are required as the sophistication of external cyber threats increases, and as more computer and control systems are inter-connected. The Enterprise Security Council comprised

of senior executives provides oversight for all aspects of physical and technology security including NERC related projects and the implementation of the Auditor General's eight recommendations, of which four have now been completed.

To protect Manitoba Hydro's information technology environment an advanced corporate firewall is in place to protect the data network. Additionally, anti-virus software and security patches are closely monitored and updated immediately to prevent data corruption. The Corporation is finalizing the implementation of a Security Information & Event Management (SIEM) tool to further raise the level of protection. It will be fully operational by spring, 2016.

3.7.4 Wholesale Electricity Markets Compliance Program (A.2.1 / H.3)

To maintain market access and mitigate exposure to market manipulation risk, the Corporation is in the process of implementing a Wholesale Electricity Markets Compliance Program to establish policies, procedures and guidelines pursuant to anti-market manipulation laws in place in the U.S. and Canada. This program will outline roles and responsibilities of those identified in the program, provide direction to employees transacting in the export markets, identify permissible and prohibited trading considerations and specify policy with respect to potential violation investigations, disputes and reporting, training requirements, record retention practices and compliance monitoring related to the Corporation's participation in the wholesale electricity markets.

3.7.5 NERC/MRO Reliability Standards (H.5)

Achieving the highest level of reliability is one of the core tenets of Manitoba Hydro's Vision statement. In support of this vision, Manitoba Hydro is a member of the North American Electric Reliability Corporation (NERC) and has been legally required to comply with nearly 100 of its reliability standards since 2007. These standards specify requirements for planning, operating and maintaining the bulk electric system. The Corporation has developed a Corporate NERC Reliability Compliance Program to manage the demands of compliance, however uncertainty continues to exist with respect to the interpretation of some standards. As well existing standards are also continually being revised and new ones are being adopted on a regular basis.

3.7.6 Supply Chain (F.1)

The Corporation requires a variety of critical goods and services to achieve its objectives. [redacted] Action is being taken to review [redacted] requirements and contingency plans.

3.7.7 Strategic Direction and Execution K.1)

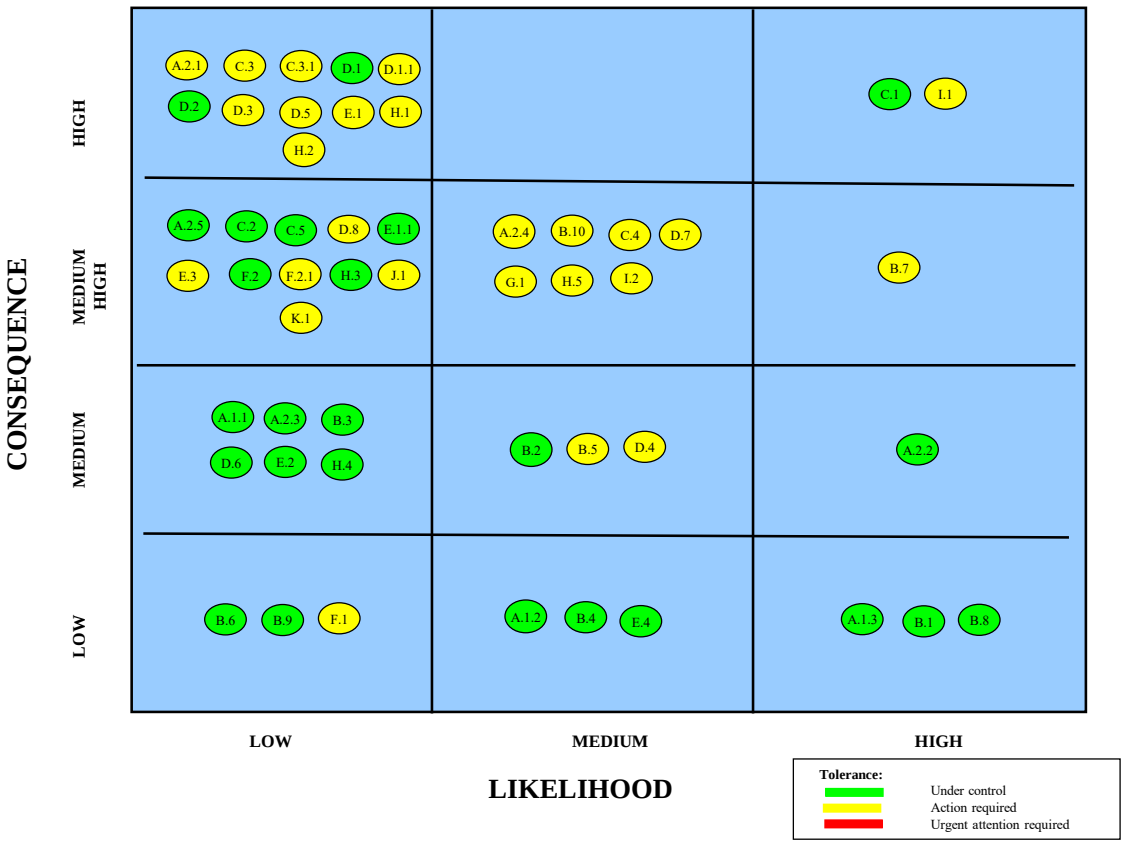
Manitoba Hydro continues to be at a critical point in renewing and expanding Manitoba's electrical and gas system. Major strategic decisions, plans and assumptions are subject to significant internal and external review and approval processes. Decisions for future power generation, transmission and distribution will depend on the best information at the time, and plans will be modified at key decision points if circumstances warrant.

4.0 CORPORATE RISK MAP

Corporate Risk Profiles (see Appendix B) identify and assess each risk facing the Corporation, describe activities used to manage the risk, and provide estimates of the potential residual impact to the Corporation in terms of likelihood and consequence after mitigation actions have been taken. The Corporation's tolerance for each risk and an assessment of whether the risk is within or outside the desired tolerance level is also provided. The risk rating and tolerance criteria are provided in Appendix C. As well, further detail of the risk tolerance assessment for each risk is provided in Appendix A.

The following Corporate Risk Map illustrates the results of a residual risk assessment for all risks facing the Corporation.

CORPORATE RISK MAP



A. Market
1. Domestic
    1. Competition
    2. Uneconomic Loads
    3. Load Growth Uncertainty
2. Export
    1. Regulatory Environment
    2. Long Term Price Uncertainty
    3. Transmission Interconnection Capacity
    4. Special Interest Groups
    5. Protectionism

B. Financial
1. Exchange
2. Interest Rates
3. Credit
4. Inflation
5. Upstream Gas Cost Uncertainty
6. Gas Derivative Instruments
7. Financial Targets
8. Energy / Fuel Price Volatility
9. Power Financial Instruments
10. Liquidity

C. Environmental
1. Water Supply Variation / Drought
2. Climate Change
3. Operational Impact and Infrastructure
    1. Legal - Species at Risk Act
4. Reliability of Supply
5. Upstream Regulation and Water Withdrawals

D. Infrastructure
1. Loss of Plant (all property, all perils)
1.1. Water Retaining Structures and Flow Control
2. Extreme Drought – Shortfall Energy
3. Prolonged Loss of System Supply
4. System Shutdown (Short Term)
5. System Shutdown (Natural Gas)
6. Technology
7. Concerned Stakeholders
8. Emergency Management Program

E. Human
1. Safety and Health
    1. Infectious Disease
2. Union / Employee Issues
3. Workforce Management
4. Technology

F. Business Operational
1. Supply Chain
2. Operational Controls
    1. Cyber Security

G. Reputation
1. Reputation

H. Governance / Regulatory / Legal
1. Regulation and Licencing
2. Export Market Access
3. Legal Compliance
4. Contracts and Ventures
5. NERC/MRO Reliability Standards

I. Indigenous
1. Relationships
2. Legal
+

J. Emerging Energy Technologies
1. Emerging Energy Technologies

K. Strategic
1. Strategic Direction and Execution

APPENDIX A

CORPORATE

RISK TOLERANCE

ASSESSMENT

RISK	RATING	TOLERANCE	STATUS	MGMT ACTION
A. MARKET				
1. Domestic				
1.1 Competition	Medium	Natural gas market share, greater than or equal to 60%.	Manitoba Hydro's natural gas market share is currently at approximately 60%.	Manitoba Hydro intends to continue offering fixed-price primary gas products to small volume consumers compatible with product demand as well as Power Smart programs and services to meet customer needs.
1.2 Uneconomic Loads	Medium	Intensive loads do not materially exceed 25 MWs.	Substantial expansion of energy intensive industry at current rates has the potential for adverse impact on financial strength.	Continue to explore rate concepts based on marginal cost. Advance Time of Use proposal for regulatory approval.
1.3 Load Growth Uncertainty	Medium	Variations in load growth from forecast are manageable.	An extensive load growth forecast that includes DSM actions and IFF update are completed annually. Development plans to meet resource requirements are revised as necessary.	Update load forecast and resource development plans as required. Implement integrated resource planning.
2. Export				
2.1 Regulatory Environment	Medium	Unfettered market access.	Market rules are continually evolving with new rules being imposed that could impact future access. These include jurisdictional overreach by FERC and MISO Tariff changes including changes to PPA requirements. Ontario recently implemented a General Conduct Rule which will potentially sanction otherwise legitimate market behaviour.	Manitoba Hydro collectively manages its market access risks through a comprehensive set of activities to monitor and address any potential threats to market access. The Corporation is in the process of implementing a Market Compliance Program to manage the risk of any potential market manipulation activities in the wholesale electricity markets.

Risk is being managed appropriately and is not expected to materially change.
Some emerging issues need to be monitored and additional action may be required.
Urgent attention required

RISK	RATING	TOLERANCE	STATUS	MGMT ACTION
2.2 Long Term Price Uncertainty	Medium	Downward price pressure due to new technologies limited to $100 million per year.	Technological developments for natural gas production & policy for wind incentives for wind development are occurring but are within tolerance limits.	Manitoba Hydro maintains a balanced portfolio with long-term contracts to reduce exposure to price variation.
2.3. Transmission Interconnection Capacity	Low	Maintain adequate transmission interconnection capacity.	Manitoba Hydro influences ratings through a cooperative process with MISO, and tie line partners. The Corporation also participates in reserve sharing agreements to maximize transfer capability. Ratings have not changed.	Maintain current efforts. To further mitigate risk, Manitoba Hydro is proceeding with a second 500 KV interconnection to the US and an additional 230 kV interconnection with Saskatchewan.
2.4 Special Interest Groups	Low	No negative image impact that materially affects opportunities for long-term firm power sales or the price that can be obtained.	Some residual risk remains. In spite of best efforts to counter anti-hydro lobbying, legislators and customers may still be negatively influenced. Regulators decisions may extend the regulatory process, deny approval or require onerous terms.	Continue to promote waterpower as clean, reliable and a renewable source of electricity. Aggressively counter Special Interest Group activities with Manitoba Hydro perspective. Expand engagement with groups who may lobby for or against Manitoba Hydro.
2.5 Protectionism	Low	Full participation in export markets	Manitoba Hydro offers a carbon-neutral energy alternative which many states will require in order to meet recently announced EPA rules requiring states to reduce CO2 emissions and develop plans as to how it will achieve those goals. MH is a sought after supplier and imports of hydropower into the US have recently been accepted as a qualifying resource in the US Clean Power Plan.	Maintain industry and regulatory representation. Continue monitoring and lobbying efforts in US and Canada for energy policy and market rules.

Risk is being managed appropriately and is not expected to materially change.
Some emerging issues need to be monitored and additional action may be required.
Urgent attention required

RISK	RATING	TOLERANCE	STATUS	MGMT ACTION
B. FINANCIAL				
1. Exchange	Medium	As defined in the Foreign Currency Exchange Risk Management Program.	Current exposure falls within the target. As well a $0.10 change in FX rate results in less than a $7.6M change in net income.	Continue to monitor USD cash forecast and take appropriate actions to stay within the risk targets.
2. Interest Rates	Medium	The aggregate of: i) floating rate debt, ii) short term debt, and iii) fixed rate long term debt to be refinanced within the subsequent 12 month period; is limited to a maximum of 35% of the total debt portfolio.	Within established policies and guidelines.	Continue to monitor economic and financial market conditions, while undertaking appropriate debt management strategies and operating within policy limits.
3. Credit	Medium	As defined by counterparty credit rating, limits and arrears policy.	Within established policies and guidelines. .	Maintain existing controls, closely monitor global credit issues, establish enhanced credit risk measurement capability to quantify credit risk exposure and ensure use of consistently applied practices to mitigate exposure.
4. Inflation	Medium	Sales rate increases within justifiable and acceptable limits.	Prolonged high levels of inflation could begin to jeopardize the achievement of Manitoba Hydro financial targets and necessary capital program. Cost constraint measures have been further implemented.	Continue to monitor inflation impacts, insert inflation adjustments into export contracts if possible, ensure all costs fully justified and monitor effectiveness of cost constraint measures.

Risk is being managed appropriately and is not expected to materially change.
Some emerging issues need to be monitored and additional action may be required.
Urgent attention required

RISK	RATING	TOLERANCE	STATUS	MGMT ACTION
5. Upstream Gas Cost Uncertainty	Medium	Sales rate increases due to increases in upstream gas commodity, transportation and / or storage costs within acceptable limits. Financial impacts from Fixed Rate Program also within acceptable limits.	There is the potential for significant future upward cost pressure for transportation services on the TCPL Canadian Mainline to which Centra is currently captive, as well as the ANR and GLGT systems which are wholly owned by TCPL. Gas cost rate uncertainty for the primary gas service is mitigated through a Rate Volatility Management Program, a fixed rate service or a third party marketer, and an equal payment plan. A self insurance risk premium and risk thresholds will mitigate financial impacts and trigger a review of the program.	Participate in NEB and FERC regulatory proceedings on matters related to the TCPL mainline and the ANR and GLGT systems in the U.S. Explore alternatives as required, such as the development of local underground natural gas storage.
6. Gas Derivative Instruments	Medium	Gas derivatives will not be used in the normal course.	Changes to the program were approved by the PUB and derivatives will not be used in the normal course.	Further use of derivatives justified and approved as required.
7. Financial Targets	Medium	Maintain adequate capital structure and other financial targets	Significant progress has been made toward achieving financial targets; however targets are expected to deteriorate for several years due to new major generation and transmission facilities and other significant capital expenditures. Targets are expected to recover towards the end of the 20 year IFF period.	Manage by adopting and updating appropriate targets, making annual contributions to retained earnings, achieving annual contributions through a combination of cost controls, high export revenues, and regular reasonable domestic rate increases.
8. Energy / Fuel Price Volatility	Medium	Included in drought tolerance for power purchase requirements.	Good water conditions currently exist, however volatility in prices has increased with the development of competitive energy markets.	Diverse sales portfolio and effective use of the MISO day ahead market. Hedging is a possibility. Retained earnings sufficient for any variations.

Risk is being managed appropriately and is not expected to materially change.
Some emerging issues need to be monitored and additional action may be required.
Urgent attention required

RISK	RATING	TOLERANCE	STATUS	MGMT ACTION
9. Power Financial Instruments	Low	As defined in the Wholesale Export Power Policy.	Within established guidelines.	Corporate Risk Management is finalizing the installation of risk software that will provide enhanced risk measurement capability.
10. Liquidity	Low	As per the Manitoba Hydro Act, the temporary borrowing limit shall not exceed in the aggregate the sum of $500 million.	Within established guidelines.	Cash receipts and disbursements are closely monitored on a daily basis. Short term debt balances and forecasted cash requirements are also monitored, with short term debt converted to long term debt as required. Fund three months in advance of requirements.
C. ENVIRONMENTAL				
1. Water Supply Variation / Drought	Medium	Operation Planning Criteria and adequate financial reserves. Potential 5 year drought impact is $1.9 billion for a drought commencing in 2017/18 (IFF 15)	Good water conditions that could change within a year. Sufficient retained earnings to withstand extended drought. Natural gas and power prices are expected to be low for the near-term.	Retained earnings sufficient for reduced flow/revenue due to drought.
2. Climate Change	Low	Climate change impacts expected to occur gradually	Climate change issues on water supply are being studied. Any required adaptation to operations and resource plans will be made as information becomes available.	Continue to monitor progress on determining climate change impacts and respond accordingly.

Risk is being managed appropriately and is not expected to materially change.
Some emerging issues need to be monitored and additional action may be required.
Urgent attention required

RISK	RATING	TOLERANCE	STATUS	MGMT ACTION
3. Operational Impact and infrastructure	Medium	No unplanned environmental impacts, ISO 14001 compliant, CSP environmental targets met.	There are a number of environmental issues that are or could affect future operations of the Corporation. The most significant include the potential of Lake Sturgeon being listed as endangered (see 3.1 below), and the need to address environmental and societal impacts and expectation for legacy facilities. See risk profile H.1.	Complete the RCEEA and continue discussions with the Province on how to proceed with re-licencing.
3.1 Legal - Species at Risk Act	Medium	No undue restrictions on current operations and ability to build future projects.	The Corporation has taken significant action to minimize the need for and likelihood of listing Lake Sturgeon under SARA. However uncertainty remains regarding whether the Federal Government will decide to list Lake Sturgeon under SARA.	Continue actions to minimize the need for listing Lake Sturgeon under SARA.
4. Reliability of Supply	Low	No major obstruction to plans and operations to build necessary facilities.	Enhanced scrutiny and regulatory oversight of proposed system improvements and the added time and cost needed to obtain licences and permits.	Be proactive in addressing concerns and ensure adequate lead times to resolve issues.
5. Upstream Regulation and Water Withdrawals	Low	Changes in water supply expected to be gradual.	Good water conditions exist reducing pressure on water supply diversions in the short term.	Continue monitoring responsible entities.

Risk is being managed appropriately and is not expected to materially change.
Some emerging issues need to be monitored and additional action may be required.
Urgent attention required

RISK	RATING	TOLERANCE	STATUS	MGMT ACTION
D. INFRASTRUCTURE				
1. Loss of Plant (all property, all perils)	Low	No major facility loss. CSP reliability targets and contingency standards. Max insurance coverage is $7.0 billion.	Maintain Reliability, Dam Safety and Insurance programs including annual reviews.	Continue to assess exposures of loss and develop appropriate risk reduction alternatives and emergency plans.
1.1. Water Retaining Structures and Flow Control	Low	No water retaining structure failures, following Canadian Dam Association guidelines, maintain appropriate emergency preparedness plans.	The risk of dam breach is addressed by ensuring the integrity and reliability of water control equipment and structures through diligent maintenance and vigilant surveillance, as well as preparing for emergencies, as per Cdn Dam Assoc guidelines. Residual risk of dam failure can be mitigated but not eliminated.	Maintain Dam safety program and improve structures where deficiencies are known.
2. Extreme Drought - Shortfall of Energy Supply	Low	Historical low flows determine firm supply and operating reservoir levels.	Current water conditions suggest that loads will be met.	Maintain current water resource management systems.
3. Prolonged Loss of System Supply	Low	. No long term system outages, compliant with reliability standards, appropriate continuity plans in place.	No long term events have been experienced recently. However, an aging system has areas of significant concern.	Several capital items have been approved which will reduce exposure to a catastrophic event. Regularly maintain, review and update business continuity plans.

Risk is being managed appropriately and is not expected to materially change.
Some emerging issues need to be monitored and additional action may be required.
Urgent attention required

RISK	RATING	TOLERANCE	STATUS	MGMT ACTION
4. System Shutdown (Short Term)	Low	No major system outages, CSP targets for reliability of service (e.g. SAIDI, SAIFI), compliance to reliability standards, emergency response plans in place.	Manitoba Hydro's reliability performance shows an increased trend of outage frequency and duration, and generation forced outage rates have increased in the last four years. The Corporation is continually upgrading the system.	Maintain reliability standards and ensure system reliability through planned maintenance and upgrades. Regularly maintain, review and update emergency preparedness plans for system restoration and response.
5. System Shutdown (Natural Gas)	Low	Gas supply is available to meet the needs of the province. No undue impact on electrical grid due to gas system failure.	TransCanada Pipelines has incorporated design practices to minimize the possibility of a catastrophic event occurring. The design practices have been effective over the course of several incidents in past decade with the exception of the 2014 Otterburne pipeline rupture that resulted in a loss of service to a number of communities. MH has retained standby services to provide compressed natural gas (CNG) for small scale outages during a supply interruption for the 2015/16 winter.	Ongoing monitoring to ensure that TransCanada Pipelines maintains a safe and secure natural gas transmission system. Maintain and review emergency response procedures and conduct exercises. CNG equipment and facilities are being purchased and constructed.
6 Technology	Low	Computer operations will not be compromised. Compliance with all security standards.	Highly complex area that is constantly changing and operations have not been compromised.	Continuous review and updating of the comprehensive disaster recovery plans. Complete actions to address security risks in the Enterprise IT Security Assessment

Risk is being managed appropriately and is not expected to materially change.
Some emerging issues need to be monitored and additional action may be required.
Urgent attention required

RISK	RATING	TOLERANCE	STATUS	MGMT ACTION
7. Concerned Stakeholders	Low	No restrictions to infrastructure requirements, particularly projects that are required for safety and reliability reasons.	Lobbying has caused delays and resultant impact on reliability in a number of projects, including BiPole III.	Proactively identify and address issues to ensure construction schedule.
8. Corporate Emergency Management Program (CEMP)	Low	Ability to provide emergency response to maintain or restore minimum acceptable energy services to protect human life and the environment. No undue financial consequences to the Corporation and Manitoba economy.	The CEMP continues to be enhanced with the revision of the Emergency Preparedness Policy and the establishment of the Executive Emergency Management Committee (EEMC). Initiatives currently underway include developing a corporate plan for business continuity for continuation of essential services and critical functions (electrical and gas restoration, bill collection, power trading) and constructing an emergency fuel depot.	Continuous oversight by the Executive Emergency Management Committee (EEMC) to confirm Business Continuity Plans (BCP), Hazard Risk Assessment (HRA), Preparedness, Response and Recovery Plans are reviewed and tested to ensure Manitoba Hydro has the ability and can respond to emergency events.
E. HUMAN				
1. Safety and Health	Low	Within CSP targets for high-risk accidents accident severity and frequency.	Focus on continuous safety improvements has resulted in a steady decline in workplace severity and frequency rates. MH is committed to continuously improving safety performance and instilling a safe and health culture in all activities.	Continue to focus on continuous safety improvements and instilling a safe and health culture. Strategies include implementing a seven point safety enhancement strategy and developing programs with an internal Rapid Response Team for various issues.
1.1. Infectious Disease	Low	Effective response to disease outbreak.	An Influenza Pandemic Plan was reviewed and updated in September, 2009. Monitor health authority requirements and make changes as required.	Continue to monitor and make any required changes to meet health authority requirements.

Risk is being managed appropriately and is not expected to materially change.
Some emerging issues need to be monitored and additional action may be required.
Urgent attention required

RISK	RATING	TOLERANCE	STATUS	MGMT ACTION
2. Union / Employee Issues	Low	Continued positive relations and contract settlements.	A new three year agreement negotiated between the Corporation and IBEW was ratified in early January, 2016. The other three agreements were renewed in 2013 and expire in 2016.	Continue to address employee issues in good faith to ensure that relationships remain positive.
3. Workforce Management	Low	Key vacant positions filled with qualified people. Continue strong relationships and enhance partnerships with post secondary institutions.	Significant retirements in the near future combined with a shrinking labour pool. Implementation of a comprehensive succession planning program.	Completion and maintenance of detailed succession plans for all key strategic & critical positions. Continuous update of retirement forecasts and recruitment plans. Continued redeployment training programs.
4. Technology	Low	Technology issues fully understood and effectively incorporated into existing systems.	Several different technologies exist within Manitoba Hydro's infrastructure and staff have been able to keep up to both older and newer technologies. This risk will increase with time.	Maintain an appropriate level of resources to manage this increasing risk.
F. BUSINESS OPERATIONAL				
1. Supply Chain	Low	Established 90 day supply for critical items. Emergency spares maintained. Materials available when needed.	Material and services delivered within policy however the demand for construction services in some trades is still a concern. In some cases have exceeded budget expectations. .	Continue risk management protocol, including monitoring market trends, sourcing strategic alliance partners, reducing single source provider and stocking emergency spares of critical items.
2. Operational Controls	Low	Adherence to all established guidelines, procedures, policies and programs.	Adequate control structures in place and working. Exceptions reported and appropriate corrective action taken.	Maintain effective control mechanisms.

Risk is being managed appropriately and is not expected to materially change.
Some emerging issues need to be monitored and additional action may be required.
Urgent attention required

RISK	RATING	TOLERANCE	STATUS	MGMT ACTION
2.1 Cyber Security	Low	No undue impacts from cyber attacks on information or critical operational assets.	Controls and processes are in place to mitigate risk. Further measures are being developed and implemented to augment efforts, consistent with recommendations of the provincial Auditor General.	Continue to develop and implement further measures under the governance of the Enterprise Security Council.
G. REPUTATION	Low	No negative image impacts. Meet CSP customer service and public attitude index targets.	Manitoba Hydro's customer satisfaction rating is just above its five year average and is well above the average for Canadian utilities. Reputation could be impacted by issues related to construction of major projects, labour relations, new Power Smart arrangements, new licencing requirements, rate increases, and corporate trust and transparency.	Continue to take steps to enhance the Corporation's reputation, through all its daily actions, including comprehensive, timely communications, respectful interactions with stakeholders, and provision of safe, reliable, and affordable energy services to customers.
H. GOVERNANCE / REGULATORY / LEGAL				
1. Regulation and Licencing	Low	Current restrictions and licences maintained. New facilities receive favourable licencing.	Issues that could have significant impact on operations and reputation include Lake Sturgeon being listed as endangered (see profile C.3.1) and addressing environmental and societal impacts and expectations for legacy facilities. These include addressing CEC recommendations for completion of a Regional Cumulative Environmental Effects Assessment (RCEEA), as well as that all legacy hydro projects be licenced under the Environment Act.	Continue to take action to minimize the need for and likelihood of Lake Sturgeon. Complete the RCEEA and continue discussions with the Province on how to proceed with re-licencing.

Risk is being managed appropriately and is not expected to materially change.
Some emerging issues need to be monitored and additional action may be required.
Urgent attention required

RISK	RATING	TOLERANCE	STATUS	MGMT ACTION
2. Export market Access	Low	Current capacity to export continues (100%)	Rules are constantly changing in export markets. Corporation vigilant in monitoring changes, assessing possible impacts and advocating resolution consistent with corporate interests.	Actively participate in organizations and processes related to rule development and application. Ongoing assessment.
3. Legal Compliance	Low	Compliant with all laws and regulations.	For a large diverse company it is not realistic to reduce the risk of non-compliance to zero. Actions are intended to provide realistic assurance that compliance risks are being addressed.	Ongoing actions to address compliance issues at various levels of the Corporation.
4. Contacts and Ventures	Low	Adherence to all terms and conditions. High risk agreements appropriately reviewed and executed.	Corporation ensures adherence through an effective contract and venture control system.	Maintain control systems.
5. NERC/MRO Reliability Standards	Low	Full compliance to all applicable NERC / MRO standards.	Uncertainty continues to exist with respect to interpretation of some standards. Existing standards are also continually being revised and new ones are being adopted on a regular basis.	Continue to build a strong culture of compliance where all staff understand the impact of day-to-day activities and make corresponding decisions that support on-going compliance.

Risk is being managed appropriately and is not expected to materially change.
Some emerging issues need to be monitored and additional action may be required.
Urgent attention required

RISK	RATING	TOLERANCE	STATUS	MGMT ACTION
I. INDIGENOUS				
1. Relationships	Low	Workable impact management frameworks or reasonable offsetting arrangements in place with all Indigenous communities adversely affected by Manitoba Hydro operations. Indigenous employment targets achieved. No Strained relations.	Reasonable arrangements are in place with the communities that do not have workable management frameworks. If a community raises an adverse effects concern, Manitoba Hydro will endeavour to investigate and address the concern. Employment numbers are generally exceeding targets. There are strained relations with many communities and resource user groups, including groups who have impact arrangements in place with Manitoba Hydro.	Continue working with indigenous communities to resolve outstanding issues to the extent possible and reasonable. Engage with government to identify appropriate strategies for managing challenges in the relationships, particularly in cases where acts of civil disobedience are used as a response to relationship impasses.
2. Legal	Low	No unfavourable rulings, Compliant with all existing legal requirements.	Demands exist from several sources which could ultimately result in unfavourable rulings. Management systems have not identified any compliance concerns that are not being addressed. Statements of Claims have been filed against Manitoba Hydro.	Measures include (1) Legal responses to legal challenges. (2) Maintain and continuously improve compliance management systems (3) Filing statements of defence, and (4) Monitoring developments in the field of Indigenous law, including Supreme Court decisions.

Risk is being managed appropriately and is not expected to materially change.
Some emerging issues need to be monitored and additional action may be required.
Urgent attention required

RISK	RATING	TOLERANCE	STATUS	MGMT ACTION
J. EMERGING ENERGY TECHNOLOGIES	Low	Develop integrated resource plan which uses appropriate combination of resources to meet MH objectives.	Significant improvements and cost reductions in new emerging energy technologies could put downward pressure on market prices and affect MH marketing opportunities, thus reducing revenues from existing assets. MH is actively assessing and working towards an integrated resource plan that determines the appropriate combination of resources to meet objectives.	Continue to assess new technologies and develop integrated resource plan that determines the appropriate combination of resources to meet objectives.
K. STRATEGIC	Low	Long term goals are pursued. No missed opportunities. No unfavourable business decisions.	High level strategic considerations include large scale capital projects to meet future needs of the province and re-investment of the existing energy system. Major strategic decisions, plans and assumptions are subject to significant internal and external review and approval processes.	Decisions for future power generation, transmission and distribution will depend on the best information at the time, and plans will be modified at key decision points if circumstances warrant.

Risk is being managed appropriately and is not expected to materially change.
Some emerging issues need to be monitored and additional action may be required.
Urgent attention required

APPENDIX B

CORPORATE

RISK PROFILES

RISK PROFILE INDEX

RISK CATEGORY	PAGE #
A. MARKET	
1. Domestic	
.1 Competition	41
.2 Uneconomic Loads	42
.3 Load Growth Uncertainty	43
2. Export	
.1 Regulatory Environment	44
.2 Long Term Price Uncertainty	45
.3 Transmission Interconnection Capacity	46
.4 Special Interest Groups	47
.5 Protectionism	48
B. FINANCIAL	
1. Exchange	49
2. Interest Rates	50
3. Credit	51
4. Inflation	52
5. Upstream Gas Cost Uncertainty	53
6. Gas Derivative Instruments	54
7. Financial Targets	55
8. Energy / Fuel Price volatility	56
9. Power Financial Instruments	57
10. Liquidity	58
C. ENVIRONMENTAL	
1. Water Supply Variation / Drought	59
2. Climate Change	60
3. Operational Impact and Infrastructure	61
.1 Legal - Species at Risk Act	62
4. Reliability of Supply	63
5. Upstream Regulation and Water Withdrawals	64

D. INFRASTRUCTURE

1. Loss of Plant (all property, all perils) 65
   .1 Water Retaining Structures and Flow Control 66
2. Extreme Drought - Shortfall Energy Supply 67
3. Prolonged Loss of System Supply 68
4. System Shutdown (Short Term) 69
5. System Shutdown (Natural Gas) 70
6. Technology 71
7. Concerned Stakeholders 72
8. Emergency Management Program 73

E. HUMAN

1. Safety and Health 74
   .1 Infectious Disease 75
2. Union / Employee Issues 76
3. Workforce Management 77
4. Technology 78

F. BUSINESS OPERATIONAL

1. Supply Chain 79
2. Operational Controls 80
   1. Cyber Security 81

G. REPUTATION

1. Reputation 82

H. GOVERNANCE / REGULATORY / LEGAL

1. Regulation and Licencing 83
2. Export Market Access 84
3. Legal Compliance 85
4. Contracts and Ventures 86
5. NERC/MRO Reliability Standards 87

I. INDIGENOUS

1. Relationships 88
2. Legal 89

J. EMERGING ENERGY TECHNOLOGIES

1. Emerging Energy Technologies 90

K. STRATEGIC

1. Strategic Direction and Execution 91

Likelihood	Low
Consequence	Med
Tolerance	Med

CATEGORY: A. Market

TITLE: 1.1 Domestic – Competition

RISK: Increasing competition may result in a reduction of domestic market share.

DESCRIPTION:
Over the past few decades, the energy utility industry has seen some structural changes with these changes varying somewhat throughout North America. Within these changes, there has been some movement towards creating a more competitive energy services environment with customers having a choice of energy supplier and more choice in energy products (e.g. time of use rates/green energy with electricity, customer self-generation, fixed price products with natural gas and a carbon neutral option).

In Manitoba, customers have a choice in their Primary Gas supplier and no choice with all other system supply electricity and natural gas related services. In the early 2000's, some regions including Manitoba reassessed their respective market structures involving primary natural gas services. In Manitoba, competition in the supply of primary natural gas is quite limited with only two brokers (Just Energy Manitoba and Planet Energy) offering service within the SGS Residential market and six offering services to Commercial and Industrial customers. Currently, a declining number of natural gas residential customers (approximately 6%) have entered into contractual arrangements with brokers involving four to five year terms to deliver their primary gas needs. The number of SGS Commercial and LGS customers combined in contractual arrangements with brokers has also declined (approximately 5%).

During 2007, following a review of the competitive landscape of the natural gas market in Manitoba, the PUB concluded that it was not satisfied with the service options and pricing currently available to Manitoba consumers for Primary Gas service. As a consequence, the PUB ordered Centra, a subsidiary of Manitoba Hydro to file a comprehensive proposal to enter the fixed-price primary gas market. In 2009, Manitoba Hydro started offering consumers the choice of 1, 3 or 5 year fixed-price primary gas products with the price and offering terms varying during various marketing periods. As of November 2015, less than 1% of SGS and LGS customers have entered into fixed rate contracts with Manitoba Hydro.

Although Manitoba Hydro enjoys a significant monopoly environment within the electricity and natural gas utility market, pressures may arise in the future which could change this situation. For this reason, the Corporation is exposed to risks associated with market share loss.

POTENTIAL IMPACT ON ACHIEVING CORPORATE OBJECTIVES:
Enhanced competition in the natural gas business would impact Manitoba Hydro's strategic goal of providing customers with exceptional value and meeting its target market share in natural gas (i.e. greater than or equal to 60% of commodity sales). Loss of market share would have a negative impact on the Corporation in terms of realizing the benefits and synergies associated with serving a larger customer base. Introduction of competition in the electric business would impact Manitoba Hydro's position of being the sole supplier of electricity in Manitoba. This would result in the loss of synergies associated with being an integrated company and those benefits provided through economics of scale.

RISK TREATMENT:
The risk associated with this category is managed through all of the Corporation's strategic goals and actions. These initiatives are dynamic in nature and are outlined within the Corporation's Strategic Plan.

Likelihood	Med
Consequence	Low
Tolerance	Med

CATEGORY: A. Market

TITLE: 1.2 Domestic – Uneconomic Loads

RISK: Manitoba Hydro's low electricity rates could attract energy intensive industries which may impact short term export revenue and cause the advancement of new generation.

DESCRIPTION:

Manitoba Hydro's rates to Manitoba consumers are based on the embedded cost of its operations less a credit for net export revenues. Manitoba Hydro is one of the lowest cost producers in the world, with substantial sales into export markets at prices which reflect the real value of electricity. As a result of this export revenue subsidy, domestic loads could be considered "uneconomic" in the sense that absent the subsidization by export revenues, domestic rates do not recover the full embedded cost to serve.

While the decisions of most new businesses or residents to locate to Manitoba are not driven substantially by electricity rates, there are some energy-intensive industries that may be attracted by the low electricity rates. In some cases, it is not apparent that other benefits to the province, such as taxes and employment derived from energy-intensive industry, outweigh the losses due to foregone export revenue.

POTENTIAL IMPACT ON ACHIEVING CORPORATE OBJECTIVES:

Substantial expansion of energy intensive industry at current rates has the potential for adverse affects on attainment of the Corporation's strategic objective to protect and improve its Financial Strength, as it may affect our ability to:1) Utilize resources efficiently and effectively to fulfill our mandate and provide maximum value to our stakeholders and ratepayers, and 2) Aggressively pursue a balanced portfolio of domestic and profitable export sales to provide the highest financial benefits to ratepayers and all Manitobans over the long term.

RISK TREATMENT:

Manitoba Hydro supports Time of Use rate concepts as well as rate concepts based on marginal cost which could be generally applicable to all major loads, not just energy intensive industrial loads. These types of rates have the virtue of being applicable to much more usage as well as being more specific with respect to time periods of usage.

As directed by the Public Utilities Board, a review of the Time of Use proposal and proposed changes to the Corporations Cost of Service Study will be addressed at a regulatory proceeding to be scheduled in 2016.

Likelihood	High
Consequence	Low
Tolerance	Med

CATEGORY: A. Market

TITLE: 1.3 Domestic – Load Growth Uncertainty

RISK: Variation in the domestic load from forecast can impact when new resources are required and the quantity of surplus available for export.

DESCRIPTION:

There is financial risk associated with uncertainty in the domestic load forecast. Lower than forecast domestic load will result in lower net revenues as unit revenues from the domestic market generally exceed those from the export market.

POTENTIAL IMPACT ON ACHIEVING CORPORATE OBJECTIVES:

The prime impact of this risk is reduced corporate net revenues. To some extent this risk may be mitigated by an increase in MH's export sales activities. If additional long term firm sales can be arranged this may offset the decline in domestic revenues. If not, additional export market sales may be insufficient in offsetting the domestic revenue reduction

RISK TREATMENT:

The Corporation can manage load forecast uncertainty by appropriately distributing export sales commitments over the complete range of power sales time horizons from long-term down to real time. If the Manitoba load growth is higher than expected, then long term export sales commitments can be reduced over the long term. Similarly, if the Manitoba load growth is less than expected, additional long term export sales can be committed.

The Manitoba load forecast, power resource plan and IFF are updated annually to reflect any changes in long-term domestic demand due to factors such as energy pricing, economic activity, population and housing, among others. The Corporation also considers higher and lower load forecast scenarios along with the base load forecast when preparing resource development plans or long-term contract recommendations.

Likelihood	Low
Consequence	High
Tolerance	Med

CATEGORY: A. Market

TITLE: 2.1 Export – Regulatory Environment

RISK: Changes in regulation could restrict access to the export market.

DESCRIPTION:

Unfettered market access is key to the Corporation's ability to maximize export revenues. Regulatory and/or industry change both in Canada and the US is considered to be a fundamental export market risk. These changes may lead to increased costs for the Corporation or limit its access to, the US and Canadian markets as market rules may conflict with the legal requirements governing the Corporation or because they lead to discriminatory treatment of Manitoba Hydro. Entities that may contribute to or influence market access risks include MISO, IESO, AESO, FERC, NERC, MRO, NAESB, State governments (Wisconsin and Minnesota), Provincial and Federal Industry and Trade departments and the Canadian Electricity Association (CEA).

This risk profile is related to Export Market Access, Governance / Regulatory / Legal (H.2). Collectively, market access risks are legal, regulatory, or structural issues which could prevent or restrict Manitoba Hydro's surplus power from reaching a competitive marketplace.

POTENTIAL IMPACT ON ACHIEVING CORPORATE OBJECTIVES:

The prime impact of restricted market access is reduced net revenue from the export power market. Similarly, the business case for building new hydro generation would also be at risk. Furthermore, changing market structure and access rules may require both legal and organizational change (e.g. adherence to reciprocity requirements of the export market).

RISK TREATMENT:

The Corporation, and when appropriate, in alliance with other industry participants such as the CEA, MISO, Transmission Owners, and other stakeholders, continues to lobby entities including MISO, IESO, AESO and FERC to develop market rules that support the elimination of barriers to trade and facilitate full participation by Canadian electrical energy producers within the US and Canadian markets. The Corporation has entered into a specialized agreement with MISO, which allows for the co-ordination and comparability in operations and tariffs, while minimizing impacts on corporate structure and maintaining Manitoba Hydro's sovereignty requirements.

Likelihood	High
Consequence	Med
Tolerance	Med

CATEGORY: A. Market

TITLE: 2.2 Export – Long Term Price Uncertainty

RISK: The average price received from future export sales may differ from forecast.

DESCRIPTION:

New technology, cost reductions or potential subsidies to various competing generation resources in Manitoba Hydro's export market may put downward pressure on the market price and result in reduced demand for the Corporation's export products.

This risk profile is related to J.1 Emerging Energy Technologies

POTENTIAL IMPACT ON ACHIEVING CORPORATE OBJECTIVES:

The impact of this risk is reduced net revenue from the export power market. Downward pressure on the market price will also negatively impact the business case for the advancement of new generation.

RISK TREATMENT:

By maintaining market intelligence associated with many factors, including resource plans in other jurisdictions and developments in technology, policy and market design, the Corporation ensures that business case analyses for the advancement of new generation or for new contracts reflect a reasonable range of possible pressures on market price.

The Corporation continues to promote waterpower as a clean, reliable and renewable source of electricity. By maintaining a positive image for its hydroelectric power, Manitoba Hydro's intention is to be seen as a responsible, competitive alternative to other renewable energy sources available in the market.

The Corporation advocates both within Canada and the US for equitable treatment for hydropower relative to other renewable sources and advocates hydropower's role in addressing climate change and air quality.
.

Likelihood	Low
Consequence	Med
Tolerance	Low

CATEGORY: A. Market

TITLE: 2.3 Export – Transmission Interconnection Capacity

RISK: Reduction in transmission interconnection capacity will reduce export revenue.

DESCRIPTION:

Maximizing export revenues and reducing import purchase costs is directly linked to available interconnection capacity and maintaining market access. Changes to reliability standards, public policy, infrastructure, load growth, and operating reserve requirements on the interconnected grid can lead to the degradation of available interconnection capacity over time. Reduced export capacity limits the volume of sales during high value times. Furthermore, limited export capability results in an increase in the volume of spilled energy during higher water years. Reduced import ratings would cause significant increased costs during low flow or high demand periods. Under these conditions, the Corporation would be forced to import energy during higher priced or on-peak periods.

Entities that influence this risk include NERC, IESO, HydroOne, SaskPower, MISO and other non-MISO Transmission Owners.

POTENTIAL IMPACT ON ACHIEVING CORPORATE OBJECTIVES:

A reduction in transmission interconnection capacity will decrease potential net revenue from the export power market.

RISK TREATMENT:

The Corporation endeavors to maintain a leadership role in and influence the policies and processes of the organizations and bodies in the USA involved with congestion management and regional transmission operations as well as those involved with transmission planning approvals. Manitoba Hydro staff also takes a leadership role in the activities associated with the formulation of transmission transfer limits for those facilities that affect Manitoba Hydro transfers with the USA. This activity occurs in a cooperative fashion (peer reviewed) with MISO and our tie line partners. Manitoba Hydro mitigates this risk by having skilled, knowledgeable staff representing the Corporation's interests at industry meetings.

In order to maximize transfer capability for commercial use, Manitoba Hydro participates in reserve sharing agreements (currently with MISO through its Coordination Agreement). The benefits of reserve sharing agreements to Manitoba Hydro include increased transmission and generator availability for commercial use.

Likelihood	Med
Consequence	M High
Tolerance	Low

CATEGORY: A. Market

TITLE: 2.4 Export – Special Interest Groups

RISK: Successful negative lobbying will result in reduced exports.

DESCRIPTION:

A positive corporate and product image enables the Corporation to maximize export sales opportunities and to develop generation and transmission projects required for both domestic needs and exports. Negative lobbying efforts by Special Interest Groups can tarnish the Corporation's image or the image of hydropower, limiting its marketability. Target groups of negative lobbying include [redacted] These Special Interest Groups can also intervene directly in capital and environmental regulatory processes (e.g. Clean Environment Commission).

Aspects of this risk profile parallel Achievement of Strategic and Operational Goals, Reputation / Image (G.1).

POTENTIAL IMPACT ON ACHIEVING CORPORATE OBJECTIVES:

Successful anti-hydro lobbying could result in fewer opportunities for long-term firm power sales or affect the price that can be obtained. Another example of a negative outcome would be the adoption of state implementation plans under the American Clean Power Plan that discriminate against Canadian hydro projects. Such discrimination could result in reduced net export revenues. In addition merchant plant decisions based upon the potential sale of firm power would be less attractive, with potential negative effects on any associated First Nation partnership (e.g. income sharing). If successful, regulatory and government approvals (e.g. environmental licences) required for export sales, generation and transmission initiatives could experience significant delays or even be denied.

RISK TREATMENT:

The Corporation continues to promote waterpower as clean, reliable and a renewable source of electricity. It engages with environmental, consumer and business stakeholder groups to discuss and promote its development plans. It is active directly and indirectly through industry groups such as CHA, IHA, and CEA and through hiring representative firms in the USA and Canada.

The Corporation aggressively counters Special Interest Group activities by sharing Manitoba Hydro's perspectives with government and community leaders, regulators, customers, industry associations, and business groups.

Likelihood	Low
Consequence	M High
Tolerance	Low

CATEGORY: A. Market

TITLE: 2.5 Export – Protectionism

RISK: Customer sentiment towards imports may negatively impact Manitoba Hydro's export sales.

DESCRIPTION:

Manitoba Hydro's energy competitors in the US may attempt to have limits or protective tariffs placed on imports of electricity from Canada for local economic benefit e.g. job creation. Alternatively, subsidies to US producers may add downward pressure on the market price.

POTENTIAL IMPACT ON ACHIEVING CORPORATE OBJECTIVES:

The impact of this risk would be reduced net revenue from export power sales. The business case for building new generation would also be at risk.

RISK TREATMENT:

The Corporation actively lobbies, in alliance with other Canadian industry representatives via trade organizations such as the Canadian Electricity Association as well as US federal and state governments and regulatory bodies for full and unfettered access by Canadian power producers to the US markets. In addition, Manitoba Hydro conforms to the same Standards of Conduct as American competitors to avoid accusations of unfair trade advantage.

The Corporation supports efforts to counter US federal and state legislation that would disadvantage Canadian producers through the CEA, direct lobbying of governments and if necessary, through legal (NAFTA) avenues. In addition, the Corporation engages the services of external legal and public relations entities to stay apprised of trends and legislative activities which might threaten its export activities in the US.

Manitoba Hydro actively participates in the development of market rules in MISO and Ontario through the stakeholder process and through its customers to ensure that market rules enhance or at the very least, do not discriminate against the Corporation's export activities in those jurisdictions.

Likelihood	High
Consequence	Low
Tolerance	Med

CATEGORY: B. Financial

TITLE: 1. Exchange

RISK: Fluctuations in foreign currency impact financial performance.

DESCRIPTION:

The risk of the potential for economic gain or loss due to foreign exchange movements for any transaction denominated in a currency other than Canadian (CAD) funds. This exposure is predominantly in United States dollars ('USD') resulting from U.S. electricity exports, electricity imports, and USD long-term debt.

POTENTIAL IMPACT ON ACHIEVING CORPORATE OBJECTIVES:

Manitoba Hydro has exposure to U.S. dollar foreign exchange rate fluctuations primarily through the sale and purchase of electricity in the U.S. and through borrowing in the U.S. markets.

In the current year's offset strategy, temporary fluctuations in net USD electricity exports create the risk of having a USD short or long position in which USD cash outflows will exceed or be less than USD cash inflows. These net short or long positions would be exposed to fluctuations in the USD/CAD exchange rate.

RISK TREATMENT:

Manitoba Hydro's exposures to foreign currency rate fluctuations are managed with the combination of natural and accounting hedges, along with applicable financial instruments. A natural hedge for USD is established by balancing USD cash inflows (primarily U.S. export revenues) and USD cash outflows (primarily U.S. debt coupon and principal payments). In order to bridge the actual timing of cash flows within a 12 month period, the Corporation may also execute applicable foreign currency financial instruments at appropriate times, such as spot, FX forward and FX swap transactions. As well, USD temporary investments and USD commercial paper can be utilized to bridge timing differences. Should the imbalance of USD inflows and USD outflows persist beyond the forecasted near term, Manitoba Hydro may adjust the volume of USD outflows; for example by issuing new USD long term debt to create USD coupon payments or by executing a cross-currency debt swap.

The Corporation has accounting cash flow hedging relationships between U.S. long-term debt balances and future U.S. export revenues as well as between U.S. interest payments on dual currency bonds and future U.S. export revenues. Accordingly, foreign exchange translation gains and losses for U.S. long-term debt obligations in effective hedging relationships with future export revenues are recorded in Other Comprehensive Income (OCI) until future hedged U.S. export revenues are realized, at which time the associated gains or losses in Accumulated OCI (AOCI) are recognized in net income.

Manitoba Hydro has conducted sensitivity analysis in IFF15 with respect to +/- $0.10 change in the USD/CAD exchange rate. As the incremental cumulative increase or decrease in retained earnings over a six year period to 2021/22 is only +/- $22 million, the Corporation's net exposure to USD/CAD currency fluctuations during this timeframe is largely eliminated.

Likelihood	Med
Consequence	Med
Tolerance	Med

CATEGORY: B. Financial

TITLE: 2. Interest Rates

RISK: Changes in interest rates impact financial performance.

DESCRIPTION:

Interest rate risk is the risk that the future cash flows will fluctuate due to changes in market interest rates. There are a number of forms of interest rate risk affecting the existing debt portfolio. Floating or variable rate debt is subject to interest rate reset risk during the life of the debt as the interest rate becomes adjusted at the periodic reset dates. Refinancing risk pertains to the interest rate exposure that exists upon refinancing a short or long term debt issue at its maturity. On a prospective basis, there is also interest rate risk on borrowings for new cash requirements.

POTENTIAL IMPACT ON ACHIEVING CORPORATE OBJECTIVES:

A one-percent increase in interest rates on Manitoba Hydro's existing floating rate and short term debt portfolio at March 31, 2015, offset by a change in the interest capitalization rate, would impact net income by approximately CAD $11.0 million (a 1% interest rate increase on a floating rate debt portfolio of $1.3 billion at March 31, 2015 is $13 million, less a $2 million offset from the change in the interest capitalization rate).

On a consolidated basis, risk sensitivity analysis in IFF15 shows that a +/- 1% change in interest rates may result in an incremental change to retained earnings of approximately $26 million to 2017/18. However, given the large size of the existing debt portfolio, as well as the need to add further debt to support the capital investments, the incremental change to 2024/25 arising from a +/- 1% change in interest rate rises is forecasted to be nearly $1 billion.

RISK TREATMENT:

Manitoba Hydro's interest rate policy on its existing debt portfolio is to limit the aggregate of: i) floating rate debt, ii) short term debt, and iii) fixed rate long term debt to be refinanced within the subsequent 12 month period; to a maximum of 35% of the total debt portfolio. Manitoba Hydro's interest rate risk guidelines for its existing debt portfolio include maintaining an aggregate of floating rate debt and short term debt within 15 – 25% of the total debt portfolio, and having the fixed rate long term debt to be refinanced within a 12 month period being less than 15% of the total debt portfolio.

Against the backdrop of unprecedented capital borrowing requirements and potentially rising interest rates, Manitoba Hydro is in a period of elevated sensitivity to interest rate changes. In order to mitigate this risk, the interest rate risk on the existing debt portfolio has been reduced by decreasing the percentage of floating rate debt within the existing debt portfolio and by selecting debt maturities, that upon refinancing will not compete with new borrowing requirements. Manitoba Hydro will continue to favor long term fixed rate financing at low interest rates.

Likelihood	Low
Consequence	Med
Tolerance	Med

CATEGORY: B. Financial

TITLE: 3. Credit

RISK: The Corporation is exposed to financial loss through credit default.

DESCRIPTION:

Credit risk is the risk that one party to a financial instrument will cause a financial loss to the other party by failing to discharge an obligation. Manitoba Hydro is exposed to credit risk related to sinking fund investments, short term investments and pension fund investments. Manitoba Hydro's gas and electric operations are exposed to credit risk related to domestic and export energy sales, and physical gas supply activities.

POTENTIAL IMPACT ON ACHIEVING CORPORATE OBJECTIVES:

Credit risk on sinking fund investments, short-term investments, and pension fund assets is minimized as the Corporation invests exclusively in government-guaranteed bonds, highly rated investments and well-diversified investment portfolios. The majority of the Corporation's accounts receivable is owed from domestic consumers who are in diversified industries. Credit risk exists from wholesale export power transactions with bilateral counterparties and within markets (ISOs).

During the period, total credit exposure due to export power transactions peaked at approximately $54 million in August. Export power bilateral transactions peaked at $39 million in August. On average, approximately 60% of the credit settlement exposure to bilateral counterparties each month is from Northern States Power (NSP). NSP had a peak credit settlement exposure of $24 million in August. Export market transactions peaked at $28 million in April.

Manitoba Hydro's accounts receivable for energy bills outstanding in excess of 60 days is approximately $16.9 million. Of this amount, $15.8 million relates to electric operations and $1.2 million to gas operations. For the electric operations $10.8 million is associated with amounts outstanding in Northern Manitoba.

Derivative instruments will no longer be used in the normal course to manage natural gas market price risk for the Fixed Rate Primary Gas Service. The Credit-Value-at-Risk limit for the gross provincial derivative exposure is $100 million per counterparty. The Province of Manitoba will act to mitigate Manitoba Hydro's risk exposure per counterparty in the context of the gross exposure per counterparty.

RISK TREATMENT:

Credit risk for physical gas supply counterparties and derivative counterparties is mitigated by establishing credit requirements, conducting standard credit reviews of all counterparties and setting and monitoring exposure limits for each of these counterparties. Financial security (letters of credit etc) and contract provisions are also in place to provide further credit risk mitigation. Credit risk resulting from export power transactions is mitigated by aligning credit limits with counterparty creditworthiness using approved credit policies and procedures. Counterparties are assigned unsecured or secured credit limits, based on generally accepted industry standards, which are monitored and reported on a regular basis. Credit risk for domestic energy sales is managed through various reporting, control and collection procedures for overdue accounts. In addition, Manitoba Hydro continues to negotiate with northern communities to resolve the outstanding accounts receivable balance in conjunction with mitigation issues. Manitoba Hydro's First Nation Accounts Department works with Manitoba's First Nation communities to establish manageable ways for the communities to get their accounts paid in full.

Likelihood	Med
Consequence	Low
Tolerance	Med

CATEGORY: B. Financial

TITLE: 4. Inflation

RISK: Increases in inflation rates result in cost increases which the Corporation is forced to recover through increases in domestic customer rates.

DESCRIPTION:

In addition to the capital costs associated with major capital projects, Manitoba Hydro expends approximately $2.0 billion annually for its routine ongoing operating and capital expenditures including fuel and power purchases. Inflationary increases to these costs result in higher costs to the Corporation. Prices charged for the sale of electricity and natural gas within Manitoba are subject to review and approval by the PUB. The Consumer Price Index (CPI) for Manitoba is often used by stakeholders as a benchmark to determine the reasonableness of proposed Manitoba Hydro general rate increases for electricity and for the non-commodity portion of natural gas rates. Manitoba Hydro uses projections of the U.S GDP implicit price deflator to forecast future electricity export prices in the opportunity market. Other, more specific, inflation indices are also used in purchasing and sales contracts negotiated by Manitoba Hydro. In addition to CPI, composite inflation indices associated with generation resources are developed and used to reflect the forecasted costs of specific commodities that are not included in the CPI basket of goods and services.

POTENTIAL IMPACT ON ACHIEVING CORPORATE OBJECTIVES:

The impact of a short duration period of inflation on the achievement of Manitoba Hydro's financial objectives and on the priority of providing excellent customer value which includes affordable rates for all Manitobans has historically been relatively small as a large portion of costs are capitalized, spreading the impact out over a longer period of time. However, as capital requirements grow for system improvements and expansion, the effects of sustained high inflation, especially with specific commodities associated with new generation or transmission construction, are more marked.. Moreover, as inflation changes, the monetary policy response from the Bank of Canada may result in impacts on Manitoba Hydro.

Current indications for Canada and the United States are that inflation expectations in the general economy are low and stable With respect to near-term outlooks of inflation for specific commodities that are significant inputs to Manitoba Hydro's capital projects, IHS Global Insight expects base metal prices to remain within a relatively tight range for the foreseeable future due to reduced demand. There has been a clear slowdown in metal and other commodity consumption growth in emerging economies such as Brazil, India, China and Indonesia and this slowdown has created an oversupply of steel products. IHS attributes the shift from strong economic activity in Asia to sluggish emerging-market demand growth and a tighter U.S. monetary policy that has weakened investor interest in commodities. In addition, sustained low oil prices over the past 18 months has caused activity in the Alberta oil sands to slow down resulting in a tempering of construction labour costs throughout western Canada. With that said, experience from the recent past has proven that sustained higher costs display resiliency to downward pressures such as reduced electricity consumption. Higher construction and operating costs driven by increases in aggregate demand both domestically and internationally may have substantial impacts on the costs and economic benefits of capital projects. Prolonged higher levels of inflation will begin to have a more significant impact if export prices do not reflect the same inflationary trends in concert with rising expenses and the costs of new plant coming into service. Inflation rates in Canada and in the US, the main export market, tend to follow similar long-run patterns, but can deviate in the short-term. Higher levels of inflation for Manitoba Hydro's costs which are not offset by similar increases in export revenues could place pressure on domestic rates for electricity and/or gas. Further, as inflation increases, there is also a risk that interest rates will be increased by the Bank of Canada, which can compound the effect cost increases will have on the Corporation.

RISK TREATMENT:

To the degree that export revenues rise as a result of corresponding increases in inflation in export markets, they can provide an offset to the higher costs of labour and materials. The Corporation's budgeting process typically imposes limits of inflation or less on baseline spending plans. With the continued downward pressure on export revenues, the Corporation has further implemented cost constraint measures. During the period of cost estimating and budgeting for major capital projects, the Corporation does not have an offset or hedge to manage the risks associated with increases in specific commodities which emphasize the need for continued cost constraint measures. Once the Corporation is in the process of negotiating contracts for major capital projects, mitigating accommodations such as including specific escalators can be incorporated. The future impacts on consumer rates due to higher capital costs will depend in part upon the long term price growth of energy exports.

Likelihood	Med
Consequence	Med
Tolerance	Med

CATEGORY: B. Financial

TITLE: 5. Upstream Gas Cost Uncertainty

RISK: A significant increase in the cost of natural gas could result in an adverse reaction from customers.

DESCRIPTION:

The cost of the physical natural gas commodity, transportation and underground gas storage represent approximately 60% of the Company's total overall annual natural gas revenue requirement in a normal weather year. Manitoba Hydro buys Primary Gas from the Western Canadian Sedimentary Basin ("WCSB") at a fairly constant level over the course of the year, with winter purchases flowing directly to customers, while a significant portion of summer purchases flow to storage. In the winter months, gas purchases flowing from the WCSB are supplemented by gas withdrawn and transported from storage. In addition, Supplemental Gas supplies are also purchased throughout the year for both immediate consumption in Manitoba and for replenishing storage inventories for use the following winter. The Corporation is currently prohibited by regulatory order from the PUB from hedging customers' exposure to volatile natural gas market prices.

POTENTIAL IMPACT ON ACHIEVING CORPORATE OBJECTIVES:

Financial - The financial exposure of significant gas cost increases to the Corporation is minimal as long as gas costs are considered to be prudently incurred. This is because the cost of gas for the quarterly rate primary gas service is considered a flow-through for rate-setting purposes and follows a prescribed regulatory process. There is some market price risk associated with the Fixed Rate Primary Gas Service whereby commodity gas is acquired at market prices while selling to customers at fixed rates for a given contract duration. If the self insurance premium imbedded in the fixed rate is insufficient and residual market price risks are not properly managed, there could be program losses.

Reputation – Although natural gas market price volatility has generally been greatly reduced during the past few years, there was a short term sharp increase in Supplemental Gas costs in the first quarter of 2014 due to the extreme cold winter and the need to purchase additional supply If the extreme upward price volatility experienced during this period continued or the 2000 through 2008 period were to return and continue, the Corporation could experience an adverse reaction from customers because of their exposure to a sharp increase in their cost of gas. In addition there continues to be significant upward cost pressure for transportation services on the TransCanada Pipelines Ltd. ("TCPL") Canadian Mainline, to which Centra is currently captive, due to underutilization of the pipeline. This market risk is compounded by a proposal by TCPL to segment the Mainline's cost allocation and tolls post – 2020 between the underutilized Western Mainline (on which Centra moves gas) and the highly utilized Eastern Ontario Triangle. The outcome is highly uncertain at this time however. The National Energy Board has approved segmentation in principle and intends to review it and other pricing issues in future proceedings.

RISK TREATMENT:

The Corporation has a number or risk measures in place to manage gas cost increases, including: (1) The Rate Volatility Management Program which includes setting quarterly Primary Gas rates based on the 12-month forward average of futures prices to remove seasonality from rates; disposing of Gas Purchase Variance Account ("PGVA") balances over the coming 12-month period; the physical price hedge provided by filling underground storage inventory during the seven-month summer period and then providing this gas to customers during the five winter months at a single average inventory value; and the management of all other non-Primary Gas PGVA's over the November through October gas year period to further reduce the rate volatility associated with bringing forward large residual balances for disposition in future periods. (2) Giving customers who are concerned about potential future rate volatility the option of either subscribing to MB Hydro's Fixed Rate Primary Gas Service ("FRPGS") or contracting for a fixed Primary Gas rate with a third-party marketer under the Western Transportation Service. (3) Mitigating market price risk associated with the Fixed Rate Program by charging an 8% self insurance risk premium in rates and establishing risk thresholds (customer migration, volumes, risk margins) that will trigger a review of the FRPGS program. (4) Providing all customers, whether on the Corporation's default Primary Gas rate, or on a fixed Primary Gas rate under either the FRPGS or with a marketer, with the option to fix the amount of their overall monthly natural gas bill by enrolling in the Equal Payment Plan. (5) Participate in TCPL's. regulatory proceedings before the National Energy Board ("NEB") as appropriate in order to ensure that Manitoba natural gas consumers' interests are adequately represented., as occurred at the NEB RH-001-2014 proceeding.

Likelihood	Low
Consequence	Low
Tolerance	Med

CATEGORY: B. Financial

TITLE: 6. Gas Derivative Instruments

RISK: By their nature, derivatives have various risks (e.g. Regulatory, market, operational) associated with them which must be managed.

DESCRIPTION:

Manitoba Hydro utilized financial gas derivatives to manage market price associated with the Fixed Rate Primary Gas Service from the inception of the program until August, 2011. Changes to the program were approved by the PUB whereby derivatives will not be used in the normal course and a self insurance premium will be employed to manage market price risk. There are however some derivative positions outstanding that will not fully expire until 2016.

POTENTIAL IMPACT ON ACHIEVING CORPORATE OBJECTIVES

The Corporation continues to be exposed to the risk of financial losses for outstanding positions in cases where market prices fell significantly after the placement of past hedges in support of FRPGS offerings and customer demand for those offerings was materially less than that forecast. This could result in excess out-of-the-money hedges on unsubscribed volumes having to be written off against Manitoba Hydro's retained earnings. The key operational risk borne by the Corporation with respect to gas hedging activities relates to the execution of the hedge purchase transactions. Similarly, if credit limits are not established and managed, and the appropriate legal documentation is not put into place, a credit default could give rise to a financial loss. Credit risks must be identified, measured and managed.

RISK TREATMENT:

The Gas Supply Risk Management Committee in coordination with the Executive Committee has oversight over all derivative related transactions and practices. A well structured control framework continues to be in place; however no further derivative transactions will be entered into in the normal course and the exposure to current derivatives is low.

Likelihood	High
Consequence	M High
Tolerance	Med

CATEGORY: B. Financial

TITLE: 7. Financial Targets

RISK: Weak financial ratios may impede the opportunity to adequately address aging infrastructure and invest in new major generation and transmission.

DESCRIPTION:

The Corporation is subject to increased risk if it fails to maintain an adequate capital structure. This is defined, under revised financial targets approved in December 2015, as maintaining a minimum debt/equity ratio of 75:25, an annual Earnings Before Interest, Taxes and Depreciation and Amortization (EBITDA) interest coverage ratio with a minimum target of 1.80 and a capital coverage ratio (excluding major new generation and transmission) of greater than 1.20. It is recognized that financial targets may not be achieved during years of major investment in the generation and transmission system.

The current 20-year Integrated Financial Forecast (IFF15) projects that the equity ratio deteriorates to 12% by 2021/22, largely due to capital investments in generation, transmission and distribution, as well as softened export market prices before recovering to the target 25% by 2031/32. Reduced income levels also weaken the interest coverage below the 1.80 target for a period of 9 years until income levels are sufficient for the target to be met in the remaining years of the forecast as a result of the 3.95% even annual rate increases and additional export revenues following the in-service of Keeyask. Capital coverage is below target for the first 6 years of IFF15 due to capital requirements to replace aging infrastructure and address capacity constraints. Thereafter, cash flows are sufficient to enable this target to be met in the remaining years of the forecast.

Manitoba Hydro is prepared to accept weaker financial ratios during the period of significant capital investment in order to spread the recovery of costs from customers over a longer period of time and minimize the impacts to customer bills. However, it will be necessary for Manitoba Hydro to demonstrate progress towards attaining its financial targets to credit rating agencies and other stakeholders over the long-term.

POTENTIAL IMPACT ON ACHIEVING CORPORATE OBJECTIVES:

An inadequate capital structure could jeopardize the self-supporting naturkae of Manitoba Hydro's debt and negatively impact the credit ratings of the Province. As well, an inadequate capital structure could lead to the need for higher rate increases and volatility in rates.

RISK TREATMENT:

The risk of an inadequate capital structure is mitigated by: (1) formally adopting and periodically updating appropriate financial targets such as the debt/equity ratio, interest coverage and capital coverage; (2) making annual contributions to retained earnings sufficient to maintain these targets; and (3) achieving these annual contributions through a combination of cost controls, export revenues and regular reasonable domestic rate increases even in years with favourable water conditions. The latter is necessary, recognizing the unpredictability and potentially severe impacts of individual drought years.

Likelihood	High
Consequence	Low
Tolerance	Med

CATEGORY: B. Financial

TITLE: 8. Energy / Fuel Price Volatility

RISK: Market energy / fuel prices are high when Manitoba Hydro requires additional energy supply or low in adverse economic cycles resulting in low export prices.

DESCRIPTION:

Manitoba Hydro is subject to significant price risk on power sales and power and gas purchases as a result of energy price volatility. Recent history has demonstrated that energy prices in the short term are volatile. There is a risk that the price of purchased energy and natural gas will be high due to energy price and/or due to limitations in the mid-western United States transmission system (i.e. congestion). The impact of the energy price volatility is the greatest in a drought where under lowest flow conditions the Corporation may have to generate about 3 million MWh from gas-fired generation and purchase in excess of 7 million MWh from the market. Conversely, even under more favourable water flow conditions, opportunity sales revenues may be lower than forecast because of lower opportunity prices due to factors such as adverse economic conditions and / or low fuel prices. Such economic cycles may last several years and could result in lower than forecast revenues. This risk profile is related to Commodity Availability (C.5) and Water Supply Variation/ Drought (C.1)

POTENTIAL IMPACT ON ACHIEVING CORPORATE OBJECTIVES:

While there is no risk of a significant drought in the current year, Manitoba Hydro continues to experience lower than forecast export prices that despite favourable water conditions, is resulting in a significant reduction in revenues compared to previous long term export revenue forecasts. It is very difficult to hedge the price risk for opportunity energy on a long-term basis due to the uncertainty as to whether this energy will be available in any given year.

The risk resulting from high fuel / purchased energy prices would significantly reduce the Corporation's ability to maintain stable rates for Manitoba customers were it to materialize during severe drought. Maximum exposure to this risk occurs during the winter demand period when gas-fired generation is required to meet peak loads and year round during drought conditions when gas-fired generation is required for energy supply. The risk from low prices for opportunity export energy would reduce Manitoba Hydro's equity compared to forecast and could result in rate increases.

Should a severe drought occur in 2015/16, the Corporation is exposed to a risk from energy price volatility estimated to be on the order of $200 million per year should fuel prices double compared to the prices assumed in the IFF. This $200 million figure is on top of reduced revenue of $300 million at expected export prices due to reduced flows in a severe one year drought. Past volatility in natural gas prices indicates that a doubling of gas prices compared to forecast is quite possible, but given the current supply situation appears to be unlikely in the near term. The overall cost of a drought has been reduced significantly since 2008/09 as a result of the economic decline and low natural gas prices.

RISK TREATMENT:

The Corporation's strategy in managing risk due to an adverse cycle of low export prices is largely based on having sufficient retained earnings. A number of changes in the power and energy market design over the last 10 years have improved the market liquidity and helped to reduce Manitoba Hydro's exposure to short-term energy price volatility and congestion pricing. The creation of an open, competitive market in the US has resulted in mechanisms for financial settlement, financial transmission rights and the use of brokers, which allow Manitoba Hydro to obtain more competitive pricing on imports. Since the 2003/04 drought, Manitoba Hydro has also secured almost 100% of the firm import transmission from the US, which will allow Manitoba Hydro to import power with lower risk of curtailment while not exposing Manitoba Hydro to non-competitive pricing for the use of another party's firm transmission. One objective of Manitoba Hydro's export strategy is to maintain a diverse portfolio of export products to mitigate exposure to price volatility.

Likelihood	Low
Consequence	Low
Tolerance	Low

CATEGORY: B. Financial

TITLE: 9. Power Financial Instruments

RISK: By their nature, financial instruments have various risks associated with them which must be managed.

DESCRIPTION:

Manitoba Hydro participates in the MISO and IESO standard markets. Prior to the advent of these standard markets, all of Manitoba Hydro's export sales and purchases were executed via physical bilateral transactions with inter-connected customers and utilities. With the introduction of these markets, Manitoba Hydro gained the capability to utilize financial instruments to settle contracts and hedge physical flow. Approved financial instruments are: (1) Contracts for Differences and/or Swaps (including MISO FinScheds); (2) MISO Auction Revenue Rights (ARRs) MISO Financial Transmission Rights (FTRs) or IESO Transmission Rights (TRs); (3) Virtual Bids and Virtual Offers; and (4) Put and Call Options for electricity and natural gas.

POTENTIAL IMPACT ON ACHIEVING CORPORATE OBJECTIVES:

Inappropriate use of financial instruments would expose Manitoba Hydro to costs beyond those necessary for the prudent management of its assets or load obligations.

RISK TREATMENT:

Manitoba Hydro has a Board approved Wholesale Export Power Policy that governs Manitoba Hydro's export market activities including the use of financial instruments. In addition an Export Power Risk Management Committee provides executive oversight of the management of the energy supply and financial risks as a result of Manitoba Hydro's participation in the export market. In addition, a management committee approves bid/offer strategies and oversees all major transactions.

The Wholesale Export Power Policy governs the use of all financial instruments related to the purchase or sale of power/natural gas. The Approval Authority for Wholesale Power Related Transactions (P190-1) sets out volume limits, approval and execution authorities and limits by transaction type in accordance with the Wholesale Export Power Policy. Front, middle and back office duties are segregated. Manitoba Hydro uses a state-of-the-art trading, scheduling, billing and settlement system to record all physical and financial transactions.

Manitoba Hydro ensures that appropriate master agreements are in place to govern all financial instrument transactions.

As per the Wholesale Export Power Policy and the Approval Authority for Wholesale Power Related Procedures, financial instruments are required to have a high level of certainty that they will be backed by energy supplies at the time the contract is entered or the transaction is executed. This restriction ensures that financial instruments are supported by Manitoba Hydro's underlying physical power position and that financial instruments are not utilized in a speculative manner.

Likelihood	Med
Consequence	M High
Tolerance	Low

CATEGORY: B. Financial

TITLE: 10. Liquidity

RISK: Having sufficient cash or cash equivalents to meet financial obligations as they come due.

DESCRIPTION:

Liquidity risk refers to the risk that Manitoba Hydro will not have sufficient cash or cash equivalents to meet its financial obligations as they come due. Liquidity risk can generally be subdivided into two categories: 1) operational liquidity risk and 2) market liquidity risk.

Operational liquidity risk arising from the availability of internally generated cash flow from operations is most pronounced for Manitoba Hydro during drought conditions as cash shortfalls occur.

Market liquidity risk has become elevated due to the high levels of required debt financing and evolving investor responses to changing financial market conditions. During 2015, issuance was characterized by periods of volatility and uneven market tone.

POTENTIAL IMPACT ON ACHIEVING CORPORATE OBJECTIVES:

Liquidity challenges arising from cash shortfalls would have potentially significant business and reputational consequences.

RISK TREATMENT:

The Corporation closely monitors its cash receipts and disbursements on a daily basis as part of regular cash balancing activities, and also monitors short term debt balances and forecasted cash requirements.

To support the Corporation's temporary cash requirements, the Manitoba Hydro Act grants the Corporation the power to issue short term borrowings in the name of the Manitoba Hydro-Electric Board up to a limit of $500 million and to have this debt unconditionally guaranteed as to principal and interest by the Province of Manitoba. With the high levels of Manitoba Hydro's cash requirements in the next few years, this short term facility provides less than two months of cash requirements.

To ensure smooth business continuity and financing flexibility during periods of intensive capital expenditures and uneven market tone, Manitoba Hydro has expanded its practice of maintaining positive cash balances. Manitoba Hydro's liquidity guideline is to be funded approximately three months in advance of the Corporation's cash requirements. Sinking fund balances, used to accumulate cash to repay future debt maturities, are another source of cash but are a restricted source of liquidity as the balances can only be withdrawn for debt maturities. In the next few years, in order to optimize the Corporation's liquidity practices and to reduce finance expense, Manitoba Hydro will seek to minimize its sinking fund balances where feasible.

Likelihood	High
Consequence	High
Tolerance	Med

CATEGORY: C. Environmental

TITLE: 1. Water Supply Variation / Drought

RISK: Reduced water supply impacts generation output

DESCRIPTION:

Variation in water (fuel) supply is a fundamental characteristic of a predominately hydro system. Actual annual hydraulic generation will vary from the long term average of all flow conditions assumed in the planning process with lower than average flows occurring approximately 40% of the time. Reduced water supply has a direct financial impact through reduced hydro generation and in turn reduced export revenues and/or the need for more expensive replacement of supply

Water Supply Variation/Drought risk is defined as a change in revenue due to deviations from average flows, under expected export market prices. The overall cost of a drought to the Corporation is a combination of this Water Supply Variation/Drought risk (i.e. volumetric risk) and the Short-Term Energy Price Volatility / Fuel Price Volatility (B.8). The possibility of a drought more severe than the drought of record is discussed in Extreme Drought-Shortfall of Energy Supply (D.2).

POTENTIAL IMPACT ON ACHIEVING CORPORATE OBJECTIVES:

Reduced water supplies impact the Corporation's ability to maximize net export revenues and maintain the projected electricity rates for Manitoba customers. The severity of impacts ranges from relatively modest costs due to subtle change in the timing of inflows, up to extreme financial losses as a result of a multi-year drought. The lost revenue due to a five year drought at expected export prices was estimated to be $1.9 billion (IFF 15) including financing costs. Risk due to Energy / Fuel Price Volatility (B.8) would be in addition to this amount.

Regulation changes that limit hydraulic operating flexibility may reduce dependable energy and, consequently, reduce net export revenue and add costs due to advancement of the in-service date for new generation. Similar effects may be realized if regulation changes upstream of Manitoba or climate change impacts alter the timing or supply of flows entering the province.

RISK TREATMENT:

The Corporation intends to have adequate retained earnings to protect against a repeat of the worst recorded drought. In addition, the Corporation constantly monitors supply conditions, updates inflow forecasts, and reviews long-term weather forecasts.

At least quarterly, the Export Power Risk Management Committee (EPRMC) reviews a quantitative assessment of the current water supply conditions and any potential financial impacts resulting from variations in market prices and water supplies including the consequences of extreme drought. During periods of increased risk, the EPRMC increases the frequency of its meetings to review and approve risk tolerances, risk mitigation strategies and significant operational decisions. The Manitoba Hydro Electric Board is also kept updated in periods of increased drought risk. Energy purchase decisions are timed and distributed appropriately to protect against price risk of electricity purchases. To protect against gas price risk, purchases are structured such that a portion of the gas needs are purchased in advance, with the option to take, store or sell the fuel.

Likelihood	Low
Consequence	M High
Tolerance	Low

CATEGORY: C. Environmental

TITLE: 2. Climate Change

RISK: A changing climate can impact hydro-electric generation, Manitoba load and export revenues.

DESCRIPTION:

There is a risk that climate change impacts could result in reduced overall hydroelectric production due to lower annual runoff, changes to the variability of the water supply, and/or extreme flooding. There is also a financial risk that climate change will increase temperatures in Manitoba which will result in increased air conditioning loads in the summer and reduced heating loads in the winter and thereby displace export sales and potentially reduce overall revenues.

POTENTIAL IMPACT ON ACHIEVING CORPORATE OBJECTIVES:

Reduced hydroelectric generation would lead to a reduction in overall energy supplies to meet firm load and reduced surplus energy available for export resulting in lower export revenues to the Corporation. Extreme flooding would increase spilling at the generating stations and raise challenges for the operation which could lead to loss of potential energy supplies.

An increase in average temperature due to climate change has the potential to increase cooling loads in the summer and reduce heating loads in the winter. Increased summer loads will potentially displace on-peak export sales. Reduced heating loads in the winter will increase on-peak and off-peak export sales which will offset some of the revenue losses in the summer. In addition, reduced winter loads could delay the in-service date of future generation options if the requirement for new resources is driven by a shortage of winter peak capacity.

RISK TREATMENT:

Manitoba Hydro is currently engaged in understanding climate change processes and is actively pursuing studies to develop future climate change scenarios for its power system. These climate scenarios are being developed by using the direct outputs from an ensemble of international Global/Regional Climate Models and by using post-treatment methods to scale the information to match Manitoba Hydro's hydraulic system. These climate scenarios can then be used in combination with hydrological and load forecast models to develop an ensemble of future conditions, which can be tested in Manitoba Hydro's generation system models as a step towards reducing the uncertainties regarding future water supply, power demands and corporate finances.

Manitoba Hydro collaborates with a number of national and international bodies involved in climate change including the Ouranos Consortium, University of Manitoba, and the Center for Energy Advancement through Technological Innovation to ensure its studies meet the industry standards and to stay informed about the latest advances in the climate change field. Manitoba Hydro expects to have sufficient lead time to adapt its operations and resource plans to accommodate long-term impacts of climate change.

Likelihood	Low
Consequence	High
Tolerance	Med

CATEGORY: C. Environment

TITLE: 3. Operational Impact and Infrastructure

RISK: Environmental concerns real or perceived can negatively impact corporate operations.

DESCRIPTION:

The Corporation operates its existing electricity supply facilities and systems on a continuous basis to meet the energy needs of its customers. While the Corporation goal is to minimize operational impacts on the environment there still remains a certain amount of negative impact. The principal risks the Corporation is faced with are interruption of operations, and/or, restrictions on how operations are carried out. These risks arise as a result of pressure from changes in stakeholder sentiment, changes to licences and/or legislation and high profile noncompliance(s) and/or environmentally damaging event(s).

POTENTIAL IMPACT ON ACHIEVING CORPORATE OBJECTIVES:

The implications of imposed restrictions on facility and system operations can vary considerably and if significant could ultimately impact the operations of the Corporation. These restrictions could impact hydraulic/thermal generating facilities, water management programs, transmission facilities and distribution infrastructure. These restrictions could impact the costs/revenues of the Corporation and force future domestic rates to increase.

RISK TREATMENT:

Manitoba Hydro utilizes many different types of controls and tools to manage the environmental risk to its operations and infrastructure. These include but are not limited to:

- Management and staff whose primary responsibility is to help address environmental issues and risks that the Corporation is facing.
- An ISO 14001 registered Environmental Management Systems covering all corporate activities.
- Agreements with stakeholders suffering adverse affects from some of the Corporation's developments.
- Identification of and responsiveness to stakeholder concerns.
- Water regime monitoring and communication with affected communities about forecasted water regimes.
- Conducting environmental research and monitoring programs that address societal expectations and meet corporate environmental management practices.
- Shaping and responding to public policy and keeping abreast of and influencing regulatory and licence changes.
- Continuously improving and implementing best management practices to anticipate and address environmental concerns.
- The development and implementation of Corporate policies and procedures intended to address environmental concerns
- Training of staff whose jobs may result in impacts to the environment.
- Emergency prevention and response planning.

Likelihood	Low
Consequence	High
Tolerance	Med

CATEGORY: C. Environment

TITLE: 3. Operational Impact and Infrastructure

SUBTITLE: 1. Legal - Species at Risk Act (SARA)

RISK: If Lake Sturgeon is listed as "Endangered" the Corporation could face restrictions on current operations, structural modifications to infrastructure, significant delays and high costs of development at Keeyask , and possible cancellation of new projects.

DESCRIPTION:

Almost all of the Corporation's hydroelectric generating stations are located where Lake Sturgeon are found. It is likely that at most generating sites infrastructure and operations have negatively affected the fish and/or their habitat to some degree. Due primarily to historical commercial overharvest, plus additional stressors including hydroelectric development and ongoing Indigenous domestic harvest, Lake Sturgeon populations have been severely depleted over the past 100 years and the species is currently under review for listing as endangered under the Species at Risk Act (SARA) at most locations in Manitoba. Decisions for Churchill River, Nelson River, Saskatchewan River, Winnipeg River, Red-Assiniboine Rivers and Lake Winnipeg populations are expected in early 2018, at the earliest.

If listed under the SARA, harm to individual fish will automatically be prohibited and protection of critical habitat will be required, once it is identified. The Corporation will immediately be at risk of non-compliance with the SARA at most of its facilities due to ongoing risk of harm to individual fish as they pass through facilities. The most likely protection measures that would be required by DFO are fish screens, provisions for upstream fish passage and flow modifications at existing generating stations. There would also be a possibility that the commissioning of Keeyask would be delayed while incidental take permits are secured. There could also be high costs for recovery measures potentially mandated under the SARA.

POTENTIAL IMPACT ON ACHIEVING CORPORATE OBJECTIVES:

Affects: (1) The revenues the Corporation will receive from existing operations; (2) The ability to build future projects and meet future requirements for electricity supply; (3) The goal to strengthen working relationships with Indigenous peoples; and (4) The goal to maintain financial strength. It could entail increased mitigation costs to Manitoba Hydro and its First Nations partners on Keeyask (and potentially Conawapa were it to proceed), although it is expected that these would not be sufficient to make the project uneconomic.

RISK TREATMENT:

The Corporation is proactive in addressing this risk by: (1) Conducting a Lake Sturgeon Stewardship and Enhancement Program to assist in recovery of the species., (2) Negotiating and implementing a Memorandum of Understanding on Lake Sturgeon with the Manitoba Government to guide cooperation on Lake Sturgeon stewardship and research in the province. (3) Regular coordination with the Manitoba Department of Conservation and Water Stewardship (Fisheries Branch (4) Regular communication with staff from DFO to keep them informed about Manitoba Hydro's approach to Lake Sturgeon stewardship, current activities, progress and outcomes. (5) Establishing a process with DFO and MCWS for negotiating a Lake Sturgeon Conservation Agreement under the SARA, (6) Working with the CHA and CEA in pursuing changes to the SARA and/or its implementation (7) Informing newly elected Manitoba Members of Parliament, who will be involved in the listing decision, that the social and economic costs and risks of listing Lake Sturgeon far outweigh any potential benefits and is not needed to provide stewardship necessary for Lake Sturgeon recovery. (8) Encouraging the Province to continue to take action with the DFO (9) Expanding its long-term commitment to the recovery of the species through the membership in, and funding for the Kischi Sipi Namao (formerly the Lower Nelson River Sturgeon Stewardship Committee) (10)Working to establish Lake Sturgeon stewardship arrangements for the lower Churchill River.

Likelihood	Med
Consequence	M High
Tolerance	Low

--

CATEGORY: C. Environmental

TITLE: 4. Reliability of Supply

RISK: On-going public scrutiny and further environmental licencing regulatory oversight could obstruct the Corporation's ability to build the necessary facilities required to provide a reliable supply of energy in a timely and cost effective manner.

.

DESCRIPTION:

Concerns over the environment will influence the Corporation's future facility requirements by either placing highly restrictive conditions on their operations, altering the design specifications, delaying or ultimately denying their construction.

The environmental review process could result in excessive time and cost that would result in the commissioning of facilities well after their required in service dates. Time delays will expose the system to increased reliability issues.

POTENTIAL IMPACT ON ACHIEVING CORPORATE OBJECTIVES:

This risk will cause the system reliability to degrade by delaying project in-service dates, thus causing more service interruptions. The Corporation will face increased costs to satisfy these environmental concerns as more costly alternatives and mitigation measures will be required to meet these higher standards.

RISK TREATMENT:

The Corporation is proactive in addressing this risk by:

- Ensuring environmental implications of its actions are understood.
- Possessing the knowledge and skills to make the right decision that minimizes the environmental impact of these facilities.
- Being proactive in the sharing of information with stakeholders
- Increasing dialogue with government early on and throughout the process
- Promoting efficient use of resources.

Likelihood	Low
Consequence	M High
Tolerance	Low

CATEGORY: C. Environmental

TITLE: 5. Upstream Regulation and Water Withdrawals

RISK: Upstream regulation, water withdrawals or climate change may reduce water supplies and hydraulic generation.

DESCRIPTION:

Reduced water supply is a fundamental risk to the financial position of the Corporation. The peril associated with this risk is that future water supplies are on average lower as a result of upstream reservoir regulation changes and water diversions for irrigation or other purposes. Water supply may also be reduced as a result of climate change.

This risk profile is related to risk profile C.2 Climate Change.

POTENTIAL IMPACT ON ACHIEVING CORPORATE OBJECTIVES:

Upstream regulation that affects the timing of inflows and diversion or extraction of water for irrigation or other purposes can limit the Corporation's ability to generate hydroelectric energy thereby increasing operating costs and reducing net revenues. Climate change may also cause similar effects if the consequence is reduced water flows or changes in the timing of flows that result in negative consequences for hydroelectric generation. In addition, these events can make the development of new hydraulic generation less economic and cause the advancement of future generation in-service dates.

RISK TREATMENT:

Since the upstream regulation is often influenced by outside entities such as Canadian Provincial and Federal Government, U.S. State and Federal Government, and other water resource management entities, Manitoba Hydro participates in providing input, where possible, to these entities. Manitoba Hydro participates in the Lake of the Woods Control Board process and can influence decisions of the Prairie Provinces Water Board. Manitoba Hydro is also a member of the Canadian Hydropower Association and participates in other organizations that have hydroelectric affiliations that can lead to discussions and cooperation.

The Corporation maintains a record of long-term streamflow data from 1912 to present which has been modified to reflect current use patterns accounting for increased consumption and regulation strategy changes upstream. This record is used for resource planning purposes. Manitoba Hydro is also engaged in developing an understanding of the potential impacts on water supply due to climate change in its watersheds. This activity is described in more detail in risk profile C.2 Climate Change.

Likelihood	Low
Consequence	High
Tolerance	Low

CATEGORY: D. Infrastructure

TITLE: 1. Loss of Plant (all property, all perils)

RISK: Loss of plant can affect the Corporation's finances, reputation and impact human life.

DESCRIPTION:

The Corporation is subject to a variety of scenarios whereby physical plant is exposed to loss. The types of value exposed to loss include property, net income, liability and personnel. Loss from a property value perspective includes equipment breakdown, loss of facility, dam failure, and other property damage.

POTENTIAL IMPACT ON ACHIEVING CORPORATE OBJECTIVES:

Potential impact from a loss of plant infrastructure will affect the Corporation's ability to: continuously improve safety performance, provide excellent customer service from a reliability perspective, maintain our financial strength due to reduced revenues and increased costs, and maximize export power net revenues due to reduced availability.

RISK TREATMENT:

A risk management decision-making process is used to manage each exposure (identify exposure, examining feasibility of alternative techniques, selecting best technique, implement and monitor chosen techniques). Equipment failure, for example, is identified at the department level. Alternative techniques to deal with exposure include preventative maintenance (loss prevention), Reliability Centered Maintenance (RCM) and loss reduction (fire sprinkler systems, fire brigades). Alternative techniques to finance the property loss include risk retention and commercial insurance. Equipment failure from a net income exposure to loss is recognized at the department level and alternative risk control techniques are used such as spare equipment, replacement contracts for equipment or replacement energy.

The loss of a facility from a property value aspect is identified at the division/department level. Perils are identified and treatment determined. Risk control techniques include loss prevention and loss reduction. Examples include fire and wind resistive construction materials, smoke and heat detection units, and automatic sprinkler protection, dyking and other measures. Property insurance is purchased to finance losses to high valued locations. The loss of a facility from a net income exposure aspect is identified at the corporate/division level. Loss prevention and reduction control techniques includes duplication and segregation of exposure units, automatic sprinkler systems, emergency response plans and replacement contracts. The Corporation retains the risk financing cost of net income losses resulting from the loss of a facility.

The impact of loss of a facility from the perspective of safety and customer service is identified at the corporate/division level. Loss prevention and reduction control techniques in place to mitigate other impacts are also designed to mitigate the impact on safety and customer service. Techniques include duplication and segregation of exposure units, emergency response plans, automatic sprinkler systems, and replacement contracts.

Likelihood	Low
Consequence	High
Tolerance	Low

CATEGORY: D. Infrastructure

TITLE: 1. Loss of Plant

SUBTITLE: 1. Water Retaining Structures and Flow Control

RISK: The failure of water retaining structures could have impacts which range from insignificant to catastrophic, and could include loss of life, financial/economic costs, damage to the environment, and loss of system reliability, reputation, public confidence and heritage resources.

DESCRIPTION:

Manitoba Hydro operates 17 major facilities for hydro power generation and water storage, comprising an inventory of some 220 individual dams and dykes with a net asset value exceeding $4 billion and an installed generating capacity of approximately 5000 MW. The facilities were designed to meet established standards at the time of their construction and are systematically maintained and upgraded to ensure they meet current standards and operate safely. The facilities are the major source of system supply for Manitoba Hydro.

Water retaining structures are vulnerable to different "failure modes" including external erosion (wave attack), internal erosion (piping), sliding or overturning, inability to pass sufficient water during floods resulting in overtopping of water retaining structures, or inability to pass sufficient water due to spillway equipment failure or personnel errors resulting in overtopping of water retaining structures. Terrorism is also a recognized risk to the safety of water retaining structures. Each facility's location, its proximity to other Manitoba Hydro facilities, the closeness of human settlement and environmental factors are some of the major considerations determining the extent of impacts of a dam or dyke failure. Water retaining structure failures cannot generally be controlled once they are initiated and mitigation/remediation is only feasible once flows have abated following the flood event or once the forebay has emptied. Hence, downstream effects and damage can be catastrophic.

POTENTIAL IMPACT ON ACHIEVING CORPORATE OBJECTIVES:

Possible consequences include loss of life, financial/economic costs, environmental damages, reduced system reliability (worst case scenario is a maximum loss of over 70% of Manitoba Hydro's generating capacity for years), and loss of reputation and public confidence.

RISK TREATMENT:

The risk of dam breach is addressed by ensuring the integrity and reliability of water control equipment and structures through diligent maintenance and vigilant surveillance, as well as preparing for emergencies, as per the Canadian Dam Association (CDA) Dam Safety Guidelines. The Corporation has established a Dam Safety Program based on the CDA Dam Safety Guidelines. The principal activities for managing risks include:

- Surveillance inspections, instrumentation monitoring, and engineering analyses of water retaining structures and related flow control equipment within a consequence category framework.
- Systematic utilization of failure modes-based condition assessment techniques.
- Preparation, maintenance, training and testing of Emergency Preparedness Plans (EPPs).
- Periodic Dam Safety Reviews by independent consultants to examine the adequacy of the design, construction, operation, maintenance, surveillance, and emergency preparedness plans

Water retaining structures and flow control equipment are designed and assessed according to the CDA Guidelines and maintenance programs address dam safety deficiencies of existing in a prioritized manner. Operating guidelines for each facility are established with inherent dam safety considerations.

Likelihood	Low
Consequence	High
Tolerance	Low

CATEGORY: D. Infrastructure

TITLE: 2. Extreme Drought – Shortfall of Energy Supply

RISK: Extreme drought with a severity worse than the drought of record has the potential to cause a shortfall in energy supply.

DESCRIPTION:

The Corporation's generation and transmission facilities are designed and operated to ensure firm demand can be supplied given a repeat of the lowest river flows since 1912. Since the Manitoba Hydro system is comprised primarily of hydroelectric resources, the design criterion translates into a requirement for power resources that will be able to supply sufficient energy under the condition of a repeat of the lowest river flows on record. In the circumstance of an extreme drought that is more severe than the worst on record, there is the possibility of insufficient energy supplies being available to meet firm load demands, which will in addition, result in extreme financial and reputational impacts to the Corporation. This risk profile is related to risk profiles Energy / Fuel Price Volatility (B.8) and Water Supply / Drought (C.1).

POTENTIAL IMPACT ON ACHIEVING CORPORATE OBJECTIVES:

The peril of an extreme drought, one that is more severe than the worst on record of approximately 100 years, may limit the Corporation's ability to provide dependable power to its customers especially those served under long term export contracts. There is the potential that some portion of the firm domestic load would have to be curtailed through enforced conservation. In addition to service limitations, there would be severe financial impacts to the Corporation in excess of those estimated for the worst drought on record (ref. profiles C.5, B.8 and C.1). Financial impacts would extend to the Corporation's domestic customers through rate increases and the Province by requiring debt financing.

RISK TREATMENT:

Water flows worse than the drought of record would be deemed to be a force majeure event under Manitoba Hydro's long term export contracts. Therefore to the extent that Manitoba Hydro needed to curtail export deliveries to serve domestic load, Manitoba Hydro anticipates that it would have the right to curtail without penalty. To the extent that these actions were insufficient and domestic energy shortages were occurring in spite of maximum imports, partial curtailment of domestic load may be required.

Non-normal hydraulic operations could also be required during a drought more severe than the drought of record. This may include operating reservoirs outside of the normal range for power production. For example, the Lake Winnipeg Regulation Water Power Licence provides for operation below the minimum level for power production limit with approval from the Minister of Conservation. Non-normal operation may also include demand reduction measures such as public appeal for conservation, enforced conservation or rotating reductions of non-essential load (e.g. street lighting). To better quantify this risk, the Corporation has participated in a number of research initiatives, using both statistical techniques and techniques that employ indicators of past extremes such as tree-rings and lake sediments. Both initiatives are aimed at defining the probability of recurrence of the worst drought on record and the likelihood of more extreme drought events. However, the results of these research initiatives to date have not been able to provide definitive conclusions on the probability of drought. The best estimate is that the Manitoba Hydro system is designed for a 1 in 100 year drought event based on the fact that the design condition occurred once in the last 100 years of record.

Likelihood	Low
Consequence	High
Tolerance	Low

CATEGORY: D. Infrastructure

TITLE: 3. Prolonged Loss of System Supply

RISK: The Corporation is exposed to a catastrophic event resulting in prolonged loss of system supply and therefore not able to meet its energy supply requirements.

DESCRIPTION:

System Blackout due to the loss of key infrastructure, specifically: Dorsey Converter station or HVDC corridor and 500 kV line.. Reason for loss could be severe weather events such as tornado/downburst (Dorsey 1996, Elie 2007), wide front wind, combined wind and icing, lightning (Dorsey August 2007), sabotage, flood or fire.

POTENTIAL IMPACT ON ACHIEVING CORPORATE OBJECTIVES:

Key potential impacts of a prolonged loss of system supply are:

- Unable to serve Manitoba load continuously (approximately 42% of the time based on 2013 calendar year loading profile). Depending on time of day and time of year, a deficiency of up to 1550 MWs resulting in rotating blackouts throughout the province. Deficiency increases with time due to load growth and assumes the availability of maximum energy imports from neighboring regions.
- Severely impact business operations and the Manitoba economy.
- Unable to provide customers with exceptional value due to high infrastructure replacement costs.
- Threat to public safety due to an inability to supply energy needs during the coldest months of the year.
- Prolonged rolling blackouts affecting customer service and potentially damaging corporate assets such as breakers.
- Potentially weaken the Corporation's financial strength due to reduced revenues from domestic and export energy sales, and increased costs for infrastructure replacement and the purchase of import energy.
- Loss of reputation as a dependable source of supply in the export market.
- Potential political and legal consequences for the Corporation.

RISK TREATMENT:

Key risk treatment activities are:

- System expansion involving Bipole III (2018) re and a new 500 kV Interconnection to the U.S (2020)
- Additional AC network generation (Keeyask 2019)
- Hardening of Dorsey facilities
- Implementation of physical and cyber security upgrades
- Emergency Preparedness initiatives - Long term deficiency plan for managing the available resources, load and system following loss of infrastructure.
- Spare infrastructure material and equipment inventory to enable timely re-building and restoration of potentially affected assets.
- Short term emergency energy agreements with Ontario, Saskatchewan and U.S. utilities
- Mutual aid agreements with Ontario, SaskPower and U.S. utilities for labour, materials, and equipment.
- Corporate Emergency Response Program.

Likelihood	Med
Consequence	Med
Tolerance	Low

CATEGORY: D. Infrastructure

TITLE: 4. System Shutdown (Short Term)

RISK: The Corporation is vulnerable to an event(s) that would cause a short term loss of system supply (electricity) resulting in the inability to meet its energy supplies requirements**.**

DESCRIPTION:

Partial or total system blackout for 8 hours or as long as several days, caused by extreme weather events, sabotage, human error, equipment failure, or an inability to import energy from the market.

POTENTIAL IMPACT ON ACHIEVING CORPORATE OBJECTIVES:

- Unable to meet customer load serving obligations and expectations.
- Threat to public safety due to inability to supply energy needs.
- Threat to Corporate reputation.

RISK TREATMENT:

- System expansion involving Bipole III (2018), an additional 500 kV interconnection to the US (2020), St. Vital – LaVerendrye 230kV transmission line (2021), and AC breaker enhancement projects (2016-2018).
- Additional AC network generation (Keeyask 2019)
- Standard Operating Practice agreements with Ontario and SaskPower for short term emergency energy.
- Restoration Plan, which includes local station restoration procedures (with/without communications) and restoration diagrams, that identify step by step restoration procedures.
- Annual participation in MISO's regional restoration drills and the development of its regional restoration plans.
- Semi-annual restoration training for System Operators.
- Annual restoration training for field staff.
- Disturbance Scenario training, such as annual ice melt training for System Operators.
- Station battery bank upgrade program.
- Regular testing of regional staffing plans that supports System Control Centre operation upon the loss of RTU communications.
- Annual black start testing at each black start facility.
- Compliance with NERC reliability standards
- Redundant communication systems (PAX, VHF, MSAT) in addition to the public telephone system.
- Storm tracker application and installed ice detection stations in ice prone areas of the province.
- Corporate Emergency Response Program.
- Actively participate and provide leadership in Congestion Management forums to exert influence on parties, such as MISO and other Congestion Process Management Council members, to ensure fair treatment of Manitoba Hydro in the formulation of industry congestion management practices.

Likelihood	Low
Consequence	High
Tolerance	Low

CATEGORY: D. Infrastructure

TITLE: 5. System Shutdown (Natural Gas)

RISK: Catastrophic system failure could result in an interruption of the supply of natural gas to approximately 267,000 customers in Manitoba. An associated risk is the impact on the electrical grid due to increased loading.

DESCRIPTION:

A secure and continuous supply of natural gas is critical, particularly during the coldest months of the year. TransCanada Pipelines ("TCPL") has five high-pressure lines entering Manitoba (with a couple of sections looped making some areas six lines on its Canadian Mainline. Manitoba Hydro's meter stations are tied into two of these five lines. At Ile des Chenes, MB (Station 41 on the Mainline), three pipes divert south to Emerson through which gas interconnects with Great Lakes Gas Transmission Company and Viking Gas Transmission Company in the U.S. The three remaining pipes continue through Manitoba in an eastward direction into Northern Ontario. Separate from TCPL and on a much smaller scale, Manitoba Hydro also relies on the TransGas Limited ("TransGas) and Many Islands Pipe Lines (Canada) Limited ("MIPL") systems for delivery of natural gas supply to the Swan Valley area of the province. Gas supply to the Swan Valley area of MH's distribution system via MIPL is from the TransGas system in Saskatchewan. Gas from one or more of three storage caverns in Melville, Regina and Moosomin can deliver gas that will flow to the Swan Valley area, depending upon the requirements and operations of the TransGas system.

POTENTIAL IMPACT ON ACHIEVING CORPORATE OBJECTIVES:

A catastrophic event could occur, resulting in a total or partial loss of supply of natural gas from the Mainline, TransGas or MIPL to the respective service areas of Manitoba for a period of four to six weeks. The potential impact could be significant. Manitoba natural gas customers could be left without natural gas for heating purposes, resulting in significant collateral damage. As well, an inordinate number of workers would need to visit each and every home at least two times before service could be restored. Gas supply connections would first have to be shut-off at all homes and then the homes would have to be entered when the lines are re-energized to ensure the appliances are re-lit and working properly. There could be substantial economic losses for customers and businesses arising from such a catastrophic event.

RISK TREATMENT:

TCPL has incorporated design practices to minimize the possibility of a catastrophic event occurring. While their large diameter, high pressure pipelines are all contained within the same right-of-way, there is physical separation between the pipes. The failure of any one segment of pipe is likely to have limited impact on the system. This design practice has proven to be effective during the course of several incidents over the past decade with the exception of the 2014 rupture of one of the Emerson laterals of the Mainline near Otterburne MB, which resulted in a loss of service to a number of communities in the south-east corner of the province.

In addition, TCPL has developed and employs a rigorous safety and inspection program. Regulatory oversight is provided by the National Energy Board. MIPL relies on a single pipeline and therefore does not have the same level of redundancy built into its system as the Mainline. MIPL does, however, employ a rigorous safety and inspection program. Regulatory oversight for MIPL is provided by the NEB.

As a result of the 2014 Mainline rupture, Manitoba Hydro has determined that Compressed Natural Gas should be used to help mitigate small scale outages during a natural gas supply interruption. For the 2015-2016 season, standby services have been retained from a supplier who has the proven capability and availability to supply requirements during a supply interruption for small scale outages. For the longer term CNG equipment and facilities are being purchased and constructed. The equipment being purchased will consist of two 170 mcf CNG trailers (capable of supplying small communities or critical loads), a decanting unit for off loading the CNG and a compressor station to allow for refilling the units locally.

An emerging risk in the coming years relating to the TCPL Mainline is that of the potential for significantly reduced physical redundancy and excess capacity on the prairies segment of the Mainline. TCPL appears to be taking steps to prepare for the decommissioning of two of the six lines currently running through Manitoba. In addition, TCPL plans to convert a third line to oil transportation as part of its Energy East project proposal. If these changes are undertaken, natural gas transportation capacity and redundancy on the TCPL Mainline will be reduced by approximately 50% relative to today.

Likelihood	Low
Consequence	Med
Tolerance	Low

CATEGORY: D. Infrastructure

TITLE: 6. Technology

RISK: Unforeseen physical events could impact computer operations and this would affect business processes.

DESCRIPTION:

The Corporation develops, implements and manages information systems to support core business processes and provides a secure, stable computing infrastructure to support non core business processes.

Manitoba Hydro's Corporate IT environment is housed in 2 data centres, one located at 820 Taylor, one located at 360 Portage.

The factors that could lead to a loss of all or part of our computing environments are either physical such as fire, flood, HVAC or power failure, and major weather related disasters or human in nature resulting in sabotage to key IT system components. Specifically, Manitoba Hydro has no diesel backup for the 820 Taylor Data Centre.

POTENTIAL IMPACT ON ACHIEVING CORPORATE OBJECTIVES:

The extended loss of Manitoba Hydro's computing environment may limit the Corporation's ability to provide customers with exceptional value (rates, service, public safety, reliability and power quality). A physical-event of significance could negatively impact all Hydro systems, with the exception of Energy Trading and the EMS/SCADA systems.

RISK TREATMENT:

Physical risks have been mitigated through the utilization of multiple computing facilities interconnected with high-speed data lines to reduce the risk of the failure of a single data centre. Improved data backup, recovery, and restore procedures have also mitigated risk. The two Winnipeg Computing centres are equipped with fire protection systems and are secured from unauthorized access. IT Services continues to work with Facilities, System Control and Station Design to investigate the costs and options of using the existing Diesel at 700 Harrow.

An initiative to formalize and harmonize the disaster recovery plans for key Information Technology Infrastructure components and Information Systems is currently underway.

A Corporate IT Security Assessment was done in 2014 on key IT functions and operations. It identified security gaps, level of risk and recommended mitigating actions to be undertaken.

Likelihood	Med
Consequence	M High
Tolerance	Low

CATEGORY: D. Infrastructure

TITLE: 7. Concerned Stakeholders

RISK: Successful lobbying efforts by concerned stakeholders could restrict implementation of the Corporation's infrastructure requirements.

DESCRIPTION:

Increased concerns voiced publically (directly or through media) may influence regulatory bodies and Governments to place restrictions on and in some cases deny the infrastructure needs of the Corporation. As well, the review process over new facilities could become excessive in regards to time and cost due to the intervention of these stakeholders. This could result in commissioning of facilities after their required in-service dates.

POTENTIAL IMPACT ON ACHIEVING CORPORATE OBJECTIVES:

Successful lobbying efforts by concerned stakeholders could result in adverse impacts on the infrastructure needs of the Corporation. These impacts could be financial and system operational and may ultimately have a negative effect on the Corporation's image, on degrading the reliability of supply from Transmission systems, and the ability to satisfy export sales agreements.

The impact of lobbying on higher profile projects such as BiPole III where delays have been imposed on the project and a resultant negative impact to reliability of supply to southern Manitoba is recognized. Lobbying also has an impact on other projects and some examples include Kilkenny Drive, Sage Creek, and now the Manitoba Minnesota Transmission Project (MMTP). In the instance of Kilkenny Drive, local lobbying resulted in delays on a subtransmission line that was required for reliability of supply. In the instance of Sage Creek, local residents raised concerns about a future Manitoba Hydro facility planned in a Manitoba Hydro owned right-of-way, which resulted in changes to the project. In both examples, local residents were objecting to Manitoba Hydro facilities being developed in their neighbourhoods. With respect to MMTP lobbying by various stakeholders could result in relocation of parts of the project, extra expense, and/or project delays.

RISK TREATMENT:

The Corporation addresses the concerns of stakeholders, where feasible, through mitigation measures. Manitoba Hydro encourages stakeholder participation in its projects early in the process which permits the identification of concerns and provides the opportunity to mitigate these concerns before they become larger issues.

Likelihood	Low
Consequence	M High
Tolerance	Low

CATEGORY: D. Infrastructure

TITLE: 8. Emergency Management Program

RISK: The Corporation is exposed to a catastrophic event, likely weather induced, that results in an extended outage of the electric and natural gas infrastructure with a limited ability to restore damaged infrastructure.

.

DESCRIPTION:

System failure caused by an extended severe weather event similar to an ice storm challenges the Corporation's ability to respond and to maintain a minimum continuity of business operations

POTENTIAL IMPACT ON ACHIEVING CORPORATE OBJECTIVES:

In today's interconnected world, all institutions depend on others to perform their daily activities. Manitoba Hydro provides essential services and has critical functions that must be maintained in the face of disruptions, emergencies, and catastrophic events

Since the creation of the Corporate Emergency Management Program in 2008, Manitoba Hydro has responded to many large scale power and natural gas outages. Manitoba Hydro infrastructure continues to be impacted by natural, manmade, accidental and deliberate events.

.

RISK TREATMENT:

Manitoba Hydro revised the Emergency Preparedness Policy in 2015 to enhance and strengthen the Corporate Emergency Management Program. Also, the Executive Emergency Management Committee was created to provide oversight of the program and to directly support the Corporate Emergency Center during an event. Manitoba Hydro continues to develop and maintain emergency preparedness and response management plans for reasonably foreseeable emergencies and risks arising from natural or man-made events that pose a real or potential threat to:

- the safety and health of employees, contractors, and the general public
- the physical assets of the Corporation and related environmental protection
- the ability to generate, transmit and distribute electricity and distribute natural gas and provide related services, and
- the ability of the Corporation to continue business in the normal course

Likelihood	Low
Consequence	High
Tolerance	Low

CATEGORY: E. Human

TITLE: 1. Safety and Health

RISK: An accident will occur that will result in loss of life or significant injury.

DESCRIPTION:

Due to the inherent nature of the operational work performed by Manitoba Hydro employee safety is always of key concern to the Corporation. Beyond the human suffering element, are the tangible and intangible costs of incidents to the Corporation for compensation and benefits, lost productivity, loss of equipment, loss of revenue, and loss of public confidence.

POTENTIAL IMPACT ON ACHIEVING CORPORATE OBJECTIVES:

Safety is the Corporation's principal goal. As such, safety is reflected in the Corporate Strategic Plan to ensure the Corporation has measures that safeguard the safety and health of Manitoba Hydro employees. The Corporation is focused on activities that promote accountability, safety and health leadership, safe work practices, strict compliance with environmental regulations, and preservation of employee health. These programs are put in place to reduce risk to a tolerable level and address any potential risk to the operations side of the business.

RISK TREATMENT:

The opportunity for an incident in the workplace is high. The Corporation has built upon the recommendations of the 2006 and 2015 Safety Improvement Process Teams to further address workplace risk and to change the safety culture to positively affect the resulting safety performance of Manitoba Hydro.

Significant changes planned for the 2015/16 year include: (1) Implementing a seven point safety enhancement strategy which includes annual executive site safety reviews; in-person reporting of serious incidents at EC meetings, and a modified safety stand downs as examples; (2) Developing corporate programs with an internal Rapid Response Team on Safe Driving, Close Call Reporting, and Human Error Reduction; (3) Promoting Manitoba Hydro's safety culture through research and recommend a strategy for a safety branding, marketing, promotion and recognition program; (4) Moving the Corporation beyond compliance by forming a new high performance Risk Prevention Services team (under Workplace Safety) dedicated to working with line management to proactively identify and eliminate risk; a forensic audit of operations/incidents with the intent to define improvement opportunities; and benchmark to industry standards for safety assessments of operations; (5) Implement a SAP Environmental Health & Safety module to address technical currency issues with the data management surrounding hazardous materials, as well as streamline and enhance the processes involved with incident management, analysis and reporting; (6) Managing Contractor Safety by revising contractor safety guidelines and incorporating the guidelines into the procurement tendering process to further development the contractor safety model; (7) Developing a program to identify arc flash and clothing ignition hazards and tasks and ensure that proper communication (including labeling of equipment) and protective measures are in place throughout the Corporation; (8) Safe Work Procedures program enhancement to ensure that employees have the safe work procedures that they need to assist in planning of work, reduce incidents and increase legal compliance with MR217; (9) Updating Safety Publications; and (10) Medical Screening improvements in the hiring process to analyze, evaluate, and modify current health evaluation steps in hiring process to ensure potential employees are fit for the work, reducing potential for on-the-job injuries.

Manitoba Hydro's international operations in developing countries exposes employees and their families to increased risk of disease, crime, or injuries from political, ethnic or religious conflict. A number of measures are taken to mitigate these risks, including providing employees with medical advice and medi-vac transportation, specialized location security advice, secure accommodations and having emergency response and evacuation plans.

Likelihood	Low
Consequence	M High
Tolerance	Low

CATEGORY: E. Human

TITLE: 1. Safety and Health

SUBTITLE: 1. Infectious Disease

RISK: A significant disease outbreak will impact a large number of employees resulting in major disruptions to business operations.

DESCRIPTION:

In response to the influenza A, H1N1 (Swine Flu) outbreak in April 2009 and the World Health Organization setting the pandemic alert level globally to phase six, Manitoba Hydro formed a task force on H1N1 to address the impact an infectious outbreak would have on the Corporation. The June 2014 outbreak of the Ebola virus in West Africa also had the potential to directly impact Manitoba Hydro's operations, as a number of Hydro employees seconded to the subsidiary company Manitoba Hydro International were working in West Africa at the time.

POTENTIAL IMPACT ON ACHIEVING CORPORATE OBJECTIVES:

While neither the H1N1 nor Ebola situations resulted in large scale outbreaks in North America, the impact of such a pandemic could be significant. There are predictions that suggest that up to 35% of the population could be impacted by the next global pandemic, or over 2,000 Hydro employees.

It is expected that a pandemic will result in significant and prolonged shortages with regard to the availability of employees, supplies and services. This may be enough to possibly compromise Manitoba Hydro's ability to provide safe, reliable service to customers. These impacts could further result in financial losses as revenues diminish putting added pressure on business operations. The inability to respond to system outages and customer requests could further impact the Corporations reputation. In addition, if the Corporation is unable to meet its export commitments, the utility could face potential liabilities.

RISK TREATMENT:

A pandemic is much more than just a problem for the health care system. It is a societal problem and is best managed by the coordinated participation and cooperation of governments, businesses, organizations and citizens. All parties need to be prepared for the potential outbreak of a pandemic. Manitoba Hydro monitors Health Canada briefings and directives, along with announcements from the World Health Organization (WHO) and local health publications. Employees that returned from West Africa were instructed by Hydro's Occupational Health Nurse to see their local doctor and report any symptoms.

Likelihood	Low
Consequence	Med
Tolerance	Low

CATEGORY: E. Human

TITLE: 2. Union/Employee Issues

RISK: Employee and union demands may not be satisfied which could result in inability to attract and retain skilled workers and / or possible labour disruption.

DESCRIPTION:

Interaction between the Corporation and its unions remain positive and co-operative. The IBEW collective agreement expired on December 31, 2015. A new three year renewal agreement negotiated between the Corporation and IBEW was ratified by the IBEW membership in early January.

POTENTIAL IMPACT ON ACHIEVING CORPORATE OBJECTIVES:

Employee and union demands may not be satisfied which could result in strained relationships and potential strike.

RISK TREATMENT:

Minor issues and disputes arising during the year are resolved through informal discussions, or occasionally via the grievance and arbitration process.

A comprehensive bargaining framework has been developed that includes an early start to the process and agreement to limit the number of issues at the table.

Likelihood	Low
Consequence	M High
Tolerance	Low

CATEGORY: E. Human

TITLE: 3. Workforce Management

RISK: The Corporation will not be able to attract and retain the necessary qualified workforce to meet its operational needs.

DESCRIPTION:

The electricity and gas industry will be facing significant labour force challenges in the years ahead. For Manitoba Hydro, the workforce will be impacted by the following factors: retirements; new requirements resulting from major construction and technology changes; and, a changing labour market. Retirement will have the most significant impact on Manitoba Hydro's human resource requirements due to the movement of the large cohort of "Baby Boomer" employees into retirement. Retirements have shifted from a long-term average of approximately 80 employees per year to a new long-term average of approximately 190 per year. Approximately 1000 employees are expected to leave within five years.

Voluntary resignations at Manitoba Hydro are still fairly low (< 1% of the workforce annually) when compared to the industry average (>2%). More recently, as a result of our demographic shift and cyclical economic conditions, voluntary resignations have risen over the last two years (>1%).Despite Manitoba Hydro's low rate of attrition, utilities across Canada are experiencing the same Baby Boomer retirement phenomena. Manitoba Hydro employees possess skill, education and experience valuable to other utilities. The need to retain knowledge and ensure the right employees are ready to fill key positions at Manitoba Hydro is essential for long term success.

POTENTIAL IMPACT ON ACHIEVING CORPORATE OBJECTIVES:

A loss of knowledgeable and experienced employees has significant effects on all the areas of the Corporation including reduced reliability, increased cost of production, infrastructure project delays and decreased safety and productivity. By way of example, a reduced skill base in Major Capital Projects or Transmission would negatively impact the Corporation's ability to plan, construct, commission and put into service the significant projects currently underway. In the Gas Supply area, capacity management and gas supply strategies would be impaired as it could diminish Manitoba Hydro's ability to deliver reliable, safe, sustainable and competitively priced gas.

RISK TREATMENT:

To ensure knowledge retention and transfer and the supply of qualified candidates, the completion and maintenance of detailed succession plans for all key strategic and critical positions is necessary. The Corporation has implemented a comprehensive executive and senior management succession planning program including the identification of key positions and high potential employees. In addition, the Corporation is conducting succession planning at lower levels in order to identify high potential candidates earlier.

Manitoba Hydro continuously updates retirement forecasts and recruitment plans. This provides the multiple benefit of an accurate corporate-wide forecast of recruitment needs, the ability to respond to changing labour market conditions and the integration of this information into related financial forecasts and budgets. The Corporation has undertaken a more systematic approach to workforce planning and its ability to respond to the changing internal and external workforce environment. Training programs continue to be deployed to existing staff resulting in the development and improvement of technical skills in key areas. This assists in providing an adequate supply of qualified internal applicants to fill most vacancies. In addition, individual development is a priority for all staff through the completion of personal development plans on an annual basis. Although recent resignation rates at Manitoba Hydro have increased they still remain below normal rates however we continue to monitor departures and conduct exit interviews to collect information and make recommendations to address any concerns identified by departing individuals.

Likelihood	Med
Consequence	Low
Tolerance	Low

CATEGORY: E. Human

TITLE: 4. Technology

RISK: The rapid change in technology and work requirements may present challenges to system reliability, safety or productivity.

DESCRIPTION:

The pace of change in the workforce has never been as rapid as it is today with new technologies being developed that require staff to study and assess these technological changes and their usefulness within the current business and energy systems. This situation is further compounded by maintaining systems that are older which require appropriate interfaces with these new technologies and having fewer capable resources to analyze their impacts on the Corporation's present systems. The demographics of the workforce suggest that this risk will only increase in the future.

POTENTIAL IMPACT ON ACHIEVING CORPORATE OBJECTIVES:

The Corporation's energy systems are both reliable and safe and its business systems are effective in meeting the Corporation's present day requirements. However, it is also important to adapt to technological advances that are required to meet changing conditions. It is conceivable that decisions or the lack of a decision in the future could reduce system reliability, safety or productivity.

RISK TREATMENT:

Manitoba Hydro has a research and development program that will help meet the needs of its business and operations, using both internal and external personnel and facilities. The primary thrust of this program will be the creation of new or significantly improved products and processes so as to obtain operational and economic benefits that will increase efficiency, reduce costs and improve the quality of service to the Corporation's customers.

The Corporation supports research and development projects carried out by students at Manitoba universities. The Corporation also supports research chairs, in collaboration with other industrial partners and with the Natural Sciences and Engineering Council (NSERC), or equivalent funding agencies at Manitoba universities, where the area of research is of direct and continuing interest to the Corporation.

New technologies are assessed to determine whether they will meet the further anticipated needs of the Corporation and detailed studies are performed when significant changes are planned so that negative outcomes are minimized. The current wind integration project which assesses the impacts of various levels of wind generation on system operations is an example of these types of studies.

All staff are encouraged to maintain their professional standards which includes keeping abreast of changes occurring within their discipline.

Likelihood	Low
Consequence	Low
Tolerance	Low

CATEGORY: F. Business Operational

TITLE: I. Supply Chain

RISK: Goods and services may not be available when required resulting in potential reliability issues, major delays, disruptions or complete loss of service to customers.

DESCRIPTION:

Managing the Supply Chain ensures the supply of goods and services are obtained in order to maintain and upgrade the current infrastructure and capital project work. The supply chain is critical in maintaining service to customers. Manitoba Hydro is dependent upon a variety of suppliers. Market trends impact the economical and financial aspects of business and the ability of suppliers to provide required goods and services on a timely basis.

The risk to Manitoba Hydro includes:

- Increased costs and lead-times due to supplier capacity, quality of workmanship and the global demand for raw materials and finished products,
- A limited diversity of supply due to company mergers, acquisitions or insolvency and a shortage of skilled labour in some trades,
- Loss and / or inability to restore service to customers due to poor supplier delivery, availability or quality of workmanship.
- Public perception and financial implications related to fraud, corruption and unethical business transactions stemming from tendering/contracting processes.

POTENTIAL IMPACT ON ACHIEVING CORPORATE OBJECTIVES:

A disruption in the supply chain impacts a majority of Manitoba Hydro's strategic goals and objectives. The Corporation requires a variety of critical goods and services to meet its obligations and commitments. An effective supply chain contributes to the Corporation's financial strength through cost minimization, planned upgrades and maintenance and the reduction in the downtime of our major assets.

Although the market has improved, the demand for construction services, particularly skilled labour, in some trades, is still a concern. In addition, recent tenders for construction have resulted in higher levels of participation, however in some cases tenders have exceeded budget estimates.

[redacted] Lead time is approximately 18 months and growing. Equipment failure may result in an extended period of reduced transmission capability of northern generation.

RISK TREATMENT:

The supply chain will continue to be managed by monitoring all market trends, identifying critical products and services, sourcing Strategic Alliance Partners, evaluating and tracking vendor performance, performing reference checks and validating vendor credentials, reducing single sources of supply, maintaining optimum inventories and identifying alternate sources of supply in case of emergency.

Likelihood	Low
Consequence	M High
Tolerance	Low

CATEGORY: F. Business Operational

TITLE: 2. Operational Controls

RISK: Unexpected operational outcomes adversely impact the Corporation's performance.

DESCRIPTION:

The Corporation has defined a vision, mission, operating principles and goals that are supported by measures, targets and strategies to direct corporate efforts toward common strategic achievements. The only manner in which the Corporation can be certain that its efforts are intended to result in a preferred outcome is to ensure that adequate controls are built into its processes. All efforts to direct, promote, restrain, govern and check progress can be described as a control. Where an operation is subject to adequate control, the odds of a positive outcome are enhanced. Where inadequate control is practiced, the result is less certain to be as intended. Where operational controls are ineffective the chance of the Corporation achieving its vision, or a subcomponent thereof, is reduced. Some of the types of operational risks that the Corporation faces include ineffective and inefficient operations, unreliable reporting and modeling systems and technology, non-compliance with applicable laws, regulations and internal policies, inability to attract and retain knowledgeable human resources and inadequate maintenance and replacement of infrastructure, to name a few.

POTENTIAL IMPACT ON ACHIEVING CORPORATE OBJECTIVES

The essential purpose of operational control is to encourage the accomplishment of the goals or objectives for which each employee or manager is responsible. Ineffective operational control increases the likelihood of an adverse outcome which could mean that a goal or objective is not met. The potential impacts of ineffective operational control are many and varied. They can range from infrastructure failure due to ineffective maintenance programs or systems to fraudulent activity to lawsuits and jail.

RISK TREATMENT

The governance process designed by the Corporation has objectives inclusive of promoting appropriate ethics and values; ensuring effective organizational performance management and accountability; effectively communicating risk and control information to appropriate responsibility areas; and effectively coordinating the activities of and communicating information among the Board, external and internal auditors, and management. This framework has been adopted with the intention of ensuring reliability and integrity of financial and operational information; effectiveness and efficiency of operations; adequate safeguarding of assets; and compliance with laws, regulations and contracts. The design of operational controls rests with line management. The effectiveness of control systems are subject to ongoing monitoring through the corporate governance process (inclusive of various committees, regulatory review, the Board, etc.) and are tested through an internal audit program and an annual external attestation audit. The Internal Audit Division Charter has been approved by the Audit Committee of the Board as is the annual audit program. Line management also engages consultants and experts as deemed appropriate to aid in the design of operational control systems and practices as well as to test the effectiveness of the implemented design. The Corporation also has an integrity program which complies with the requirements of the Provincial Whistleblowing legislation. The program provides a mechanism for anyone to report a situation in which operational controls are not functioning at any level.

Likelihood	Low
Consequence	M High
Tolerance	Low

CATEGORY: F. Business Operational

TITLE: 2. Operational Controls

SUBTITLE: 1. Cyber-Security

RISK: Cyber Security incidents that could result in the theft of information and / or the disruption or misuse of critical operations / assets

DESCRIPTION:

The growth of electronic communication and automation, while delivering significant benefits, has also increased risk to the Corporation. This risk includes any cyber attack that could impact the resiliency, reliability, confidentiality, availability or the integrity of Manitoba Hydro information and \operational technology assets, including the theft of personal and or business information, and or the disruption/misuse of critical operations/assets. Any computer or control system if not secured properly may be considered a potential target.

POTENTIAL IMPACT ON ACHIEVING CORPORATE OBJECTIVES

These cyber attacks could have a significant impact on Manitoba Hydro operationally and financially, and may have a rippling effect on the Manitoba economy.

RISK TREATMENT

Countermeasures, management controls and processes are in place to mitigate this risk. The Corporation is has implemented a series of measures to further augment cyber-security efforts consistent with recommendations of the Office of the Auditor General. Concurrently, to meet current NERC security standards Manitoba Hydro has also undertaken several projects targeted at increasing safeguards over critical cyber assets.

Ongoing assessment and enhanced mitigation strategies are required as the sophistication of external cyber threats increases, and as more computer and control systems are inter-connected. The Enterprise Security Council comprised of senior executives provides oversight for all aspects of physical and technology security including NERC related projects and the implementation of the Auditor General's eight recommendations, of which four have now been completed.

To protect Manitoba Hydro's information technology environment an advanced corporate firewall is in place to protect the data network. Additionally, anti-virus software and security patches are closely monitored and updated immediately to prevent data corruption. The Corporation is finalizing the implementation of a Security Information & Event Management (SIEM) tool to further raise the level of protection. It will be fully operational by spring, 2016.

The Industrial Data Network has measures of protection and is being assessed to identify any required actions necessary to raise the levels of protection.

Likelihood	Med
Consequence	M High
Tolerance	Low

CATEGORY: G. Reputation

TITLE: 1. Reputation

RISK: The occurrence of a negatively public perceived event which receives significant attention and affects the Corporation's operations in a significant negative manner.

DESCRIPTION:

Reputation risk exposes Manitoba Hydro's ability to achieve its overall strategic and operational goals in an effective and efficient manner.

The impacts of reputation cover a broad range of activities at Manitoba Hydro and include many significant initiatives, including:

- Obtaining approvals and constructing new generating stations, both hydraulic and other types;
- Renewing licences (e.g. Lake Winnipeg Regulation, Churchill River Diversion, and various generating stations);
- Obtaining approvals and constructing new transmission lines and maintaining existing transmission lines;
- Extending export opportunities and protecting access to export markets;
- Maintaining market share in the domestic retail natural gas market;
- Receiving favorable regulatory (e.g. PUB) approvals;
- International operations in developing countries and emerging economies where corrupt or unethical practices are common to varying degrees, and
- Other activities.

POTENTIAL IMPACT ON ACHIEVING CORPORATE OBJECTIVES:

The significance of the impact varies depending on the strategic or operational goal, however the impact can range from having insignificant costs to significant costs (e.g. the potential impact can result in the Corporation not achieving its strategic goals or achieving significant objectives such as constructing a new generating station or a major transmission line). As a publicly owned entity, Manitoba Hydro cannot under any circumstances operate outside the laws of Canada, internationally accepted standards of conduct, or the laws of the countries in which it does business.

RISK TREATMENT:

To support fulfillment of its mandate, Manitoba Hydro has identified key areas of focus which are directly related to enhancing its Corporate reputation including:

- Customer Value
- Indigenous Relations
- Financial Strength
- Protect the Environment
- Demand Side Management

Manitoba Hydro has developed and is undertaking a range of comprehensive communication actions to protect and enhance its reputation to secure trust in its ability to serve customer energy needs and gain acceptance for corporate activities. This includes effective engagement with stakeholders.

For all domestic and international operations, the Corporation requires that employees are aware of and comply with all applicable laws, regulations, standards of conduct and policies.

Likelihood	Low
Consequence	High
Tolerance	Low

CATEGORY: H. Governance / Regulatory / Legal

TITLE: 1. Regulation and Licencing

RISK: The Corporation could face regulatory and licencing issues that restrict its operations.

DESCRIPTION:

The Corporation requires a variety of regulatory approvals and licences to carry out its activities. Key approvals and licences include those issued under the National Energy Board Act, Water Power Act and Environment Act either to build new generation and transmission facilities or to maintain the operation of existing facilities.

There are two significant issues currently facing the Corporation that could have significant impact on operations and reputation if they are not addressed. These are the risk of Lake Sturgeon being listed as endangered under the Species at Risk Act (see risk profile C.3.1) and addressing environmental and societal impacts and expectations for legacy facilities. Specifically the Clean Environmental Commission (CEC) made a non-licencing recommendation that both the Province and Manitoba Hydro conduct a Regional Cumulative Environmental Effects Assessment (RCEEA) of all Manitoba Hydro projects in the lower Nelson River sub-basin before any more projects are licenced for construction. In the recently completed Lake Winnipeg Regulation (LWR) Final Licence hearing the CEC went even further and recommended that all legacy hydro projects in the Province should be licenced under the Environment Act.

POTENTIAL IMPACT ON ACHIEVING CORPORATE OBJECTIVES:

Failure to obtain approvals and licences on favourable terms or in a timely fashion could have significant financial, operating and water regime impacts, increasing costs, and reducing hydraulic generation, capacity and export sales. Expiration of a licence without renewal will expose the Corporation to embarrassment and loss of reputation. Although highly unlikely, cancelation of a licence could expose the Corporation to the possibility that a third party could acquire the water power rights at a location and potentially the loss of the asset.

RISK TREATMENT:

With respect to the Lake Sturgeon issue, the Corporation continues to take significant action to minimize the need for and likelihood of listing Lake Sturgeon under SARA (see detail of risk treatment on profile C.3.1), however uncertainty remains.

Over the next ten years, twelve of Manitoba Hydro's Water Power Act licences will have to be renewed. Although legally this should be a relatively simple process as prescribed under the Water Power Act regulations, public expectations, the requirement for the Province of Manitoba to consult under Section 35 of the Constitution with Indigenous peoples on all licencing decisions and the recent recommendations from the CEC on re-licencing that includes full environmental assessments and public reviews will expose Manitoba Hydro to significant costs, and potential operational restrictions. Manitoba Hydro is currently in discussions with the Province on how to proceed with re-licencing.

Likelihood	Low
Consequence	High
Tolerance	Low

CATEGORY: H. Governance / Regulatory / Legal

TITLE: 2. Export Market Access

RISK: The Corporation loses its legal capability to sell power outside the province due to legal and industry change issues.

DESCRIPTION:

The energy industry in North America has undergone fundamental restructuring. There are now in place market-based approaches to generation, transmission, distribution and sale of energy in the Midwest region of North America in which Manitoba is located, and new industry bodies have been formed to facilitate these activities. Opportunities for the Corporation include (1) Opportunities to export power to new markets or further develop existing markets, and (2) Opportunity to define new roles for the Corporation in the delivery of gas services in Manitoba to better serve consumers.

Manitoba Hydro's access to the U.S. market is to an extent conditioned on the adoption of measures in Manitoba to level the playing field e.g. transmission tariff, standards of conduct. Risks include: (1) Measures adopted in Manitoba to level the playing field could affect rates to Manitobans or quality of service. (2) Risk of Manitoba Hydro losing functional control of its transmission facilities in Manitoba to U.S.-based transmission operators (i.e. loss of sovereignty, lose control of transmission facilities). (3) The risk of losing market access or receiving access on adverse terms (e.g. transmission pancaking, less competitive, more costly).

As well, the Corporation requires the legal ability to sell power into other provinces and the U.S. on favourable terms. Risks include: (1) The Corporation may be prevented from selling into a particular market or obtaining transmission or ancillary services that are necessary for the sale to take place. (2) Unfavourable terms may be imposed on sales, by U.S. regulators or trading partners (3) May affect amount of power Manitoba Hydro can be assured of importing during times of drought.

POTENTIAL IMPACT ON ACHIEVING CORPORATE OBJECTIVES:

The above opportunities and risks may affect the amount of revenue from export sales and could impact the reliability of supply and service to Manitobans. They might also impact Manitoba Hydro's mandate, control over facilities and raise issues of Canadian and Manitoba sovereignty.

RISK TREATMENT:

The rules are constantly changing in export markets. Accordingly, corporate strategies for ensuring market access will continue to require ongoing management. Strategies (all subject to change) include: (1) Ongoing development and assessment of strategic plans. (2) Ongoing alignment of strategic plans and participation by Manitoba Hydro personnel in export based operations. This includes: coordination agreement with MISO; membership in Midwest Reliability Organization; active input into MISO committees and bodies; FERC filings; Ontario marketing licence; adoption in Manitoba of transmission tariff, standards of conduct, reliability, security and operating procedures consistent with U.S. requirements; promotion of the corporate image in export markets; and active engagement with Manitoba Hydro's principal export customers to confirm they are able to obtain needed regulatory approvals.

Likelihood	Low
Consequence	M High
Tolerance	Low

CATEGORY: H. Governance / Regulatory / Legal

TITLE: 3. Legal Compliance

RISK: The Corporation does not comply with legal requirements

DESCRIPTION:

The Corporation must comply with a broad variety of legislation, regulations, common law and other legal requirements.

POTENTIAL IMPACT ON ACHIEVING CORPORATE OBJECTIVES:

Depending on the type of legal requirement the consequences of non-compliance may include:

- Financial penalties for the Corporation.
- Fines / imprisonment for individual directors, officers or employees.
- Impact on corporate reputation.
- Restrictions on corporate operations.

RISK TREATMENT:

The Corporation fosters a positive culture of compliance through measures such as a Corporate Code of Ethics, periodic messages from the President to all employees emphasizing the importance of compliance with the Law, and an Integrity Program to enable employees to report any violations of the Code of Ethics without fear of reprisal.

Management has identified a short list of compliance risks that pose the most material risk to the Corporation. Management has developed for the Audit Committee of the Board profiles of the compliance programs for these risks and provides to the Committee annual updates and metrics associated with them.

An Integrity Officer coordinates the investigation of all Integrity Program reports. Summaries and analysis of reports received pursuant to the Integrity Program are shared with the Audit Committee annually (with identifying details removed to protect confidentiality). Summaries of all material litigation, communications with licensors and other potential indicia of compliance or non-compliance are also reviewed by the Audit Committee on an annual basis.

In order to mitigate exposure to market manipulation risk, the Corporation is in the process of implementing a Wholesale Electricity Markets Compliance Program to establish policies, procedures and guidelines pursuant to anti-market manipulation laws in place in the U.S. and Canada. This program will outline roles and responsibilities of those identified in the program, provide direction to employees transacting in the export markets, identify permissible and prohibited trading considerations and specify policy with respect to potential violation investigations, disputes and reporting, training requirements, record retention practices and compliance monitoring related to the Corporation's participation in the wholesale electricity markets.

In all cases it is the responsibility of management to ensure compliance with the law. The generally accepted elements of a corporate compliance program are:

- Standards and procedures that are reasonably capable of reducing non-compliance.
- Assign specific high-level personnel to oversee compliance.
- Prevent delegation of discretion to individuals likely to engage in non-compliance.
- Effectively communicate standards and procedures to relevant employees.
- Implement monitoring, auditing and reporting systems.
- Use disciplinary measures to enforce standards and procedures.
- Respond to breaches that are detected including modification for systemic problems.
- Continually evaluate the risk of non-compliance.

Likelihood	Low
Consequence	Med
Tolerance	Low

CATEGORY: H. Governance / Regulatory / Legal

TITLE: 4. Contracts & Ventures

RISK: Contracts are not fulfilled or business ventures expose the Corporation to undesirable events.

DESCRIPTION:

The Corporation engages in a variety of commercial activities. It purchases goods and services, sells its own goods and services, purchases and sells land and intellectual property and signs a variety of other contracts and agreements. The Corporation also purchases businesses such as Centra and Winnipeg Hydro, and sets up subsidiaries and joint-ventures to pursue particular opportunities. Some of the risks include:

- Failure to comply with contract obligations and contract law (e.g. anti-corruption law).
- Acceptance of unfavourable contract risk, liability clauses or indemnity requirements.
- Failure to obtain property rights and easements needed for corporate activities.
- Failure to obtain software licences or other intellectual property.
- Failure to secure sufficient audit rights to protect the corporate interest.
- Entanglement in foreign legal proceedings.
- Failure to exercise appropriate governance over joint-ventures / subsidiaries.

POTENTIAL IMPACT ON ACHIEVING CORPORATE OBJECTIVES:

Management of the above risks will impact the revenues or other advantages that the Corporation is seeking to achieve, and the potential lawsuits and financial liabilities that the Corporation may be exposed to.

RISK TREATMENT:

The Corporation has risk management programs in place for particular, high risk commercial activities such as the purchase of gas hedges and power trading.

Board approval is required for all contracts of first importance to the Corporation (meaning contracts with high impact on the Corporation's ongoing operations over the long term (e.g. Northern Flood Agreement, Joint Keeyask Development Agreement, Winnipeg Hydro Purchase Agreement), contracts introducing fundamental change to the Corporation and purchases beyond specified signing limits and discretionary payments over $5 million. There are Board guidelines for the creation of subsidiaries and joint-ventures.

The majority of commercial risks are managed within the Business Units. Management is responsible to manage the opportunities, obligations, adherence to contract law (e.g. anti-corruption law), and risks in all documents that are signed. Policy requires the approval of a Division Manager for any contract containing non-standard risk, liability or indemnity provisions. Contracts and ventures of first importance to the Corporation are coordinated at the executive level with Board reporting and approvals. Policy requires legal approval of all contracts of first importance to the Corporation. Policy requires legal approval of all consulting contracts, with any exceptions approved by a Vice-President and reported to the Audit Committee.

Likelihood	Med
Consequence	M High
Tolerance	Low

CATEGORY: H. Governance / Regulatory / Legal

TITLE: 5. NERC/MRO Reliability Standards

RISK: The Corporation could face negative consequences if it does not comply with mandatory NERC/MRO reliability standards.

DESCRIPTION:

NERC/MRO standards identify specific reliability requirements for the planning, design, reliable operation, and maintenance and security of the North American bulk power system. NERC reliability standards are binding on the Corporation pursuant to the Reliability Standards Regulation under the Manitoba Hydro Act. The National Energy Board, which regulates international power lines also requires Manitoba Hydro to comply with applicable Reliability Standards under its General Order on Mandatory Reliability Standards.

A finding of non-compliance to these standards could result in the following potential consequences: (1) Financial penalties up to $1 million per day per violation; (2) Increased regulatory scrutiny by the PUB and NEB as a result of violations; (3) Public disclosure of non-compliances, which may result in a negative impact on the Corporation's reputation and its exceptional standing in the industry; (4) Immediate Remedial Action Directives imposed by NERC/MRO on the Corporation; (5) Negative impact to Manitoba Hydro's export capability; and (6) Monetary penalties to both employees and the Corporation up to $100,000 pursuant to the NEB's Administrative Monetary Penalties (AMPs) Regulation

POTENTIAL IMPACT ON ACHIEVING CORPORATE OBJECTIVES:

The violation of mandatory standards could threaten the reliability of the bulk power system. Manitoba Hydro recognizes reliability as an important priority; one which provides exceptional value to customers. Public disclosure of non-compliance on a single significant matter, or numerous times on points of lesser significance, could put negative pressure on the Corporation's image. Furthermore, financial penalties imposed on the Corporation could be substantial.

RISK TREATMENT:

To mitigate the risks of non-compliance to reliability standards, the Corporation has developed a Corporate NERC Reliability Compliance Program to manage the demands of compliance. The role of the program is to promote a culture of compliance, act as the primary contact with external entities, manage the flow of information both internally and externally, and provide high level support for corporate compliance-related activities. A decentralized approach to the assignment of responsibility for each standard has placed accountability for the Corporation's compliance squarely in the hands of subject matter experts who can assess current practices against the requirements of the standards and take action to ensure compliance. These subject matter experts (generally Department Managers) are designated as either standard owners or requirement owners depending on their level of involvement relative to the specific requirements of the standards. The Program has created clearly defined roles and responsibilities for both standard owners and requirement owners. In addition, standard owners and requirement owners are expected to participate in the MRO/NERC standards development process, through commenting periods, voting strategies, and/or as members of standard drafting teams, to influence the development of a standard before it becomes mandatory and enforceable.

Under the Reliability Standards Regulation, the Corporation works collectively with the Province to update the list of reliability standards applicable in Manitoba as well as the NERC Rules of Procedure applicable in Manitoba, providing flexibility to deal with future events and changing circumstances.

Likelihood	High
Consequence	High
Tolerance	Low

CATEGORY: I. Indigenous

TITLE: 1. Relationships

RISK: Poor relationships will have negative impacts on future Corporate activities.

DESCRIPTION:

Manitoba Hydro ("MH") has a goal in its Corporate Strategic Plan to " Engage impacted communities in a positive way to enhance working relationships". Effective working relationships adhere to the basic principles of mutual recognition, mutual respect, sharing and mutual responsibility Working relationships encompass activities in the areas of employment, training, environmental stewardship, purchasing, contract work, customer service, business opportunities and addressing adverse effects.

Working relationships exist with Indigenous individuals, communities and organizations. In managing relationships Manitoba Hydro takes into consideration issues and concerns raised by the community, Indigenous and Treaty rights, impacts of hydro-electric development, employment equity and human rights concerns, and the societal need to move towards reconciliation.

The risks in this area include both substantive and process issues such as disputes arising in relation to: adequacy and continuation of process funding; adequacy and eligibility for compensation arising from existing and future development; eligibility for and adequacy of corporate programs and initiatives; equitable allocation of programming dollars and opportunities; and the representative capacity with respect to Indigenous interests. Any of the above can result in legal action.

POTENTIAL IMPACT ON ACHIEVING CORPORATE OBJECTIVES:

- Lack of trust on the part of many Communities which were impacted by hydro-electric development.
- Continued existence of ongoing impacts that cannot be totally eliminated even with decommissioning of the project which would have other impacts.
- Significant needs of many Indigenous communities that have resulted from numerous social, political and economic issues most of which are not related to hydro development.
- Need to create a level playing field in dealing with Indigenous communities requiring significant expenditures for the Corporation for consultants, lawyers and capacity building.
- Widely different views on respective obligations. Compensation paid under settlement agreements that does not address ongoing impacts leave future groups dissatisfied.
- Dissatisfied groups and/or their supporters damage Manitoba Hydro's image with export customers in particular and domestic stakeholders generally.
- Requests for financial donations and sponsorships increase, while fiscal constraints minimize the amount of discretionary funding available..
- Intervention by disaffected Indigenous entities adversely affects the outcome of regulatory processes.
- Significant reduction in process funding may impact communities' ability to manage their relationships with Manitoba Hydro.
- Dissatisfied groups and/or their supporters may take legal action and/or engage in acts of civil disobedience resulting in financial, operational and reputational impacts.

RISK TREATMENT:

- Behave in ways that earn trust and respect and contribute to mutual gains.
- Build on the mutual interests in the land and water that Manitoba Hydro shares with Indigenous peoples and seek to understand and accept different world views.
- Continue to design and deliver meaningful programs, projects and activities to address NFA obligations.
- Encourage fair public comment on hydropower issues and facilitate open communication with customers and government entities.
- Operate in compliance with corporate goals, operating principles and sustainable development principles.
- Agree on work plans and budgets for negotiating processes that include community assurances that a local expenditure control system exists, with expenditure control procedures in place, for both internal and external service providers.

Likelihood	Med
Consequence	M High
Tolerance	Low

CATEGORY: I. Indigenous

TITLE: 2. Legal

RISK: Unfavourable relationships and rulings could negatively impact Corporate operations.

DESCRIPTION:

Manitoba Hydro facilities can adversely affect Indigenous people with rights and interests in the area of the facilities. Interactions with Indigenous people and organizations are undertaken within a unique framework created by the following factors:

- Canada's constitution and legislation recognizes rights and provides protections to Indigenous peoples and Indian Reserve land in particular.
- Manitoba Hydro has significant contractual obligations under the NFA, the related NFA Implementation Agreements and other agreements with First Nations, the Manitoba Metis Federation (MMF), northern Indigenous communities and resource users.
- Manitoba Hydro's issues are often interwoven with broader federal and provincial responsibilities and Indigenous Self-Government issues.
- Indigenous concerns frequently command a high public profile.
- The Corporation is committed to enhancing working relationships with Indigenous peoples.
- There is often a lack of legal clarity, agreement, or common understanding with First Nations or Metis regarding the nature of Treaty and Indigenous rights (including Indigenous Title) and the obligations that arise for the Crown or proponent of a project in relation to such rights.

The risks in this area include:

- Inadvertent breach of legal obligations under contracts, legislation, regulations and constitutional requirements
- Restrictions on the use of land and water for energy production.
- Imposition of post project environmental reviews and assessments.
- Claims (e.g. breach of contract, interference with the exercise of rights, trespass, negligence) resulting in adverse orders including orders for damages or injunctions
- Delayed government approvals and unfavorable licence conditions for new projects
- Operating restrictions placed on existing projects
- Political interventions and civil disobedience (e.g. blockades)
- Lack of suitable judicial remedies
- Loss of export market opportunities
- Project delays and cost escalation.
- Competing interpretation of contractual arrangements.
- Long and costly arbitration processes and/or litigation.

POTENTIAL IMPACT ON ACHIEVING CORPORATE OBJECTIVES:

Damage claims and operating restrictions have monetary implications. In an extreme case there could be risk to persons or property. Depending on the management of the risks, there is potential for damage to the corporate reputation and export market opportunities.

RISK TREATMENT:

Management systems exist or are being developed to flag obligations and to follow up on compliance which reduce the likelihood of inadvertent non-compliance with legal obligations. The Corporation is pursuing enhanced working relationships through mutually beneficial arrangements with Indigenous groups when developing new hydro facilities and is continually seeking improvements to its relationship with Indigenous peoples. The Corporation monitors developments in the field of Indigenous law to ensure ongoing awareness of evolutions in jurisprudence on Indigenous rights.

Likelihood	Low
Consequence	M High
Tolerance	Low

CATEGORY: J. Emerging Energy Technologies

TITLE: 1. Emerging Energy Technologies

RISK: New technology renders current facilities cost excessive.

DESCRIPTION:

Significant breakthroughs or improvements involving large scale mass production of new emerging technologies (energy storage, bioenergy, solar, wind, etc.) could result in lower electricity capital or production costs. Such technology breakthroughs could impact both Manitoba Hydro's export revenue and domestic revenue. The potential impact on export revenue is one of the factors discussed in category A2.2 Export - Long Term Price Uncertainty. Emerging renewables put downward pressure on export market prices along with providing more fixed price/non-emitting resource options to counterparties which affects the export marketing opportunities and related long term pricing premiums available to Manitoba Hydro. New small scale domestic emerging technology resources such as solar could reduce expected load growth, and reduce energy revenue in Manitoba over the long run, if the cost of the resources becomes low enough to become economic.

Alternative generation technologies, without tax incentives or subsidies, are currently more expensive than conventional generation. Generally the more mature alternative technologies, such as utility scale wind power, are closer to commercial parity even without subsidy as their costs continue to decrease slowly. With subsidies, new wind power in the Midwest US is currently being contacted at below market prices, creating substantial challenges for merchant generators. There remains substantial uncertainty around the availability of these subsidies (specifically for wind power) post-2015. Less mature technologies, such as solar photovoltaics, have costs which are decreasing more quickly, but costs would still need to decrease by at least a factor of two for them to be commercially viable without subsidy or mandate. However drastic technology cost reductions in the past few years has set a trajectory where commercial viability in many medium/higher cost regions of the US within the next five to ten years.

Manitoba has biomass resources, primarily from crop residues, but individual utility scale generating plants would be small (<30 MW) and disbursed. Costs associated with biomass fuel collection and transportation continue to limit the development potential for this option in Manitoba. Utilization of biomass resources would also be subject to competition from other bio-product demand such as heating.

Energy storage technology is predicted to play a significant role in future electrical grids with distributed generation components by helping to manage intermittency, which could enable the integration of more non-dispatchable energy sources such as wind or solar. The historical price drop for lithium-ion batteries has accelerated with the recent expenditures of multiple billions of dollars on new higher-scale manufacturing facilities and larger battery chemistry research laboratories.

POTENTIAL IMPACT ON ACHIEVING CORPORATE OBJECTIVES:

The impact of this risk is reduced revenue from both domestic and export energy sales from existing assets while also impacting the business case for new hydro-electric generation. Development changes in emerging energy technologies have tended to be more evolutionary than sudden, which means that relative value thresholds between conventional and emerging generation are likely to be approached gradually.

RISK TREATMENT:

Manitoba Hydro retains expertise and keeps well informed of the direction occurring within the industry. The current resource plan indicates that no new generation is required until 2033. This requirement is based on current load forecasts that include new DSM targets both of which are updated annually to reflect information that is available. This time frame allows the Corporation to assess new alternative energy technologies and work towards an integrated resource plan which determines the appropriate combination of resources to meet multiple objectives (technical, environmental etc) at the lowest cost to Manitobans.

Likelihood	Low
Consequence	M High
Tolerance	Low

CATEGORY: K. Strategic

TITLE: 1. Strategic Direction and Execution

RISK: Missed opportunities, unfavourable business decisions.

DESCRIPTION:

Strategic planning is the overarching methodology by which the Corporation sets direction and aligns corporate priorities and resources.

POTENTIAL IMPACT ON ACHIEVING CORPORATE OBJECTIVES:

Establishing, communicating and implementing strategic direction is essential in managing threats and opportunities. Strategic decisions have the potential to significantly impact corporate performance and the achievement of financial targets, either positively or negatively, pertaining to any of the Corporate Strategic Plan (CSP) goals and/or identified risk categories. High level strategic considerations may include: large scale capital projects to meet the future needs of the province, re-investment in the existing energy system to maintain high reliability, attraction and retention of a high caliber workforce, stakeholder and indigenous relationships, implications of evolving power markets including access to export markets, potential industry-wide implications of shale gas, prioritization of capital projects and resource optimization, performance management and process improvement.

RISK TREATMENT:

Manitoba Hydro's integrated planning cycle commences annually with key inputs such as: economic variables and energy price forecast, load forecast, demand side management forecast, export price assumptions, capital costs and OM&A forecasts. These inputs drive the Integrated Resource Plan (IRP), capital expenditure forecasts and ultimately the Integrated Financial Forecast (IFF). The CSP is a companion document for consideration throughout the planning cycle.

Major strategic decisions and strategic, plans are subject to an internal review and approval process. Many strategic decisions are also subject to external review and approval through regulatory processes.

Senior management is responsible for communicating and ensuring the implementation of strategy throughout the Corporation. Manitoba Hydro's Vision, Mission and corporate targets are communicated to employees via the CSP.

Business units incorporate the CSP into their respective business plans as appropriate. Applicable goals, measures and strategies become increasingly oriented to operations as the process moves downward through the organization.

APPENDIX C

CORPORATE

RISK MANAGEMENT

FRAMEWORK

APPENDIX C - CORPORATE RISK MANAGEMENT FRAMEWORK

The Corporation has adopted the following six step Risk Management Process, Risk Rating Criteria and Risk Tolerance Rating Criteria to consistently identify, assess and manage risks:

Six Step Risk Management Process

1) Mission / Mandate

The process of identifying and managing risk is initiated at the Corporate, Business Unit, Division, Department, or project level by focusing on the underlying mission / mandate and specific strategic goals established for that particular area of the Corporation.

2) Risk Identification

Risks are identified based on the factors that influence the performance of the area of the Corporation being assessed.

3) Potential Impact

Risks are analyzed for potential impact and measured in terms of consequence and likelihood. Consequence is quantified in terms of system reliability, safety, finance, environmental impact and customer satisfaction. For each consequence identified, the likelihood (probability) is determined of the event occurring.

4) Risk Treatment

Actions are taken to reduce the likelihood of a negative event occurring or to reduce the negative consequences should a negative event occur. Risk treatment can include a reduction of the risk through modification of operational activities, a sharing of the risk through external insurance or acceptance of the risk as a normal consequence of the business and/or operations. The acceptance of risk is subject to that risk being within the approved tolerance levels of the Corporation.

5) Residual Risk

Certain levels of residual risk may remain even after actions have been taken to reduce their likelihood and consequences. An assessment is performed to confirm that the residual risk levels are within approved tolerances.

6) Reporting and Monitoring

Systems are implemented to monitor key risks, and information provided by these systems are used to facilitate management actions. Reporting systems ensure that senior management and other stakeholders are appropriately informed and risks are managed within the Corporation’s approved risk tolerances.

Corporate Risk Rating Criteria

CORPORATE RISK PROFILE RATING CRITERIA

	MEASURES	RATING		
		Low	Medium	Medium High
ANNUAL CONSEQUENCE -				
Financial	Net income / capital investment	$0 - $50 million	$51 - $150 million	> $150 million
System Reliability	Domestic Customers	Outage affecting 50 customers for 4 hours Not life threatening	Outage affecting 500 customers for up to 24 hours. Have ability to serve critical loads. Not life threatening as critical loads served.	Do not have capacity to serve Manitoba load for extended period of time. Life threatening. Loss of public confidence.
	MW generation or interconnection capacity	NERC level 1 In compliance with industry reliability standards.	Loss of 2000 MW. NERC level 2 - load management procedures in effect. In compliance with industry reliability standards.	Loss of > 2000 MW. NERC level 3 - firm load interruption imminent or in progress; and / or non-compliance with industry reliability standards.
Safety - Employee and Public	High risk accidents, severity rate, frequency rate and public contacts.	Minor injuries. In compliance with laws and industry standards.	Disabling injuries. In compliance with laws and industry standards.	Severe injuries and fatalities; and / or non- compliance with legislation and industry standards resulting in imprisonment for MH mgmt, significant fines and loss public trust.
Environment	Environmental impact - air emissions, water mgmt, spills, land & habitat disturbances, etc.	Minor impact to environment. In compliance with stakeholder expectations and laws and regulations. Ability to obtain / renew environmental licensing and operating approvals.	Local and contained damage to environment. In compliance with stakeholder expectations and laws and regulations. Ability to obtain / renew environmental licensing operating approvals.	Severe widespread and uncontained damage to environment; and / or non-compliance with stakeholder expectations, laws, and regulations resulting in imprisonment for MH mgmt, significant fines, loss of public trust and long term operating restrictions
Customer Value	Customer perception service with regard to:			
	Retail electricity rates	No rate increase	Annual increase < 10%	Annual increase > 10%
	Reliability and quality service	Restoration service within 4 hours, no threat to public safety,. < 1.3 outages/customer/ year, provision energy related services.	Restoration service within 24 hours with no threat to public safety. 2 outages/customer/year,	Outage for extended period of time. Life threatening. Loss of public confidence.
	Reputation	Local media coverage with negligible impact on stakeholders.	A highly visible event attracting national media coverage or environmental concern; and /or a moderate negative impact on stakeholders.	A highly visible event attracting international media coverage or environmental concern; and / or a significant negative impact on stakeholders such as breach of privacy, contractual obligation or environmental stewardship.
LIKELIHOOD		Event is not likely to occur within 10 years.	Event is likely to occur within 5 - 10 years.	Event is likely to occur within 1 to 10 years.

Note: While risk impact ratings are outlined for low, medium and medium-high those considered more significant than others in the medium-high category are elevated to a high category to signify their potential higher impact on the Corporation.

Corporate Risk Tolerance Definition / Rating Criteria

Tolerance is defined as the allowable or permissible variation from a standard. For Manitoba Hydro's purposes, tolerance is further defined as the extent to which the amount of residual risk is deemed to be reasonably acceptable within the resources available to the Corporation. To the extent that tolerances fall beyond reasonably acceptable levels, actions have been taken (or are being taken) to mitigate that risk.

Typically, risks with high consequence have corresponding low tolerances. Safety and Health (E.1) and Reliability of Service (C.4) are examples where the Corporation has a low tolerance for risk due to the severe consequences of negative events.

Tolerance is rated as either, low, medium or high based on the following parameters:

- Low – Zero or limited variability is accepted. Low tolerance is usually associated with an area where the consequences of negative events are significant and the Corporation has the ability to control the risk.

- Medium - Some variability is accepted. Medium tolerance may also be associated with high risk but the ability of the Corporation to control the risk may be limited.

- High – Significant variability is accepted. Consequence is always low.

To ensure adequate control and monitoring of risk, management establishes rules, limits, targets and guidelines and continually monitors these indicators and responses accordingly. The Corporation has created three levels to illustrate this:

- Green: no additional action required at this time as the risk is under control and is not subject to significant change.

- Yellow: there are or appears to be some emerging issues that need to be closely monitored and addressed. Additional action is required to bring the risk back to the established tolerance. Management has time to respond in an orderly manner.

- Red: the risk has become critical to business operations and requires day to day senior management attention. If not resolved quickly, it could have catastrophic impacts on the organization.

PUB MFR 20
Financial Information

20 year forecasts of revenue requirements including cost components (Finance/ Depreciation/ Operating/ Water Rentals/ F&PP/ Taxes) for:
- Keeyask generating station
- Manitoba-Minnesota Transmission Project
- Great Northern Transmission Line
- Bipole III and Riel station
- Pointe du Bois spillway & powerhouse
- DSM
- Sustaining Capital
[Appendix 11.15, 2015/16 GRA]

Public disclosure of the response to this MFR (or portions thereof) would result in the release of information considered to be confidential and commercially sensitive. As directed by the PUB, Manitoba Hydro will be filing a letter seeking confidential treatment of the redacted information contained in this response pursuant to Rule 13.

This Minimum Filing Requirement seeks to simulate the Revenue Requirement impact of individual Major New Generation and Transmission projects. However, this type of analysis is limited by virtue of treating individual projects on an incremental cost basis. While costs such as Depreciation Expense, water rentals, and Operating & Administrative Expenses may be estimated and may be directly attributable to a Major New Generation and Transmission asset, other costs such as Finance Expense, capital taxes and benefits are not readily estimated on an incremental basis. Furthermore, this analysis disregards the estimated export revenues to be obtained through sales of surplus energy associated with new electric generating plant.

The most reliable measure of Manitoba Hydro's revenue requirement is the additional Domestic Revenue indicated on the electric operations projected operating statement (Appendix 3.3, pages 1 and 2) which is derived based on balancing the costs of the integrated hydro-electric system, for new asset additions as well as existing assets, with maintaining minimum financial ratios as well as rate stability and affordability for customers.

Reliance on the estimated carrying and operating costs in the attached schedule as a representation of revenue requirement must be viewed with caution considering the inherent limitations of the analysis, estimation assumptions and methods described below.

1) Manitoba Hydro issues debt based on the consolidated cash requirements of the Corporation and does not assign specific debt issues on a project-by-project basis. As such, finance expense attributable to a specific project is estimated for the purposes of this analysis by applying Manitoba Hydro's average cost of debt to the asset's net book value (projected in-service cost net of accumulated depreciation). Using the net book value as the principal outstanding for debt associated with an asset assumes that annual depreciation expense approximates revenues available to reduce debt over the life of the asset. This estimation method does not consider that extraprovincial revenues partially offset the costs. As a result, the implied impacts to customers for each project may not be representative.

2) Capital taxes are estimated by applying a fixed 0.5% capital tax rate to construction work in progress until the asset is in-service and the net book value thereafter. Similar to finance expense, the use of net book value as a proxy for paid up capital to estimate capital taxes may result in implied impacts to customers for each project that are not representative.

3) Manitoba Hydro operates the integrated hydro-electric system to optimize the efficient use of water resources and maximize overall Corporate revenues for the benefit of customers. The output of one facility may not be maximized on its own but contributes to the maximization of the system as a whole. The assumption that depreciation expense approximates the revenue attributable to a project may be reasonable for understanding costs but does not reflect the value of a particular asset to the integrated system and should not be used for resource planning purposes.

4) The analysis considers only the prospective costs of asset additions and does not address the ability of revenues at current PUB approved rates to cover ongoing carrying and operating costs of existing assets. Current domestic rates are lower than what they otherwise would have been due to extraprovincial revenues partially

offsetting costs. In years of low water flow or low opportunity export prices, domestic revenues are not sufficient to cover the resulting reduction in extraprovincial revenues.

5) The analysis does not consider contributions to reserves in order to maintain Manitoba Hydro's self-supporting financial status and ensure affordable, predictable rates for customers.

Thus, the summation of total costs in the attached schedule may not accurately reflect the overall revenue requirement for Manitoba Hydro or how a particular asset contributes to the overall revenue requirement.

If one accepts the estimated carrying and operating costs in the attached schedule with its inherent limitations, cumulative rate increases that would be required to cover the costs of forecast additions in the 10 year forecast period from 2017/18 to 2026/27 are up to 37 percentage points higher (99%) compared to the proposed and indicative cumulative rate increases of 62% over the same time period in MH16. Annual rate increases are between 5% and 19% in the period 2017/18 to 2023/24 with minimal rate adjustments thereafter to 2035/36.

Even if it is assumed that all extraprovincial revenues (net of water rentals and fuel and power purchases) are allocated to offset the prospective costs of additions, the cumulative rate increases that would still be required are up to 8 percentage points higher (70%) compared to the projected 62% cumulative rate increase in MH16 by 2026/27. Annual rate increases range up to 13% in the period 2017/18 to 2023/24 with minimal rate adjustments thereafter.

The lower overall revenue requirements in the integrated system analysis shown in additional Domestic Revenues in MH16 compared to this analysis demonstrates that extraprovincial revenues have a key role in offsetting the costs of investments and reducing the compounding effects of the higher carrying costs over time. The annual differences in rate increases compared to MH16's 7.90% rate increases also show that there is not a direct flow through of costs in each year to customers. Customers benefit directly from Manitoba Hydro's approach of five year even annual rate increases above inflation before reverting back to inflationary increases within six years while Manitoba Hydro deviates from its

financial targets during the capital build-out returns to a position of financial strength near the end of a ten year period.

The schedule below has been updated for IFF16 Major New Generation & Transmission, as well as the addition of DSM and Business Operations Capital Expenditures.

KEEYASK (ISD 2021/22)
(In Millions of Dollars)

For the year ended March 31

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Finance Expense	-	-	-	-	-	114	310	387	380	377	370
OM&A Costs	-	-	-	-	-	9	16	16	16	16	17
Depreciation	-	-	-	-	-	23	107	121	121	121	121
Capital Tax	16	22	28	34	38	42	43	42	42	41	41
Water Rentals	-	-	-	-	-	4	14	15	18	18	18
	16	22	28	34	38	191	489	581	577	573	566

MANITOBA-MINNESOTA TRANSMISSION PROJECT
(In Millions of Dollars)

For the year ended March 31

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Finance Expense	-	0	0	0	10	21	20	19	19	19	18
OM&A Costs	-	-	-	-	-	0	0	0	0	0	0
Depreciation	-	0	0	0	6	7	7	7	7	7	7
Transmission Charges	-	-	-	-	-	-	-	-	-	-	-
Capital Tax	0	1	1	2	2	2	2	2	2	2	2
	0	1	2	2	18	30	29	29	28	28	28

KEEYASK (ISD 2021/22)
(In Millions of Dollars)

For the year ended March 31

	2028	2029	2030	2031	2032	2033	2034	2035	2036
Finance Expense	362	349	344	358	348	343	325	302	275
OM&A Costs	17	16	17	17	17	16	16	17	17
Depreciation	121	121	121	121	121	121	121	121	121
Capital Tax	40	39	39	38	38	37	36	36	35
Water Rentals	18	18	18	18	18	19	19	19	19
	558	544	538	552	542	535	517	494	467

MANITOBA-MINNESOTA TRANSMISSION PROJECT
(In Millions of Dollars)

For the year ended March 31

	2028	2029	2030	2031	2032	2033	2034	2035	2036
Finance Expense	18	17	17	18	17	17	16	15	13
OM&A Costs	0	0	0	0	0	0	0	0	0
Depreciation	7	7	7	7	7	7	7	7	7
Transmission Charges	-	-	-	-	-	-	-	-	-
Capital Tax	2	2	2	2	2	2	2	2	2
	27	27	26	27	26	26	25	24	22

GREAT NORTHERN TRANSMISSION LINE
(In Millions of Dollars)

For the year ended March 31

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Finance Expense	[redacted]										
OM&A Costs											
Amortization											
Transmission Charges											
Capital Tax											
	0	1	3	3	77	101	98	95	93	91	88

WUSKWATIM
(In Millions of Dollars)

For the year ended March 31

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Finance Expense	84	79	71	67	68	68	66	64	63	62	61
OM&A Costs	11	11	12	11	12	13	13	14	14	14	14
Depreciation	26	26	26	26	26	26	26	26	26	26	26
Capital Tax	8	8	8	8	8	7	7	7	7	7	7
Water Rentals	5	5	5	5	5	5	5	5	5	5	5
	134	129	122	117	118	120	118	116	115	114	113

GREAT NORTHERN TRANSMISSION LINE
(In Millions of Dollars)

For the year ended March 31

	2028	2029	2030	2031	2032	2033	2034	2035	2036
Finance Expense	[redacted]								
OM&A Costs									
Amortization									
Transmission Charges									
Capital Tax									
	86	83	81	85	84	82	78	75	72

WUSKWATIM
(In Millions of Dollars)

For the year ended March 31

	2028	2029	2030	2031	2032	2033	2034	2035	2036
Finance Expense	59	57	56	58	56	55	51	48	43
OM&A Costs	15	15	12	11	11	11	11	11	11
Depreciation	26	26	26	26	26	26	26	26	26
Capital Tax	7	7	6	6	6	6	6	6	6
Water Rentals	5	5	5	5	5	5	5	5	5
	112	109	105	106	104	103	100	96	91

BIPOLE III & RIEL STATION
(In Millions of Dollars)

For the year ended March 31

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Finance Expense	14	9	115	217	220	223	219	214	208	205	199
OM&A Costs	-	-	8	13	13	13	14	14	14	15	15
Depreciation	9	10	73	107	107	107	107	107	107	107	107
Amortization of BPIII Reserve	-	-	(47)	(71)	(71)	(71)	(71)	(24)	-	-	-
Capital Tax	16	22	25	25	24	24	24	24	23	23	22
	39	40	175	290	293	296	292	334	352	348	343

FINANCING IMPACTS OF THE SUNK COSTS RELATING TO CONAWAPA
(In Millions of Dollars)

For the year ended March 31

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Finance Expense	-	-	-	8	16	16	15	15	14	14	13
Amortization	-	-	-	12	13	13	13	13	13	13	13
	-	-	-	20	29	29	28	27	27	26	26

BIPOLE III & RIEL STATION
(In Millions of Dollars)

For the year ended March 31

	2028	2029	2030	2031	2032	2033	2034	2035	2036
Finance Expense	193	184	180	185	178	173	162	149	134
OM&A Costs	15	15	16	16	16	17	17	17	18
Depreciation	107	106	106	106	106	106	106	106	106
Amortization of BPIII Reserve	-	-	-	-	-	-	-	-	-
Capital Tax	21	21	20	20	19	19	18	18	17
	336	327	322	327	320	315	303	290	275

FINANCING IMPACTS OF THE SUNK COSTS RELATING TO CONAWAPA
(In Millions of Dollars)

For the year ended March 31

	2028	2029	2030	2031	2032	2033	2034	2035	2036
Finance Expense	12	11	11	11	10	10	9	8	7
Amortization	13	13	13	13	13	13	13	13	13
	25	24	24	24	23	22	21	20	19

POINTE DU BOIS SPILLWAY
(In Millions of Dollars)

For the year ended March 31

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Finance Expense	29	28	25	23	24	24	23	22	22	22	21
OM&A Costs	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)
Depreciation	8	8	8	8	8	8	8	8	8	8	8
Capital Tax	3	3	3	3	3	3	2	2	2	2	2
	40	38	35	33	34	34	33	32	32	31	31

DSM
(In Millions of Dollars)

For the year ended March 31

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Finance Expense	3	4	7	10	13	16	17	18	18	18	18
OM&A Costs	1	1	1	1	1	1	1	1	1	1	1
Amortization	-	5	11	21	30	39	48	54	60	66	73
Capital Tax	1	1	2	2	2	2	2	2	2	2	2
	5	11	20	33	46	58	68	75	81	88	94

POINTE DU BOIS SPILLWAY
(In Millions of Dollars)

For the year ended March 31

	2028	2029	2030	2031	2032	2033	2034	2035	2036
Finance Expense	21	20	20	20	20	19	18	17	15
OM&A Costs	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)
Depreciation	8	8	8	8	8	8	8	8	8
Capital Tax	2	2	2	2	2	2	2	2	2
	30	29	29	30	29	28	27	26	24

DSM
(In Millions of Dollars)

For the year ended March 31

	2028	2029	2030	2031	2032	2033	2034	2035	2036
Finance Expense	18	17	18	19	19	20	20	19	18
OM&A Costs	1	1	1	1	1	1	1	1	1
Amortization	75	77	75	74	73	73	75	78	80
Capital Tax	2	2	2	2	2	2	2	2	2
	96	98	96	96	96	96	98	100	102

BUSINESS OPERATIONS CAPITAL
(In Millions of Dollars)

For the year ended March 31

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Finance Expense	8	21	30	40	48	55	62	69	75	80	84
Depreciation	9	29	45	61	79	95	107	120	136	153	169
Capital Tax	5	8	10	13	15	17	20	22	25	27	30
	22	57	86	114	143	168	189	211	235	260	282
Total Incremental Revenue Requirement (without Net Extraprovincial Revenues)	257	298	469	647	797	1 026	1 345	1 502	1 540	1 559	1 571
Annual Rate Increase/(Decrease)	0.00%	19.01%	9.28%	8.91%	6.87%	9.75%	12.10%	5.13%	0.95%	0.38%	0.10%
Cumulative Rate Increase	0.00%	19.01%	30.06%	41.65%	51.38%	66.15%	86.26%	95.81%	97.67%	98.43%	98.63%
Net Extraprovincial Revenues	(206)	(195)	(154)	(196)	(302)	(429)	(528)	(552)	(572)	(448)	(454)
Total Incremental Revenue Requirement (with Net Extraprovincial Revenues)	51	104	316	450	495	597	817	949	968	1 111	1 117
Annual Rate Increase/(Decrease)	0.00%	6.61%	12.77%	7.31%	2.23%	5.01%	10.03%	5.37%	0.51%	5.42%	0.00%
Cumulative Rate Increase	0.00%	6.61%	20.23%	29.01%	31.89%	38.50%	52.39%	60.57%	61.39%	70.13%	70.14%
IFF16 Annual Rate Increase	0.00%	7.90%	7.90%	7.90%	7.90%	7.90%	2.00%	2.00%	2.00%	2.00%	2.00%
IFF16 Cumulative Rate Increase	0.00%	7.90%	16.42%	25.62%	35.55%	46.25%	49.18%	52.16%	55.21%	58.31%	61.48%

BUSINESS OPERATIONS CAPITAL
(In Millions of Dollars)

For the year ended March 31

	2028	2029	2030	2031	2032	2033	2034	2035	2036
Finance Expense	88	91	96	103	101	98	92	86	74
Depreciation	185	199	217	234	254	274	292	310	328
Capital Tax	32	35	38	40	43	46	48	51	54
	305	326	351	378	398	418	432	446	456
Total Incremental Revenue Requirement (without Net Extraprovincial Revenues)	1 575	1 566	1 572	1 624	1 622	1 625	1 602	1 572	1 529
Annual Rate Increase/(Decrease)	-0.07%	-0.53%	-0.30%	1.13%	-0.89%	-0.82%	-1.56%	-1.79%	-2.14%
Cumulative Rate Increase	98.48%	97.43%	96.83%	99.07%	97.30%	95.68%	92.63%	89.18%	85.13%
Net Extraprovincial Revenues	(447)	(458)	(466)	(468)	(461)	(451)	(439)	(421)	(348)
Total Incremental Revenue Requirement (with Net Extraprovincial Revenues)	1 128	1 109	1 105	1 157	1 161	1 173	1 164	1 150	1 181
Annual Rate Increase/(Decrease)	0.23%	-0.92%	-0.50%	1.45%	-0.53%	-0.32%	-1.08%	-1.19%	0.28%
Cumulative Rate Increase	70.52%	68.96%	68.11%	70.55%	69.65%	69.10%	67.27%	65.29%	65.75%
IFF16 Annual Rate Increase	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
IFF16 Cumulative Rate Increase	64.71%	68.00%	71.36%	74.79%	78.28%	81.85%	85.49%	89.19%	92.98%

PUB MFR 24 (Updated)
Export & Domestic Revenues

Schedules of export volumes, revenues/costs, and average unit revenues for the 20 years of the current IFF and actual results for 2014/15, 2015/16, and 2016/17. Split firm and opportunity volumes, revenues, and average revenues for each year. [Attachment 16, 2016/17 Interim; PUB/MH-71a, 2016 COSS]

The response to PUB MFR 24 has been updated to reflect the July 2017 update to the financial forecast for electric operations (MH16 Update).

Public disclosure of the response to this MFR (or portions thereof) would result in the release of information considered to be confidential and commercially sensitive. As directed by the PUB, Manitoba Hydro will be filing a letter seeking confidential treatment of the redacted information contained in this response pursuant to Rule 13.

Please see the following tables for the requested information.

AVERAGE UNIT REVENUE/COST CALCULATION MH16 UPDATE

	VOLUMES (in GW.h)	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27
	Demand:										
A	Manitoba Domestic Energy Sales	22510	22224	21977	21750	21971	21940	21947	22103	22303	22531
B	Domestic energy Losses	3203	3261	2824	2788	2808	2742	2744	2766	2796	2838
C	Firm Export Sales to Canada (excl. Lake St. Joseph)	[redacted]									
D	Opportunity Export Sales to Canada										
	Firm & Opportunity Export Sales to Canada (excl. Lake St. Joseph) (C+D)	469	320	562	845	923	1008	1059	1056	1127	1115
E	Lake St. Joseph	83	92	91	91	91	91	91	91	91	91
F	Firm Export Sales to US	[redacted]									
G	Opportunity Export Sales to US										
	Firm & Opportunity Export Sales to US (F+G)	10036	8090	6216	7266	8067	10091	10210	10066	9570	9343
H	Net Transmission Losses	1024	867	633	738	829	1074	1092	1076	1046	1021
	Total Demand Volumes:	**37325**	**34854**	**32303**	**33478**	**34688**	**36947**	**37143**	**37158**	**36931**	**36938**
	Supply:										
I	MH Hydraulic Generation	35990	32799	30050	30833	32124	35076	35292	35281	35303	35289
J	MH Thermal Generation	61	29	264	81	67	56	56	57	49	49
K	Purchased Energy	1274	2025	1990	2564	2497	1815	1795	1820	1580	1600
	Total Supply Volumes:	**37325**	**34854**	**32303**	**33478**	**34688**	**36947**	**37143**	**37158**	**36931**	**36938**

	REVENUE/COST (in millions of dollars)	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27
	Total Manitoba Domestic Energy Sales:										
L	Manitoba Domestic Energy Sales @ Approved Rates	1 577.658	1 564.889	1 551.060	1 536.663	1 544.021	1 542.063	1 542.139	1 552.700	1 566.671	1 582.755
M	Additional Domestic Revenue	87.770	255.635	397.186	545.912	713.771	757.947	803.970	856.705	913.022	972.487
	Manitoba Domestic Sales	**1 665.428**	**1 820.525**	**1 948.247**	**2 082.575**	**2 257.792**	**2 300.010**	**2 346.108**	**2 409.405**	**2 479.693**	**2 555.242**
	Extraprovincial Revenue:										
N	Total Firm Export Sales to Canada	[redacted]									
O	Total Opportunity Export Sales to Canada										
	Total Export Sales to Canada (N+O)	20.801	17.929	29.999	65.746	75.699	73.619	74.603	76.267	82.957	84.947
P	Total Firm Export Sales to USA	[redacted]									
Q	Total Opportunity Export Sales to USA										
	Total Export Sales to USA (P+Q)	483.189	442.513	386.118	497.193	613.655	700.842	709.605	724.574	579.872	581.244
R	Other Non-Energy Related Revenues	6.980	5.761	1.110	1.132	1.153	1.172	1.191	1.215	1.240	1.265
S	Transmission Credits	2.970	2.965	2.958	2.974	2.985	2.948	2.907	2.965	3.025	3.085
	Extraprovincial Revenue	**513.940**	**469.168**	**420.186**	**567.044**	**693.493**	**778.580**	**788.307**	**805.022**	**667.094**	**670.541**
	Water Rentals & Assessments:										
T	MH Water Rentals	120.304	110.022	100.446	103.062	107.378	117.248	117.968	117.932	118.004	117.960
U	Assessments	7.628	7.615	7.598	7.637	7.667	7.570	7.466	7.616	7.768	7.923
V	Other Costs	2.443	2.302	2.383	2.407	2.431	2.455	2.480	5.732	5.423	5.476
	Water Rentals & Assessments:	**130.375**	**119.939**	**110.427**	**113.106**	**117.477**	**127.273**	**127.914**	**131.279**	**131.196**	**131.359**
	Fuel & Power Purchased:										
W	MH Thermal Generation	3.656	1.936	18.552	6.547	6.100	5.502	5.577	5.917	5.304	5.591
X	Purchased Energy	77.634	96.590	100.899	113.864	111.683	93.969	94.576	97.525	93.382	95.328
Y	Other Non-Energy related Costs	5.814	5.248	6.607	8.327	6.781	12.328	6.970	7.174	7.299	7.509
Z	Transmission Charges	36.408	36.225	31.772	36.092	30.969	28.528	27.738	27.643	20.990	20.643
	Fuel & Power Purchased	**123.512**	**139.998**	**157.830**	**164.829**	**155.533**	**140.327**	**134.860**	**138.259**	**126.975**	**129.070**

AVERAGE UNIT REVENUE/COST ($/MW.h))	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27
Manitoba Domestic Energy Sales @ Approved Rates (L/A)	$ 70.09	$ 70.41	$ 70.58	$ 70.65	$ 70.28	$ 70.28	$ 70.27	$ 70.25	$ 70.25	$ 70.25
Additional Domestic Revenue (M/A)	3.90	11.50	18.07	25.10	32.49	34.55	36.63	38.76	40.94	43.16
Total Manitoba Domestic Energy Sales @ meter (L+M)/A	73.99	81.92	88.65	95.75	102.76	104.83	106.90	109.01	111.18	113.41
Total Firm Export Sales to Canada (N/C)	[redacted]									
Total Opportunity Export Sales to Canada (O/D)										
Total Export Sales to Canada (N+O)/(C+D)	44.33	56.06	53.39	77.76	82.00	73.01	70.42	72.23	73.63	76.22
Total Firm Export Sales to USA (P/F)	[redacted]									
Total Opportunity Export Sales to USA (Q/G)										
Total Export Sales to USA (includes Net Trans Credits) (P+Q+S-Z)/(F+G)	44.81	50.59	57.48	63.87	72.60	66.91	67.07	69.53	58.72	60.33
Total Export Sales (includes Net Trans Credits) (N+O+P+Q+S-Z)/(C+D+F+G)	$ 44.79	$ 50.80	$ 57.14	$ 65.32	$ 73.57	$ 67.47	$ 67.39	$ 69.79	$ 60.29	$ 62.03
MH Hydraulic Generation (Water Rentals) (T/I)	$ 3.34	$ 3.35	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34
MH Thermal Generation (W/J)	$ 60.33	$ 66.68	$ 70.32	$ 81.04	$ 91.04	$ 98.78	$ 99.75	$ 103.67	$ 109.34	$ 113.38
Purchased Energy (Including Assessments) (X+U)/K	$ 66.90	$ 51.46	$ 54.53	$ 47.38	$ 47.79	$ 55.95	$ 56.83	$ 57.78	$ 64.02	$ 64.55

	VOLUMES (in GW.h)	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34	2034/35	2035/36
	Demand:									
A	Manitoba Domestic Energy Sales	22758	22976	23204	23443	23819	24216	24614	25024	25442
B	Domestic energy Losses	2879	2917	2957	2999	3082	3146	3202	3260	3319
C	Firm Export Sales to Canada (excl. Lake St. Joseph)	[redacted]								
D	Opportunity Export Sales to Canada									
	Firm & Opportunity Export Sales to Canada (excl. Lake St. Joseph) (C+D)	1116	1104	1079	1061	1011	989	961	932	947
E	Lake St. Joseph	91	91	91	91	91	91	91	91	91
F	Firm Export Sales to US	[redacted]								
G	Opportunity Export Sales to US									
	Firm & Opportunity Export Sales to US (F+G)	9078	8879	8688	8484	8003	7644	7331	7044	6356
H	Net Transmission Losses	996	973	949	925	866	823	784	747	689
	Total Demand Volumes:	**36918**	**36940**	**36969**	**37002**	**36872**	**36907**	**36983**	**37097**	**36844**
	Supply:									
I	MH Hydraulic Generation	35301	35279	35273	35264	35261	35257	35247	35237	35187
J	MH Thermal Generation	48	50	51	53	55	56	59	64	59
K	Purchased Energy	1568	1611	1644	1686	1555	1595	1677	1795	1597
	Total Supply Volumes:	**36918**	**36940**	**36969**	**37002**	**36872**	**36907**	**36983**	**37097**	**36844**

	REVENUE/COST (in millions of dollars)	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34	2034/35	2035/36
	Total Manitoba Domestic Energy Sales:									
L	Manitoba Domestic Energy Sales @ Approved Rates	1 598.893	1 614.186	1 630.398	1 647.337	1 673.454	1 700.928	1 728.509	1 756.710	1 785.528
M	Additional Domestic Revenue	1 034.017	1 097.057	1 162.833	1 231.349	1 309.350	1 391.476	1 476.885	1 566.130	1 659.364
	Manitoba Domestic Sales	**2 632.910**	**2 711.243**	**2 793.231**	**2 878.687**	**2 982.804**	**3 092.404**	**3 205.395**	**3 322.839**	**3 444.892**
	Extraprovincial Revenue:									
N	Total Firm Export Sales to Canada	[redacted]								
O	Total Opportunity Export Sales to Canada									
	Total Export Sales to Canada (N+O)	88.233	90.763	92.358	93.850	93.510	94.228	94.308	94.405	97.681
P	Total Firm Export Sales to USA	[redacted]								
Q	Total Opportunity Export Sales to USA									
	Total Export Sales to USA (P+Q)	569.737	582.015	599.835	610.479	606.902	601.724	596.431	594.265	499.351
R	Other Non-Energy Related Revenues	1.290	1.316	1.342	1.369	1.397	1.425	1.454	1.483	1.513
S	Transmission Credits	3.147	3.210	3.274	3.340	3.406	3.474	3.544	3.615	3.687
	Extraprovincial Revenue	**662.407**	**677.305**	**696.809**	**709.038**	**705.215**	**700.852**	**695.736**	**693.768**	**602.232**
	Water Rentals & Assessments:									
T	MH Water Rentals	117.999	117.924	117.906	117.874	117.866	117.851	117.817	117.786	117.618
U	Assessments	8.082	8.244	8.408	8.577	8.748	8.923	9.102	9.284	9.469
V	Other Costs	5.539	5.666	5.912	6.148	6.423	6.697	6.923	7.149	7.077
	Water Rentals & Assessments:	**131.619**	**131.833**	**132.227**	**132.598**	**133.038**	**133.471**	**133.842**	**134.218**	**134.165**
	Fuel & Power Purchased:									
W	MH Thermal Generation	5.663	6.003	6.379	6.777	7.345	7.669	8.315	9.298	8.848
X	Purchased Energy	96.915	100.406	103.887	107.587	87.589	86.660	91.990	100.225	91.818
Y	Other Non-Energy related Costs	7.708	7.933	8.164	8.402	8.658	8.902	9.173	9.476	8.718
Z	Transmission Charges	20.228	19.814	19.401	24.558	25.261	24.850	24.440	24.032	24.110
	Fuel & Power Purchased	**130.513**	**134.155**	**137.831**	**147.323**	**128.852**	**128.081**	**133.918**	**143.031**	**133.494**

AVERAGE UNIT REVENUE/COST ($/MW.h))	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34	2034/35	2035/36
Manitoba Domestic Energy Sales @ Approved Rates (L/A)	$ 70.26	$ 70.26	$ 70.26	$ 70.27	$ 70.26	$ 70.24	$ 70.23	$ 70.20	$ 70.18
Additional Domestic Revenue (M/A)	45.43	47.75	50.11	52.52	54.97	57.46	60.00	62.59	65.22
Total Manitoba Domestic Energy Sales @ meter (L+M)/A	115.69	118.00	120.38	122.79	125.23	127.70	130.23	132.79	135.40
Total Firm Export Sales to Canada (N/C)									
Total Opportunity Export Sales to Canada (O/D)									
Total Export Sales to Canada (N+O)/(C+D)	79.08	82.19	85.57	88.45	92.49	95.31	98.15	101.33	103.20
Total Firm Export Sales to USA (P/F)									
Total Opportunity Export Sales to USA (Q/G)									
Total Export Sales to USA (includes Net Trans Credits) (P+Q+S-Z)/(F+G)	60.88	63.68	67.18	69.46	73.10	75.92	78.51	81.47	75.35
Total Export Sales (includes Net Trans Credits) (N+O+P+Q+S-Z)/(C+D+F+G)	$ 62.87	$ 65.73	$ 69.21	$ 71.57	$ 75.28	$ 78.14	$ 80.79	$ 83.79	$ 78.96
MH Hydraulic Generation (Water Rentals) (T/I)	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34
MH Thermal Generation (W/J)	$ 117.04	$ 120.76	$ 124.79	$ 128.87	$ 132.63	$ 136.53	$ 140.72	$ 144.34	$ 149.53
Purchased Energy (Including Assessments) (X+U)/K	$ 66.94	$ 67.43	$ 68.30	$ 68.89	$ 61.95	$ 59.94	$ 60.28	$ 61.00	$ 63.41

PUB MFR 24

Export & Domestic Revenues

Schedules of export volumes, revenues/costs, and average unit revenues for the 20 years of the current IFF and actual results for 2014/15, 2015/16, and 2016/17. Split firm and opportunity volumes, revenues, and average revenues for each year. [Attachment 16, 2016/17 Interim; PUB/MH-71a, 2016 COSS]

Please see the following tables for the requested information.

Portions of the response to this MFR would result in the release of information considered to be confidential and commercially sensitive. As directed by the PUB, Manitoba Hydro will be filing a letter seeking confidential treatment of the redacted information pursuant to Rule 13.

ACTUAL AVERAGE PRICE CALCULATION

VOLUMES (in GW.h)	2014/15	2015/16
Firm Export Sales to Canada	0	61
Opportunity Export Sales to Canada	970	719
Total Export Sales to Canada	**970**	**780**
Firm Export Sales to USA	3133	2640
Opportunity Export Sales to USA	5907	6861
Total Export Sales to USA	**9040**	**9501**
Purchased Energy	**1382**	**938**
REVENUE/COST (in millions of dollars)		
Firm Export Revenues to Canada	0.000	5.194
Opportunity Export Revenues to Canada	38.207	23.109
Total Export Revenues to Canada	**38.207**	**28.303**
Firm Export Revenues to USA	182.737	200.666
Opportunity Export Revenues to USA	162.795	177.851
Total Export Revenues to USA	**345.532**	**374.360**
Total Export Sales to USA (includes net Trans & Enviro charges)	**225.635**	**341.353**
Total Import Energy	**84.442**	**66.104**
AVERAGE PRICE ($/MW.h))		
Firm Export Sales to Canada	0.00	85.67
Opportunity Export Sales to Canada	39.25	26.61
Total Export Sales to Canada	**39.25**	**31.21**
Firm Export Sales to USA	58.34	76.00
Opportunity Export Sales to USA	26.56	25.21
Total Export Sales to USA	**37.67**	**39.33**
Total Export Sales	**37.82**	**38.71**
Import Energy Including Wind	**65.82**	**69.87**

AVERAGE UNIT REVENUE/COST CALCULATION IFF16

	VOLUMES (In GW.h)	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27
	Demand:											
A	Manitoba Domestic Energy Sales	22135	22519	22259	22088	22075	22094	22210	22339	22477	22590	22721
B	Domestic energy Losses	2825	3328	2864	2785	2836	2802	2785	2802	2785	2800	2816
C	Firm Export Sales to Canada (excl. Lake St. Joseph)	[redacted]										
D	Opportunity Export Sales to Canada											
	Firm & Opportunity Export Sales to Canada (excl. Lake St. Joseph) (C+D)	766	314	597	621	840	900	1030	1025	1011	1099	1094
E	Lake St. Joseph	19	92	91	91	91	91	91	91	91	91	91
F	Firm Export Sales to US	[redacted]										
G	Opportunity Export Sales to US											
	Firm & Opportunity Export Sales to US (F+G)	10600	8760	6568	6748	7220	7928	9846	9928	9841	9396	9262
H	Net Transmission Losses	1048	942	678	706	736	819	1051	1058	1047	1025	1011
	Total Demand Volumes:	37392	35954	33056	33039	33797	34634	37013	37243	37252	37000	36996
	Supply:											
I	MH Hydraulic Generation	36494	34270	30835	31117	31306	32314	35202	35421	35418	35427	35426
J	MH Thermal Generation	54	59	364	233	86	69	59	59	60	53	52
K	Purchased Energy	845	1625	1857	1689	2405	2251	1751	1763	1774	1521	1518
	Total Supply Volumes:	37392	35954	33056	33039	33797	34634	37013	37243	37252	37000	36996

	REVENUE/COST (in millions of dollars)	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27
	Total Manitoba Domestic Energy Sales:											
L	Manitoba Domestic Energy Sales @ Approved Rates	1 517.030	1 569.093	1 561.215	1 552.164	1 550.919	1 551.621	1 558.739	1 567.393	1 576.614	1 584.175	1 592.636
M	Additional Domestic Revenue	-	87.638	255.069	397.473	550.986	717.295	766.157	817.152	869.916	923.239	978.572
	Manitoba Domestic Sales	1 517.030	1 656.732	1 816.284	1 949.637	2 101.905	2 268.916	2 324.896	2 384.545	2 446.530	2 507.414	2 571.208
	Extraprovincial Revenue:											
N	**Total Firm Export Sales to Canada**	[redacted]										
O	**Total Opportunity Export Sales to Canada**											
	Total Export Sales to Canada (N+O)	34.083	16.121	31.265	33.703	66.535	74.952	76.209	76.768	78.691	85.880	88.250
P	**Total Firm Export Sales to USA**	[redacted]										
Q	**Total Opportunity Export Sales to USA**											
	Total Export Sales to USA (P+Q)	420.959	425.899	395.884	417.005	507.169	616.258	714.204	736.455	760.715	616.259	620.702
R	Other Non-Energy Related Revenues	9.016	8.656	1.110	1.130	1.154	1.174	1.192	1.214	1.236	1.259	1.281
S	Transmission Credits	3.510	3.525	3.511	3.467	3.533	3.511	3.480	3.539	3.599	3.660	3.722
	Extraprovincial Revenue	467.568	454.201	431.769	455.306	578.391	695.895	795.085	817.976	844.241	707.057	713.956
	Water Rentals & Assessments:											
T	MH Water Rentals	121.989	114.733	103.069	104.012	104.643	108.011	117.667	118.397	118.389	118.418	118.414
U	Assessments	7.030	7.060	7.033	6.944	7.076	7.031	6.969	7.088	7.208	7.331	7.455
V	Other Costs	2.190	2.337	2.362	2.387	2.411	2.434	2.456	2.478	5.528	5.286	5.334
	Water Rentals & Assessments:	131.209	124.130	112.463	113.342	114.129	117.477	127.093	127.963	131.125	131.034	131.204
	Fuel & Power Purchased:											
W	MH Thermal Generation	3.130	4.156	21.072	15.019	6.598	6.035	5.745	6.002	6.294	5.821	5.976
X	Purchased Energy	73.788	83.632	96.464	92.584	111.986	107.043	94.803	97.476	100.412	94.077	95.287
Y	Other Non-Energy related Costs	4.852	4.538	7.349	6.390	8.220	6.641	12.014	6.833	7.032	7.164	7.361
Z	Transmission Charges	48.156	43.102	40.817	31.780	35.208	29.754	27.509	27.406	27.320	20.668	20.327
	Fuel & Power Purchased	129.926	135.428	165.702	145.772	162.012	149.472	140.071	137.717	141.058	127.730	128.952

AVERAGE UNIT REVENUE/COST ($/MW.h))	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27
Manitoba Domestic Energy Sales @ Approved Rates (L/A)	$ 68.54	$ 69.68	$ 70.14	$ 70.27	$ 70.26	$ 70.23	$ 70.18	$ 70.16	$ 70.14	$ 70.13	$ 70.10
Additional Domestic Revenue (M/A)	-	3.89	11.46	18.00	24.96	32.47	34.50	36.58	38.70	40.87	43.07
Total Manitoba Domestic Energy Sales @ meter (L+M)/A	68.54	73.57	81.60	88.27	95.22	102.69	104.68	106.74	108.85	110.99	113.17
Total Firm Export Sales to Canada (N/C)	[redacted]										
Total Opportunity Export Sales to Canada (O/D)											
Total Export Sales to Canada (N+O)/(C+D)	44.52	51.41	52.33	54.23	79.25	83.32	74.01	74.86	77.85	78.16	80.63
Total Firm Export Sales to USA (P/F)	[redacted]										
Total Opportunity Export Sales to USA (Q/G)											
Total Export Sales to USA (includes Net Trans Credits) (P+Q+S-Z)/(F+G)	35.50	44.10	54.60	57.61	65.86	74.42	70.09	71.78	74.89	63.78	65.22
Total Export Sales (N+O+P+Q+S-Z)/(C+D+F+G)	$ 36.11	$ 44.35	$ 54.41	$ 57.32	$ 67.25	$ 75.33	$ 70.46	$ 72.07	$ 75.17	$ 65.28	$ 66.85
MH Hydraulic Generation (Water Rentals) (T/I)	$ 3.34	$ 3.35	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34
MH Thermal Generation (W/J)	$ 58.50	$ 70.19	$ 57.83	$ 64.36	$ 76.56	$ 87.01	$ 97.52	$ 101.25	$ 105.38	$ 110.40	$ 114.72
Purchased Energy (Including Assessments) (X+U)/K	$ 95.70	$ 55.80	$ 55.74	$ 58.94	$ 49.51	$ 50.68	$ 58.11	$ 59.32	$ 60.68	$ 66.68	$ 67.68

	VOLUMES (in GW.h)	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34	2034/35	2035/36
	Demand:									
A	Manitoba Domestic Energy Sales	22827	22952	23213	23487	23930	24413	24915	25430	25969
B	Domestic energy Losses	2829	2845	2876	2909	2966	3029	3095	3162	3233
C	**Firm Export Sales to Canada (excl. Lake St. Joseph)**	[redacted]								
D	**Opportunity Export Sales to Canada**									
	Firm & Opportunity Export Sales to Canada (excl. Lake St. Joseph) (C+D)	1107	1101	1078	1052	1013	986	956	922	937
E	Lake St. Joseph	91	91	91	91	91	91	91	91	91
F	**Firm Export Sales to US**	[redacted]								
G	**Opportunity Export Sales to US**									
	Firm & Opportunity Export Sales to US (F+G)	9099	8977	8767	8551	8200	7822	7444	7063	6351
H	Net Transmission Losses	999	986	961	934	891	846	799	751	690
	Total Demand Volumes:	**36953**	**36952**	**36986**	**37024**	**37090**	**37187**	**37299**	**37420**	**37271**
	Supply:									
I	MH Hydraulic Generation	35430	35420	35410	35397	35390	35389	35377	35368	35348
J	MH Thermal Generation	49	50	52	54	57	59	61	66	61
K	Purchased Energy	1474	1482	1524	1573	1643	1739	1861	1986	1862
	Total Supply Volumes:	**36953**	**36952**	**36986**	**37024**	**37090**	**37187**	**37299**	**37420**	**37271**

	REVENUE/COST (in millions of dollars)	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34	2034/35	2035/36
	Total Manitoba Domestic Energy Sales:									
L	Manitoba Domestic Energy Sales @ Approved Rates	1 599.471	1 607.568	1 622.994	1 639.376	1 667.105	1 697.836	1 729.739	1 762.224	1 796.368
M	Additional Domestic Revenue	1 034.402	1 092.569	1 157.562	1 225.408	1 304.394	1 388.960	1 477.951	1 571.063	1 669.459
	Manitoba Domestic Sales	**2 633.873**	**2 700.137**	**2 780.556**	**2 864.784**	**2 971.499**	**3 086.796**	**3 207.691**	**3 333.287**	**3 465.828**
	Extraprovincial Revenue:									
N	**Total Firm Export Sales to Canada**	[redacted]								
O	**Total Opportunity Export Sales to Canada**									
	Total Export Sales to Canada (N+O)	91.768	93.904	95.060	95.949	95.746	96.222	96.673	96.563	100.557
P	**Total Firm Export Sales to USA**	[redacted]								
Q	**Total Opportunity Export Sales to USA**									
	Total Export Sales to USA (P+Q)	610.983	621.559	632.765	642.976	643.795	641.080	637.075	630.131	547.665
R	Other Non-Energy Related Revenues	1.305	1.329	1.353	1.377	1.402	1.428	1.454	1.480	1.507
S	Transmission Credits	3.786	3.850	3.915	3.982	4.050	4.119	4.189	4.260	4.332
	Extraprovincial Revenue	**707.842**	**720.642**	**733.094**	**744.284**	**744.994**	**742.848**	**739.391**	**732.434**	**654.062**
	Water Rentals & Assessments:									
T	MH Water Rentals	118.428	118.395	118.362	118.319	118.294	118.291	118.251	118.220	118.156
U	Assessments	7.582	7.711	7.842	7.975	8.111	8.249	8.389	8.532	8.677
V	Other Costs	5.392	5.512	5.685	5.908	6.169	6.430	6.643	6.856	6.785
	Water Rentals & Assessments:	**131.402**	**131.618**	**131.890**	**132.203**	**132.574**	**132.970**	**133.283**	**133.607**	**133.617**
	Fuel & Power Purchased:									
W	MH Thermal Generation	5.839	6.167	6.628	7.123	7.863	8.348	8.946	9.953	9.521
X	Purchased Energy	95.903	97.870	101.224	105.018	110.242	116.942	125.440	134.765	130.518
Y	Other Non-Energy related Costs	7.537	7.758	7.996	8.241	8.509	8.760	9.028	9.328	8.565
Z	Transmission Charges	19.920	19.514	19.109	24.179	24.870	24.468	24.066	23.665	23.743
	Fuel & Power Purchased	**129.200**	**131.309**	**134.956**	**144.561**	**151.484**	**158.517**	**167.480**	**177.710**	**172.346**

AVERAGE UNIT REVENUE/COST ($/MW.h))	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34	2034/35	2035/36
Manitoba Domestic Energy Sales @ Approved Rates (L/A)	$ 70.07	$ 70.04	$ 69.92	$ 69.80	$ 69.67	$ 69.55	$ 69.42	$ 69.30	$ 69.17
Additional Domestic Revenue (M/A)	45.32	47.60	49.87	52.17	54.51	56.89	59.32	61.78	64.29
Total Manitoba Domestic Energy Sales @ meter (L+M)/A	115.39	117.64	119.78	121.97	124.18	126.44	128.74	131.07	133.46
Total Firm Export Sales to Canada (N/C)	[redacted]								
Total Opportunity Export Sales to Canada (O/D)									
Total Export Sales to Canada (N+O)/(C+D)	82.86	85.32	88.21	91.18	94.52	97.63	101.15	104.68	107.32
Total Firm Export Sales to USA (P/F)	[redacted]								
Total Opportunity Export Sales to USA (Q/G)									
Total Export Sales to USA (includes Net Trans Credits) (P+Q+S-Z)/(F+G)	65.37	67.49	70.44	72.83	75.97	79.36	82.92	86.47	83.18
Total Export Sales (N+O+P+Q+S-Z)/(C+D+F+G)	$ 67.27	$ 69.44	$ 72.39	$ 74.84	$ 78.01	$ 81.40	$ 84.99	$ 88.57	$ 86.28
MH Hydraulic Generation (Water Rentals) (T/I)	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34
MH Thermal Generation (W/J)	$ 119.39	$ 124.02	$ 128.36	$ 132.57	$ 137.06	$ 141.92	$ 146.00	$ 151.00	$ 156.55
Purchased Energy (Including Assessments) (X+U)/K	$ 70.20	$ 71.24	$ 71.58	$ 71.83	$ 72.02	$ 71.98	$ 71.91	$ 72.15	$ 74.75

PUB MFR 79 (Updated)
Export & Domestic Revenue

Manitoba Hydro's electricity export price forecast including the supporting forecasts of any third-party forecasting firms. Explain any changes in Manitoba Hydro's forecasting methodology since the NFAT. Provide additional details of how carbon pricing is incorporated into the forecast.

The response to PUB MFR 79 has been updated to reflect the July 2017 update to the financial forecast for electric operations (MH16 Update).

Public disclosure of the response to this MFR (or portions thereof) would result in the release of information considered to be confidential and commercially sensitive. As directed by the PUB, Manitoba Hydro will be filing a letter seeking confidential treatment of the redacted information contained in this response pursuant to Rule 13.

Methodological Changes since 2013 Electricity Export Price Forecast (EEPF)
Manitoba Hydro's consensus methodology to produce the long term Electricity Export Price Forecast (EEPF) Reference case for the On-Peak Energy, Off-Peak Energy and Capacity products remain unchanged from the 2013 EEPF through the 2016 EEPF.

For 2013 EEPF through the 2015 EEPF, the high and low forecasts were also produced using the consensus approach. For the 2016 EEPF, the High and Low cases for the On-Peak Energy, Off-Peak Energy and Capacity products were based on the Brattle Group's high and low price scenario work, similar to scenario work that Brattle prepared for the NFAT, and hence did not use a consensus forecast approach. This change was implemented for cost savings reasons.

For the 2013 EEPF through the 2015 EEPF, the Long Term Dependable Product forecast was based on the On-Peak Energy combined with the Capacity Product Forecast, [redacted] which is the approach discussed in the Confidential NFAT response LCA/MH I-433. For the 2016 EEPF, [redacted] to better reflect current market conditions.

For 2017, the forecast was renamed Energy Price Forecast (EPF) and combined with other forecasts (coal, crude oil and domestic prices) the Long Term Dependable Product was removed [redacted] High and Low forecasts were removed from Capacity as they weren't used by stakeholders.

2017 Third-party forecasts

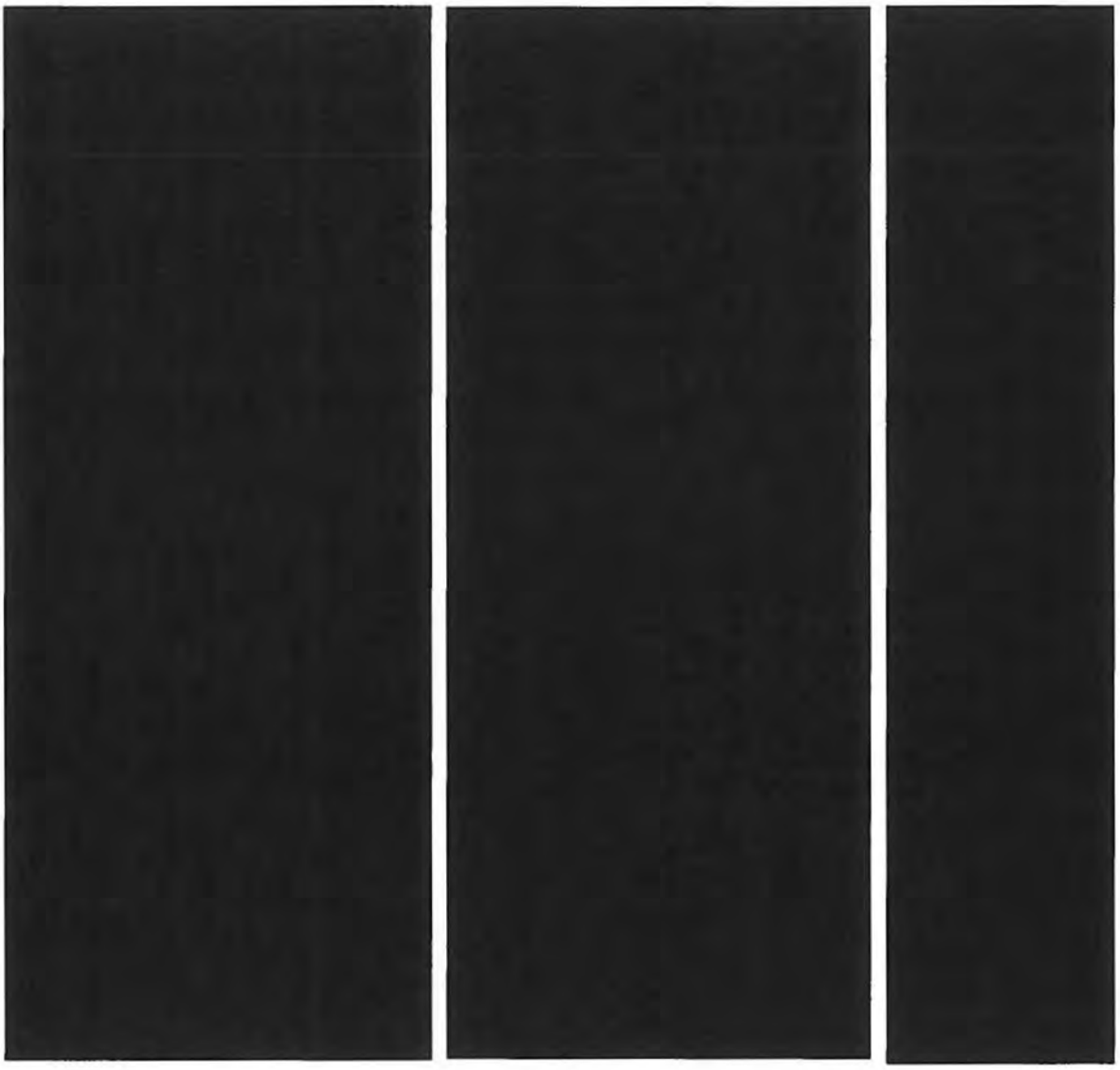
The table below includes export price forecasts received in the spring of 2017 for the MHEB pricing node from four of the independent price forecast consultants. Price forecasts are generally subject to strict confidentiality requirements. The consultants have agreed to provide their forecast to the Public Utilities Board in confidence, provided their names have been removed.



2017 EPF Forecasts

Over the last 12 months, energy markets have continued to evolve in a manner that has put further downward pressure on long term power prices. The primary driver of reduced long term power price expectations is a reduction in long term natural gas prices. Increased renewable development, primarily wind generation, in the MISO market has also contributed to the downward pressure on prices. Significant changes in US energy and environmental policy continue, particularly as a result of the November 2016 election. As of 2017, there are now expectations of decreased coal generation and mining regulations, reduced oil and natural gas exploration regulations, and the elimination carbon pricing programs such as what is contained in the Clean Power Plan.

Manitoba Hydro updated the electricity export price forecast in February 2017 to reflect recent changes in the long term market outlook, referred to as the 2016 Adjusted EEPF. [redacted] Capacity prices are particularly uncertain at this time as coal closures have been delayed under the Trump administration, increasing capacity supply. The MISO Planning Resource (Capacity) Auction for the 2017/18 planning year cleared at the very low price of $1.50/MW-day (US $547.50 per MW-yr or US $0.55 per kW-yr). For IFF16, Manitoba Hydro did not firm up any surplus dependable energy not already sold under long term contract, and did not attribute any capacity revenue to surplus dependable energy not already sold under long term contract.



Carbon Forecasts

The 2017 no longer assumes the Clean Power Plan (CPP) or similar construct was put in place compared to the 2016 Adjusted. Some consultants include additional cases with and without carbon as they aren't sure which future is likely. Some forecasters still include carbon assumptions but to a lower degree.

PUB MFR 79 (Revised)
Export & Domestic Revenue

Manitoba Hydro's electricity export price forecast including the supporting forecasts of any third-party forecasting firms. Explain any changes in Manitoba Hydro's forecasting methodology since the NFAT. Provide additional details of how carbon pricing is incorporated into the forecast.

Portions of the response to this MFR would result in the release of information considered to be confidential and commercially sensitive. As directed by the PUB, Manitoba Hydro will be filing a letter seeking confidential treatment of the redacted information pursuant to Rule 13.

Methodological Changes since 2013 Electricity Export Price Forecast (EEPF)
Manitoba Hydro's consensus methodology to produce the long term Electricity Export Price Forecast (EEPF) Reference case for the On-Peak Energy, Off-Peak Energy and Capacity products remain unchanged from the 2013 EEPF through the 2016 EEPF.

For 2013 EEPF through the 2015 EEPF, the high and low forecasts were also produced using the consensus approach. For the 2016 EEPF, the High and Low cases for the On-Peak Energy, Off-Peak Energy and Capacity products were based on the Brattle Group's high and low price scenario work, similar to scenario work that Brattle prepared for the NFAT, and hence did not use a consensus forecast approach. This change was implemented for cost savings reasons.

For the 2013 EEPF through the 2015 EEPF, the Long Term Dependable Product forecast was based on the On-Peak Energy combined with the Capacity Product Forecast, [redacted], which is the approach discussed in NFAT IR PUB/MH II-301. For the 2016 EEPF, [redacted] to better reflect current market conditions.

2016 Third-party forecasts
The table below includes export price forecasts received in the spring of 2016 for the MHEB pricing node from four of the five independent price forecast consultants. Price forecasts are generally subject to strict confidentiality requirements. All five consultants have agreed

to provide their forecast to the Public Utilities Board in confidence, provided their names have been removed.



2016 (Adjusted) EEPF Forecasts

Over the last 24 months, energy markets have continued to evolve in a manner that has put further downward pressure on long term power prices. The primary driver of reduced long term power price expectations is a reduction in long term natural gas prices. Increased renewable development, primarily wind generation, in the MISO market has also contributed to the downward pressure on prices. The 2016 EEPF was prepared in the spring of 2016. Significant changes in US energy and environmental policy continue, particularly as a result of the November 2016 election. As of spring 2017, there are now expectations of decreased coal generation and mining regulations, reduced oil and natural gas exploration regulations, and the elimination carbon pricing programs such as what is contained in the Clean Power Plan.

Manitoba Hydro updated the electricity export price forecast in February 2017 to reflect recent changes in the long term market outlook, referred to as the 2016 Adjusted EEPF. Overall, electricity export prices are down about 20% relative to the comparable 2015 forecast used for IFF15. Capacity prices are particularly uncertain at this time as coal closures have been delayed under the Trump administration, increasing capacity supply. The MISO Planning Resource (Capacity) Auction for the 2017/18 planning year cleared at the very low price of $1.50/MW-day (US $547.50 per MW-yr or US $0.55 per kW-yr). For IFF16, Manitoba Hydro did not firm up any surplus dependable energy not already sold under long term contract, and did not attribute any capacity revenue to surplus dependable energy not already sold under long term contract.



Carbon Forecasts

The 2016 EEPF assumed the Clean Power Plan (CPP) or similar construct was put in place. The independent price forecast consultants may either directly use a value for carbon in computing their energy prices, or more commonly input a carbon emission limit into their models and have their model solve for a resource mix and related energy and carbon prices required to meet this carbon constraint. The 2016 Adjusted EEPF was prepared primarily on the basis of the decline in natural gas prices, and potential changes to the Clean Power Plan were not explicitly factored into the adjustment.

Preparation of the 2017 Electricity Export Price Forecast is currently underway and will be incorporated in the 2017 Integrated Financial Forecast.

PUB MFR 81
Export & Domestic Revenue

Summary table of Manitoba Hydro's export commitments showing the minimum annual energy obligation, maximum annual achievable energy sales, annual free clean energy credits to buyer, and pricing. [NFAT PUB/MH I-028]

Public disclosure of the response to this MFR (or portions thereof) would result in the release of information considered to be confidential and commercially sensitive. As directed by the PUB, Manitoba Hydro will be filing a letter seeking confidential treatment of the redacted information contained in this response pursuant to Rule 13.

Please see the following table for a summary of the minimum annual energy obligation, dependable energy sales, environmental attributes to buyer, and pricing descriptions for dependable export contracts from 2020/21 onwards [NFAT PUB/MH I-028]. Maximum annual achievable energy sales include both the dependable energy sales and any opportunity energy sales, dependent on the provisions specified in the individual contracts and water conditions. Opportunity energy forecasts can be found in PUB MFR 24.

Contract	Capacity	Min. Annual Energy Obligation (GWh)	Dependable Energy Sales (GWh)	Annual Environmental Attributes to Buyer	Energy Pricing (GWh)
NSP 375/325 MW	Summer 375 MW Winter 325 MW				
NSP 125 MW	125 MW Year Round				
MP 250 MW	250 MW Year Round				
WPS 100 MW	100 MW Year Round				
WPS 108 MW	108 MW Year Round				
SP 25 MW	25 MW Year Round				
SP 2020-2040	100 MW Year Round				

PUB MFR 82 (Revised)

Export & Domestic Revenue

Incremental revenues and unit revenues from Keeyask by year, broken down by firm and opportunity sales.

Public disclosure of the response to this MFR (or portions thereof) would result in the release of information considered to be confidential and commercially sensitive. As directed by the PUB, Manitoba Hydro will be filing a motion seeking confidential treatment of the redacted information contained in this response pursuant to Rule 13.

The following schedules have been prepared using simplifying assumptions with respect to the allocation of dependable energy that is used to serve firm sales, and consequently the revenue to attribute to Keeyask energy. There are many operational decisions made to manage reservoir levels and stream flow in order to maximize the overall value of energy generated by an integrated hydro-electric system. These decisions involve optimizing the collective generation output of the hydro-electric facilities on the system, thermal generation, and energy purchases. The output of individual facilities may appear to be sub-optimal in order to benefit the system as a whole. As a result, it is an arbitrary exercise to attribute the generation of an individual facility to serving any of Manitoba demand, the overall portfolio of firm sales or any one firm sale in an integrated hydro-electric system.

The first schedule calculates the total system average unit revenues (at generation) for domestic, firm export and non-firm export sales. The appropriate average unit revenue is applied to the Keeyask energy allocated for domestic, firm export and non-firm export energy to derive the revenue for each category.

For the purposes of this response, the Keeyask energy has been allocated between firm exports and opportunity exports under three sets of assumptions in order to provide an indicative range of revenue allocations as follows:

- Scenario 1: All of Keeyask energy assumed to be sold as opportunity sales.

- Scenario 2: Keeyask firm energy is assumed to serve the MP250 sale plus an amount of remaining firm contracts based proportionally on Keeyask firm energy to total system firm energy (approximately 10% declining gradually as Manitoba load grows).
- Scenario 3: All of Keeyask firm energy serves firm export sales.

In all three scenarios, Keeyask energy will not be used to serve domestic load until it is approximately needed for load growth. Scenarios 2 and 3 are shown below in **Figure 1** (Scenario 1 is commercially sensitive).

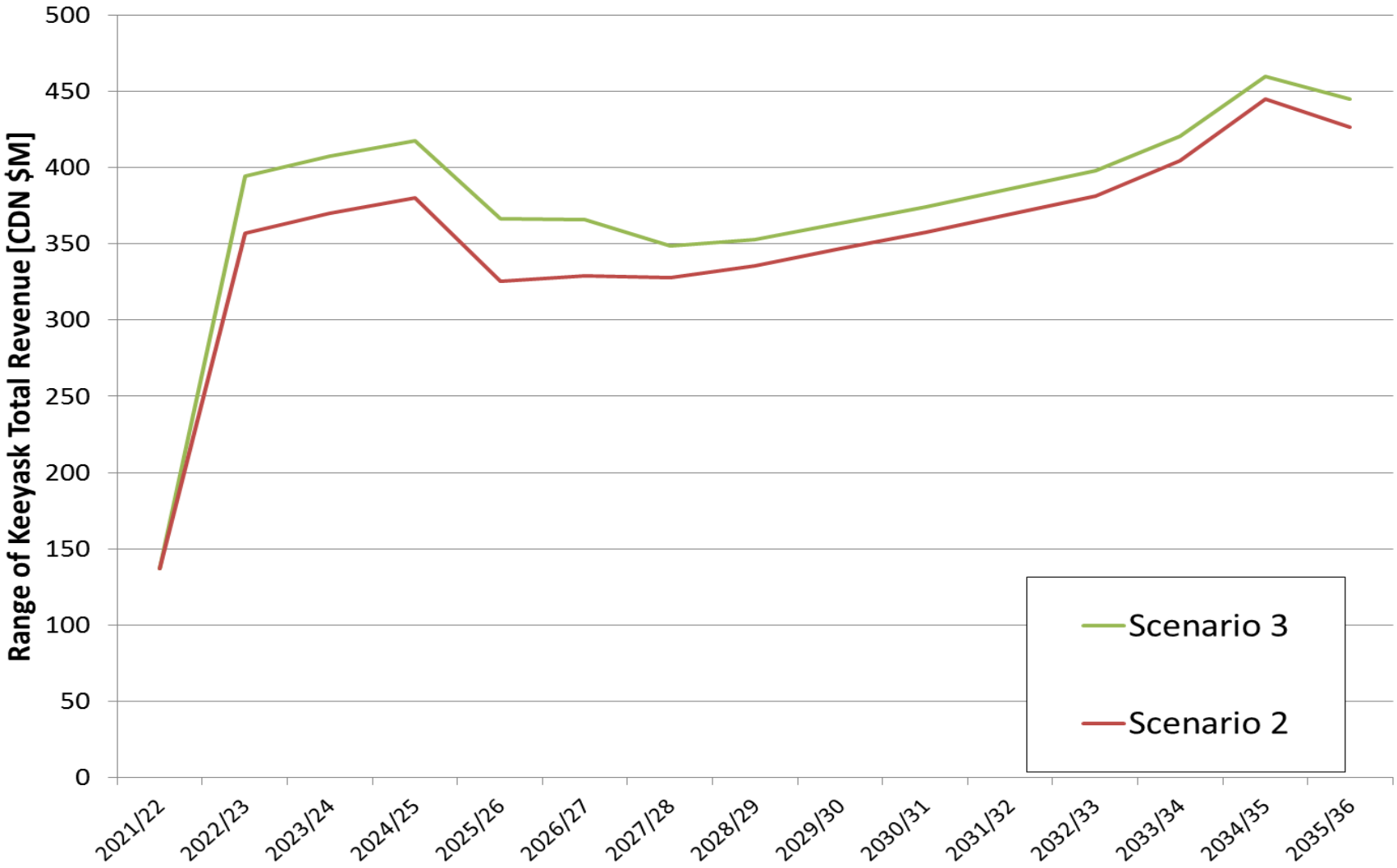
Total System Sales @ Generation

Fiscal	Domestic Revenue [CDN $M]	Domestic Energy [GWh]	Firm Export Revenue [CDN $M]	Non-Firm Export Revenue [CDN $M]	Total Export Revenue [CDN $M]	Firm Export Energy [GWh]	Non-Firm Export Energy [GWh]	Total Export Energy [GWh]	Domestic Average Unit Revenue [CDN $/MWh]	Firm Export Average Unit Revenue [CDN $/MWh]	Non-Firm Export Average Unit Revenue [CDN $/MWh]	Total Export Average Unit Revenue [CDN $/MWh]
2021/22	2 476.7	24 904			681.0			9 710	$ 99.45			$ 70.14
2022/23	2 536.1	25 001			779.2			11 964	$ 101.44			$ 65.13
2023/24	2 601.9	25 147			802.6			12 049	$ 103.47			$ 66.61
2024/25	2 666.8	25 268			823.8			11 937	$ 105.54			$ 69.01
2025/26	2 733.8	25 395			683.8			11 545	$ 107.65			$ 59.23
2026/27	2 804.6	25 542			691.3			11 392	$ 109.80			$ 60.68
2027/28	2 874.0	25 661			681.4			11 227	$ 112.00			$ 60.69
2028/29	2 947.6	25 802			693.6			11 085	$ 114.24			$ 62.57
2029/30	3 040.7	26 095			705.7			10 829	$ 116.52			$ 65.17
2030/31	3 138.0	26 402			715.3			10 563	$ 118.86			$ 67.71
2031/32	3 261.3	26 901			715.4			10 134	$ 121.23			$ 70.60
2032/33	3 394.2	27 449			712.3			9 688	$ 123.66			$ 73.52
2033/34	3 533.7	28 017			706.8			9 239	$ 126.13			$ 76.50
2034/35	3 679.4	28 599			698.4			8 784	$ 128.65			$ 79.51
2035/36	3 833.0	29 209			611.7			8 016	$ 131.23			$ 76.31

Fiscal	Scenario 1: Keeyask Sales @ Generation - All Non-Firm							
	Keeyask Firm Energy Domestic [GWh]	Keeyask Firm Energy Export [GWh]	Keeyask Non-Firm Energy Export [GWh]	Keeyask Total Energy [GWh]	Keeyask Firm Revenue Domestic [CDN $M]	Keeyask Firm Revenue Export [CDN $M]	Keeyask Non-Firm Revenue Export [CDN $M]	Keeyask Total Revenue [CDN $M]
2021/22	-	-	1 353	1 353	-	[redacted]		
2022/23	-	-	4 351	4 351	-			
2023/24	-	-	4 434	4 434	-			
2024/25	-	-	4 433	4 433	-			
2025/26	-	-	4 431	4 431	-			
2026/27	-	-	4 430	4 430	-			
2027/28	-	-	4 430	4 430	-			
2028/29	-	-	4 429	4 429	-			
2029/30	-	-	4 427	4 427	-			
2030/31	-	-	4 426	4 426	-			
2031/32	-	-	4 425	4 425	-			
2032/33	-	-	4 425	4 425	-			
2033/34	213	-	4 211	4 424	26.9			
2034/35	796	-	3 627	4 423	102.4			
2035/36	1 405	-	3 014	4 419	184.4			

Fiscal	Scenario 2: Keeyask Sales @ Generation - MP250 + ProRated contracts							
	Keeyask Firm Energy Domestic [GWh]	Keeyask Firm Energy Export [GWh]	Keeyask Non-Firm Energy Export [GWh]	Keeyask Total Energy [GWh]	Keeyask Firm Revenue Domestic [CDN $M]	Keeyask Firm Revenue Export [CDN $M]	Keeyask Non-Firm Revenue Export [CDN $M]	Keeyask Total Revenue [CDN $M]
2021/22	-	[redacted]		1 353	-	[redacted]		137.0
2022/23	-			4 351	-			357.2
2023/24	-			4 434	-			369.7
2024/25	-			4 433	-			380.1
2025/26	-			4 431	-			325.3
2026/27	-			4 430	-			329.1
2027/28	-			4 430	-			327.9
2028/29	-			4 429	-			335.6
2029/30	-			4 427	-			346.6
2030/31	-			4 426	-			357.4
2031/32	-			4 425	-			369.3
2032/33	-			4 425	-			381.4
2033/34	213			4 424	26.9			404.2
2034/35	796			4 423	102.4			445.2
2035/36	1 405			4 419	184.4			426.4

Fiscal	Scenario 3: Keeyask Sales @ Generation - All Firm							
	Keeyask Firm Energy Domestic [GWh]	Keeyask Firm Energy Export [GWh]	Keeyask Non-Firm Energy Export [GWh]	Keeyask Total Energy [GWh]	Keeyask Firm Revenue Domestic [CDN $M]	Keeyask Firm Revenue Export [CDN $M]	Keeyask Non-Firm Revenue Export [CDN $M]	Keeyask Total Revenue [CDN $M]
2021/22	-	[redacted]		1 353	-	[redacted]		137.0
2022/23	-			4 351	-			394.2
2023/24	-			4 434	-			407.3
2024/25	-			4 433	-			417.7
2025/26	-			4 431	-			366.6
2026/27	-			4 430	-			366.0
2027/28	-			4 430	-			348.4
2028/29	-			4 429	-			352.8
2029/30	-			4 427	-			363.6
2030/31	-			4 426	-			374.4
2031/32	-			4 425	-			386.1
2032/33	-			4 425	-			398.0
2033/34	213			4 424	26.9			420.7
2034/35	796			4 423	102.4			459.6
2035/36	1 405			4 419	184.4			445.0


Range of Keeyask Total Revenue [CDN $M]
500
450
400
350
300
250
200
150
100
50
0
2021/22
2022/23
2023/24
2024/25
2025/26
2026/27
2027/28
2028/29
2029/30
2030/31
2031/32
2032/33
2033/34
2034/35
2035/36
Scenario 3
Scenario 2

PUB MFR 83

Export & Domestic Revenue

NFAT CSI Exhibit MH-2 and an update showing the anticipated export revenues broken down by contract and by capacity, firm energy, contracted surplus energy, and non-contracted surplus energy.

Public disclosure of the response to this MFR (or portions thereof) would result in the release of information considered to be confidential and commercially sensitive. As directed by the PUB, Manitoba Hydro will be filing a letter seeking confidential treatment of the redacted information contained in this response pursuant to Rule 13.

Figures 1 through **3** provide a breakdown of forecast dependable revenue by contract. All market priced dependable and surplus energy forecasts are included in revenues provided in PUB MFR 24.

Figure 1 reflects fixed price weekday capacity and dependable energy revenues, which will vary with differences in actual US exchange rate and escalation rates relative to forecast.

Figure 2 reflects fixed price weekend energy revenues, which will also vary with differences in US exchange rates and escalation rates.

Figure 3 is a summary table for all weekday and weekend capacity and dependable energy revenues.

Figure 1. MH Export Contracts and Revenues for Fiscal Year Beginning 2016 – Weekday Dependable Capacity & Energy

Customer	Contract Name	Capacity (MW)	Energy Product	Capacity Revenue	Energy Revenue	Total Revenue
Minnesota Power	MP 250	250	5x16	[redacted]	[redacted]	[redacted]
	MP 50	50	5x16	[redacted]	[redacted]	[redacted]
	MP 50 ZRC	50	7x4	[redacted]	[redacted]	[redacted]
Northern States Power	NSP125	125	5x16(S) 5x12(W)	[redacted]	[redacted]	[redacted]
	NSP 375/325 SPS	375(S) 325(W)	5x16(S) 5x12(W)	[redacted]	[redacted]	[redacted]
Wisconsin Public Service	WPS 100 Product A	100	5x16	[redacted]	[redacted]	[redacted]
	WPS 108	108	5x16	[redacted]	[redacted]	[redacted]
SaskPower	SaskPower 25	25	5x16	[redacted]	[redacted]	[redacted]
	SaskPower 2020-2040	100	5x16	[redacted]	[redacted]	[redacted]
Nextera	Nextera 100 ZRC	100	7x4	[redacted]	[redacted]	[redacted]
	Nextera 30 ZRC	30	7x4	[redacted]	[redacted]	[redacted]
AEP	AEP 79/50 ZRC	79/50	7x4	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	50	7x4	[redacted]	[redacted]	[redacted]
	[redacted]	50	7x4	[redacted]	[redacted]	[redacted]
Total				[redacted]	[redacted]	**$5,326M**

Figure 2. MH Export Contracts and Revenues for Fiscal Year Beginning 2016 – Weekend Dependable Capacity & Energy

Customer	Contract Name	Energy Product	Energy Revenue
Minnesota Power	MP 250	2x16	[redacted]
	MP 50	2x16	[redacted]
Northern States Power	NSP125	2x4	[redacted]
	NSP 375/325 SPS	2x4	[redacted]
Wisconsin Public Service	WPS 100 Product A	2x16	[redacted]
	WPS 108	2x4	[redacted]
SaskPower	SaskPower 25	2x16	[redacted]
	SaskPower 2020-2040	1x16	[redacted]
Total			**$742M**

Figure 3. MH Export Contracts Fiscal Year Beginning 2016 – Total Revenue

Customer	Contract Name	Capacity Revenue	Energy Revenue	Total Revenue (Expense)
Minnesota Power	MP 250	[redacted]	[redacted]	[redacted]
	MP 50	[redacted]	[redacted]	[redacted]
	MP 50 ZRC	[redacted]	[redacted]	[redacted]
Northern States Power	NSP125	[redacted]	[redacted]	[redacted]
	NSP 375/325 SPS	[redacted]	[redacted]	[redacted]
Wisconsin Public Service	WPS 100 Product A	[redacted]	[redacted]	[redacted]
	WPS 108	[redacted]	[redacted]	[redacted]
SaskPower	SaskPower 25	[redacted]	[redacted]	[redacted]
	SaskPower 2020-2040	[redacted]	[redacted]	[redacted]
Nextera	Nextera 100 ZRC	[redacted]	[redacted]	[redacted]
	Nextera 30 ZRC	[redacted]	[redacted]	[redacted]
AEP	AEP 79/50 ZRC	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]	[redacted]
Total		[redacted]	[redacted]	$6,070M

PUB MFR 115

Sustaining and Major Capital

For each of the capital projects in the following list, provide:

i. **Justification (technical and economic) for the proposed expenditures.**
ii. **Explanations of why each project must be initiated or completed in the test year(s) as opposed to deferring to a future date.**
iii. **Alternatives to each project, including a "do nothing" alternative, with corresponding costs, benefits or avoided costs, and risks identified.**
iv. **the risk analyses that demonstrate why the project must be completed or initiated in the test year.**
v. **the asset condition assessment for the assets being replaced or supplemented.**

Major New Projects:

1. **Kelsey Improvements and Upgrades**
2. **Kettle Improvements and Upgrades**
3. **Riel 230kV/500kV Station**
4. **Pointe du Bois Spillway Replacement**
5. **Gillam Redevelopment and Expansion Program (GREP)**

Major Generation Projects:

6. **Pointe du Bois Unit and Accessories Replacement**
7. **Pine Falls Units 1-4 Major Overhauls**
8. **Slave Falls Major Overhauls**
9. **Great Falls Unit 4 Overhaul**

Major Transmission Projects:

10. **HVDC Transformer Replacement Program**
11. **Bipole II Thyristor Valve Replacement**
12. **Dorsey Synchronous Condenser Refurbishment**
13. **Lake Winnipeg East System Improvements**
14. **Letellier-St. Vital 230kV Station**

Major Distribution Projects:

15. **Madison New 115kV/24kV Station**
16. **Adelaide New 66kV/12kV Station**
17. **St. Vital 115kV/24kV Station**

Base Capital Projects:

18. Rover 4kV Station Salvage&Feeder Conversion
19. Winnipeg Distribution Infrastructure Requirement
20. Grand Rapids Excitation Program
21. McArthur Falls/Pine Falls Breaker Replacement Program
22. Seven Sisters Protection Upgrades
23. Slave Falls G.S. Creek Spillway Rehabilitation
24. Slave Falls Spillway Rehabilitation
25. 13.2kV Shunt Reactor Replacements
26. Enterprise Asset Management (EAM) Phase 2
27. Bi-Pole I & II Spacer Damper Replacements (Phase 2)
28. HVDC BP2 Smoothing Reactor Replacement
29. Southern AC System Breaker Replacements
30. Transmission Transformer Sustainment Capital Program
31. BP1 & 2 DC Converter Transformer Bushing Replacement
32. HVDC BP2 Valve Hall Wall Bushing Replacement

Please find Capital Project Justification (CPJ) and CPJ Addendum (CPJA) for each of the projects requested at the link below:
https://www.hydro.mb.ca/regulatory_affairs/pdf/electric/general_rate_application_2017/mfrs/pub_mfr_115_attachments.pdf

PUB MFR 123
Keeyask

Provide a breakdown of the revised $8.7 billion cost estimate including reserves, contingencies, escalation, interest, and major contract costs.

Public disclosure of the response to this MFR (or portions thereof) would result in the release of information considered to be confidential and commercially sensitive. As directed by the PUB, Manitoba Hydro will be filing a letter seeking confidential treatment of the redacted information contained in this response pursuant to Rule 13.

Please see the **Table 1** below.

Table 1 - Keeyask Budget Summary (in Billions $)	
Item	**Approved Budget as of Dec. 31, 2016 (2016$)**
Generating Station Costs	
Final Design Engineering – Hatch	[redacted]
Camp Operations Services - Fox, York and Sodexo Joint Venture	[redacted]
Maintenance Services - Maintenance Services Joint Venture	[redacted]
Main Camp – Britco	[redacted]
South Access Road - Amisk Construction	[redacted]
General Civil Works - BBE Hydro Construction	[redacted]
Reservoir Clearing - Amisk Construction	[redacted]
Spillway Gates, Guides, Hoists, Towers and Monorail Crane - Canmec Industriel Inc.	[redacted]
Intake Gates, Guides and Hoists - Canmec Industriel Inc.	[redacted]
Turbines & Generators - Voith Hydro	[redacted]
Other Generating Station Costs	[redacted]
Generation Outlet Transmission (GOT)	[redacted]
Escalation @ CPI[1]	0.249
Interest [1]	1.749
Base Contingency[1]	0.578
Labour Mgmt Reserve	0.000
Escalation Mgmt Reserve	0.000
Total	**8.726**
First in-service Date	**Aug-21**

[1] Base Contingency in the table above is consistent with what was reported in the response to PUB MFR 147, $0.578 billion. Contingency in the form of schedule delay from the risk analysis accrues an interest cost of $0.294 billion and $0.028 billion respectively and are shown as such in the response to PUB MFR 147. These amounts are included in the interest and escalation values in the table above.

PUB MFR 129
Keeyask

a) **Provide the Keeyask Project Risk Registry detailing the risks to the Keeyask project and Manitoba Hydro's mitigation actions [provided at NFAT]**
b) **Identify and explain whether any of the risks in the Registry with an impact score of Very High have materialized, how Manitoba Hydro addressed the risks, and what the impact of the risk has been and is expected to be on the total project cost and project schedule.**
c) **Identify whether any of the risks in the Registry with impact scores other than Very High have materialized but which have had a financial impact of greater than $20 million or a schedule impact of greater than 6 months. Explain how Manitoba Hydro attempted to mitigate the risks, and what Manitoba Hydro has done or continues to do to manage the impact of the risk.**

Public disclosure of the response to this MFR (or portions thereof) would result in the release of information considered to be confidential and commercially sensitive. As directed by the PUB, Manitoba Hydro will be filing a letter seeking confidential treatment of the redacted information contained in this response and the information in the attachment, pursuant to Rule 13.

a) The Keeyask Project Risk Registry [provided at NFAT] is included in the attached document. This document is confidential in its entirety.

b) Table 1. Keeyask Project Very High Risks Materialized. Full Risk Registry details are included in the attached document;

Table 1: Keeyask Very High Risks Materialized

Materialized Very High Risk	Mitigation Undertaken	Impact to Project Cost and/or Schedule	Future Expected Additional Impact
Labour Productivity (including the experience level of the workforce and the contractor's productivity rates assumed within the tender)	[redacted]	The estimated impact is in the [redacted] to [redacted] range. This figure represents both schedule and cost.	The estimated future impact is in the [redacted] to [redacted] range. This figure represents both schedule and cost.
Weather (including record high river flows, formation of stable ice cover in the winter)	1. Early onset of winter and late onset of spring mitigated with additional heating and hoarding to permit extension of concrete season through shoulder months. 2. High flows mitigated with cofferdam top-up of up to 10m of additional height. 3. Stable ice cover achieved through redesigned and reinstalled ice boom each spring as well as relocating of boom. 4. extensive dewatering performed to minimize cofferdam leakage into working areas	The estimated impact is in the [redacted] to [redacted] range. This figure represents both schedule and cost.	The estimated future impact is in the [redacted] to [redacted] range. This figure represents both schedule and cost.

Table 1: Keeyask Very High Risks Materialized

Materialized Very High Risk	Mitigation Undertaken	Impact to Project Cost and/or Schedule	Future Expected Additional Impact
Geotechnical / Geological Conditions More Challenging than Planned (including boreholes not representative of actual site conditions for excavation and borrow pits)	[redacted]	The estimated impact is in the [redacted] to [redacted] range. This figure represents both schedule and cost.	The estimated future impact is in the [redacted] to [redacted] range. This figure represents both schedule and cost.

c) Table 2. Keeyask Project Risks (other than Very High impacts) Realized > $20 million or Schedule > 6 months. Full Risk Registry details are included in the attached document.

Table 2. Keeyask Project Risks Realized

Materialized Risk	Mitigation Undertaken	Continued Mitigation Activities	Impact to Project Cost and/or Schedule
Inaccurate Quality Assurance (QA) / Quality Control (QC) Assessment to Meet Project Requirements	As a result of initial insufficient execution of QC work, additional quality control technicians were brought on to the construction management team to perform on-site inspections. Additionally, several alternate models for ongoing on-site QC/QA activities for this contract were developed and evaluated and a revised model implemented beginning in November 2016.	Continuing with the revised model for on-site QC/QA activities for the General Civil Contract, as well as maintaining a high degree of close collaboration between MH and GCC contractor quality teams. Increasing the presence of MH representatives in GCC supplier fabrication facilities for quality assurance (QA) and expediting of schedule-critical components for items such as: draft tube formwork, superstructure steel, rebar, piping, etc.	[redacted] related to the General Civil Contractor's increased QA/QC staff.
Extension of Service Contracts	[redacted]	[redacted]	[redacted] Delay cost impact added to the service contracts.

PUB MFR 136
Keeyask

Provide any of Manitoba Hydro's reports to senior management detailing the Keeyask general civil works proposals.

Public disclosure of the response to this MFR (or portions thereof) would result in the release of information considered to be confidential and commercially sensitive. As directed by the PUB, Manitoba Hydro will be filing a letter seeking confidential treatment of the redacted information contained in the attachments to this response pursuant to Rule 13.

The following four reports were provided to senior management detailing the Keeyask general civil works proposals and can be found at the link below:
https://www.hydro.mb.ca/regulatory_affairs/pdf/electric/general_rate_application_2017/mfrs/pub_mfr_136_attachments.pdf

1. **243994-0020-PRES-Keeyask GCC Procurement Presentation to MHEB - 2013 11 26**
   Presentation to the Manitoba-Hydro Electric Board ("MHEB") regarding the procurement of the Keeyask General Civil Works Contract – Presented on November 26, 2013.

2. **243994-0020-016203-REC-Keeyask GCC Board Recommendation - 2014 02 11**
   Manitoba Hydro Executive Committee Recommendation to the MHEB to approve the Keeyask General Civil Works Contract.

3. **243994-0020-016203-REC-Keeyask GCC Board Recommendation - 2014 02 25 Rev1**
   Revised Manitoba Hydro-Electric Board Recommendation for award of the Keeyask General Civil Works Contract.

4. **243994-0020-PRES-Keeyask GCC Board Rec Presentation - 2014 02 26**
   Presentation to the Manitoba Hydro-Electric Board regarding the award of the Keeyask General Civil Works Contract – Presented on February 26, 2014.

PUB MFR 139

Keeyask

Provide a summary table of Keeyask turbines and generators proposals as well as any estimates prepared by Manitoba Hydro or third parties.

Public disclosure of the response to this MFR (or portions thereof) would result in the release of information considered to be confidential and commercially sensitive. As directed by the PUB, Manitoba Hydro will be filing a letter seeking confidential treatment of the redacted information contained in this response pursuant to Rule 13.

The table below summarizes the estimated price from the approved bidders for the Keeyask turbines and generators request for proposal.

Manitoba Hydro prepared an initial estimate value of [redacted] for the turbine and generator contract in 2009 by soliciting budget estimates from major vendors as the basis for approval for early tendering.

	Alstom Option A	Alstom Option B	Andritz	Voith
Proposal price*	[redacted]	[redacted]	[redacted]	[redacted]

*Price in 2011 dollars. Price does not including contingency or taxes.

Voith had the lowest bid price of [redacted], and as result was selected as the successful candidate. Following negotiations, the contract was awarded at [redacted]. The final agreed contract price was subject to Manitoba Hydro-Electric Board approval, which was provided on May 24, 2012.

PUB MFR 140
Keeyask

Provide any of Manitoba Hydro's reports to senior management detailing the Keeyask turbines and generators proposals and bids.

Public disclosure of the response to this MFR (or portions thereof) would result in the release of information considered to be confidential and commercially sensitive. As directed by the PUB, Manitoba Hydro will be filing a letter seeking confidential treatment of the redacted information contained in the attachments to this response pursuant to Rule 13.

The reports provided to senior management detailing the Keeyask turbine and generators proposal and bids are included in the attached document. The attachment consists of two reports:

1. **20101220 – Briefing Note – Keeyask – Pre Qual Design Supply Install Turbines Generators – RFPQ 016320**
   A 2010 briefing note outlining the prequalified candidates to be invited to submit proposals for the turbines and generators contract.

2. **20120425 – EC Rec – Keeyask GS Turbine and Generator Equipment 241**
   A 2012 Executive Committee Recommendation for the approval of a contract award for the design, supply and installation of the turbines and generators equipment to Voith Hydro.

Press F-11 to tab from field to field.

RFPQ 016320 - PRE-QUALIFICATION FOR KEEYASK DESIGN, SUPPLY AND INSTALLATION OF TURBINES AND GENERATORS

BRIEFING NOTE

ISSUE:

Pre-qualification for the design, supply, and installation of turbines and generators for the Keeyask Generating Station project.

RESPONSE / KEY MESSAGES:

- Andritz, Alstom, and Voith will be invited to submit proposals for the work.
- Dongfang Electric Corporation (DEC) will not be invited to submit a proposal; however we are committing to work with this company to address their shortcomings so that they will be successful in future pre-qualifications.

BACKGROUND:

Four companies responded to RFPQ 016320.

Andritz, Alstom, and Voith have adequately demonstrated that they have the commercial and technical capacity and experience to carry out the design, supply, and installation of the Keeyask Turbine and Generator work. These three companies have passed all of our pass/fail criteria for safety, experience, and technical capability.

DEC did not qualify to be invited to propose for the Keeyask turbines and generators because they have no references for installation work in North America, no installation safety plan or statistics and no existing relationship with a North American firm capable of carrying out the installation. Although DEC has demonstrated that they are capable of designing and supplying hydraulic turbines and generators, they are not prepared to manage the installation portion of the job. This represents safety and schedule risks that are not tolerable.

It is in Manitoba Hydro's best interest to have DEC as a qualified proponent on future work. New Generation Construction Division will invite DEC to meet in Winnipeg to review their response and communicate where they need to improve to be qualified in the future. Our goal is to have DEC fully qualified to provide a proposal for Conawapa and to invite DEC to compete for equipment supply contracts for overhaul projects where installation is not part of the contractor's scope of work.

EXECUTIVE COMMITTEE RECOMMENDATION

SUBJECT:

Keeyask Generating Station Project –Turbine and Generator Equipment

RECOMMENDATION:

Executive Committee approve for submission to the Manitoba Hydro Electric Board to approve a contract for the design, supply, and installation of turbine and generator equipment to Voith Hydro at a price not to exceed $[redacted] Million including contingency and excluding taxes and future escalation.

BACKGROUND:

The Keeyask Generating Station project requires seven turbine and generator units. Request for Proposals 016321 was issued in February 2011 for the design, supply, and installation of turbines and generators to three pre-qualified proponents, Voith Hydro, Alstom, and Andritz Hydro.

Voith Hydro is headquartered in Heidenheim Germany with a Canadian regional office in Brossard, Quebec and a representative based in Manitoba. Alstom and Andritz are based in France and Austria, respectively. Proposals were received from the proponents in October 2011. The evaluation process considered numerous criteria and the result was largely determined by the evaluated cost. Evaluated cost is comprised of construction cost, turbine and generator performance and the contract price. Voith Hydro has the lowest construction cost, comparable performance and the lowest lump sum contract price at $[redacted] Million. Their bid was $[redacted] Million below the second place proposal.

Negotiations with Voith Hydro commenced in December 2011 and have reached substantial completion. All significant technical and commercial issues and the allocation of contract risk have been resolved and account for the difference between the initial proposal price and the total price of this recommendation. The contractual agreement authorizes a model test for a price of $[redacted] Million commencing immediately with the balance of the work to be separately authorized upon final approval of the construction of the Keeyask Generating Station project in 2014.

JUSTIFICATION:

Voith Hydro submitted a proposal that represents the lowest price and best value to Manitoba Hydro. The contract price is within the project budget for the work.

RISKS:

The immediate financial commitment is $[redacted] Million for model testing and is required to finalize water passage geometry and validate the performance guarantees. The remaining $[redacted] Million does not represent a risk to Manitoba Hydro as there is no obligation to proceed until the Keeyask Project is formally approved in 2014. Furthermore, we may cancel the contract for convenience at any time.

Voith Hydro's supply chain plan creates currency risk due to manufacturing in Brazil and China. A risk management plan has been established that will limit Manitoba Hydro's exposure to foreign currency risk. Residual currency risk is accounted for with contingency and is included in the total price of this recommendation.

New Generation Construction
Power Supply
2012 04 25

PUB MFR 142
Keeyask

Provide a summary of the forecast contract values underpinning the $6.5 billion Keeyask capital cost, actual expenditures to date, and forecast expenditure at completion. Explain all variances between the forecast contract values and the forecast expenditures at completion.

Public disclosure of the response to this MFR (or portions thereof) would result in the release of information considered to be confidential and commercially sensitive. As directed by the PUB, Manitoba Hydro will be filing a letter seeking confidential treatment of the redacted information contained in this response pursuant to Rule 13.

The table below summarizes the forecast contract values that underpinned the $6.5 billion Keeyask capital cost, actual expenditures to date and forecast at completion (the confidential portions of this response have been highlighted). Note that only contracts with values greater than $ [redacted] illion are included as this represents 90% of the total value of open contracts.

Table 1 Summary of Forecasted Contract Values
As at April 30, 2017
(in millions of dollars)

	Forecasted Contract Value	Actual costs to date	Forecast at Completion
Final Design Engineering – *Hatch*	[redacted]	[redacted]	[redacted]
Camp Operations Services - *Fox, York and Sodexo Joint Venture*	[redacted]	[redacted]	[redacted]
Maintenance Services - *Maintenance Services Joint Venture*	[redacted]	[redacted]	[redacted]
Main Camp – *Britco*	[redacted]	[redacted]	[redacted]
Work Areas Site Development - *Amisk Construction*	[redacted]	[redacted]	[redacted]
South Access Road - *Amisk Construction*	[redacted]	[redacted]	[redacted]
General Civil Works - *BBE Hydro Construction*	[redacted]	[redacted]	[redacted]
Reservoir Clearing - *Amisk Construction*	[redacted]	[redacted]	[redacted]
Spillway Gates, Guides, Hoists, Towers and Monorail Crane - *Canmec Industriel Inc.*	[redacted]	[redacted]	[redacted]
Intake Gates, Guides and Hoists - *Canmec Industriel Inc.*	[redacted]	[redacted]	[redacted]
Turbines & Generators - *Voith Hydro*	[redacted]	[redacted]	[redacted]

Note: Forecast at Completion and Actual Costs to date for South Access Road and Reservoir Clearing exclude scope relating to transmission

Variance Explanation:

The following points summarize the variances between the forecast at completion and the forecasted contract value underpinning the $6.5 billion.

- Final Design Engineering: increased as a result of the schedule extension and new scope.
- Camp Operations Services: increased as a result of an increased workforce and the schedule extension.
- Maintenance Services: increased as a result of an increased workforce and the schedule extension.
- South Access Road: increased as a result of quantity variance.
- General Civil Works: increased as a result of unachievable productivity rates provided in the bid, delayed ramp up in 2016 and more challenging geotechnical and geological conditions than anticipated.
- Reservoir Clearing: increased as a result of quantity variance.
- Spillway Gates, Guides, Hoists, Towers and Monorail Crane: increased as a result of schedule extension which caused additional costs related to storage, handling,

delivery and installation; and the addition of new scope to include the installation of spillway Stoplog guides and sills.

- Intake Gates, Guides and Hoists: increased as a result of schedule extension which caused additional costs related to storage, handling, delivery and installation; and the addition of new scope to include the installation of trashrack guides, bulkhead guides, draft tube guides and associated lintels and sills and testing of bulkhead gates and installation of trashracks.
- Turbines and Generators: increased as a result of the schedule extension which caused additional costs related to storage, handling, delivery and installation as well as staff and expenses.

PUB MFR 143
Keeyask

Explain how Manitoba Hydro calculated productivity in each of the Keeyask contracts listed in MFR#142. Provide forecast versus actual productivity for each contract by construction season. Explain any variances and identify measures implemented by Manitoba Hydro to mitigate the variances.

Public disclosure of the response to this MFR (or portions thereof) would result in the release of information considered to be confidential and commercially sensitive. As directed by the PUB, Manitoba Hydro will be filing a letter seeking confidential treatment of the redacted information contained in this response pursuant to Rule 13.

On the Keeyask Project, Manitoba Hydro regularly monitors and tracks productivity for cost reimbursable forms of contract such as the General Civil Contract and the Final Design Engineering Contract. Due to the nature of other forms of contracts (such as fixed price and unit price contracts), productivity determinations are not as critical because the contractor owns this risk. On fixed price and unit price contracts, Manitoba Hydro's monitoring efforts shift to ensuring that the contractor is maintaining schedule, progressing the work and proactively mitigating schedule risks.

General Civil Contract

The General Civil Contract is a cost reimbursable target-priced contract and as such, the productivity rates are critically important to Manitoba Hydro. In this form of contract, the Contractor's risk is limited to the profit, while Manitoba Hydro retains the responsibility for all costs to execute the scope of work. Based on this contract structure, the contractor fee is at risk – in other words, profit is earned if the cost of the work is less than the target, but the profit is eroded if the contractor's cost of execution exceeds the target price. As a result, Manitoba Hydro has been monitoring actual productivity against forecasted productivity on specific work fronts including concrete and earthworks, since the start of construction.

Forecasted productivity rates were provided by contractors in their initial bid for concrete and earthworks. BBE's forecasted rates for concrete work on the Keeyask Project were based on the productivity rates achieved during the construction of the Limestone Generating Station Project. The estimated productivity rate considers cycle times

calculated for concrete related activities including placement of formwork, tying of rebar, installing embedments, batching of concrete, placement of concrete, formwork removal, green cutting, etc. Other variables considered include concrete placing methods (pumps, telebelts, buckets, etc.), and the mix of crews selected to achieve optimum rates for concrete placement.

Forecasted earthworks productivity was established through the Contractor's previous experience on other projects. The rates were developed using cycle time calculations based on the selection of appropriate earthmoving equipment, haul distances for moving material between the source (excavations, quarries, borrow areas, etc.) and the destination (excavated material placement areas, dams, dyke, crusher, etc). Based on the cycle time calculations the right mix of equipment, crews (excavators, haul trucks, etc.) were selected to achieve optimum production rates for moving material.

See the Table 1 below for forecasted versus actual productivity for each construction season.

Table 1: Productivity Rates- 2016 Construction Season

	2014		2015		2016	
Work front	**Forecasted**	**Actual**	**Forecasted**	**Actual**	**Forecasted**	**Actual**
Concrete*	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Earthworks**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

*These productivities do not include the supply of concrete.

**The forecast productivity for earthworks is different for each structure so a range is provided. The earthworks productivities vary based on the class of material, how the material is being placed, haul distance, equipment used, etc.

Results from the first season of concrete placement indicated that BBE's productivity assumptions were overly optimistic. The Contractor's bid for the Keeyask Project relied heavily on their experience with the Limestone Project and experience on the project-to-

date has demonstrated that those productivity rates are not achievable in the current labour market with the prevailing mega-project environment in Canada. Many factors affect the variance in productivity rates including workforce experience, complexity of the work, work environment (including rotational schedules), increased regulatory requirements for safety and the environment and planning and execution at the work fronts causing an increase in the number of person-hours per cubic meter of concrete poured. In order to further understand the cause of concrete productivity variances, the Project team undertook a root cause analysis in the fall of 2016. The recommendations from this analysis form the basis of recovery planning also referenced in PUB MFR 122.

The Contractor has been able to achieve forecast earthworks productivity rates; however, the earthworks schedule was impacted due to challenges in river management, geotechnical subsurface conditions, exploiting the borrow sources and other technical requirements.

Final Design Engineering Contract

The Final Design Engineering Contract, awarded to Hatch, is a cost reimbursable contract with a guaranteed maximum upset limit. As a result of the contract structure, the contractor assumes all labour productivity risk associated with the scope within the contracts limits. The contractor is at risk for any productivity issues resulting in cost overruns beyond the limit. Manitoba Hydro monitors productivity to ensure activities remain on schedule by utilizing the Cost Performance Index to measure the value of the work completed compared to the actual cost spent. While monitoring of productivity is the contractor's responsibility, the rate of development of the detailed design of the Project is critical to the execution of the work. Please see **Table 2** below for the productivity rate.

Table 2: Productivity Rates - since 2014.

	Forecasted	Actual
CPI*	[redacted]	[redacted]

*The forecasted and actual productivity is based on an average annual CPI for all the work packages.

Since the Project's inception no material variances between forecasted versus actual productivity have occurred.

PUB MFR 144
Keeyask

Contrast the productivity for each major Keeyask contract with those of each major Wuskwatim contract.

Public disclosure of the response to this MFR (or portions thereof) would result in the release of information considered to be confidential and commercially sensitive. As directed by the PUB, Manitoba Hydro will be filing a letter seeking confidential treatment of the redacted information contained in this response pursuant to Rule 13.

The comparable major contracts for the Keeyask and Wuskwatim projects are the General Civil Contract and the Turbines and Generators Contract. BBE is the General Civil Contractor for Keeyask while O-N-E was the General Civil Contractor for Wuskwatim. Voith Hydro is the Turbines and Generators Contractor for Keeyask while Andritz Hydro was the Turbines and Generators Contractor for Wuskwatim.

Each contractor develops different means and methods of construction based on their past experiences making a direct comparison of productivity subjective. During construction, each project experiences its own challenges due to the site geology, the volume of work being executed, the available labor force, and the quality of the engineering design and/or specifications required to complete the work. As a result, the productivity levels may not be uniformly comparable from one contractor or project to another.

Additionally, Wuskwatim's productivity is based on the average levels experienced throughout the life of the Project. Keeyask's productivity is based on the productivity levels experienced to date and most likely will vary during the course of the remaining work. Productivity is likely to improve over the life of the project as workers gain additional experience. Accordingly, it would not be an objective comparison to contrast the current Keeyask levels to those of Wuskwatim.

General Civil Contract

The general civil contracts were awarded as cost reimbursable with a target price on both projects. Based on the contract structure, Manitoba Hydro assumes the risk for productivity and associated cost overruns. Manitoba Hydro currently monitors the contractor's actual

productivity on specific work fronts; including concrete and earthworks. A similar monitoring system was carried out on Wuskwatim. See **Figure 1** for the productivity figures for Keeyask and Wuskwatim (the confidential portions of this response have been highlighted).

Figure 1: Productivity Comparison – General Civil Contract

Project	Actual Concrete Productivity*	Actual Earthworks Productivity
Wuskwatim	[redacted]	[redacted]
Keeyask	[redacted]	[redacted]

*Productivities do not include the supply of concrete

**Average concrete productivity over the life of the Project

***Concrete work started in the 2016 construction season. Values only include 2016 information

****Average productivity over the life of the Project. The productivity ranges due to factors such as the class of material, how the material is being placed, haul distance, and equipment used.

Turbines and Generators Contract

The Turbines and Generators contracts on both the Keeyask and Wuskwatim projects were awarded as a performance-based milestone fixed price contracts. Due to the nature of these types of contracts, the contractor assumes responsibility for labour productivity and required mitigation strategies, including increasing the labour force. Manitoba Hydro's role is limited to ensuring the contractor is maintaining the schedule and mitigating schedule risks.

Previously, the Wuskwatim contract was completed on time and currently the Turbines and Generator work on the Keeyask Project remains on track to meet the current schedule. Productivity rate calculations were not prepared for Wuskwatim and are not undertaken for Keeyask.

PUB MFR 145

Keeyask

Provide a summary of the contingency, management reserve, and escalation reserve original budget, draw-down, remaining, and allocated amounts for the Keeyask project. Provide details of the draw-down and allocation amounts by indicating to which contract they are assigned and for what purpose. Explain how contingency, management reserve, and escalation reserve are applied.

Public disclosure of the response to this MFR (or portions thereof) would result in the release of information considered to be confidential and commercially sensitive. As directed by the PUB, Manitoba Hydro will be filing a letter seeking confidential treatment of the redacted information contained in this response pursuant to Rule 13.

Table 1 provides a summary of the approved contingency, draw downs and contingency remaining in the revised Keeyask budget.

Table 1: Contingency Allocations and Drawdowns (in Millions $)

	Contingency (Based on approved CPJA #5)	Draw-down (Jan 1 - Apr 30, 2017)	Remaining
Contingency unallocated	[redacted]	[redacted]	[redacted]
Contingency allocated	[redacted]	[redacted]	[redacted]
Sub Total (Base Contingency)	578	[redacted]	[redacted]
Escalation	28	[redacted]	[redacted]
Interest	294	[redacted]	[redacted]
Total Contingency	900	[redacted]	[redacted]
Management Reserve	0	0	0
Escalation Reserve	0	0	0
Total	900	[redacted]	[redacted]

The original contingency budget of $307 million has been expended due to significant risks experienced since the start of construction. Capital Project Justification Addendum #5 (CPJA) revised the Keeyask budget to $8.7 billion and re-established a contingency budget of $900 million to account for the risks remaining on the project. Within the revised Keeyask budget of $8.7 billion, there is no budget for management reserves and similarly there is no

budget for escalation reserves. Additional details are provided in the response to PUB MFR 147

Table 2 Contingency Allocations by Contract (in Millions $)			
Contract	**Contingency (Based on CPJA#5)**	**Draw-down (Jan 1 to Apr 30, 2017)**	**Remaining**
Final Design Engineering - Hatch	[redacted]	[redacted]	[redacted]
Camp Operations Services - Fox, York and Sodexo Joint Venture	[redacted]	[redacted]	[redacted]
Maintenance Services - Maintenance Services Joint Venture	[redacted]	[redacted]	[redacted]
Main Camp - Britco	[redacted]	[redacted]	[redacted]
South Access Road - Amisk Construction	[redacted]	[redacted]	[redacted]
General Civil Works - BBE Hydro Construction	[redacted]	[redacted]	[redacted]
Reservoir Clearing - Amisk Construction	[redacted]	[redacted]	[redacted]
Spillway Gates, Guides, Hoists, Towers and Monorail Crane - Canmec Industriel Inc.	[redacted]	[redacted]	[redacted]
Intake Gates, Guides and Hoists - Canmec Industriel Inc.	[redacted]	[redacted]	[redacted]
Turbines & Generators - Voith Hydro	[redacted]	[redacted]	[redacted]
Other Generating Station Allocated Contingency	[redacted]	[redacted]	[redacted]
Unallocated Contingency	[redacted]	[redacted]	[redacted]
Total Base Contingency	578.00	[redacted]	[redacted]
[redacted]			

Contingency is allocated to contracts to cover risks and is drawn down via approved changes to the contract. Unallocated contingency is what remains after the contingency pool has been allocated to specific contracts. The amount remaining is used to manage other project-related risks as they arise. Contract risks are further detailed in the risk register referenced in MFR 129.

There are no escalation reserves and management reserves within the revised budget.

PUB MFR 155

Bipole III

Provide the original Capital Project Justifications (2001) and all subsequent addenda for the Transmission Line, Converter Stations, Collector Lines, Community Development Initiative, Bipole III Western Route, and Converter Upgrade to 2300 MW. Include any CPJ addenda recommended for implementation but not approved by Executive Committee or MHEB.

Public disclosure of the response to this MFR (or portions thereof) would result in the release of information considered to be confidential and commercially sensitive. As directed by the PUB, Manitoba Hydro will be filing a letter seeking confidential treatment of the redacted information contained in this response pursuant to Rule 13.

The following CPJ / CPJ Addenda documents prepared for Bipole III are provided as Attachment 1 to this response.

Document	Date	Approval
Original CPJ	2001.06.13	Executive Committee, 2001.09.05
Addendum #01	2003.05.08	Executive Committee, 2003.08.19
Addendum #02	2003.11.12	Executive Committee, 2003.09.30
Addendum #03	2004.04.06	Executive Committee, 2004.06.01
Addendum #04	2005.06.23	Executive Committee, 2005.09.13
Addendum #05	2007.05.15	Manitoba Hydro Board of Directors, 2007.09.20
Addendum #06	2009.08.18	unapproved
Addendum #06a (Trans Line)	2011.03.30	Executive Committee, 2011.03.31
Addendum #06b (Converter Stns)	2011.03.29	Executive Committee, 2011.03.31
Addendum #06c (Collector Lines)	2011.03.30	Executive Committee, 2011.03.31
Community Development Initiative	2013.07.19	Executive Committee, 2013.08.20
Addendum #07a (Trans Line)	2014.09.24	Executive Committee, 2014.10.21
Addendum #07b (Converter Stns)	2014.09.24	Executive Committee, 2014.10.21
Addendum #07c (Collector Lines)	2014.09.24	Executive Committee, 2014.10.21
Addendum #07d (Comm Dev Init)	2014.09.26	Executive Committee, 2014.10.21
Addendum #08a (Trans Line)	2016.10.14	Manitoba Hydro-Electric Board, 2016.10.26
Addendum #08b (Converter Stns)	2016.10.12	Manitoba Hydro-Electric Board, 2016.10.26
Addendum #08c (Collector Lines)	2016.10.14	Manitoba Hydro-Electric Board, 2016.10.26
Addendum #08d (Comm Dev Init)	2016.10.dd	Manitoba Hydro-Electric Board, 2016.10.26 .

ORIGINAL CPJ

Dated 2001.06.13

Approved by Executive Committee on 2001.09.05

CAPITAL PROJECT JUSTIFICATION
FOR

RADISSON to RIEL ± 500 KV HVDC LINE

ORIGINATING DIVISION: Transmission Planning & Design

W.B.S.: ~~1.1.2.1.2.1~~ 1.5

MAJOR ITEM [X] **DOMESTIC ITEM** [ ]

PREPARED BY: J.B. Davies/K.L. Kent

DATE PREPARED: 2001 06 13

REPORT NO.: SPD-01/7

FILE NO. (Optional):

REVIEWED BY:
(Originating Department Manager)

NOTED BY: (if applicable)

Designing Division:

Constructing Division:

Financial Department:
(for capital item over $1 million)

RECOMMENDED FOR IMPLEMENTATION:

Originating Division Manager: D.J. Stecuik

Business Unit Vice-President:

APPROVED BY EXECUTIVE COMMITTEE
MINUTE # 900.11

DATE: 2001 0905
MANAGEMENT SERVICES

			ORIGINATING

Project Description

An 800 km, ±500 kV dc transmission line is constructed between the proposed Bipole I and II emergency paralleling site near Radisson and the proposed Riel site. A dc paralleling line is constructed between the proposed Riel site and Dorsey Station to provide HVDC transmission during an Interlake corridor loss. Before Bipole III is in service, the new line will be used for Bipole II and the existing Bipole I & II lines are paralleled for Bipole I, resulting in loss savings of about 78 MW at maximum generation.

Recommendation

Build an 800 km, +/-500 kV dc transmission line between the proposed Bipole I and II emergency paralleling site near Radisson and the proposed Riel site, and build a dc paralleling line between the proposed Riel site and Dorsey station.

Project Scope

Includes the 500 kV dc transmission line from near Radisson to Riel, and a paralleling line from Riel to Dorsey.

Background

This project is being recommended based on the economics of up to 78 MW of HVDC transmission power loss savings and reliability benefits discussed in the report, Manitoba Hydro Transmission System Reliability and Enhancement Options, which will be released in the fall of 2001.

JUSTIFICATION—BUSINESS CASE ANALYSIS (SUMMARY):

Justification and Link to Corporate/Business Unit Goals

This transmission only alternative provides increased reliability to the Manitoba Hydro system. In normal steady-state operation, this item provides an increase in southern power of about 78 MW at full load due to decreased HVDC transmission losses.

ANALYSIS OF ALTERNATIVES:

Economic Analysis		
Discount Rate	10%	

Recommended Option	NPV
800 km, ±500 kV dc transmission line is constructed between the proposed Bipole I and II emergency paralleling site near Radisson and the proposed Riel site.	zero

Other Alternatives Considered	NPV

Other Alternatives Considered	NPV

Risk Analysis

Risk Analysis was documented in System Planning and Resource Planning and Market Analysis joint report on Manitoba Hydro Transmission System Reliability and Enhancement Options.

RESOURCE REQUIREMENTS AND CAPITAL BUDGET ESTIMATE:

Resource Requirements

Total Budget

2002/03	$ 2,500,000
2003/04	$ 4,586,000
2004/05	$ 13,063,000
2005/06	$ 13,533,000
2006/07	$ 12,269,000
2007/08	$149,096,000
2008/09	$ 46,111,000
2009/10	$ 62,373,000
2010/11	$ 57,248,000
Total	$360,779,000

Proposed Schedule

Work start date: 2002/04/01
In service date: 2010/10/31

Related Projects

SECTIONALIZATION OF LINE D602F AT RIEL

Reference Documents

This project is recommended in the report, Minimum Transmission Requirements for HVDC Bulk System Reliability, which also recommends Sectionalization of the 500 kV line D602F at Riel.
These two projects are the first recommendations to which come out of

Reference Documents

the work associated with the report, Manitoba Hydro Transmission System Reliability and Enhancement Options, which will be released in the fall of 2001.

ADDENDUM #01

Dated 2003.05.08

Approved by Executive Committee on 2003.08.19

D1678(A)

CAPITAL PROJECT JUSTIFICATION ADDENDUM FOR

HENDAY – RIEL ± 500 KV HVDC LINE

Addendum Number 01

REVIEWED BY:
(Owning Dept Manager)
Ron Mayer

NOTED BY:
(if applicable)

Designing Division:

Constructing Division:

Financial Department
(if over $1 million) Nieuwenburg 2003 08 05

RECOMMENDED FOR IMPLEMENTATION:

Owning Div. Manager: RW Mayer / for G.N.

Business Unit V.P.: Schneider 03 08 06

APPROVED BY EXECUTIVE COMMITTEE
MINUTE # 993.03

DATE: 2003 08 19
MANAGEMENT SERVICES

PREV. APPROVED BUDGET $: (Use $ value from approved CPJ or last approved CPJ Addendum)	$351,916,000
REVISED BUDGET $: (Total Net Cost)	$360,161,000
START DATE: (1st Cost Flow)	2002 04
PREV. APPROVED ISD: (Use In-service Date from approved CPJ or last approved CPJ Addendum)	2010 10
REVISED ISD: (Last Major In-service Date)	2010 10
RISK MATRIX/ BUSINESS CASE TIER:	
INVESTMENT REASON:	

OWNING DIVISION:	TRANSMISSION PLANNING & DESIGN
I.M. NODE NUMBER:	1.5.1.2.2.1
W.B.S. NUMBER:	P4218, P4220, P4221
MAJOR ITEM ☒	**DOMESTIC ITEM** ☐
PREPARED BY:	J.B. Davies / K.L. Kent
DATE PREPARED:	2003 05 08
REPORT NUMBER:	
FILE NUMBER (Optional):	

ADDENDUM NUMBER	DATE (yyyy mm dd)	REVISION	REVISED BY	APPROVED BY
-	2001 06 13	Original CPJ	J.B. Davies/K.L. Kent	Executive Committee

MANITOBA HYDRO
CAPITAL PROJECT JUSTIFICATION ADDENDUM

Project Name (This section is required for all Addendums).

Henday-Riel ±500 kV HVDC Line

Recommendation (This section is required for all Addendums).

Change the location of the northern termination of the dc transmission line, from Radisson to Henday, thereby increasing the line length by 20 km for a revised length of 820 km. The revised total net cost of the complex is now $360,161,000, an increase of $8,245,000 over the previously approved budget.

Project Scope (This section is be filled out only if there is a change to the scope).

Build an 820 km, ±500 kV dc transmission line between Henday and the proposed Riel site, rather than an 800 km line between Radisson and Riel.

Background (This section is be filled out only if there is information relevant to the recommendation).

The original northern termination of the line at a remote site near Radisson was consistent with an earlier plan to locate the Bipole III rectifier at the future Gull generating station site. Further studies have resulted in a recommendation that the Bipole III rectifier be located at the future Conawapa generating station site, since it is more consistent with the ultimate 2000 MW rating of Bipole III.
The HVdc Task Force at the May 9, 2003 meeting approved this recommendation.
Since the Bipole III HVdc line was justified based on loss saving while connected to Bipole II, the line presently only needs to be built to the Bipole II rectifier site at Henday. The line would then be extended to the Conawapa generating station site when the Bipole III converters are installed at that site. The future location of the Bipole III rectifier at Conawapa can still accommodate a possible Gull generating station first generation development sequence.

JUSTIFICATION—BUSINESS CASE ANALYSIS (SUMMARY):

Justification and Link to Corporate/Business Unit Goals (This section is be filled out only if there is a change to the recommended alternative).

The termination of the Bipole III HVdc line at Henday reduces the risk associated with outages of the Bipole I & II HVdc lines, because the connection of Bipole I & II converters to the Bipole III line can be done in a staffed station with switches, rather than at a remote location with manual connections made by a line crew. The termination of the Bipole III HVdc line at Henday does not lead to the risk of all three HVdc lines crossing at one point, which is a difficult and expensive risk to mitigate.

ANALYSIS OF ALTERNATIVES: (This section is be filled out only if there is a change to which alternative is being recommended).

Economic Analysis		
Discount Rate	For current corporate rates see G911 %	For clarification on hurdle rates, contact Economic Analysis Department

Recommended Option	**NPV** **(= PV of BENEFITS - PV of COSTS)**

Other Alternatives Considered	NPV (= PV of BENEFITS - PV of COSTS)

Risk Analysis - (This section is be filled out only if there is a change to the project risk).

RESOURCE REQUIREMENTS AND CAPITAL BUDGET ESTIMATE:

Resource Requirements (This section is be filled out only if there is a change to the resource requirements).

Total Budget - (This section is required for all Addendums).

The impact on annual budget requirements is as follows (in thousands of dollars):

Fiscal Year	Approved CPJ Budget (after Rollover to CEF02-2)	Current CEF Budget (after Rollover to CEF02-2)	Revised CPJ Budget	CPJ Increase (Decrease)	CEF/ Revised CPJ Increase (Decrease)
Prev.	$ 1,664 *	$ 1,664 *	$ 1,664 *	$ 0	$ 0
2003/04	$ 5,422	$ 5,422	$ 4,462	($ 960)	($ 960)
2004/05	$ 13,063	$ 13,063	$ 12,914	($ 149)	($ 149)
2005/06	$ 13,533	$ 13,534	$ 13,349	($ 184)	($ 185)
2006/07	$ 12,269	$ 12,269	$ 13,055	$ 786	$ 786
2007/08	$149,096	$101,273	$ 79,390	($ 69,706)	($ 21,883)
2008/09	$ 46,111	$ 76,331	$ 78,976	$ 32,865	$ 2,645
2009/10	$ 62,373	$ 84,329	$ 99,425	$ 37,052	$ 15,096
2010/11	$ 57,248	$ 44,031	$ 56,926	($ 322)	$ 12,895
Total	$360,779	$351,916	$360,161	($ 618)	$ 8,245

* as per SAP (does not agree with the March 2003 Capital Expenditure Report)

Proposed Schedule (This section is be filled out only if there is a change to the project schedule).

Related Projects (This section is be filled out only if changed).

Reference Documents (This section is be filled out only if changed).
Memorandum from K.L. Kent to J.B. Davies, BIPOLE III TRANSMISSION LINE – BIPOLE III NORTHERN CONVERTER LOCATION, 2002 11 19, System Planning File 6-7G.

ADDENDUM #02

Dated 2003.11.12

Approved by Executive Committee on 2003.09.30

D1876(A)

CAPITAL PROJECT JUSTIFICATION ADDENDUM FOR

HENDAY – RIEL ± 500 KV HVDC LINE

Addendum Number 02

REVIEWED BY:
(Owning Dept Manager)

NOTED BY:
(if applicable)

- Designing Division:

Constructing Division:

Financial Department:
(if over $1 million) C.A. Nieuwenburg 2003 11 13

RECOMMENDED FOR IMPLEMENTATION:

Owning Div. Manager:

Business Unit V.P.: A.L. Thuyer 03 11 14

REVIEWED BY EXECUTIVE COMMITTEE
MINUTE # 999.05

DATE: 2003 09 30
MANAGEMENT SERVICES

PREV. APPROVED BUDGET $: (Use $ value from approved CPJ or last approved CPJ Addendum)	$360,161,000
REVISED BUDGET $: (Total Net Cost)	$360,157,000
START DATE: (1st Cost Flow)	2002 04
PREV. APPROVED ISD: (Use In-service Date from approved CPJ or last approved CPJ Addendum)	2010 10
REVISED ISD: (Last Major In-service Date)	2010 10
RISK MATRIX/ BUSINESS CASE TIER:	
INVESTMENT REASON:	
OWNING DIVISION:	TRANSMISSION PLANNING & DESIGN
I.M. NODE NUMBER:	1.5.1.2.2.1
W.B.S. NUMBER:	P4218, P4220, P4221
MAJOR ITEM ☒	**DOMESTIC ITEM** ☐
PREPARED BY:	C.A. Nieuwenburg
DATE PREPARED:	2003 11 12
REPORT NUMBER:	
FILE NUMBER (Optional):	

ADDENDUM NUMBER	DATE (yyyy mm dd)	REVISION	REVISED BY	APPROVED BY
01	2003 05 08	Change northern termination from Radisson to Henday, increasing line length by 20 km and costs by $8,245k.	J.B. Davies/K.L. Kent	Executive Committee (Minute #993.03)
-	2001 06 13	Original CPJ	J.B. Davies/K.L. Kent	Executive Committee (Minute #900.11)

MANITOBA HYDRO
CAPITAL PROJECT JUSTIFICATION ADDENDUM

Project Name (This section is required for all Addendums).

Henday-Riel ±500 kV HVDC Line

Recommendation (This section is required for all Addendums).

Defer $2,462,000 worth of budget requirements from 2003/04 to future years.

Project Scope (This section is be filled out only if there is a change to the scope).

Background (This section is be filled out only if there is information relevant to the recommendation).

Reduction to 2003/04 was made to help offset an unexpected over-expenditure on one of Transmission & Distribution's other complexes, namely Communications (complex #1.1.2.6.2.1 – project #P2993 – Interlake and Nelson River Communications-Fibre).

JUSTIFICATION—BUSINESS CASE ANALYSIS (SUMMARY):

Justification and Link to Corporate/Business Unit Goals (This section is be filled out only if there is a change to the recommended alternative).

ANALYSIS OF ALTERNATIVES: (This section is be filled out only if there is a change to which alternative is being recommended).

Economic Analysis

Discount Rate	For current corporate rates see G911 %	For clarification on hurdle rates, contact Economic Analysis Department

Recommended Option	**NPV** **(= PV of BENEFITS - PV of COSTS)**

Other Alternatives Considered	**NPV** **(= PV of BENEFITS - PV of COSTS)**

Risk Analysis - (This section is be filled out only if there is a change to the project risk).

RESOURCE REQUIREMENTS AND CAPITAL BUDGET ESTIMATE:

Resource Requirements (This section is be filled out only if there is a change to the resource requirements).

Total Budget - (This section is required for all Addendums).

The impact on annual budget requirements is as follows (in thousands of dollars):

Fiscal Year	Approved CPJ Budget (after Rollover)	Current CEF Budget (after Rollover to CEF02-2)	Revised CPJ Budget	CPJ Increase (Decrease)	CEF/ Revised CPJ Increase (Decrease)
Prev.	$ 1,664	$ 1,664	$ 1,664	$ 0	$ 0
2003/04	$ 4,462	$ 5,422	$ 2,000	($ 2,462)	($ 3,422)
2004/05	$ 12,914	$ 13,063	$ 13,529	$ 615	$ 466
2005/06	$ 13,349	$ 13,534	$ 13,965	$ 616	$ 431
2006/07	$ 13,055	$ 12,269	$ 14,286	$ 1,231	$ 2,017
2007/08	$ 79,390	$101,273	$ 79,390	$ 0	($ 21,883)
2008/09	$ 78,976	$ 76,331	$ 78,973	($ 3)	$ 2,642
2009/10	$ 99,425	$ 84,329	$ 99,424	($ 1)	$ 15,095
2010/11	$ 56,926	$ 44,031	$ 56,926	$ 0	$ 12,895
Total	$360,161	$351,916	$360,157	($ 4)	$ 8,241

Proposed Schedule (This section is be filled out only if there is a change to the project schedule).

Related Projects (This section is be filled out only if changed).

Reference Documents (This section is be filled out only if changed).

ADDENDUM #03

Dated 2004.04.06

Approved by Executive Committee on 2004.06.01

CAPITAL PROJECT JUSTIFICATION ADDENDUM FOR

HENDAY – RIEL ± 500 KV HVDC LINE

Addendum Number 03

REVIEWED BY:
(Owning Dept Manager)
Ron Mayer
2004/05/14

NOTED BY:
(if applicable)

Designing Division:

Constructing Division:

Financial Department:
(if over $1 million) C.A. Nieuwenburg 2004 05 25

RECOMMENDED FOR IMPLEMENTATION:

Owning Div. Manager:

Business Unit V.P.:

PREV. APPROVED BUDGET $: (Use $ value from approved CPJ or last approved CPJ Addendum)	$360,157,000
REVISED BUDGET $: (Total Net Cost)	$387,620,000
START DATE: (1st Cost Flow)	2002 04
PREV. APPROVED ISD: (Use In-service Date from approved CPJ or last approved CPJ Addendum)	2010 10
REVISED ISD: (Last Major In-service Date)	2012 10
RISK MATRIX/ BUSINESS CASE TIER:	
INVESTMENT REASON:	

OWNING DIVISION:	TRANSMISSION PLANNING & DESIGN
I.M. NODE NUMBER:	1.5.1.2.2.1
W.B.S. NUMBER:	P4218, P4220, P4221
MAJOR ITEM ☒	**DOMESTIC ITEM** ☐
PREPARED BY:	J.B. Davies / K.L. Kent
DATE PREPARED:	2004 04 06
REPORT NUMBER:	
FILE NUMBER (Optional):	

REVIEWED BY EXECUTIVE COMMITTEE
MINUTE # 1030.05

DATE: 2004 06 01
MANAGEMENT SERVICES

ADDENDUM NUMBER	DATE (yyyy mm dd)	REVISION	REVISED BY	APPROVED BY
02	2003 11 12	Defer $2,462,000 worth of budget requirements from 2003/04 to future years.	C.A. Nieuwenburg	Executive Committee (Minute #999.05)
01	2003 05 08	Change northern termination from Radisson to Henday, increasing length by 20 km and costs by $8,245K.	J.B. Davies/K.L. Kent	Executive Committee (Minute #993.03)
-	2001 06 13	Original CPJ	J.B. Davies/K.L. Kent	Executive Committee (Minute #900-11)

MANITOBA HYDRO
CAPITAL PROJECT JUSTIFICATION ADDENDUM

Project Name (This section is required for all Addendums).
Henday-Riel ±500 kV HVDC Line

Recommendation (This section is required for all Addendums).
The extended environmental process has resulted in a delay in the expected license date by two years and thus it is recommended that the in-service date be delayed by two years from 2010 10 to 2012 10.

Project Scope (This section is be filled out only if there is a change to the scope).

Background (This section is be filled out only if there is information relevant to the recommendation).

JUSTIFICATION—BUSINESS CASE ANALYSIS (SUMMARY):

Justification and Link to Corporate/Business Unit Goals (This section is be filled out only if there is a change to the recommended alternative).

ANALYSIS OF ALTERNATIVES: (This section is be filled out only if there is a change to which alternative is being recommended).

Economic Analysis		
Discount Rate	For current corporate rates see G911 %	For clarification on hurdle rates, contact Economic Analysis Department

Recommended Option	**NPV** (= PV of BENEFITS - PV of COSTS)

Other Alternatives Considered	**NPV** (= PV of BENEFITS - PV of COSTS)

Risk Analysis - (This section is be filled out only if there is a change to the project risk).
The Henday-Riel ±500 kV HVDC Line provides additional southern generation through loss savings, and also a reliability benefit to the Manitoba Hydro system. Any delay to the ISD means additional risk to the system for the duration of the delay. Riel station and Bipole III share common elements, so the environmental strategy must be considered as a whole.

RESOURCE REQUIREMENTS AND CAPITAL BUDGET ESTIMATE:

Resource Requirements (This section is be filled out only if there is a change to the resource requirements).

Total Budget - (This section is required for all Addendums).

The impact on annual budget requirements is as follows (in thousands of dollars):

Fiscal Year	Approved CPJ Budget	Current CEF Budget	Revised CPJ Budget	CPJ Increase (Decrease)	CEF/ Revised CPJ Increase (Decrease)
Prev.	$ 1,664	$ 1,664	$ 1,664	$ 0	$ 0
2003/04	$ 2,000	$ 2,000	$ 907	($ 1,093)	($ 1,093)
2004/05	$ 13,529	$ 13,530	$ 2,147	($ 11,382)	($ 11,383)
2005/06	$ 13,965	$ 13,966	$ 3,961	($ 10,004)	($ 10,005)
2006/07	$ 14,286	$ 14,286	$ 12,761	($ 1,525)	($ 1,525)
2007/08	$ 79,390	$ 79,389	$ 14,568	($ 64,822)	($ 64,821)
2008/09	$ 78,973	$ 78,975	$ 66,866	($ 12,107)	($ 12,109)
2009/10	$ 99,424	$ 99,424	$ 64,647	($ 34,777)	($ 34,777)
2010/11	$ 56,926	$ 56,927	$ 71,478	$ 14,552	$ 14,551
2011/12	$ 0	$ 0	$ 89,424	$ 89,424	$ 89,424
2012/13	$ 0	$ 0	$ 59,198	$ 59,198	$ 59,198
Total	$360,157	$360,159	$387,620	$ 27,463	$ 27,461

Proposed Schedule (This section is be filled out only if there is a change to the project schedule).

Related Projects (This section is be filled out only if changed).

Reference Documents (This section is be filled out only if changed).

ADDENDUM #04

Dated 2005.06.23

Approved by Executive Committee on 2005.09.13

CAPITAL PROJECT JUSTIFICATION ADDENDUM
FOR

HENDAY – RIEL ± 500 KV HVDC LINE
Renamed to:
BIPOLE III WESTERN ROUTE
Addendum Number 04

REVIEWED BY:
(Owning Dept Manager) Ron Mayer 2005 08 29.

NOTED BY:
(if applicable)

Designing Division:

Constructing Division:

Financial Department: (if over $1 million) C Nieuwenburg 2005 08 29

RECOMMENDED FOR IMPLEMENTATION:

Owning Div. Manager: G Neufeld. 2005 08 29

Business Unit V.P.: A Snyder 05 08 29

REVIEWED BY EXECUTIVE COMMITTEE
MINUTE # 1090.06

DATE: 2005 09 13
Capital Plans, Corp Budget Services

PREV. APPROVED BUDGET $: (Use $ value from approved CPJ or last approved CPJ Addendum)	$387,620,000
REVISED BUDGET $: (Total Net Cost)	$1,879,896,000
START DATE: (1st Cost Flow)	2002 04
PREV. APPROVED ISD: (Use In-service Date from approved CPJ or last approved CPJ Addendum)	Multi - 2010 10
REVISED ISD: (Last Major In-service Date)	Multi - 2017 10
RISK MATRIX/ BUSINESS CASE TIER:	
INVESTMENT REASON:	

OWNING DIVISION:	TRANSMISSION PLANNING & DESIGN
I.M. NODE NUMBER:	1.5.1.2.2.1
W.B.S. NUMBER:	P4218, P4220, P4221, P10155, P10157
MAJOR ITEM ☒	**DOMESTIC ITEM** ☐
PREPARED BY:	System Planning Department Brett Davies / K Kent
DATE PREPARED:	2005 06 23
REPORT NUMBER:	
FILE NUMBER (Optional):	

03	2004 04 06	Defer the in-service date by two years from 2010 10 to 2012 10.	J.B. Davies/K.L. Kent	Executive Committee (Minute #1030.05)
02	2003 11 12	Defer $2,462,000 worth of budget requirements from 2003/04 to future years.	C.A. Nieuwenburg	Executive Committee (Minute #999.05)
01	2003 05 08	Change northern termination from Radisson to Henday, increasing length by 20 km and costs by $8,245K.	J.B. Davies/K.L. Kent	Executive Committee (Minute #993.03)
-	2001 06 13	Original CPJ	J.B. Davies/K.L. Kent	Executive Committee (Minute #900.11)
ADDENDUM NUMBER	**DATE** (yyyy mm dd)	**REVISION**	**REVISED BY**	**APPROVED BY**

MANITOBA HYDRO
CAPITAL PROJECT JUSTIFICATION ADDENDUM

Project Name (This section is required for all Addendums).

Bipole III with the HVdc line routed west of Lakes Winnipegosis and Manitoba.

Recommendation (This section is required for all Addendums).

Manitoba Hydro has been asked to look at other alternatives for routing the Bipole III transmission line from the east side of Lake Winnipeg. In the interim, a west side of the province (west of Lakes Winnipegosis and Manitoba) routed Bipole III transmission line from Conawapa Station to Riel Station with 2000 MW of HVdc converters at both stations is being advanced as a placeholder in the budget. In October 2006, a recommendation for an alternative to the east-side of Lake Winnipeg routed Bipole III line for Manitoba Hydro system reliability will be made. Also, the recommendation will address the reliability of equipment associated with common mode HVdc station outages in addition to common mode outages of the HVdc lines. The October 2006 recommendation may be quite different from the above.

Project Scope (This section is be filled out only if there is a change to the scope).

The Bipole III scheme as a placeholder in the budget includes:

- An HVdc transmission line of a minimum length of 1295 km from Riel Converter Station to Conawapa Converter Station.
- A converter station with 2000 MW of converters at Conawapa.
- Six ac transmission lines approximately 30 km long to connect the Conawapa Converter Station to Henday Converter Station (three of these lines are not necessary with Conawapa generation development).
- A converter station with 2000 MW of converters at Riel, including 3 synchronous compensators

A paralleling line between Dorsey Converter Station and Riel Converter Station is not required as paralleling with Bipole II will not be possible and the western-routed Bipole III line will not be usable by Bipole I or Bipole II.

Background (This section is be filled out only if there is information relevant to the recommendation).

A Bipole III transmission line routed on the east side of Lake Winnipeg was originally recommended and approved (I.M. Node Number 1.5.1.2.2.1). The Board of Manitoba Hydro has directed that alternative transmission line (Bipole III) routes other than the east side of Lake Winnipeg be evaluated.

JUSTIFICATION—BUSINESS CASE ANALYSIS (SUMMARY):

Justification and Link to Corporate/Business Unit Goals (This section is be filled out only if there is a change to the recommended alternative).

Due to the severe critical risk to the Province and Corporation of not mitigating an Interlake (Bipole I&II) corridor outage or a Dorsey station common mode outage, this budget item is being included as a placeholder pending an October 2006 recommendation of an alternative to an east-side of Lake Winnipeg routed Bipole III line.

ANALYSIS OF ALTERNATIVES: (This section is be filled out only if there is a change to which alternative is being recommended).

Economic Analysis		
Discount Rate	For current corporate rates see G911 %	For clarification on hurdle rates, contact Economic Analysis Department

Recommended Option	NPV (= PV of BENEFITS - PV of COSTS)

Other Alternatives Considered	NPV (= PV of BENEFITS - PV of COSTS)
An East-side routed Bipole III line.	

Risk Analysis - (This section is be filled out only if there is a change to the project risk).

The risks associated with this project are as follows:

1) Technically inferior solution to the eastern-routed Bipole III line with converters; less load served on average in situations for which the line is to be built.
2) Less reliable solution since the west side scheme would still only provide an outlet of 2000 MW of northern generation in the event of another Bipole I&II corridor outage, while an east side Bipole III line would allow the paralleling of Bipole I&II converters on the Bipole III line providing the outlet of 3300 MW of northern generation. Also the longer line length associated with a western route increases exposure to outages on Bipole III.
3) A delayed ISD over an eastern routed line, placing Manitoba customers at greater risk for a longer period of time. A western line will likely take longer for conducting environmental assessment/public work consultation and will take more time to build. The earliest date for initiation of environmental work is after the October 2006 recommendation of an alternative to the east of Lake Winnipeg Bipole III line.
4) Justification at a public hearing by Manitoba Hydro of the westerly routing concept vs. an easterly route concept will be problematic.
5) Although 1265 km is used as a proxy minimum for the line length, it is likely the actually built line will be considerably longer with more cost and losses, due to efforts to maximize separation from the existing HVDC right of way.
6) The siting of Bipole III in a western corridor would make the placement of the next north/south transmission line very problematic with the east of Lake Winnipeg routing being blocked and the Interlake routing presenting significant risk of a common mode outage.

There is a risk of further delays in the expected in-service date as the siting of the southern station at Riel may need to be re-evaluated with a western routing of Bipole III

RESOURCE REQUIREMENTS AND CAPITAL BUDGET ESTIMATE:

Resource Requirements (This section is be filled out only if there is a change to the resource requirements).

To be determined.

Total Budget - (This section is required for all Addendums).

The impact on annual budget requirements is as follows (in thousands of dollars):

Fiscal Year	Approved CPJ Budget	Current CEF Budget	Revised CPJ Budget	CPJ Increase (Decrease)	CEF Increase (Decrease)
Prev.	$ 2,571	$ 2,571	$ 2,571	$ 0	$ 0
2004/05	$ 2,147	$ 2,147	$ 2,357	$ 210	$ 210
2005/06	$ 3,961	$ 3,961	$ 1,040	($ 2,921)	($ 2,921)
2006/07	$ 12,761	$ 12,761	$ 956	($ 11,805)	($ 11,805)
2007/08	$ 14,568	$ 14,568	$ 1,862	($ 12,706)	($ 12,706)
2008/09	$ 66,866	$ 66,866	$ 2,877	($ 63,989)	($ 63,989)
2009/10	$ 64,647	$ 64,647	$ 9,067	($ 55,580)	($ 55,580)
2010/11	$ 71,478	$ 71,478	$ 12,559	($ 58,919)	($ 58,919)
2011/12	$ 89,424	$ 89,424	$ 23,388	($ 66,036)	($ 66,036)
2012/13	$ 59,198	$ 59,197	$ 118,975	$ 59,778	$ 59,778
2013/14	$ 0	$ 0	$ 266,921	$ 266,921	$ 266,921
2014/15	$ 0	$ 0	$ 349,682	$ 349,682	$ 349,682
2015/16	$ 0	$ 0	$ 503,939	$ 503,939	$ 503,939
2016/17	$ 0	$ 0	$ 456,655	$ 456,655	$ 456,655
2017/18	$ 0	$ 0	$ 123,990	$ 123,990	$ 123,990
2018/19	$ 0	$ 0	$ 3,056	$ 3,056	$ 3,056
Total	$ 387,620	$ 387,620	$1,879,896	$1,492,276	$1,492,276

Proposed Schedule (This section is be filled out only if there is a change to the project schedule).

To be determined.

Related Projects (This section is be filled out only if changed).

No change.

Reference Documents (This section is be filled out only if changed).

No change.

ADDENDUM #05

Dated 2007.05.15

Approved by Manitoba Hydro Board of Directors 2007.09.20

CAPITAL PROJECT JUSTIFICATION ADDENDUM FOR

BIPOLE III WESTERN ROUTE

Addendum Number 05

REVIEWED BY:
(Owning Dept Manager)
26 JUN 07 Ron W. Magnus 2007-06-26

NOTED BY:
(if applicable)

Coordinating Division:

Constructing Division:

Financial Department:
(if over $1 million) C. Nieuwenburg 2007/07/05

RECOMMENDED FOR IMPLEMENTATION:

Owning Div. Manager: 2007 06 27

Business Unit V.P.: 07 07 19

Approved By MH Board of Directors
MINUTE # 786-07-05

DATE: 2007 09 20
Capital Plans, Accounting, Research & Capital

PREV. APPROVED BUDGET $: (Use $ value from approved CPJ or last approved CPJ Addendum)	$1,879,896,000
REVISED BUDGET $: (Total Net Cost)	$2,247,835,000
START DATE: (1st Cost Flow)	2002 03
PREV. APPROVED ISD: (Use In-service Date from approved CPJ or last approved CPJ Addendum)	Mult - 2017 10
REVISED ISD: (Last Major In-service Date)	Mult - 2017 10
RISK MATRIX/ BUSINESS CASE TIER:	Tier 1 (160 pts)
INVESTMENT REASON:	

OWNING DIVISION:	Transmission Planning & Design
I.M. NODE NUMBER:	1.5.1.2.2.1
W.B.S. NUMBERs:	P4218, P4220 (old), P4221, P10155, P10157
MAJOR ITEM ☒	**DOMESTIC ITEM** ☐
PREPARED BY:	A.A. Poulin / J.B. Davies / K.L. Kent
DATE PREPARED:	AAP 2007/06/13 2007 05 15
REPORT NUMBER:	
FILE NUMBER (Optional):	

ADDENDUM NUMBER	DATE (yyyy mm dd)	REVISION	REVISED BY	APPROVED BY
04	2005 06 23	Western route placeholder. Defer the in-service date by five years from 2012 10 to 2017 10.	J.B. Davies/K.L. Kent	Executive Committee (Minute #1090.06)
03	2004 04 06	Defer the in-service date by two years from 2010 10 to 2012 10.	J.B. Davies/K.L. Kent	Executive Committee (Minute #1030.05)
02	2003 11 12	Defer $2,462,000 worth of budget requirements from 2003/04 to future years.	C.A. Nieuwenburg	Executive Committee (Minute #999.05)
01	2003 05 08	Change northern termination from Radisson to Henday, increasing length by 20 km and costs by $8,245K.	J.B. Davies/K.L. Kent	Executive Committee (Minute #993.03)
-	2001 06 13	Original CPJ	J.B. Davies/K.L. Kent	Executive Committee (Minute #900.11)

MANITOBA HYDRO
CAPITAL PROJECT JUSTIFICATION ADDENDUM

Project Name (This section is required for all Addendums).

Bipole III with the HVdc line routed west of Lakes Winnipegosis and Manitoba.

Recommendation (This section is required for all Addendums).

Increase the proposed budget for the Bipole III western route budget placeholder by $367,940,000 to $2,247,835,000.

Project Scope (This section is be filled out only if there is a change to the scope).

No Change.

Background (This section is be filled out only if there is information relevant to the recommendation).

The estimate is higher due to:

- an increase in line length for the western route as refined for the October 2006 report, from 1296 km to 1341 km;
- moderate increases being experienced in transmission line material costs due to price volatility in the marketplace (approx. 20%);
- considerable increases being experienced in transmission line construction costs, doubling since Addendum #04 due to market conditions (approx. 40% increase applied in late 2005 due to factors such as increased labour and fuel costs, and a further 50% increase applied in 2007 due to recent experience with tendered prices for the Wuskwatim-Birchtree transmission line and further upward trends in construction costs across western Canada), and
- resultant increases in interest and escalation.

JUSTIFICATION—BUSINESS CASE ANALYSIS (SUMMARY):

Justification and Link to Corporate/Business Unit Goals (This section is be filled out only if there is a change to some aspect of the recommended alternative).

No Change.

ANALYSIS OF ALTERNATIVES: (This section is be filled out only if there is a change to which alternative is being recommended).

Economic Analysis		
Discount Rate	% For current corporate rates see G911	For clarification on hurdle rates, contact Economic Analysis Department

Recommended Option	NPV (= PV of BENEFITS - PV of COSTS)
No Change.	

Other Alternatives Considered	NPV (= PV of BENEFITS - PV of COSTS)
No Change.	

Risk Analysis - (This section is be filled out only if there is a change to the project risk).

No Change.

RESOURCE REQUIREMENTS AND CAPITAL BUDGET ESTIMATE:

Resource Requirements (This section is be filled out only if there is a change to the resource requirements).

To be determined.

Total Budget - (This section is required for all Addendums).

The impact on annual budget requirements is as follows (in thousands of dollars):

Fiscal Year	Previous CPJ Addendum	This CPJ Addendum	Increase (Decrease)
Prev. Actuals	$ 6,141	$ 6,141	$ -
2006/07	$ 1,472	$ 1,472	$ -
2007/08	$ 1,174	$ 1,875	$ 701
2008/09	$ 2,877	$ 2,901	$ 24
2009/10	$ 9,067	$ 9,298	$ 231
2010/11	$ 12,559	$ 12,994	$ 434
2011/12	$ 23,388	$ 25,115	$ 1,727
2012/13	$ 118,975	$ 172,475	$ 53,501
2013/14	$ 266,921	$ 331,532	$ 64,611
2014/15	$ 349,682	$ 420,146	$ 70,464
2015/16	$ 503,939	$ 579,614	$ 75,675
2016/17	$ 456,655	$ 535,141	$ 78,485
2017/18	$ 123,990	$ 145,948	$ 21,959
2018/19	$ 3,056	$ 3,184	$ 128
Total	$ 1,879,896	$ 2,247,835	$ 367,940

Proposed Schedule (This section is be filled out only if there is a change to the project schedule).

No change.

Related Projects (This section is be filled out only if changed).

No change.

Reference Documents (This section is be filled out only if changed).

No change.

ADDENDUM #06

Dated 2009.08.18

Unapproved

CAPITAL PROJECT JUSTIFICATION ADDENDUM FOR

BIPOLE III WESTERN ROUTE 500kV HVDC TRANSMISSION LINE & 2000MW CONVERTERS

Addendum Number 06

REVIEWED BY:
(Owning Dept Mgr - Transmission)

(Owning Dept Mgr – Power Supply)

NOTED BY:
(if applicable)

Coordinating Div:

Constructing Div:

Financial:

PREV. APPROVED BUDGET $: (Use $ value from approved CPJ or last approved CPJ Addendum)	$2,247,835,000
REVISED BUDGET $: (Total Net Cost)	$3,953,749,000
START DATE: (1st Cost Flow)	2001 06
PREV. APPROVED ISD: (Use In-service Date from approved CPJ or last approved CPJ Addendum)	2017 10
REVISED ISD: (Indicate "Mult" if more than 1)	2017 10
RISK MATRIX/ BUSINESS CASE TIER:	Tier 2 (950 pts)
INVESTMENT REASON: (Category and % Split)	Operational Enhancement (60%) New/increased Gen. Delivery (20%) Capacity Enhancement (20%)

RECOMMENDED FOR IMPLEMENTATION:

Owning Div. Mgr – Transmission:

Owning Div. Mgr – Power Supply:

Vice-President – Transmission: 2009.09.10

Vice President – Power Supply: 09 09 10

OWNING DIVISIONs:	Transmission Planning & Design New Generation Construction
I.M. NODE NUMBER:	1.5.2.1
W.B.S. NUMBERs:	P:04218, P:04221, P:10155, P:14363 P:14364, P:14518, P:15533 - P:15537, P:15540 – P15544, P:15696, P:15697
MAJOR ITEM ☒	**DOMESTIC ITEM** ☐
PREPARED BY:	K.L. Kent (Complex Owner) A.A. Poulin (Complex Manager) H.S. Jhinger (Proj. Mgr, Converters)
DATE PREPARED:	2009 08 18
REPORT NUMBER:	

ADDENDUM NUMBER	DATE (yyyy mm dd)	REVISION	REVISED BY	APPROVED BY
05	2007 05 15	Revised western route placeholder. Increase costs due to Construction and material cost increases.	A.A. Poulin / J.B. Davies / K.L. Kent	MH Board of Directors (Minute #786-07-05)
04	2005 06 23	Western route placeholder. Defer the in-service date by five years from 2012 10 to 2017 10.	J.B. Davies / K.L. Kent	Executive Committee (Minute #1090.06)
03	2004 04 06	Defer the in-service date by two years from 2010 10 to 2012 10.	J.B. Davies / K.L. Kent	Executive Committee (Minute #1030.05)
02	2003 11 12	Defer $2,462,000 worth of budget requirements from 2003/04 to future years.	C.A. Nieuwenburg	Executive Committee (Minute #999.05)
01	2003 05 08	Change northern termination from Radisson to Henday, increasing length by 20 km and costs by $8,245K.	J.B. Davies / K.L. Kent	Executive Committee (Minute #993.03)
-	2001 06 13	Original CPJ	J.B. Davies / K.L. Kent	Executive Committee (Minute #900.11)

MANITOBA HYDRO
CAPITAL PROJECT JUSTIFICATION ADDENDUM

Project Name (This section is required for all Addendums).

Bipole III Western Route 500kV HVdc Transmission Line & 2000MW Converters

Recommendation (This section is required for all Addendums).

Increase the budget for the Bipole III complex by $1706 million to a revised total of $3954 million, in order to incorporate the following:

- review of estimates for all components of the complex (total increase of $739 million to the base estimate, 2009$),
- inclusion of contingency for all components of the complex (total increase of $525 million to the base estimate, 2009$), and
- the resultant changes to interest and escalation (increase of $442 million).

Project Scope (This section is be filled out only if there is a change to the scope).

No change to the high-level concept at this time. Potential future changes to scope (cost and schedule) that may be forthcoming in a subsequent CPJ Addendum (i.e., are not part of this submission) are as follows:

- Changes to the existing transmission network or at existing generation facilities that may be necessary as a result of the Bipole III transmission line and converters being added to the system.
- Changes that may be necessary for an HVdc transmission line and converters rated at 2500MW.
- Application of Transmission Development Fund (TDF) and/or Adverse Effects policies that may be recommended for the Bipole III complex.

Background (This section is be filled out only if there is information relevant to the recommendation).

CPJ Addendum #04, submitted in April 2005, was the first introduction to the Capital Expenditure Forecast of a western-routed 500kV HVdc transmission line with 2000MW of converters. The budget submitted with CPJ Addendum #04 was a placeholder only, pending completion of studies by System Planning, and was based on a 2001 estimate prepared by Teshmont Consultants.

CPJ Addendum #05, submitted in May 2007, addressed an increase of 45km to the length of the transmission line, as well as increases being experienced in transmission line material and construction costs due to market prices. The cost of licensing, property and converters were not updated at that time, nor was contingency identified in that estimate.

This CPJ Addendum #06 covers re-estimates that have been prepared since either the 2001 Teshmont report or the May 2007 CPJ Addendum, for all components of the Bipole III complex. These re-estimates result in an increase of $739 million to the base estimate, detailed as follows (all amounts are in 2009$).

TRANSMISSION-RELATED ITEMS (total increase of $142 million to base estimate):

a) <u>500kV dc Transmission Line</u>
The base estimate for the transmission line has increased by $72 million due to a design change from double to triple conductor, in order to lower the surface field gradient to accepted worldwide practices and thus minimize flashovers, and by $25 million due to the application of the Transmission Line Agreement (TLA), or unionization of labour.

Background (This section is be filled out only if there is information relevant to the recommendation).

b) Northern 230kV Collector Lines
Reflects increases since 2001 to both construction material and labour costs ($23 million). Also reflects an increase of 39km to the overall length of transmission line construction required ($9 million). In addition, the line from Limestone to Conawapa, previously assumed to be established with the construction power for the Conawapa G.S, is now required first for construction power of the Northern Converter Station ($9 million).

c) Licensing & Environmental Assessment
Costs have increased by $2 million due to more comprehensive aboriginal and community consultations.

d) Sectionalize 230kV Transmission Line R49R at Riel
This is a new item, estimated at $2 million. R49R sectionalization is required to accommodate and reliably transmit a 2000MW Bipole III at Riel. This had been recommenced with the Riel Sectionalization project but was deferred to coincide with Bipole III converters.

In addition to the above, the risk assessment yielded a contingency estimate of $143 million (see the Risk Analysis section for details). These changes, along with an increase of $57 million for interest and escalation, make the total net increase equal to $343 million and the revised total net cost equal to $1477 million, for the transmission-related portion of the complex.

CONVERTER-RELATED ITEMS (total increase of $596 million to base estimate):

e) Riel Converter Station
Converter and HVdc equipment costs remain relatively unchanged; however, the costs for synchronous condensers have more than doubled. Studies have also recommended the addition of a fourth synchronous condenser for the 2000MW Bipole ($193 million combined increase). Other increases to the base estimate include: higher construction management, project management and engineering costs, which were not fully considered in the 2001 placeholder ($49 million); and increase in site size, development and infrastructure costs driven by safety and maintenance requirements, as well as additional facilities for fast drain and oil spill containment systems ($29 million).

f) Northern Converter Station at Conawapa
Converter and HVdc equipment costs remain relatively unchanged. Changes to the base cost are as a result of: inclusion of the construction camp previously assumed to be built and covered by the Conawapa G.S. Project ($38 million); higher construction management, project management and engineering costs not fully considered in the 2001 placeholder ($61 million), and site size increase of 2.2 times that assumed in 2001 and the associated increase in site development and infrastructure costs driven by safety and maintenance requirements, as well as additional facilities for fast drain and oil spill containment systems ($54 million).

g) Riel Site Development for Converters & 230kV Switchyard
Part of the switchyard will be established under a separate project, Riel Sectionalization; however, the concept was developed to more easily accommodate the future HVdc requirements (5 bays and 12 breakers vs. just 3 bays and 9 breakers) and reconfiguration to accommodate a transfer bus scheme, therefore 50% of the equipment costs are included in this estimate ($33 million). An expansion of the 230kV switchyard is required with Bipole III to output the 2000MW, establishing 4 new bays and 11 breakers, and required terminations for HVdc equipment are included in the base estimate ($51

Background (This section is be filled out only if there is information relevant to the recommendation).

million). Half of the site development costs at Riel are included here as attributable to the Converter Station and 230 Switchyard, whereas the 2001 report did not have any site development costs (assumed it would be developed at Riel prior to Bipole III). Like the northern converter station, the site size at Riel has increased (approx. 2.6 times) due to maintenance and security requirements, changes to oil spill containment systems, and planning the layout to accommodate for future additions to the station (i.e. paralleling line and additional 500kV and 230kV AC lines). The associated site development and infrastructure costs have increased ($28 million).

h) Northern 230kV Switchyard
Estimate has increased by $25 million to accommodate the following scope changes: two temporary additional AC lines required to transmit a 2000MW Bipole in the interval when Bipole III is in service before Conawapa G.S. (due to the change in generation sequence), and three lines for future Gilliam Island addition, for a total of 8 bays and 32 breakers.

i) Property for the Riel Converter Station
Not previously included in the estimate. Includes $6 million worth of station site properties and $12 million worth of buffer properties, all purchased from private owners.

j) Construction Power Station for Northern Converter
This item was not previously included, as it had been assumed to be part of the construction of the Conawapa Generation Station. Due to a change in sequencing this complex will be the first to require construction power, and hence the estimated cost of $15 million is now part of this complex.

k) Electrode Lines and Stations
Other components not previously included that have now been estimated are for the electrode lines and stations for both the Northern and the Riel Converter Stations, for a total of $2 million.

In addition to the above, the risk assessment yielded a contingency estimate of $382 million (see the Risk Analysis section for details). These changes, along with an increase of $384 million for interest and escalation, make the total net increase equal to $1363 million and the revised total net cost equal to $2477 million, for the converter-related portion of the complex.

JUSTIFICATION—BUSINESS CASE ANALYSIS (SUMMARY):

Justification and Link to Corporate/Business Unit Goals (This section is be filled out only if there is a change to some aspect of the recommended alternative).

On July 4th, 2001 a System Planning report entitled "Minimum Transmission Requirements for HVDC Bulk System Reliability" (SPD 01/7) was issued and subsequently approved. A major recommendation of that report was for a Bipole III transmission line routed east of Lake Winnipeg. Converter capacity to be connected to the line would be considered in subsequent studies.

At the request of the MHEB, System Planning examined reliability alternatives to an eastern routed Bipole III line. The report entitled "Manitoba HVDC Reliability Alternatives" (SPD 2006/11) was issued on October 4th, 2006, and concluded that Bipole III routed west of Lakes Winnipegosis and Manitoba with 2000 MW of converter capacity was the leading reliability alternative to an eastern routed line.

JUSTIFICATION—BUSINESS CASE ANALYSIS (SUMMARY):

Justification and Link to Corporate/Business Unit Goals (This section is be filled out only if there is a change to some aspect of the recommended alternative).

Based on the conclusions of this report, a recommendation was made by the Executive to the MHEB to proceed with Bipole III, routed west of Lakes Winnipegosis and Manitoba, and with 2000 MW of converter capacity.

Capital Investment Categorization:

Driver	Category	Sub-category	Split	Amount
Reliability-Outage Related	Operational Enhancement	New Asset Addition	60%	$2,372,250,000
Reliability-Load Related	Capacity Enhancement (for domestic load)	New Asset Addition	20%	$ 790,750,000
Reliability-Load Related	New/increased Generation Delivery (for domestic load)	New Asset Addition	20%	$ 790,750,000
				$3,953,750,000

ANALYSIS OF ALTERNATIVES: (This section is be filled out only if there is a change to which alternative is being recommended).

Economic Analysis		
Discount Rate	%	For current corporate rates see G911 For clarification on hurdle rates, contact Economic Analysis Department

Recommended Option	**NPV (= PV of BENEFITS - PV of COSTS)**
No change.	

Other Alternatives Considered	**NPV (= PV of BENEFITS - PV of COSTS)**
No change.	

Risk Analysis - (This section is be filled out only if there is a change to the project risk).

Contingency (total of $525 million in base 2009$):

The contingency estimate is based on risk assessments that were conducted to identify areas of uncertainty or potential fluctuation, and is detailed as follows:

TRANSMISSION-RELATED ITEMS (total contingency of $143 million or 15% of the base costs):

a) 500kV dc Transmission Line (total contingency = $116 million or 15% of the base costs)
- A potential change to the detailed route selection or line length of up to 10%, as the final route has not yet been determined ($87 million).
- Related to lack of geotechnical information, uncertainty with soil conditions calls for the purchase of extra foundation types to allow for flexibility during the tight construction window ($15 million).
- Potential premiums in association with maximizing aboriginal content ($10 million).
- Higher compensation to property owners for damages during construction, based on National Energy Board (NEB) compensation settlements recently experienced in Alberta ($4 million).

Risk Analysis - (This section is be filled out only if there is a change to the project risk).

b) Licensing & Environmental Assessment (total contingency = $13 million or 21% of the base costs)
- Greatest risk for licensing is in the costs for aboriginal and community consultations ($9 million).
- Potential for even more extensive environmental monitoring and assessments, based on our experiences with the Wuskwatim project ($4 million).

c) Northern 230kV Collector Lines (total contingency = $10 million or 12 % of the base costs)
Design uncertainty and exact location of the northern converter station could increase the total line lengths assumed.

d) Property for 500kV dc Transmission Line (total contingency = $4 million or 18% of the base costs)
Potential increases in land values, by as much as 50%, based on the NEB compensation settlements recently experienced in Alberta. Note however that this risk estimate does not include any costs for expropriation of land and the associated legal expenses.

CONVERTER-RELATED ITEMS (total contingency of $382 million or 26% of the base costs):

e) Riel Converter Station (total contingency = $200 million or 39% of the base costs)
Based on a Range Estimating session, recommend contingency for equipment costs due to limited number of suppliers worldwide and variability on exchange rates ($100 million for converters and $100 million for synchronous condensers).

f) Northern Converter Station (total contingency = $135 million or 18% of the base costs)
Based on a Range Estimating session, recommend contingency for equipment costs due to limited number of suppliers worldwide and variability on exchange rates ($100 million for converters); and potential for higher costs associated with northern work ($35 million).

g) Riel Site Development for Converters & AC Switchyard (total contingency = $25 million or 19% of the base costs)
Final Design for Phase A of the Riel Switchyard won't be available from the engineer and procure contract until January 2010, while final design for Phase B is three to six years away. There is also uncertainty with line protection, cyber security, and building strength. Re-work is anticipated for site preparation, as construction will be started ahead of final design to protect against the risk of a wet summer delaying the construction progress.

h) Northern 230kV AC Switchyard (total contingency = $15 million or 31% of the base costs)
Based on a Range Estimating session, recommend contingency for potentially higher costs associated with northern work.

i) Construction Power Station for Northern Converter Station (total contingency = $4 million or 27% of the base costs)
Design and construction estimate are based on a conceptual Single Line Diagram (SLD) only; the site size and exact location of the Converter Station is not yet confirmed.

j) Northern and Riel Electrode Lines (total contingency = $3 million or 36% of the base costs)
The length of the lines is not certain, as Electrode sites have not yet been determined. Also provides for the use of steel towers if necessary (base estimate assumes wood).

Risk Analysis - (This section is be filled out only if there is a change to the project risk).

Management Reserve (total of $334 million in base 2009$):

Also identified during the risk assessment but not included in the contingency estimate at this time, are the management reserve items listed below. Though each of the components covered by this list has a contingency amount included within the project estimate, there is potential for further increases above those contingency amounts, for the following factors:

- Premium if basing the converters estimate on pricing received from the most experienced supplier ($102 million, high probability).
- Uncertainty on the northern interconnecting station modifications at Henday Converter Station and Long Spruce Generating Station, as the scope is not well defined at this time ($20 million, high probability).
- Allowance for greater requirement for engineering, project management and construction management on the Northern Converter Station and the Riel Converter Station projects ($14 million, high probability).
- Allowance for poor soil conditions during construction of the Northern Converter Station ($12 million, high probability)
- Market conditions for transmission line construction labour may increase costs by as much as 20% ($70 million, low probability).
- Market conditions for transmission-related materials or commodities (e.g., towers, hardware, conductor, insulators, foundations, communications equipment) may increase by 10-25% ($61 million, low probability).
- Increase to design, supply and install (construction) costs for the Northern 230kV AC Switchyard if a gas-insulated station (GIS) is chosen instead of an air-insulated station (AIS), due to unknown soil conditions ($55 million, low probability).

Some of the schedule-related risks associated with meeting an October 2017 in-service are as follows:

- The detailed route selection must be finalized by December 2010.
- An Environmental Licence must be received by September 2012.
- Certain activities will need to proceed in parallel with the environmental licensing process:
  - acquiring permits to work on crown lands,
  - purchase of some materials and/or purchase of extra towers and foundations types to accommodate unexpected conditions due to lack of geotechnical information,
  - temporary permits for site investigation activities (including field drilling) in order for design of foundations to be finalized and materials ordered for the construction start date.
- Completion of the northern portion of the Western route is based on having five winter seasons for access and construction. The southern portion of the Western route can be built year-round, however it is subject to more property and land access issues.

RESOURCE REQUIREMENTS AND CAPITAL BUDGET ESTIMATE:

Resource Requirements (This section is be filled out only if there is a change to the resource requirements).

No change.

Total Budget - (This section is required for all Addendums).

The impact on annual budget requirements is as follows (in thousands of dollars):

Fiscal Year	Previous CPJ / CPJ Addendum	This CPJ Addendum	Increase (Decrease)
Prev. Actuals	$ 7,613	$ 7,613	$ -
2007/08	$ 1,875	$ 1,955	$ 80
2008/09	$ 2,901	$ 17,878	$ 14,977
2009/10	$ 9,298	$ 33,037	$ 23,739
2010/11	$ 12,994	$ 80,542	$ 67,548
2011/12	$ 25,115	$ 110,970	$ 85,855
2012/13	$ 172,475	$ 271,913	$ 99,438
2013/14	$ 331,532	$ 671,609	$ 340,077
2014/15	$ 420,146	$ 691,071	$ 270,926
2015/16	$ 579,614	$ 823,189	$ 243,576
2016/17	$ 535,141	$ 866,711	$ 331,570
2017/18	$ 145,948	$ 375,335	$ 229,387
2018/19	$ 3,184	$ 1,926	$ (1,258)
Total	$ 2,247,835	$ 3,953,749	$ 1,705,914

Proposed Schedule (This section is be filled out only if there is a change to the project schedule).

No change.

Related Projects (This section is be filled out only if changed).

No change.

Reference Documents (This section is be filled out only if changed).

No change.

ADDENDUM #06a (Transmission Line)

Dated 2011.03.30

Approved by Executive Committee 2011.03.31

ADDENDUM #06b (Converter Stations)

Dated 2011.03.29

Approved by Executive Committee 2011.03.31

ADDENDUM #06c (Collector Lines)

Dated 2011.03.30

Approved by Executive Committee 2011.03.31

D1876(A)

REVIEWED BY EXECUTIVE COMMITTEE
MINUTE # 1348.02

DATE: 2011 03 31
Financial Planning

CAPITAL PROJECT JUSTIFIC FOR

Bipole III Western Routed T/L & 2000MW Converters
TRANSMISSION LINE
Addendum Number 06a

REVIEWED BY:
(Owning Dept Manager) Ron Mayer 2011/03/30

NOTED BY:
(if applicable)

Coordinating Div: S. Railey 2011/03/30

Constructing Div:

Designing Div.:

Financial: Nieuwenburg 2011.03.30

RECOMMENDED FOR IMPLEMENTATION:

Owning Div. Manager: G Neufeld 2011 03 30

Business Unit V.P.: [illegible] 2011.03.30

PREV. APPROVED BUDGET $: (Use S value from approved CPJ or last approved CPJ Addendum)	$1,081,923,000
REVISED BUDGET $: (Total Net Cost)	$1,259,915,000
START DATE: (1st Cost Flow)	2001 06
PREV. APPROVED ISD: (Use In-service Date from approved CPJ or last approved CPJ Addendum)	2017 10
REVISED ISD: (Indicate "Mult" if more than 1)	2017 10
RISK MATRIX/ BUSINESS CASE TIER:	Tier 2 (950 points)
INVESTMENT REASON: (Category and % Split)	Operational Enhancement (60%) New/increased Gen. Delivery (20%) Capacity Enhancement (20%)
OWNING DIVISION:	TRANSMISSION PLANNING & DESIGN
I.M. NODE NUMBER:	1.5.2.1.1.1
W.B.S. NUMBERs:	P:04218, P:04221, P:10155, P:14518
MAJOR ITEM ☒	**DOMESTIC ITEM** ☐
PREPARED BY:	Project Owner: Pei Wang Project Manager: Adele Poulin
DATE PREPARED:	2011.03.30
REPORT NUMBER:	
FILE NUMBER (Optional):	

ADDENDUM NUMBER	DATE (yyyy mm dd)	REVISION	REVISED BY	APPROVED BY
05	2007 05 15	Revised western route placeholder. Increase costs due to Construction and material cost increases.	A.A. Poulin / J.B. Davies / K.L. Kent	MH Board of Directors (Minute #786-07-05)
04	2005 06 23	Western route placeholder. Defer the in-service date by five years from 2012 10 to 2017 10.	J.B. Davies / K.L. Kent	Executive Committee (Minute #1090.06)
03	2004 04 06	Defer the in-service date by two years from 2010 10 to 2012 10.	J.B. Davies / K.L. Kent	Executive Committee (Minute #1030.05)
02	2003 11 12	Defer $2,462,000 worth of budget requirements from 2003/04 to future years.	C.A. Nieuwenburg	Executive Committee (Minute #999.05)
01	2003 05 08	Change northern termination from Radisson to Henday, increasing length by 20 km and costs by $8,245K.	J.B. Davies / K.L. Kent	Executive Committee (Minute #993.03)
-	2001 06 13	Original CPJ	J.B. Davies / K.L. Kent	Executive Committee (Minute #900.11)

MANITOBA HYDRO
CAPITAL PROJECT JUSTIFICATION ADDENDUM

Project Name (This section is required for all Addendums).

Bipole III Western Routed T/L & 2000MW Converters – **TRANSMISSION LINE**

Recommendation (This section is required for all Addendums).

Increase the budget by $177,991,000 for the Transmission Line components of the Bipole III Western Routed Transmission Line & 2000MW Converters complex, to a revised total of $1,259,915,000, in order to incorporate the following:

- review of the base estimate for the property, design and construction of the HVdc transmission line, and of the licensing and environmental assessment for the overall complex (total increase of $152,122,000);
- inclusion of contingency for the above-mentioned components (total increase of $49,353,000); and
- the resultant changes to interest and escalation (decrease of $23,485,000).

Project Scope (This section is be filled out only if there is a change to the scope).

The scope of this portion of the Bipole III complex includes the following major components:

- Design and construction of a western-routed 500kV HVdc transmission line from the Keewatinoow Converter Station to the Riel Converter Station, approximately 1341km in length.
- Licensing and environmental assessment for the overall Bipole III complex (i.e., including the 2000 MW converters and AC collector system).
- Property acquisition and/or easements for the 500kV HVdc transmission line.

Background (This section is be filled out only if there is information relevant to the recommendation).

CPJ Addendum #04, submitted in April 2005, was the first introduction to the Capital Expenditure Forecast of a western-routed 500kV HVdc transmission line with 2000MW of converters. The budget submitted with CPJ Addendum #04 was preliminary only, pending completion of studies by System Planning. It was based on an estimate prepared by Teshmont Consultants in 2001.

CPJ Addendum #05, submitted in May 2007, addressed an increase of 45km to the length of the transmission line, as well as increases being experienced in transmission line material and construction costs due to market prices. The cost estimates for licensing, property and contingency were not updated at that time.

This CPJ Addendum #06a covers a budget increase of $177,991,000 in association with the Transmission Line components of the Bipole III Western Routed Transmission Line & 2000MW Converters complex:

a) <u>500kV HVdc Transmission Line (base increase of $140,714,000):</u>
   - Design change from double to triple conductor, in order to lower the surface field gradient to accepted worldwide practices and thus minimize the likelihood of anomalous flashovers that have been experienced on the existing bipoles in the past 20 years.
   - Incorporation of the Transmission Line Agreement for unionization of construction labour.
   - Application of the revised corporate policy for compensation for private property.

b) <u>Licensing & Environmental Assessment for the Bipole III complex (base increase of $4,912,000):</u>
   - More comprehensive aboriginal and community consultations.
   - Additional studies related to converter size.

Background (This section is be filled out only if there is information relevant to the recommendation).

c) Property Acquisition and/or Easements for the Transmission Line (base increase of $6,497,000):
- More privately-owned land associated with the western route.

d) The revised budget also includes contingency at $49,353,000 (Project Risk Analysis section contains details).

The above changes to the base estimate and contingency, and a change in base dollars from 2007 to 2010, result in a net decrease of $23,485,000 to forecasted escalation and interest.

JUSTIFICATION—BUSINESS CASE ANALYSIS (SUMMARY):

Justification and Link to Corporate/Business Unit Goals (This section is required for all Addendums).

A third 500kV HVdc transmission line with converter stations rated for 2000MW will provide for increased reliability to the Manitoba Hydro system, due to the critical risk to the Province and the Corporation of a Dorsey Converter Station outage or an Interlake (Bipole I and II) corridor outage. It will also provide an increase in southern power due to reduced line losses on the existing Bipoles I and II (approximately 76MW in normal steady state operation prior to the addition of new generation into the northern collector system).

ANALYSIS OF ALTERNATIVES: (This section is be filled out only if there is a change to which alternative is being recommended).

Economic Analysis		
Discount Rate	%	For current corporate rates see G91-1

Recommended Option	NPV Benefits (Costs)
No change.	

Other Alternatives Considered	NPV Benefits (Costs)

Project Risk Analysis - (This section is be filled out only if there is a change to the project risk).

A total of $49,353,000 of contingency (approximately 6% of the base estimate) is included in the budget amount for CPJ Addendum #06a, to cover the following:

a) 500kV HVdc Transmission Line (contingency of $39,967,000 or 5% of the base estimate):
Potential changes to the detailed route selection or line length.

b) Licensing & Environmental Assessment (contingency of $9,386,000 or 15% of the base estimate):
Potential for greater requirements for aboriginal and community consultations, and for more extensive environmental monitoring and assessments during construction.

Project Risk Analysis - (This section is be filled out only if there is a change to the project risk).

The following risks create a potential for additional costs:
- Market conditions for transmission line construction labour, materials or commodities.
- Unforeseen geotechnical conditions.
- Further changes to corporate policy for private property compensation.

Some of the schedule-related risks associated with meeting an October 2017 in-service are as follows:
- Environmental License to be received by September 2012.
- Certain activities will need to proceed in parallel with the environmental licensing process:
  - acquiring permits to work on crown lands,
  - purchase of some materials and/or purchase of extra towers and foundations types to accommodate unexpected conditions due to lack of geotechnical information,
  - temporary permits for site investigation activities (including field drilling) in order for design of foundations to be finalized and materials ordered for the construction start date.
- Completion of the northern portion of the line is based on having five winter seasons for access and construction.

Capital Budget Estimate - (This section is required for all Addendums).

The impact on annual budget requirements is as follows (in thousands of dollars):

Fiscal Year	Previous CPJ / CPJ Addendum	This CPJ Addendum	Increase (Decrease)
Prev. Actuals	$ 17,207	$ 24,613	$ 7,406
2010/11	$ 5,801	$ 16,118	$ 10,317
2011/12	$ 10,235	$ 24,830	$ 14,595
2012/13	$ 146,630	$ 59,866	$ (86,764)
2013/14	$ 181,825	$ 162,043	$ (19,782)
2014/15	$ 201,556	$ 298,935	$ 97,379
2015/16	$ 216,344	$ 318,454	$ 102,110
2016/17	$ 227,477	$ 234,575	$ 7,098
2017/18	$ 71,665	$ 120,055	$ 48,390
2018/19	$ 3,184	$ 426	$ (2,758)
2019/20	$ -	$ -	$ -
Total	$ 1,081,923	$ 1,259,915	$ 177,991

Proposed Schedule (This section is be filled out only if there is a change to the project schedule).

No change.

Related Projects (This section is be filled out only if changed).

No change.

Reference Documents (This section is be filled out only if changed).
No change.

D1876(A)

REVIEWED BY EXECUTIVE COMMITTEE
MINUTE # 1348.02

DATE: 2011 03 31
Financial Planning

CAPITAL PROJECT JUSTIFICA
FOR

Bipole III Western Routed T/L & 2000MW Converters
CONVERTER STATIONS
Addendum Number 06b

REVIEWED BY:
(Owning Dept Manager)

RA FOR RME

NOTED BY:
(if applicable)

Coordinating Div:

Constructing Div:

Designing Div.:

Financial:

RECOMMENDED FOR IMPLEMENTATION:

Owning Div. Manager:

Business Unit V.P.:

11 03 30

PREV. APPROVED BUDGET $: (Use $ value from approved CPJ or last approved CPJ Addendum)	$1,104,197,000
REVISED BUDGET $: (Total Net Cost)	$1,828,532,000
START DATE: (1st Cost Flow)	2001 06
PREV. APPROVED ISD: (Use In-service Date from approved CPJ or last approved CPJ Addendum)	2017 10
REVISED ISD: (Indicate "Mult" if more than 1)	2017 10
RISK MATRIX/ BUSINESS CASE TIER:	Tier 2 (950 points)
INVESTMENT REASON: (Category and % Split)	Operational Enhancement (60%) New/increased Gen. Delivery (20%) Capacity Enhancement (20%)

OWNING DIVISION: NEW GENERATION CONSTRUCTION

I.M. NODE NUMBER: 1.5.2.1.2.1

W.B.S. NUMBERs: P:14363, P:14364, P:15533, P:15540, P:15541, P:15544

MAJOR ITEM ☒ **DOMESTIC ITEM** ☐

PREPARED BY:

DATE PREPARED: 2011.03.29

REPORT NUMBER:

FILE NUMBER (Optional):

ADDENDUM NUMBER	DATE (yyyy mm dd)	REVISION	REVISED BY	APPROVED BY
05	2007 05 15	Revised western route placeholder. Increase costs due to Construction and material cost increases.	A.A. Poulin / J.B. Davies / K.L. Kent	MH Board of Directors (Minute #786-07-05)
04	2005 06 23	Western route placeholder. Defer the in-service date by five years from 2012 10 to 2017 10.	J.B. Davies / K.L. Kent	Executive Committee (Minute #1090.06)
03	2004 04 06	Defer the in-service date by two years from 2010 10 to 2012 10.	J.B. Davies / K.L. Kent	Executive Committee (Minute #1030.05)
02	2003 11 12	Defer $2,462,000 worth of budget requirements from 2003/04 to future years.	C.A. Nieuwenburg	Executive Committee (Minute #999.05)
01	2003 05 08	Change northern termination from Radisson to Henday, increasing length by 20 km and costs by $8,245K.	J.B. Davies / K.L. Kent	Executive Committee (Minute #993.03)
-	2001 06 13	Original CPJ	J.B. Davies / K.L. Kent	Executive Committee (Minute #900.11)

MANITOBA HYDRO
CAPITAL PROJECT JUSTIFICATION ADDENDUM

Project Name (This section is required for all Addendums).

Bipole III Western Routed T/L & 2000MW Converters – **CONVERTER STATIONS**

Recommendation (This section is required for all Addendums).

Increase the budget by $724,335,000 for the Riel and Keewatinoow Converter Station components of the Bipole III Western Routed Transmission Line & 2000MW Converters complex, to a revised total of $1,828,532,000, in order to incorporate the following:

- review of the base estimate for the property, design and construction of the Riel and Keewatinoow Converter Stations and 230kV Switchyards (total increase of $474,226,000);
- inclusion of contingency for the above-mentioned components (total increase of $138,926,000); and
- the resultant changes to interest and escalation (increase of $111,183,000).

Project Scope (This section is be filled out only if there is a change to the scope).

The scope of this portion of the Bipole III complex includes the following major components:

- Design and construction of the 2000 MW Riel Converter Station and 230kV AC Switchyard.
- Design and construction of the 2000 MW Keewatinoow Converter Station and 230kV AC Switchyard.
- Property acquisition and/or easements for the Riel and Keewatinoow Converter Stations.

The proposed budget assumes use of voltage source converters for both the Riel and Keewatinoow Converter Stations without synchronous condensers at the Riel Converter Station.

Background (This section is be filled out only if there is information relevant to the recommendation).

CPJ Addendum #04, submitted in April 2005, was the first introduction to the Capital Expenditure Forecast of a western-routed 500kV HVdc transmission line with 2000MW of converters. The budget submitted with CPJ Addendum #04 was preliminary only, pending completion of studies by System Planning. It was based on an estimate prepared by Teshmont Consultants in 2001.

CPJ Addendum #05, submitted in May 2007, did not include re-estimates for the converter stations, nor was contingency included for the converter stations, as these components had not yet been reviewed in detail.

This CPJ Addendum #06b covers a budget increase of $724,335,000 in association with the Riel and Keewatinoow Converter Station components of the Bipole III Western Routed Transmission Line & 2000MW Converters complex:

a) <u>Riel Converter Station and 230kV AC Switchyard (base increase of $169,355,000):</u>
   - Converter and HVdc equipment costs have remained relatively unchanged when comparing 2009 mini-spec pricing versus the escalated 2001 estimate figures; however, there were no explicit indirect costs in the 2001 estimate and no interfacing costs.

b) <u>Keewatinoow Converter Station and 230kV AC Switchyard (base increase of $286,069,000):</u>
   - Converter and HVdc equipment costs have remained relatively unchanged when comparing 2009 mini-spec pricing versus the escalated 2001 estimate figures; however, there were no explicit indirect costs in the 2001 estimate and no interfacing costs.

Background (This section is be filled out only if there is information relevant to the recommendation).

- Site development costs have increased for the following reasons: the previous budget assumed that the Conawapa Generating Station infrastructure would be built ahead of Bipole III and therefore costs associated with a construction camp and work areas would be covered by that project's budget; mechanical services such as fire, water, sewer and oil containment, along with security and environmental requirements, were not considered in the 2001 estimate; the site size has increased and soil conditions are worse than identified in the 2001 estimate; the transformer change-out method and the emergency response buildings were not included in the 2001 estimate.

c) Property Acquisition and/or Easements for the Converter Stations (base increase of $18,802,000): Property costs for Riel and Keewatinoow Converter Stations were not included in the 2001 estimate. Costs for the Riel site are more substantial than the Keewatinoow site, and include $6.4 million for station site properties, and $12.3 million for buffer properties that have been purchased from private owners.

In addition to the above, the revised budget also includes the introduction of contingency at $138,926,000 (Project Risk Analysis section contains details).

The changes to the base estimate and inclusion of contingency, along with the change in base dollars from 2007 to 2010, result in an increase of $111,183,000 to forecasted escalation and interest.

JUSTIFICATION—BUSINESS CASE ANALYSIS (SUMMARY):

Justification and Link to Corporate/Business Unit Goals (This section is required for all Addendums).

A third 500kV HVdc transmission line with converter stations rated for 2000MW will provide for increased reliability to the Manitoba Hydro system, due to the critical risk to the Province and the Corporation of aDorsey Converter Station outage or an Interlake (Bipole I and II) corridor outage. It will also provide an increase in southern power due to reduced line losses on the existing Bipoles I and II (approximately 76MW in normal steady state operation prior to the addition of new generation into the northern collector system).

ANALYSIS OF ALTERNATIVES: (This section is be filled out only if there is a change to which alternative is being recommended).

Economic Analysis		
Discount Rate	%	For current corporate rates see G911

Recommended Option	NPV Benefits (Costs)
No change.	

Other Alternatives Considered	NPV Benefits (Costs)

Project Risk Analysis - (This section is be filled out only if there is a change to the project risk).

A total of $138,926,000 of contingency (approximately 11% of the base estimate) is included in the budget amount for CPJ Addendum #06b, to cover the following:

a) Keewatinoow Converter Station and 230kV AC Switchyard (contingency of $71,960,000 or 12% of the base estimate):
   - Potential changes to equipment costs due to a limited number of suppliers worldwide and variability of exchange rates until contracts are signed.
   - Potentially higher costs due to northern work conditions.

b) Riel Converter Station and 230kV AC Switchyard (contingency of $66,966,000 or 11% of the base estimate):
   - Potential changes to equipment costs due to limited number of suppliers worldwide and variability of exchange rates until contracts are signed.
   - Uncertainty with protection, cyber security and building strength (physical security).

The following risks create a potential for additional costs:
- Potential for greater requirement for engineering, project management and construction management.
- Potential for poor site conditions during construction.
- The potential requirement for synchronous condensers at the Riel Converter Station.

The assumed use of new technology in the form of voltage source converters at both the Keewatinoow and Riel Converter Stations represents an additional risk factor. Confirmation or otherwise of the feasibility of this technology is expected by late 2011.

Capital Budget Estimate - (This section is required for all Addendums).

The impact on annual budget requirements is as follows (in thousands of dollars):

Fiscal Year	Previous CPJ / CPJ Addendum	This CPJ Addendum	Increase (Decrease)
Prev. Actuals	$ 4,243	$ 30,423	$ 26,181
2010/11	$ 6,812	$ 46,255	$ 39,443
2011/12	$ 14,092	$ 59,696	$ 45,604
2012/13	$ 24,477	$ 148,883	$ 124,406
2013/14	$ 141,783	$ 300,258	$ 158,475
2014/15	$ 207,019	$ 290,185	$ 83,166
2015/16	$ 344,041	$ 294,281	$ (49,759)
2016/17	$ 291,378	$ 308,460	$ 17,082
2017/18	$ 70,351	$ 347,692	$ 277,341
2018/19	$ -	$ 2,398	$ 2,398
2019/20	$ -	$ -	$ -
Total	$ 1,104,197	$ 1,828,532	$ 724,335

Proposed Schedule (This section is be filled out only if there is a change to the project schedule).

No change.

Related Projects (This section is be filled out only if changed).

No change.

Reference Documents (This section is be filled out only if changed).

No change.

D1876(A)

REVIEWED BY EXECUTIVE COMMITTEE
MINUTE # 1348.02

DATE: 2011 03 31
Financial Planning

CAPITAL PROJECT JUSTIFIC
FOR

Bipole III Western Routed T/L & 2000MW Converters
COLLECTOR LINES
Addendum Number 06c

REVIEWED BY:
(Owning Dept Manager: Ron Mazur) Ron Mazur 2011/03/30

NOTED BY:
(if applicable)

Coordinating Div: Shane Mailey S. Mailey 2011/03/30

Constructing Div:

Designing Div.:

Financial: C.A. Nieuwenburg 2011.03.30

RECOMMENDED FOR IMPLEMENTATION:

Owning Div. Manager: J. Neufeld 2011 03 30

Business Unit V.P.: B. Lynn Fedchuk 2011.03.30

PREV. APPROVED BUDGET $: (Use $ value from approved CPJ or last approved CPJ Addendum)	$61,715,000
REVISED BUDGET $: (Total Net Cost)	$191,438,000
START DATE: (1st Cost Flow)	2001 06
PREV. APPROVED ISD: (Use In-service Date from approved CPJ or last approved CPJ Addendum)	2017 10
REVISED ISD: (Indicate "Mult" if more than 1)	2017 10
RISK MATRIX/ BUSINESS CASE TIER:	Tier 2 (950 points)
INVESTMENT REASON: (Category and % Split)	Operational Enhancement (60%) New/increased Gen. Delivery (20%) Capacity Enhancement (20%)
OWNING DIVISION:	TRANSMISSION PLANNING & DESIGN
I.M. NODE NUMBER:	1.5.2.1.3.1
W.B.S. NUMBERs:	P:15534 - P:15537, P:15542, P:15543, P:15696, P:15697
MAJOR ITEM ☒	**DOMESTIC ITEM** ☐
PREPARED BY:	Project Owner: Pei Wang Project Manager: Adele Poulin
DATE PREPARED:	2011.03.30
REPORT NUMBER:	
FILE NUMBER (Optional):	

ADDENDUM NUMBER	DATE (yyyy mm dd)	REVISION	REVISED BY	APPROVED BY
05	2007 05 15	Revised western route placeholder. Increase costs due to Construction and material cost increases.	A.A. Poulin / J.B. Davies / K.L. Kent	MH Board of Directors (Minute #786-07-05)
04	2005 06 23	Western route placeholder. Defer the in-service date by five years from 2012 10 to 2017 10.	J.B. Davies / K.L. Kent	Executive Committee (Minute #1090.06)
03	2004 04 06	Defer the in-service date by two years from 2010 10 to 2012 10.	J.B. Davies / K.L. Kent	Executive Committee (Minute #1030.05)
02	2003 11 12	Defer $2,462,000 worth of budget requirements from 2003/04 to future years.	C.A. Nieuwenburg	Executive Committee (Minute #999.05)
01	2003 05 08	Change northern termination from Radisson to Henday, increasing length by 20 km and costs by $8,245K.	J.B. Davies / K.L. Kent	Executive Committee (Minute #993.03)
-	2001 06 13	Original CPJ	J.B. Davies / K.L. Kent	Executive Committee (Minute #900.11)

MANITOBA HYDRO
CAPITAL PROJECT JUSTIFICATION ADDENDUM

Project Name (This section is required for all Addendums):

Bipole III Western Routed T/L & 2000MW Converters – **COLLECTOR LINES**

Recommendation (This section is required for all Addendums):

Increase the budget by $129,722,000 for the Collector Lines components of the Bipole III Western Routed Transmission Line & 2000MW Converters complex, to a revised total of $191,438,000, in order to incorporate the following:

- review of the base estimate for the property, design and construction of the 230kV collector lines for the Keewatinoow Converter Station, the construction power for the Keewatinoow Converter Station, the sectionalization of 230kV transmission line R49R at the Riel Converter Station, and the electrode lines for the Riel and Keewatinoow Converter Stations (total increase of $73,222,000);
- inclusion of contingency for the above-mentioned components (total increase of $17,203,000); and
- the resultant changes to interest and escalation (increase of $39,297,000).

Project Scope (This section is be filled out only if there is a change to the scope):

The scope of this portion of the Bipole III complex includes the following major components:

- Design and construction of three permanent and two temporary 230kV collector lines for the Keewatinoow Converter Station.
- Construction power substation for the Keewatinoow Converter Station.
- Design and construction for the Riel and Keewatinoow electrode lines.
- Sectionalization of 230kV transmission line R49R at Riel.
- Property acquisition and/or easements for the collector and electrode lines.

Background (This section is be filled out only if there is information relevant to the recommendation):

CPJ Addendum #04, submitted in April 2005, was the first introduction to the Capital Expenditure Forecast of a western-routed 500kV HVdc transmission line with 2000MW of converters. The budget submitted with CPJ Addendum #04 was preliminary only, pending completion of studies by System Planning. It was based on an estimate prepared by Teshmont Consultants in 2001.

CPJ Addendum #05, submitted in May 2007, did not include re-estimates for the northern collector lines, the two electrode lines, the related property, or contingency.

This CPJ Addendum #06c covers a budget increase of $129,722,000 in association with the Collector Lines components of the Bipole III Western Routed Transmission Line & 2000MW Converters complex:

a) <u>Keewatinoow 230kV Collector Lines (base increase of $35,756,000):</u>
The 2001 estimate included only three collector lines, while this estimate has two more (temporary) collector lines. The two temporary lines are required in lieu of an earlier introduction of additional generation in the northern collector system. At the time of the 2001 estimate, the planned in-service for the Conawapa Generating Station (GS) was only two years after Bipole III. Now that the in-service for Conawapa GS is planned for several years later, two temporary lines are required in order to permit full use of a 2000MW rating for Bipole III in the event of a Dorsey Station or Bipole I / II outage.

In addition, the cost of transmission line material and construction has increased since 2001.

Background (This section is be filled out only if there is information relevant to the recommendation).

b) Keewatinoow Construction Power (base increase of $23,381,000):
The 2001 estimate did not include the requirement for a construction power substation, as it was assumed it would have already been built for construction of the Conawapa GS. With the change in the sequence, the Bipole III project will now be the first development to require this construction power substation.

c) Property Acquisition and/or Easements for the Collector and Electrode Lines (base increase of $10,732,000):
The 2001 estimate did not include any property costs for the Keewatinoow collector lines or the Riel and Keewatinoow electrode lines.

d) Sectionalization of 230kV Transmission Line R49R at Riel (base increase of $1,955,000):
This had been included in the Riel Sectionalization project but was deferred to coincide with the Bipole III converters. It is required to accommodate and reliably transmit a 2000MW Bipole III at Riel.

e) Riel and Keewatinoow Electrode Lines (base increase of $1,398,000):
The cost of line material and construction has increased since 2001.

f) The revised budget also includes contingency at $17,203,000 (Project Risk Analysis section contains details).

The above changes to the base estimate and contingency, and a change in base dollars from 2007 to 2010, result in an increase of $39,297,000 to forecasted escalation and interest.

JUSTIFICATION—BUSINESS CASE ANALYSIS (SUMMARY):

Justification and Link to Corporate/Business Unit Goals (This section is required for all Addendums).

A third 500kV HVdc transmission line with converter stations rated for 2000MW will provide for increased reliability to the Manitoba Hydro system, due to the critical risk to the Province and the Corporation of a Dorsey Converter Station outage or an Interlake (Bipole I and II) corridor outage. It will also provide an increase in southern power due to reduced line losses on the existing Bipoles I and II (approximately 76MW in normal steady state operation prior to the addition of new generation into the northern collector system).

ANALYSIS OF ALTERNATIVES: (This section is be filled out only if there is a change to which alternative is being recommended).

Economic Analysis		
Discount Rate	%	For current corporate rates see G911

Recommended Option	NPV Benefits (Costs)
No change.	

Other Alternatives Considered	NPV Benefits (Costs)

Project Risk Analysis - (This section is be filled out only if there is a change to the project risk).

A total of $17,203,000 of contingency (approximately 15% of the base estimate) is included in the budget amount for CPJ Addendum #06c, to cover the following:

a) Keewatinoow Collector Lines (contingency of $8,952,000 or 13% of the base estimate):
Provides for potentially higher costs for material and construction labour.

b) Keewatinoow Construction Power (contingency of $5,451,000 or 23% of the base estimate):
Estimates are based on a conceptual Single Line Diagram only. The site size and exact location are not yet finalized. Backup power requirements are currently under review.

c) Riel and Keewatinoow Electrode Lines (contingency of $2,800,000 or 34% of the base estimate):
Line lengths are uncertain, as the Electrode sites for Riel and Keewatinoow have not been finalized. Also provides for use of steel towers if necessary for reliability.

The following risks create a potential for additional costs:
- Potential for poor site conditions during construction.
- Potentially higher costs due to northern work conditions.
- Further changes to corporate policy for private property compensation.

Capital Budget Estimate - (This section is required for all Addendums).

The impact on annual budget requirements is as follows (in thousands of dollars):

Fiscal Year	Previous CPJ / CPJ Addendum	This CPJ Addendum	Increase (Decrease)
Prev. Actuals	$ 237	$ 0	$ (237)
2010/11	$ 381	$ 2,121	$ 1,740
2011/12	$ 788	$ 19,917	$ 19,130
2012/13	$ 1,368	$ 52,709	$ 51,341
2013/14	$ 7,924	$ 30,141	$ 22,217
2014/15	$ 11,571	$ 30,927	$ 19,357
2015/16	$ 19,229	$ 34,255	$ 15,026
2016/17	$ 16,286	$ 13,549	$ (2,737)
2017/18	$ 3,932	$ 7,818	$ 3,886
2018/19	$ -	$ -	$ -
2019/20	$ -	$ -	$ -
Total	$ 61,715	$ 191,438	$ 129,722

Proposed Schedule (This section is be filled out only if there is a change to the project schedule).

No change.

Related Projects (This section is be filled out only if changed).
No change.

Reference Documents (This section is be filled out only if changed).
No change.

COMMUNITY DEVELOPMENT INITIATIVE

Dated 2013.07.19

Approved by Executive Committee 2013.08.20

D1876

APPROVED BY EXECUTIVE COMMITTEE
MINUTE # 1453.03

DATE: 2013 08 20
Financial Planning

CAPITAL PROJECT JUS[illegible]
FOR

Community Development Initiative

REVIEWED BY:
(Owning Dept Manager)

NOTED BY:
(if applicable)

Coordinating Division:

Constructing Division:

Financial Department:
(if over $1 million)

RECOMMENDED FOR IMPLEMENTATION:

Owning Div. Manager:

Business Unit V.P.: ER Kristjanson 2013/08/15

PRIMARY JUSTIFICATION:
Indicate key project driver(s):

☐	Safety	☐	Customer Service
☐	System Supply	☒	Efficiency
☒	System Reliability	☐	Environmental

NERC COMPLIANCE*: ☒ YES ☐ NO

*Determine if the project requires compliance with North American Electric Reliability Corporation (NERC) CIP Cyber Security Standards.

BUDGET $: (Total Net Cost)	$60,782,000
START DATE: (1st Cost Flow)	2014 03
IN-SERVICE DATE: (Last Major In-service Date)	2017 10
RISK MATRIX/ BUSINESS CASE TIER: (Optional)	Tier 2 (950 points)
INVESTMENT REASONS: (Optional)	Operational Enhancement (60%) New/increased Gen. Delivery (20%) Capacity Enhancement (20%)

OWNING DIVISION: Aboriginal Relations

I.M. NODE NUMBER: 1.5.2.1.1.2

W.B.S. NUMBERs: P:21948

MAJOR ITEM ☒ **DOMESTIC ITEM** ☐

PREPARED BY: Louis Demers

DATE PREPARED: 2013 07 19

REPORT NUMBER:

FILE NUMBER (Optional):

MANITOBA HYDRO
CAPITAL PROJECT JUSTIFICATION

Project Name
Bipole III Community Development Initiative – **TRANSMISSION LINE**

Recommendation
Establish budget to incorporate Bipole III Community Development Initiative ("CDI") that was approved by the Manitoba Hydro-Electric Board in May 2010.

Project Scope
Estimate based on the net present value of a 10-year program valued at up to $6 million per year.

Background

The Manitoba Hydro-Electric Board approved the establishment of a Bipole III Community Development Initiative ("CDI"), valued at up to $6 million a year, for Manitoba Hydro to provide benefits to communities in the vicinity of the Bipole III project facilities (May 20, 2010, minute 808-10-03). Following this approval, the Bipole III Preliminary Preferred Route became known and was released publicly in July 2010. From the time of Board approval, a multi-business unit CDI Working Group continued to meet to refine the CDI approach, in light of the preliminary preferred route, and to develop related communications material. Following feedback regarding the CDI, there was consensus that the refinements described in the recommendation be implemented, which include the following:

a) That CDI payments be provided for a 10 year period, with the possibility of program renewal at the end of the 10 year period;
b) That CDI payments begin upon receipt of the Bipole III regulatory approvals;
c) That the boundary for communities whose eligibility is based on proximity to the line be limited to 40 km;
d) That the eligibility requirements for incorporated towns and villages be such that a town or village must be located within a municipality traversed by the line and be located within 40 km of the line; and
e) That the CDI payments to communities be adjusted annually with the change in inflation.

The requested budget increase is planned as a 2013/14 expense based on all regulatory approvals being received no later than December 2013.

JUSTIFICATION—BUSINESS CASE ANALYSIS (SUMMARY):

Justification and Link to Corporate/Business Unit Goals

The CDI program remains inclusive of a variety of interests; is strongly linked to the Bipole III facilities; and will be an effective means of promoting community support for hosting the Bipole III project facilities.

ANALYSIS OF ALTERNATIVES:

Economic Analysis		
Discount Rate	For current corporate rates see G911 %	For clarification on hurdle rates, contact the Economic Analysis Department

Recommended Option	NPV Benefits (Costs)
No change.	

Other Alternatives Considered	NPV Benefits/(Costs)
N/A	

Risk Analysis

No change.

Capital Budget Estimate

The annual net budget requirements are as follows (in thousands of dollars):

Fiscal Year	Proposed Budget	
Prev. Actuals	$	-
2013/14	$	53,937
2014/15	$	2,157
2015/16	$	1,979
2016/17+	$	2,709
Total	$	60,782

Proposed Schedule

No change.

Related Projects

No change.

Reference Documents

Executive Committee Board Recommendation for the "Bipole III Community Development Initiative" (document approved under EC minute # 913-10-06 - plus revision of August 12, 2013 (revising the distance from the line to 40km) EC minute # pending.

ADDENDUM #07a (Transmission Line)

Dated 2014.09.24

Approved by Executive Committee 2014.10.21

ADDENDUM #07b (Converter Stations)

Dated 2014.09.24

Approved by Executive Committee 2014.10.21

ADDENDUM #07c (Collector Lines)

Dated 2014.09.24

Approved by Executive Committee 2014.10.21

ADDENDUM #07d (Community Development Initiative)

Dated 2014.09.26

Approved by Executive Committee 2014.10.21

D1876(A)

APPROVED BY EXECUTIVE COMMITTEE
MINUTE # 1503.02

DATE: 2014 10 21
Financial Planning

CAPITAL PROJECT JUSTIFICATION AD
FOR

Bipole III Project
TRANSMISSION LINE
Addendum Number 07a

REVIEWED BY:
(Owning Dept Manager)
Adele Poulin 2014/10/01
A. Fogg 2014/10/02

NOTED BY:
(if applicable)

Coordinating Division:

Constructing Division:

Financial Department:
(if over $1 million)
2014/10/01

RECOMMENDED FOR IMPLEMENTATION

Owning Div. Manager: 2014/10/01

Business Unit V.P.: 7 Oct 2014

PREV. APPROVED BUDGET $: (Use $ value from approved CPJ or last approved CPJ Addendum)	$1,259,915,000
REVISED BUDGET $: (Total Net Cost)	$1,655,371,000
START DATE: (1st Cost Flow)	2001 06
PREV. APPROVED ISD: (Use In-service Date from approved CPJ or last approved CPJ Addendum)	2017 10
REVISED ISD: (Last Major In-service Date)	2018 07
RISK MATRIX/ BUSINESS CASE TIER: (Optional)	N.A.
INVESTMENT REASONS: (Optional)	Operational Enhancement (60%) New/increased Gen. Delivery (20%) Capacity Enhancement (20%)

PRIMARY JUSTIFICATION:
Indicate key project driver(s):

- ☐ Safety
- ☐ System Supply
- ☒ System Reliability
- ☐ Customer Service
- ☐ Efficiency
- ☐ Environmental

NERC COMPLIANCE*: ☒ **YES** ☐ **NO**

*Determine if the project requires compliance with North American Electric Reliability Corporation (NERC) CIP Cyber Security Standards.

OWNING DIVISION:	BIPOLE III PROJECT
I.M. NODE NUMBER:	1.5.2.1.1.1
W.B.S. NUMBERs:	P:04218, P:04221, P:10155, P:14518, P:18414, P:20255, P:23817
MAJOR ITEM ☒	**DOMESTIC ITEM** ☐
PREPARED BY:	Alastair Fogg / Adele Poulin
DATE PREPARED:	2014 09 24
REPORT NUMBER:	
FILE NUMBER (Optional):	

ADDENDUM NUMBER	DATE (yyyy mm dd)	REVISION	REVISED BY	APPROVED BY
06a	2011 03 31	Revised estimate for increased length to 1341 km, construction cost increases, and inclusion of contingency.	A.A. Poulin / P. Wang	Executive Committee (Minute #1348.02)
05	2007 05 15	Revised western route placeholder. Increase costs due to Construction and material cost increases.	A.A. Poulin / J.B. Davies / K.L. Kent	MH Board of Directors (Minute #786-07-05)
04	2005 06 23	Western route placeholder. Defer the in-service date by five years from 2012 10 to 2017 10.	J.B. Davies / K.L. Kent	Executive Committee (Minute #1090.06)
03	2004 04 06	Defer the in-service date by two years from 2010 10 to 2012 10.	J.B. Davies / K.L. Kent	Executive Committee (Minute #1030.05)
02	2003 11 12	Defer $2,462,000 worth of budget requirements from 2003/04 to future years.	C.A. Nieuwenburg	Executive Committee (Minute #999.05)
01	2003 05 08	Change northern termination from Radisson to Henday, increasing length by 20 km and costs by $8,245K.	J.B. Davies / K.L. Kent	Executive Committee (Minute #993.03)
-	2001 06 13	Original CPJ	J.B. Davies / K.L. Kent	Executive Committee (Minute #900.11)

MANITOBA HYDRO
CAPITAL PROJECT JUSTIFICATION ADDENDUM

Project Name (This section is required for all Addendums).

Bipole III Project – **TRANSMISSION LINE**

Recommendation (This section is required for all Addendums).

Increase the budget by $395 million for the Transmission Line components of the Bipole III Project, to a revised total of $1,655 million and a revised in-service date of July, 2018.

Project Scope (This section is be filled out only if there is a change to the scope).

The scope of this portion of the Bipole III Project includes the following major components:

- Design and construction of a western-routed 500kV HVdc transmission line from the Keewatinohk (Keewatinoow) Converter Station to the Riel Converter Station.
- Property acquisition and/or easements for the 500kV HVdc transmission line.
- Design and construction of the Bipole III Communications transport system.
- Licensing and environmental assessment for the overall Bipole III complex (i.e., including the 2000 MW converters and AC collector system).

Changes to scope include: revised line length of final approved route, issued Licence & Conditions, revised landowner compensation strategy and policy, increased Bipole III rating to 2300 MW, and revised project in-service date of July 2018.

Background (This section is be filled out only if there is information relevant to the recommendation).

The last project re-estimate was completed in 2010, based on a preferred routing of the line prior to issuance of the Project Licence.

The revised estimate incorporates a more detailed scope based on an issued environment act licence, approved finalized route and right-of-way width, as well as up-to-date market information. Also since the last estimate, the project licence and permits were received later than planned, resulting in 1.5 lost winter seasons of 5 total planned. The estimate is based on the need for at least 4 more winter seasons to construct the transmission line and change to project in-service of July 2018.

The recommended budget is based on a P50 estimate that includes all base costs and contingency at a 50% confidence level and management reserves for market uncertainty risk for transmission line construction work.

P50 Estimate:

Since the last estimate was developed in 2010 it was necessary to bring the estimate to 2014$ and several items in the point estimate had to be adjusted to match the increased level of detail that has been identified within the current scope. This resulted in an increase of $363 million to the P50 Estimate as a result of the following:

- Incorporation of Environment Act Licence conditions and monitoring requirements
- Changes to the finalized route (increased length, additional towers and increased right-of-way width)
- Updated land acquisition costs
- Recommended contingency of [redacted] (increase of $61M) to address remaining uncertainty. See

Background (This section is be filled out only if there is information relevant to the recommendation).

Risk Analysis section.

Reserves:
A Management Reserve has been established to address significant risks related to bidding market and pricing uncertainty for Transmission Line construction work (increase of $100M). See Risk Analysis section.

In-Service Costs:
The overall increase to the in-service cost of the project is $395M (31%). This increase to the in-service cost is due to the increases in the P50 base estimate, the change to the project in-service date, and addition of the Management Reserve. These increases are offset by reduced interest and escalation costs.

Justification (This section is required for all addendums).

A third 500kV HVdc transmission line with converter stations will provide for increased reliability to the Manitoba Hydro system, due to the critical risk to the Province and the Corporation of a Dorsey Converter Station outage or an Interlake (Bipole I and II) corridor outage. It will also provide an increase in southern power due to reduced line losses on the existing Bipoles I and II (approximately 76MW in normal steady state operation prior to the addition of new generation into the northern collector system).

The rating for Bipole III was increased from 2000MW to 2300MW to ensure adequate spare HVdc transmission on the northern collector system. The increased rating ensures future generation associated with Keeyask and Conawapa can be transmitted via Bipole I, Bipole II and Bipole III in the event of a single valve group outage. The increased rating limits the amount of future upgrades and equipment replacement needed on the Bipole III HVdc system to accommodate future Conawapa generation.

ANALYSIS OF ALTERNATIVES: (This section is be filled out only if there is a change to which alternative is being recommended).

Economic Analysis		
Discount Rate	% For current corporate rates see G911	For clarification on hurdle rates, contact Economic Analysis Department

Recommended Option	**NPV Benefits/(Costs)**
No change.	

Other Alternatives Considered	**NPV Benefits/(Costs)**
N/A.	

Risk Analysis – (This section is be filled out only if there is a change to the project risk).

The risk & contingency methodology outlined at the NFAT for Keeyask & Conawapa Projects has been applied to the revised Bipole III Project estimate. The estimate includes a recommended project contingency at a P50 confidence level to address remaining areas of uncertainty.

Risk Analysis – (This section is be filled out only if there is a change to the project risk).

Additionally, this portion of the Bipole III Project includes a recommended Management Reserve of $100M associated with bidding market and pricing uncertainty for Transmission Line construction work. This remains the greatest area of uncertainty for Bipole III and the potential cost variation associated with this risk is best addressed through the inclusion of Management Reserve funds.

An additional, significant area of uncertainty is the potential impacts to schedule due to further delays in acquisition of private lands. A Management Reserve for this risk has not been recommended as part of the project budget. However, there will be cost impacts to the project should the risk occur.

Total Budget – (This section is required for all Addendums).

The impact on annual budget requirements is as follows (in thousands of dollars):

Fiscal Year	Prev. Approved CPJ/Addendum	Proposed CPJ Addendum	Increase (Decrease)
Prev. Actuals	$ 24,613	$ 24,613	$ -
2010/11	$ 16,118	$ 19,002	$ 2,884
2011/12	$ 24,830	$ 18,350	$ (6,480)
2012/13	$ 59,866	$ 25,091	$ (34,775)
2013/14	$ 162,043	$ 54,276	$ (107,767)
2014/15	$ 298,935	$ 203,458	$ (95,477)
2015/16	$ 318,454	$ 360,455	$ 42,001
2016/17	$ 234,575	$ 381,047	$ 146,472
2017/18	$ 120,055	$ 493,821	$ 373,766
2018/19	$ 426	$ 75,257	$ 74,831
Total	$ 1,259,915	$ 1,655,371	$ 395,456

Proposed Schedule (This section is be filled out only if there is a change to the project schedule).

The schedule has been updated for the proposed change to in-service date of July 2018.

Related Projects (This section is be filled out only if changed).

1.5.2.1.2.1 Bipole III Project – Converter Stations
1.5.2.1.3.1 Bipole III Project – Collector Lines
1.5.2.1.7.1 Bipole III Project – Community Development Initiative

1.1.2.3.62.1 Southern AC System Breaker Replacements

Reference Documents (This section is be filled out only if changed).

1. System Planning Department Report on Bipole III Rating, 2012 11 02
2. System Planning Department Report on Integrated Transmission Plan for Keeyask and Conawapa Generation, 2012 07 06

D1876(A)
2675083

APPROVED BY EXECUTIVE COMMITTEE
MINUTE # 1503.02

DATE: 2014 10 21
Financial Planning

CAPITAL PROJECT JUSTIFICATION A
FOR

Bipole III Project
CONVERTER STATIONS
Addendum Number 07b

REVIEWED BY:
(Owning Dept Manager)
Adele Poulin 2014/10/01
A. Fogg 2014/10/02

NOTED BY:
(if applicable)

Coordinating Division:

Constructing Division:

Financial Department:
(if over $1 million)
Owen Fevez 2014/10/01

RECOMMENDED FOR IMPLEMENTATION:

Owning Div. Manager: 2014/10/02

Business Unit V.P.: Oct 2014

PREV. APPROVED BUDGET $: (Use $ value from approved CPJ or last approved CPJ Addendum)	$1,828,532,000
REVISED BUDGET $: (Total Net Cost)	$2,675,083,000
START DATE: (1st Cost Flow)	2001 06
PREV. APPROVED ISD: (Use In-service Date from approved CPJ or last approved CPJ Addendum)	2017 10
REVISED ISD: (Last Major In-service Date)	2018 07
RISK MATRIX/ BUSINESS CASE TIER: (Optional)	N.A.
INVESTMENT REASONS: (Optional)	Operational Enhancement (60%) New/increased Gen. Delivery (20%) Capacity Enhancement (20%)

PRIMARY JUSTIFICATION:
Indicate key project driver(s):

- ☐ Safety
- ☐ System Supply
- ☒ System Reliability
- ☐ Customer Service
- ☐ Efficiency
- ☐ Environmental

NERC COMPLIANCE*: ☒ **YES** ☐ **NO**

*Determine if the project requires compliance with North American Electric Reliability Corporation (NERC) CIP Cyber Security Standards.

OWNING DIVISION:	BIPOLE III PROJECT
I.M. NODE NUMBER:	1.5.2.1.2.1
W.B.S. NUMBERs:	P:14363, P:14364, P:15533, P:15540, P:15541, P:15544, P:21082, P:23788, P:23837
MAJOR ITEM ☒	**DOMESTIC ITEM** ☐
PREPARED BY:	Alastair Fogg / Adele Poulin
DATE PREPARED:	2014 09 24
REPORT NUMBER:	
FILE NUMBER (Optional):	

ADDENDUM NUMBER	DATE (yyyy mm dd)	REVISION	REVISED BY	APPROVED BY
06a	2011 03 31	Revised Converter Stations estimate, including assumption of VSC technology for HVdc	R.M. Elder	Executive Committee (Minute #1348.02)
05	2007 05 15	Revised western route placeholder. Increase costs due to Construction and material cost increases.	A.A. Poulin / J.B. Davies / K.L. Kent	MH Board of Directors (Minute #786-07-05)
04	2005 06 23	Western route placeholder. Defer the in-service date by five years from 2012 10 to 2017 10.	J.B. Davies / K.L. Kent	Executive Committee (Minute #1090.06)
03	2004 04 06	Defer the in-service date by two years from 2010 10 to 2012 10.	J.B. Davies / K.L. Kent	Executive Committee (Minute #1030.05)
02	2003 11 12	Defer $2,462,000 worth of budget requirements from 2003/04 to future years.	C.A. Nieuwenburg	Executive Committee (Minute #999.05)
01	2003 05 08	Change northern termination from Radisson to Henday, increasing length by 20 km and costs by $8,245K.	J.B. Davies / K.L. Kent	Executive Committee (Minute #993.03)
-	2001 06 13	Original CPJ	J.B. Davies / K.L. Kent	Executive Committee (Minute #900.11)

MANITOBA HYDRO
CAPITAL PROJECT JUSTIFICATION ADDENDUM

Project Name (This section is required for all Addendums).

Bipole III Project – **CONVERTER STATIONS**

Recommendation (This section is required for all Addendums).

Increase the budget by $ 846.5 million for the Converter Station components of the Bipole Project, to a revised total of $2,675 and a revised in-service date of July, 2018.

Project Scope (This section is be filled out only if there is a change to the scope).

The scope of this portion of the Bipole III complex includes the following major components:

- Design and construction 2300 MW Riel Converter Station and 230 kV AC Switchyard.
- Design and construction 2300 MW Keewatinohk (Keewatinoow) Converter Station and 230 kV AC Switchyard.
- Property acquisition and/or easements for the Riel and Keewatinohk Converter Stations.

Changes to scope include: Selection of LCC HVdc technology requiring the inclusion of Synchronous Condensers, increased Bipole III rating to 2300 MW, and revised project in-service date of July 2018.

Background (This section is be filled out only if there is information relevant to the recommendation).

The last project re-estimate was completed in 2010, based largely on historical and budgetary pricing from vendors as well as an assumption of VSC technology for the HVdc Converter and therefore no requirement for synchronous condensers.

The revised estimate is based on LCC HVdc technology as this was the technology bid by all vendors and incorporates the bid pricing received. The selection of LCC technology has resulted in synchronous condensers being included in the revised estimate. Additionally, the awarded contract prices for the Keewatinohk Camp, Keewatinohk Site Development and the Keewatinohk 230kV AC Switchyard have been incorporated into the revised estimate. The estimate is based on a project in-service of July 2018, which is required to complete the HVdc Converters installation.

The recommended budget is based on a P50 estimate that includes all base costs and contingency at a 50% confidence level.

<u>P50 Estimate:</u>

Since the last estimate was developed in 2010 it was necessary to bring the estimate to 2014$ and several items in the point estimate had to be adjusted to match the increased level of detail that has been identified within the current scope. This resulted in an increase of $649 million to the P50 Estimate as a result of the following:

- Incorporation of contract costs for the Keewatinohk 230kV AC Switchyard, Keewatinohk Site Development, Keewatinohk Camp and Keewatinohk Camp Services
- Incorporation of bid price for the Keewatinohk and Riel HVdc Converter Equipment contract
- Inclusion of Synchronous Condensers in the scope of work as a result of LCC technology for the HVdc equipment
- Incorporation of allocated portion of actual costs for Riel Sectionalization project
- Incorporation of updated costs for the Riel 230kV AC Switchyard Expansion

Background (This section is be filled out only if there is information relevant to the recommendation).

- Recommended contingency of [redacted] (decrease of $16M) to address remaining uncertainty.

Reserves:
No Management Reserve for the Converter Stations component of the project is recommended to include in the estimate at this time.

In-Service Costs:
The overall increase to the in-service cost of the project is $846.5 (46%). This increase to the in-service cost is due to the increases in the P50 base estimate, the change to the project in-service date, and addition of the Management Reserve. These increases are offset by reduced interest and escalation costs.

Justification (This section is required for all addendums).

A third 500kV HVdc transmission line with converter stations will provide for increased reliability to the Manitoba Hydro system, due to the critical risk to the Province and the Corporation of a Dorsey Converter Station outage or an Interlake (Bipole I and II) corridor outage. It will also provide an increase in southern power due to reduced line losses on the existing Bipoles I and II (approximately 76MW in normal steady state operation prior to the addition of new generation into the northern collector system).

The rating for Bipole III was increased from 2000MW to 2300MW to ensure adequate spare HVdc transmission on the northern collector system. The increased rating ensures future generation associated with Keeyask and Conawapa can be transmitted via Bipole I, Bipole II and Bipole III in the event of a single valve group outage. The increased rating limits the amount of future upgrades and equipment replacement needed on the Bipole III HVdc system to accommodate future Conawapa generation.

ANALYSIS OF ALTERNATIVES: (This section is be filled out only if there is a change to which alternative is being recommended).

Economic Analysis		
Discount Rate	% For current corporate rates see G911	For clarification on hurdle rates, contact Economic Analysis Department

Recommended Option	**NPV Benefits/(Costs)**
No change.	

Other Alternatives Considered	**NPV Benefits/(Costs)**
N/A.	

Risk Analysis – (This section is be filled out only if there is a change to the project risk).

The risk & contingency methodology outlined at the NFAT for Keeyask & Conawapa Projects has been applied to the revised Bipole III Project estimate. The estimate includes a recommended project contingency at a P50 confidence level to address remaining areas of uncertainty.

Inclusion of a Management Reserve for this portion of the Bipole III complex is not considered necessary

Risk Analysis – (This section is be filled out only if there is a change to the project risk).

at this time.

Total Budget – (This section is required for all Addendums).

The impact on annual budget requirements is as follows (in thousands of dollars):

Fiscal Year	Prev. Approved CPJ/Addendum	Proposed CPJ Addendum	Increase (Decrease)
Prev. Actuals	$ 30,423	$ 30,423	$ -
2010/11	$ 46,255	$ 28,069	$ (18,186)
2011/12	$ 59,696	$ 36,417	$ (23,279)
2012/13	$ 148,883	$ 79,718	$ (69,165)
2013/14	$ 300,258	$ 144,153	$ (156,105)
2014/15	$ 290,185	$ 221,051	$ (69,134)
2015/16	$ 294,281	$ 580,792	$ 286,511
2016/17	$ 308,460	$ 828,733	$ 520,273
2017/18	$ 347,692	$ 507,689	$ 159,997
2018/19	$ 2,399	$ 195,085	$ 192,686
2019/20	$ -	$ 18,432	$ 18,432
2020/21	$ -	$ 4,520	$ 4,520
Total	$ 1,828,532	$ 2,675,083	$ 846,551

Proposed Schedule (This section is be filled out only if there is a change to the project schedule).

The schedule has been updated for the proposed change to in-service date of July 2018.

Related Projects (This section is be filled out only if changed).

1.5.2.1.1.1 Bipole III Project – Transmission Line
1.5.2.1.3.1 Bipole III Project – Collector Lines
1.5.2.1.7.1 Bipole III Project – Community Development Initiative

1.1.2.3.62.1 Southern AC System Breaker Replacements

Reference Documents (This section is be filled out only if changed).

1. System Planning Department Report on Bipole III Rating, 2012 11 02
2. System Planning Department Report on Integrated Transmission Plan for Keeyask and Conawapa Generation, 2012 07 06

D1876(A)
26026

APPROVED BY EXECUTIVE COMMITTEE
MINUTE # 1503.02

DATE: 2014 10 21
Financial Planning

CAPITAL PROJECT JUSTIFICATION AI
FOR

Bipole III Project
COLLECTOR LINES
Addendum Number 07c

REVIEWED BY:
(Owning Dept Manager)
Adele Poulin 2014/10/01
A. Fogg 2014/10/02

NOTED BY:
(if applicable)

Coordinating Division:

Constructing Division:

Financial Department:
(if over $1 million)
Dave Forbes 2014/10/01

RECOMMENDED FOR IMPLEMENTATION:

Owning Div. Manager: 2014/10/02

Business Unit V.P.: 7 Oct 2014

PREV. APPROVED BUDGET $: (Use $ value from approved CPJ or last approved CPJ Addendum)	$191,438,000
REVISED BUDGET $: (Total Net Cost)	$260,150,000
START DATE: (1st Cost Flow)	2001 06
PREV. APPROVED ISD: (Use In-service Date from approved CPJ or last approved CPJ Addendum)	2017 10
REVISED ISD: (Last Major In-service Date)	2018 07
RISK MATRIX/ BUSINESS CASE TIER: (Optional)	N.A.
INVESTMENT REASONS: (Optional)	Operational Enhancement (60%) New/increased Gen. Delivery (20%) Capacity Enhancement (20%)

PRIMARY JUSTIFICATION:
Indicate key project driver(s):

- ☐ Safety
- ☐ System Supply
- ☒ System Reliability
- ☐ Customer Service
- ☐ Efficiency
- ☐ Environmental

NERC COMPLIANCE*: ☒ YES ☐ NO

*Determine if the project requires compliance with North American Electric Reliability Corporation (NERC) CIP Cyber Security Standards.

OWNING DIVISION:	BIPOLE III PROJECT
I.M. NODE NUMBER:	1.5.2.1.3.1
W.B.S. NUMBERs:	P:15534-P:15537, P:15542, P:15543, P:15696, P:15697, P:18260, P:18261, P:20790, P:21201, P:23816
MAJOR ITEM ☒	**DOMESTIC ITEM** ☐
PREPARED BY:	Alastair Fogg / Adele Poulin
DATE PREPARED:	2014 09 24
REPORT NUMBER:	
FILE NUMBER (Optional):	

ADDENDUM NUMBER	DATE (yyyy mm dd)	REVISION	REVISED BY	APPROVED BY
06c	2011 03 31	Revised estimates for increase to five collector lines, two electrode lines, include construction power and sectionalization of R49R and all related property.	A.A. Poulin / P. Wang	Executive Committee (Minute #1348.02)
05	2007 05 15	Revised western route placeholder. Increase costs due to Construction and material cost increases.	A.A. Poulin / J.B. Davies / K.L. Kent	MH Board of Directors (Minute #786-07-05)
04	2005 06 23	Western route placeholder. Defer the in-service date by five years from 2012 10 to 2017 10.	J.B. Davies / K.L. Kent	Executive Committee (Minute #1090.06)
03	2004 04 06	Defer the in-service date by two years from 2010 10 to 2012 10.	J.B. Davies / K.L. Kent	Executive Committee (Minute #1030.05)
02	2003 11 12	Defer $2,462,000 worth of budget requirements from 2003/04 to future years.	C.A. Nieuwenburg	Executive Committee (Minute #999.05)
01	2003 05 08	Change northern termination from Radisson to Henday, increasing length by 20 km and costs by $8,245K.	J.B. Davies / K.L. Kent	Executive Committee (Minute #993.03)
-	2001 06 13	Original CPJ	J.B. Davies / K.L. Kent	Executive Committee (Minute #900.11)

MANITOBA HYDRO
CAPITAL PROJECT JUSTIFICATION ADDENDUM

Project Name (This section is required for all Addendums).

Bipole III Project – **COLLECTOR LINES**

Recommendation (This section is required for all Addendums).

Increase the budget by $68.7 million for the Collector Lines components of the Bipole III Project, to a revised total of $260.2 million and a revised in-service date of July, 2018.

Project Scope (This section is be filled out only if there is a change to the scope).

The scope of this portion of the Bipole III Project includes the following major components:

- Design and construction of three permanent and two temporary 230 KV collector lines for the Keewatinohk (Keewatinoow) Converter Station.
- Construction power substation, 138 KV line, microwave tower, and distribution feeders for the Keewatinohk Converter Station.
- Design and construction of the Riel and Keewatinohk electrode lines.
- Sectionalization of 230 KV transmission line R49R at Riel and associated modifications at Ridgeway and Rosser stations.
- Property acquisition and/or easements for the above components.
- Design and construction of a new bay and modifications at existing Long Spruce 230 KV AC switchyard for the new collector line to Keewatinohk Converter Station.
- Design and construction of a new bay and modifications at existing Henday 230 KV AC switchyard for the four new collector lines to Keewatinoow Converter Station.
- Design and construction of breaker replacements at existing stations (Ridgeway, Rosser, and McPhillips) for Bipole III.

Changes to scope include: the issued Licence & Conditions, double circuit requirement for one collector line, increased reliability design for electrode lines, updated assumptions for direct negotiated clearing and construction contracts, inclusion of Long Spruce and Henday 230 KV station expansions/modifications, inclusion of breaker replacements, and revised schedule and project in-service date to July 2018.

Background (This section is be filled out only if there is information relevant to the recommendation).

The last project re-estimate was completed in 2009/10, based on conceptual scope of collector line components, prior to issuance of the Project Licence.

The revised estimate incorporates a more detailed scope based on an issued environment act licence, increased scope (new items in this component), as well as up-to-date market information. The estimate is based on a project in-service of July 2018, which is required to complete the HVdc Converters installation.

The recommended budget is based on a P50 estimate that includes all base costs and contingency at a 50% confidence level.

P50 Estimate:

Since the last estimate was developed in 2010 it was necessary to bring the estimate to 2014$ and several items in the point estimate had to be adjusted to match the increased level of detail that has been identified within the current scope. In addition, new items were included in the current scope for this component.

Background (This section is be filled out only if there is information relevant to the recommendation).

This resulted in an increase of $83 million to the P50 Estimate as a result of the following:

- Incorporation of Environment Act Licence conditions and monitoring requirements
- Change to include a double circuit requirement for the Keewatinoow to Long Spruce AC collector line
- Incorporation of increased reliability design for both electrode lines
- Change to assume Clearing, 230kV AC transmission line construction and Construction Power contracts as Direct Negotiated Contracts (DNCs)
- Inclusion of new items – Long Spruce and Henday 230 KV station expansions/modifications and breaker replacements projects
- Recommended contingency of [redacted] (increase of $800K) for this component, to address remaining uncertainty. See Risk Analysis section.

Reserves:
No Management Reserve for the Collector Lines components is recommended to include in the estimate at this time. See Risk Analysis section.

In-Service Costs:
The overall increase to the in-service cost of the project for this component is $68 M (36%). This increase to the in-service cost is due to the increases in the P50 base estimate, the change to the project in-service date and increase in the recommended contingency. These increases are offset by reduced interest and escalation costs.

Justification (This section is required for all addendums).

A third 500kV HVdc transmission line with converter stations will provide for increased reliability to the Manitoba Hydro system, due to the critical risk to the Province and the Corporation of a Dorsey Converter Station outage or an Interlake (Bipole I and II) corridor outage. It will also provide an increase in southern power due to reduced line losses on the existing Bipoles I and II (approximately 76MW in normal steady state operation prior to the addition of new generation into the northern collector system).

The rating for Bipole III was increased from 2000MW to 2300MW to ensure adequate spare HVdc transmission on the northern collector system. The increased rating ensures future generation associated with Keeyask and Conawapa can be transmitted via Bipole I, Bipole II and Bipole III in the event of a single valve group outage. The increased rating limits the amount of future upgrades and equipment replacement needed on the Bipole III HVdc system to accommodate future Conawapa generation.

ANALYSIS OF ALTERNATIVES: (This section is be filled out only if there is a change to which alternative is being recommended).

Economic Analysis		
Discount Rate	% For current corporate rates see G911	For clarification on hurdle rates, contact Economic Analysis Department

Recommended Option	**NPV Benefits/(Costs)**
No change.	

Other Alternatives Considered	NPV Benefits/(Costs)
N/A	

Risk Analysis – (This section is be filled out only if there is a change to the project risk).

The risk & contingency methodology outlined at the NFAT for Keeyask & Conawapa Projects has been applied to the revised Bipole III Project estimate. The estimate includes a recommended project contingency at a P50 confidence level to address remaining areas of uncertainty.

Inclusion of a Management Reserve for this portion of the Bipole III complex is not considered necessary at this time.

Total Budget – (This section is required for all Addendums).

The impact on annual budget requirements is as follows (in thousands of dollars):

Fiscal Year	Prev. Approved CPJ/Addendum	Proposed CPJ Addendum	Increase (Decrease)
Prev. Actuals	$ 0	$ 0	$ -
2010/11	$ 2,121	$ 386	$ (1,735)
2011/12	$ 19,917	$ 2,075	$ (17,842)
2012/13	$ 52,709	$ 4,394	$ (48,315)
2013/14	$ 30,141	$ 26,265	$ (3,876)
2014/15	$ 30,927	$ 58,432	$ 27,505
2015/16	$ 34,255	$ 75,516	$ 41,261
2016/17	$ 13,549	$ 51,722	$ 38,173
2017/18	$ 7,819	$ 36,708	$ 28,889
2018/19	$ -	$ 4,653	$ 4,653
Total	$ 191,438	$ 260,150	$ 68,711

Proposed Schedule (This section is be filled out only if there is a change to the project schedule).

The schedule has been updated for the proposed change to in-service date of July 2018.

Related Projects (This section is be filled out only if changed).

1.5.2.1.1.1 Bipole III Project – Transmission Line
1.5.2.1.2.1 Bipole III Project – Converter Stations
1.5.2.1.7.1 Bipole III Project – Community Development Initiative

1.1.2.3.62.1 Southern AC System Breaker Replacements

Reference Documents (This section is be filled out only if changed).

1. System Planning Department Report on Bipole III Rating, 2012 11 02
2. System Planning Department Report on Integrated Transmission Plan for Keeyask and Conawapa Generation, 2012 07 06

D1876(A)

APPROVED BY EXECUTIVE COMMITTEE
MINUTE # 1503.02

DATE: 2014 10 21
Financial Planning

CAPITAL PROJECT JUSTIFICATION AI
FOR

Bipole III Project
COMMUNITY DEVELOPMENT INITIATIVE
Addendum Number 07d

REVIEWED BY:
(Owning Dept Manager)
A. Fogg 2014/10/02

NOTED BY:
(if applicable)

Coordinating Division:
2014/10/14

Constructing Division:

Financial Department:
(if over $1 million)
2014/10/01

RECOMMENDED FOR IMPLEMENTATION:

Owning Div. Manager: 2014/10/02

Business Unit V.P.: 7 Oct 2014

PREV. APPROVED BUDGET $: (Use $ value from approved CPJ or last approved CPJ Addendum)	$60,782,000
REVISED BUDGET $: (Total Net Cost)	$61,954,000
START DATE: (1st Cost Flow)	2014 03
PREV. APPROVED ISD: (Use In-service Date from approved CPJ or last approved CPJ Addendum)	2017 10
REVISED ISD: (Last Major In-service Date)	2018 07
RISK MATRIX/ BUSINESS CASE TIER: (Optional)	N.A.
INVESTMENT REASONS: (Optional)	

OWNING DIVISION: BIPOLE III PROJECT

I.M. NODE NUMBER: 1.5.2.1.7.1

W.B.S. NUMBERs: P:21948

MAJOR ITEM ☒ **DOMESTIC ITEM** ☐

PREPARED BY: Alastair Fogg / Adele Poulin

DATE PREPARED: 2014 09 26

REPORT NUMBER:

FILE NUMBER (Optional):

PRIMARY JUSTIFICATION:
Indicate key project driver(s):

- ☐ Safety
- ☐ System Supply
- ☒ System Reliability
- ☐ Customer Service
- ☐ Efficiency
- ☐ Environmental

NERC COMPLIANCE*: ☒ **YES** ☐ **NO**

*Determine if the project requires compliance with North American Electric Reliability Corporation (NERC) CIP Cyber Security Standards.

ADDENDUM NUMBER	DATE (yyyy mm dd)	REVISION	REVISED BY	APPROVED BY
-	2001 06 13	Original CPJ	E.R. Kristjanson	Executive Committee (Minute #1453.03)

MANITOBA HYDRO
CAPITAL PROJECT JUSTIFICATION ADDENDUM

Project Name (This section is required for all Addendums).

Bipole III Project – **COMMUNITY DEVELOPMENT INITIATIVE (CDI)**

Recommendation (This section is required for all Addendums).

Increase the budget by $1.2 million for the Bipole III Community Development Initiative ("CDI") fund, that was approved by the Manitoba Hydro-Electric Board in May 2010, to a revised total of $62.0 million

Project Scope (This section is be filled out only if there is a change to the scope).

Community Development Initiative ("CDI") fund for Manitoba Hydro to provide benefits to communities in vicinity of the Bipole III Project

Background (This section is be filled out only if there is information relevant to the recommendation).

The Manitoba Hydro-Electric Board approved the establishment of a Bipole III Community Development Initiative ("CDI"), valued at up to $6 million a year, for Manitoba Hydro to provide benefits to communities in the vicinity of the Bipole III project facilities (May 20, 2010, minute 808-10-03).

Following this approval, the Bipole III Preliminary Preferred Route became known and was released publicly in July 2010. From the time of Board approval, a multi-business unit CDI Working Group continued to meet to refine the CDI approach, in light of the preliminary preferred route, and to develop related communications material. Following feedback regarding the CDI, there was consensus that the refinements described in the recommendation be implemented, which include the following:

a) That CDI payments be provided for a 10 year period, with the possibility of program renewal at the end of the 10 year period;
b) That CDI payments begin upon receipt of the Bipole III regulatory approvals;
c) That the boundary for communities whose eligibility is based on proximity to the line be limited to 40 km;
d) That the eligibility requirements for incorporated towns and villages be such that a town or village must be located within a municipality traversed by the line and be located within 40 km of the line; and
e) That the CDI payments to communities be adjusted annually with the change in inflation.

Justification (This section is required for all addendums).

The CDI program remains inclusive of a variety of interests; is required as part of Bipole III; and will be an effective means of promoting community support for hosting the Bipole III project facilities

ANALYSIS OF ALTERNATIVES: (This section is be filled out only if there is a change to which alternative is being recommended).

Economic Analysis		
Discount Rate	% For current corporate rates see G911	For clarification on hurdle rates, contact Economic Analysis Department

Recommended Option	NPV Benefits/(Costs)
No Change	

Other Alternatives Considered	NPV Benefits/(Costs)
N.A.	

Risk Analysis – (This section is be filled out only if there is a change to the project risk).

No Change.

Total Budget – (This section is required for all Addendums).

The impact on annual budget requirements is as follows (in thousands of dollars):

Fiscal Year	Prev. Approved CPJ/Addendum	Proposed CPJ Addendum	Increase (Decrease)
Prev. Actuals	$ -	$ -	$ -
2013/14	$ 53,937	$ 53,863	$ (73)
2014/15	$ 2,157	$ 2,291	$ 134
2015/16	$ 1,979	$ 1,979	$ -
2016/17	$ 1,787	$ 1,787	$ -
2017/18	$ 922	$ 1,581	$ 659
2018/19	$ -	$ 453	$ 453
Total	$ 60,782	$ 61,954	$ 1,172

Proposed Schedule (This section is be filled out only if there is a change to the project schedule).

The schedule has been updated for the proposed change to in-service date of July 2018.

Related Projects (This section is be filled out only if changed).

1.5.2.1.1.1 Bipole III Project – Transmission Line
1.5.2.1.2.1 Bipole III Project – Converter Stations
1.5.2.1.3.1 Bipole III Project – Collector Lines

1.1.2.3.62.1 Southern AC System Breaker Replacements

Reference Documents (This section is be filled out only if changed).

Identify any additional reference documents (relative to those already listed in the previous CPJ/Addendum) that support or provide background on this recommendation.

ADDENDUM #08a (Transmission Line)

Dated 2016.10.14

Approved by Manitoba Hydro-Electric Board 2016.10.26

ADDENDUM #08b (Converter Stations)

Dated 2016.10.12

Approved by Manitoba Hydro-Electric Board 2016.10.26

ADDENDUM #08c (Collector Lines)

Dated 2016.10.14

Approved by Manitoba Hydro-Electric Board 2016.10.26

ADDENDUM #08d (Community Development Initiative)

Dated 2016.10.dd

Approved by Manitoba Hydro-Electric Board 2016.10.26

D1876(A)

APPROVED BY MHEB
MINUTE # 872.07

DATE: 2016 10 26
Financial Planning

CAPITAL PROJECT JUSTIFICATION ADDENDUM FOR

BIPOLE III PROJECT
TRANSMISSION LINE
Addendum Number 08a

REVIEWED BY:
(Requesting Dept Manager) Adele Poulin 2016/10/19

NOTED BY:
(if applicable)

Responsible Division: 2016/10/19

Constructing Division:

Financial Department: (if over $1 million) Oct. 19/16.

RECOMMENDED FOR IMPLEMENTATION:

Requesting Div. Manager: 2016/10/19

Business Unit V.P.: A. Mailey 2016/10/20

PREV. APPROVED BUDGET $: (Use $ value from approved CPJ or last approved CPJ Addendum)	$1,655,371,000
REVISED BUDGET $: (Total Net Cost)	$1,957,616,000
START DATE: (1st Cost Flow)	2001 06
PREV. APPROVED ISD: (Use In-service Date from approved CPJ or last approved CPJ Addendum)	2018 07
REVISED ISD: (Last Major In-service Date)	2018 07
RISK MATRIX/ BUSINESS CASE TIER: (Optional)	N.A.
INVESTMENT REASONS: (Optional)	

PRIMARY JUSTIFICATION:
Indicate key project driver(s):

- ☐ Safety
- ☐ System Supply
- ☒ System Reliability
- ☐ Customer Service
- ☐ Efficiency
- ☐ Environmental

NERC COMPLIANCE*: ☒ YES ☐ NO

*Determine if the project requires compliance with North American Electric Reliability Corporation (NERC) CIP Cyber Security Standards.

REQUESTING DIVISION:	Transmission Construction & Line Maintenance
I.M. NODE NUMBER:	1.5.2.1.1.1
W.B.S. NUMBERs:	P:04218, P:04221, P:10155, P:14518, P:18414, P:20255, P:23817, P:23622, P:25505, P:25508 - P:25511, P:18767
MAJOR ITEM ☒	**DOMESTIC ITEM** ☐
PREPARED BY:	Adele Poulin / Ryan Bilcowski
DATE PREPARED:	2016 10 14
REPORT NUMBER:	
FILE NUMBER (Optional):	

See list of Addendums next page.

07a	2014 10 21	Revised estimate for inclusion of final approved route, issued Licence & Conditions, revised landowner compensation, increased Bipole III rating to 2300 MW, and revised project in-service date of July 2018.	Alastair Fogg / Adele Poulin	Executive Committee (Minute #1503.02)
06a	2011 03 31	Revised estimate for increased length to 1341 km, construction cost increases, and inclusion of contingency.	A.A. Poulin / P. Wang	Executive Committee (Minute #1348.02)
05	2007 05 15	Revised western route placeholder. Increase costs due to Construction and material cost increases.	A.A. Poulin / J.B. Davies / K.L. Kent	MH Board of Directors (Minute #786-07-05)
04	2005 06 23	Western route placeholder. Defer the in-service date by five years from 2012 10 to 2017 10.	J.B. Davies / K.L. Kent	Executive Committee (Minute #1090.06)
03	2004 04 06	Defer the in-service date by two years from 2010 10 to 2012 10.	J.B. Davies / K.L. Kent	Executive Committee (Minute #1030.05)
02	2003 11 12	Defer $2,462,000 worth of budget requirements from 2003/04 to future years.	C.A. Nieuwenburg	Executive Committee (Minute #999.05)
01	2003 05 08	Change northern termination from Radisson to Henday, increasing length by 20 km and costs by $8,245K.	J.B. Davies / K.L. Kent	Executive Committee (Minute #993.03)
-	2001 06 13	Original CPJ	J.B. Davies / K.L. Kent	Executive Committee (Minute #900.11)
ADDENDUM NUMBER	**DATE** (yyyy mm dd)	**REVISION**	**REVISED BY**	**APPROVED BY**

MANITOBA HYDRO
CAPITAL PROJECT JUSTIFICATION ADDENDUM

Project Name (This section is required for all Addendums).

Bipole III Project – **TRANSMISSION LINE**

Recommendation (This section is required for all Addendums).

Total net in-service cost has increased by $302.245 million, from $1,655.371 million to $1,957.616 million from the last approved CPJ addendum, with the in-service date to remain at July, 2018.

Project Scope (This section is be filled out only if there is a change to the scope).

The scope for this portion of the Bipole III complex includes the following major components:

- Design and construction of a western-routed 500kV HVdc transmission line from the Keewatinohk Converter Station to the Riel Converter Station.
- Property acquisition and/or easements for the 500kV HVdc transmission line.
- Design and construction of the Bipole III Communications transport system.
- Licensing and environmental assessment for the overall Bipole III complex (i.e. including the Converter Stations and AC Collector system).
- Contingency for this Transmission Line project.

Changes to scope: awarded contracts and compressed schedule, CEC prescribed route finalization, additional tower steel suppliers, biosecurity measures implementation in the south and some helicopter tower erection for a portion of the line.

Background (This section is be filled out only if there is information relevant to the recommendation).

The previous project re-estimate was completed in 2014 and was based on a P50 confidence level. The recommended budget is based on a P80 estimate for the Transmission Line, that includes all base costs and contingency at an 80% confidence level.

The revised estimate incorporates actual costs to date as well as awarded contracts and reflects current market conditions. The estimate is based on maintaining a project in-service date of July 2018. The resultant revised P80 point estimate of $1,751 million from $1,400 million (an increase of $350 million relative to the current approved budget) is a result of the following changes:

- Incorporation of actual construction costs and awarded values as a result of higher market rates for anchor and foundations as well as tower assembly erection and stringing contracts than planned; incorporated delay claims (weather and material) experienced to date, construction schedule compression; and increased equipment and vehicles to support construction.
- Incorporation of additional materials required for CEC prescribed southern route changes, delays in materials, premiums to accelerate materials and associated engineering.
- Incorporation of property costs for CEC prescribed southern route, inclusion of LVAC (Land Valuation Appraisal Council) certification and legal fees.
- Incorporation of greater material management costs, project management and construction management.
- Inclusion of greater than planned costs for indigenous relationships management and agreements, as well as actual licensing costs and required project environmental monitoring as a result of the licence conditions.

Background (This section is be filled out only if there is information relevant to the recommendation).

- Recommended [redacted] contingency for remaining risks and schedule acceleration (as the previously approved $210 M , of which included $100 management reserve, has been allocated and spent for the above increases in point estimate; remaining risks are detailed in the Risk Analysis portion of this CPJ addendum).

In-Service Costs:
The overall increase to the in-service cost of the project is $302 million (18%), from $1,655.4 million to $1,957.6 million. This increase to the in-service cost is due to the increases in the P80 base estimate as noted above ($350 million). These increases are offset by reduced interest and escalation costs ($48 million reduction).

Justification (This section is required for all addendums).

A third 500kV HVdc transmission line with converter stations will provide for increased reliability to the Manitoba Hydro system, due to the critical risk to the Province and the Corporation of a Dorsey Converter Station outage or an Interlake (Bipole I and II) corridor outage. It will also provide an increase in southern power due to reduced line losses on the existing Bipoles I and II (approximately 76MW in normal steady state operation prior to the addition of new generation into the northern collector system).

The DC converter rating was increased from 2000MW to 2300MW in the 2014 CPJA. The additional 300MW converter rating is a pre-investment to allow for economical transmission options for future generation development and to maintain adequate HVDC spare capacity to cover the valve group outages, the most frequently occurred events based on operation experience.

ANALYSIS OF ALTERNATIVES: (This section is be filled out only if there is a change to which alternative is being recommended).

Economic Analysis		
Discount Rate	% For current corporate rates see G911	For clarification on hurdle rates, contact Economic Analysis Department

Recommended Option	**NPV Benefits/(Costs)**
No Change.	

Other Alternatives Considered	**NPV Benefits/(Costs)**
N.A.	

Risk Analysis – (This section is be filled out only if there is a change to the project risk).

The risk & contingency methodology outlined at the NFAT for Keeyask & Conawapa Projects has been applied to the revised Bipole III Project estimate. The revised estimate includes a recommended Transmission Line project contingency at a P80 confidence level to address remaining areas of uncertainty to the completion of the project and maintain desired in-service date of July 2018.

The previously approved Management Reserve ($100 million) for this portion of the Bipole III complex has been allocated or spent, no further management reserve is not considered necessary at this time.

Risk Analysis – (This section is be filled out only if there is a change to the project risk).

The Transmission Line components require a revised contingency amount of [redacted] for remaining risks and for schedule protection of the July 2018 in-service date. The previously approved $210 million for a P50 (2014) estimate has been allocated as noted in the point estimate (see Background section of this CPJ addendum above). The $100 million in management reserve was approved to be allocated to the two major transmission line contracts for awarded values, and for increases as a result of changes to the Burntwood Nelson Agreement as part of the Converter Stations project.

Remaining risks identified for [redacted] include:

[redacted]

Total Budget – (This section is required for all Addendums).

The impact on annual budget requirements is as follows (in thousands of dollars):

Fiscal Year	Prev. Approved CPJ/Addendum	Proposed CPJ Addendum	Increase (Decrease)
Prev. Actuals	$ 141,332	$ 141,618	$ 286
2014/15	$ 203,458	$ 125,584	$ (77,874)
2015/16	$ 360,455	$ 345,779	$ (14,676)
2016/17	$ 381,047	$ 549,625	$ 168,578
2017/18	$ 493,821	$ 426,982	$ (66,839)
2018/19	$ 75,257	$ 356,283	$ 281,026
2019/20	$ -	$ 9,676	$ 9,676
2020/21	$ -	$ 2,069	$ 2,069
Total	$ 1,655,371	$ 1,957,616	$ 302,245

Proposed Schedule (This section is be filled out only if there is a change to the project schedule).

No Change.

Related Projects (This section is be filled out only if changed).
1.5.2.1.2.1 Bipole III Project – Converter Stations 1.5.2.1.3.1 Bipole III Project – Collector Lines 1.5.2.1.7.1 Bipole III Project – Community Development Initiative

Reference Documents (This section is be filled out only if changed).
No Change.

D1876(A)

APPROVED BY MHEB
MINUTE # 872.07

DATE: 2016 10 26
Financial Planning

CAPITAL PROJECT JUSTIFICATION ADDENDUM FOR

Bipole III Project
CONVERTER STATIONS
Addendum Number 08b

REVIEWED BY:
(Requesting Dept Manager)

2016/10/19

NOTED BY:
(if applicable)

Responsible Division: 2016/10/19

Constructing Division:

Financial Department:
(if over $1 million) 2016/10/18

RECOMMENDED FOR IMPLEMENTATION:

Requesting Div. Manager: 2016/10/19

Business Unit V.P.: A. Railey 2016/10/19

PREV. APPROVED BUDGET $: (Use $ value from approved CPJ or last approved CPJ Addendum)	$2,675,083,000
REVISED BUDGET $: (Total Net Cost)	$2,780,691,000
START DATE: (1st Cost Flow)	2001 06
PREV. APPROVED ISD: (Use In-service Date from approved CPJ or last approved CPJ Addendum)	2018 07
REVISED ISD: (Last Major In-service Date)	2018 07
RISK MATRIX/ BUSINESS CASE TIER: (Optional)	N.A.
INVESTMENT REASONS: (Optional)	Operational Enhancement (60%) New/increased Gen. Delivery (20%) Capacity Enhancement (20%)

PRIMARY JUSTIFICATION:
Indicate key project driver(s):

- [ ] Safety
- [ ] System Supply
- [X] System Reliability
- [ ] Customer Service
- [ ] Efficiency
- [ ] Environmental

NERC COMPLIANCE*: [X] YES [ ] NO

*Determine if the project requires compliance with North American Electric Reliability Corporation (NERC) CIP Cyber Security Standards.

REQUESTING DIVISION:	BIPOLE III PROJECT
I.M. NODE NUMBER:	1.5.2.1.2.1
W.B.S. NUMBERs:	P:14363, P:14364, P:15533, P:15540, P:15541, P:15544, P:21082, P:23788, P:23837
MAJOR ITEM X	**DOMESTIC ITEM** [ ]
PREPARED BY:	Alastair Fogg
DATE PREPARED:	2016 10 12
REPORT NUMBER:	
FILE NUMBER (Optional):	

07b	2014 10 21	Revised Converter Stations estimate to incorporate numerous updates including LCC HVdc technology, Synchronous Condensers, BPIII rating to 2300MW, ISD from 2017 10 to 2018 07.	A.A. Poulin / A. Fogg	Executive Committee (Minute #1503.02)
06a	2011 03 31	Revised Converter Stations estimate, including assumption of VSC technology for HVdc.	R.M. Elder	Executive Committee (Minute #1348.02)
05	2007 05 15	Revised western route placeholder. Increase costs due to Construction and material cost increases.	A.A. Poulin / J.B. Davies / K.L. Kent	MH Board of Directors (Minute #786-07-05)
04	2005 06 23	Western route placeholder. Defer the in-service date by five years from 2012 10 to 2017 10.	J.B. Davies / K.L. Kent	Executive Committee (Minute #1090.06)
03	2004 04 06	Defer the in-service date by two years from 2010 10 to 2012 10.	J.B. Davies / K.L. Kent	Executive Committee (Minute #1030.05)
02	2003 11 12	Defer $2,462,000 worth of budget requirements from 2003/04 to future years.	C.A. Nieuwenburg	Executive Committee (Minute #999.05)
01	2003 05 08	Change northern termination from Radisson to Henday, increasing length by 20 km and costs by $8,245K.	J.B. Davies / K.L. Kent	Executive Committee (Minute #993.03)

-	2001 06 13	Original CPJ	J.B. Davies / K.L. Kent	Executive Committee (Minute #900.11)
ADDENDUM NUMBER	**DATE** (yyyy mm dd)	**REVISION**	**REVISED BY**	**APPROVED BY**

MANITOBA HYDRO
CAPITAL PROJECT JUSTIFICATION ADDENDUM

Project Name (This section is required for all Addendums).

Bipole III Project – **CONVERTER STATIONS**

Recommendation (This section is required for all Addendums).

Increase the budget by $106 million for the Converter Station components of the Bipole Project, to a revised total of $2,781 with the in-service date to remain at July, 2018.

Project Scope (This section is be filled out only if there is a change to the scope).

The scope for this portion of the Bipole III complex includes the following major components:

- Design and construction 2300 MW Riel Converter Station and 230 kV AC Switchyard.
- Design and construction 2300 MW Keewatinohk (Keewatinoow) Converter Station and 230 kV AC Switchyard.
- Property acquisition and/or easements for the Riel and Keewatinohk Converter Stations.
- Design & Construction of the Riel Synchronous Condensers.

Changes to scope include: Provincial Road 280, Provincial Road 290 and Conawapa Access Road upgrades.

Background (This section is be filled out only if there is information relevant to the recommendation).

The last project re-estimate was completed in 2014 and incorporated a majority of the project's contract costs and scope updates. The 2014 estimate was based on a P50 confidence level.

The revised estimate incorporates previously out of scope provincial road upgrades and an increase in contingency levels to a P75 confidence level to better address project risks to the completion of the work. There are no other scope changes from the 2014 estimate.

Justification (This section is required for all addendums).

A third 500kV HVdc transmission line with converter stations will provide for increased reliability to the Manitoba Hydro system, due to the critical risk to the Province and the Corporation of a Dorsey Converter Station outage or an Interlake (Bipole I and II) corridor outage. It will also provide an increase in southern power due to reduced line losses on the existing Bipoles I and II (approximately 76MW in normal steady state operation prior to the addition of new generation into the northern collector system).

The DC converter rating was increased from 2000MW to 2300MW. The additional 300MW converter rating is a pre-investment to allow for economical transmission options for future generation development and to maintain adequate HVDC spare capacity to cover the valve group outages, the most frequently occurred events based on operation experience

ANALYSIS OF ALTERNATIVES: (This section is be filled out only if there is a change to which alternative is being recommended).

Economic Analysis		
Discount Rate	% For current corporate rates see G911	For clarification on hurdle rates, contact Economic Analysis Department

Recommended Option	NPV Benefits/(Costs)
No change.	

Other Alternatives Considered	NPV Benefits/(Costs)
N/A	

Risk Analysis – (This section is be filled out only if there is a change to the project risk).

The risk & contingency methodology outlined at the NFAT for Keeyask & Conawapa Projects has been applied to the revised Bipole III Project estimate. The revised estimate includes a recommended project contingency at a P75confidence level to address remaining areas of uncertainty to the completion of the project.

Inclusion of a Management Reserve for this portion of the Bipole III complex is not considered necessary at this time.

Total Budget – (This section is required for all Addendums).

The impact on annual budget requirements is as follows (in thousands of dollars):

Fiscal Year	Prev. Approved CPJ/Addendum	Proposed CPJ Addendum	Increase (Decrease)
Prev. Actuals	$ 318,781	$ 318,781	$ -
2014/15	$ 221,051	$ 198,269	$ (22,782)
2015/16	$ 580,792	$ 468,260	$ (112,532)
2016/17	$ 828,733	$ 955,621	$ 126,888
2017/18	$ 507,689	$ 593,197	$ 85,508
2018/19	$ 195,085	$ 237,967	$ 42,882
2019/20	$ 18,432	$ 8,024	$ (10,408)
2020/21	$ 4,520	$ 574	$ (3,946)
Total	$ 2,675,083	$ 2,780,691	$ 105,609

Proposed Schedule (This section is be filled out only if there is a change to the project schedule).
The schedule remains unchanged with an in-service date of July 2018.

Related Projects (This section is be filled out only if changed).
1.5.2.1.1.1 Bipole III Project – Transmission Line 1.5.2.1.3.1 Bipole III Project – Collector Lines 1.5.2.1.7.1 Bipole III Project – Community Development Initiative *1.1.2.3.62.1. Southern AC System Breaker Replacements*

Reference Documents (This section is be filled out only if changed).
1. System Planning Department Report on Bipole III Rating, 2012 11 02 2. System Planning Department Report on Integrated Transmission Plan for Keeyask and Conawapa Generation, 2012 07 06

D1876(A)
26026

APPROVED BY MHEB
MINUTE # 872.07

DATE: 2016 10 26
Financial Planning

CAPITAL PROJECT JUSTIFICATION ADDENDUM FOR

BIPOLE III PROJECT
COLLECTOR LINES
Addendum Number 08c

REVIEWED BY:
(Owning Dept Manager)
2016/10/19

NOTED BY:
(if applicable)

Coordinating Division: 2016/10/19

Constructing Division:

Financial Department:
(if over $1 million) Oct. 18/16.

RECOMMENDED FOR IMPLEMENTATION:

Owning Div. Manager: 2016/10/19

Business Unit V.P.: 2016/10/20

PREV. APPROVED BUDGET $: (Use $ value from approved CPJ or last approved CPJ Addendum)	$260,150,000
REVISED BUDGET $: (Total Net Cost)	$246,567,000
START DATE: (1st Cost Flow)	2001 06
PREV. APPROVED ISD: (Use In-service Date from approved CPJ or last approved CPJ Addendum)	2018 07
REVISED ISD: (Last Major In-service Date)	2018 07
RISK MATRIX/ BUSINESS CASE TIER: (Optional)	N.A.
INVESTMENT REASONS: (Optional)	Operational Enhancement (60%) New/increased Gen. Delivery (20%) Capacity Enhancement (20%)
OWNING DIVISION:	Transmission Construction & Line Maintenance
I.M. NODE NUMBER:	1.5.2.1.3.1
W.B.S. NUMBERs:	P:15534-P:15537, P:15542, P:15543, P:15696, P:15697, P:18260, P:18261, P20790, P21201, P23816, P27469
MAJOR ITEM ☒	**DOMESTIC ITEM** ☐
PREPARED BY:	Ryan Bilcowski / Luc Collet
DATE PREPARED:	2016 10 14
REPORT NUMBER:	
FILE NUMBER (Optional):	

PRIMARY JUSTIFICATION:
Indicate key project driver(s):

☐ Safety	☐ Customer Service
☐ System Supply	☐ Efficiency
☒ System Reliability	☐ Environmental

NERC COMPLIANCE*: ☒ **YES** ☐ **NO**

*Determine if the project requires compliance with North American Electric Reliability Corporation (NERC) CIP Cyber Security Standards.

See list of Addendums next page.

07c	2014 09 24	Revised estimate for increase double circuit requirements for one collector line, increased reliability design for electrode line, inclusion of Long Spruce and Henday station expansion/modifications and breaker replacements. Revised schedule and project in-service date to July 2018.	A. Fogg / A.A. Poulin	Executive Committee (Minute #1503.02)
06c	2011 03 31	Revised estimates for increase to five collector lines, two electrode lines, include construction power and sectionalization of R49R and all related property.	A.A. Poulin / P. Wang	Executive Committee (Minute #1348.02)
05	2007 05 15	Revised western route placeholder. Increase costs due to Construction and material cost increases.	A.A. Poulin / J.B. Davies / K.L. Kent	MH Board of Directors (Minute #786-07-05)
04	2005 06 23	Western route placeholder. Defer the in-service date by five years from 2012 10 to 2017 10.	J.B. Davies / K.L. Kent	Executive Committee (Minute #1090.06)
03	2004 04 06	Defer the in-service date by two years from 2010 10 to 2012 10.	J.B. Davies / K.L. Kent	Executive Committee (Minute #1030.05)
02	2003 11 12	Defer $2,462,000 worth of budget requirements from 2003/04 to future years.	C.A. Nieuwenburg	Executive Committee (Minute #999.05)
01	2003 05 08	Change northern termination from Radisson to Henday, increasing length by 20 km and costs by $8,245K.	J.B. Davies / K.L. Kent	Executive Committee (Minute #993.03)
-	2001 06 13	Original CPJ	J.B. Davies / K.L. Kent	Executive Committee (Minute #900.11)
ADDENDUM NUMBER	**DATE** (yyyy mm dd)	**REVISION**	**REVISED BY**	**APPROVED BY**

MANITOBA HYDRO
CAPITAL PROJECT JUSTIFICATION ADDENDUM

Project Name (This section is required for all Addendums).

Bipole III Project – **COLLECTOR LINES**

Recommendation (This section is required for all Addendums).

Decrease the budget by $13.6 million for the Collector Lines components of the Bipole III Project, to a revised total of $246.6 million, with the in-service date to remain at July 2018.

Project Scope (This section is be filled out only if there is a change to the scope).

The scope of this portion of the Bipole III Project remains the same as the previous estimate, with the addition of a secondary communications link between the Keewatinohk CS and Henday.

Background (This section is be filled out only if there is information relevant to the recommendation).

The previous project re-estimate was completed in 2014 and was based on a P50 confidence level.

The revised estimate incorporates a detailed scope based on the actual construction progress to date, reflects current market conditions, and includes the changes noted below. The estimate is based on maintaining a project in-service date of July 2018. The recommended budget for the Collector Lines project is based on a P75 estimate that includes all base costs and contingency at a 75% confidence level.

The Total Net Cost decrease of $13.6M relative to the current approved budget is a result of the following changes:

1. Decrease of $13.0M to forecast escalation and interest.
2. Decrease of $11.0M due to savings in accommodation costs for Long Spruce generating station (GS), Henday converter station (CS) and the AC Collector lines.
3. Decrease of $6.0M in the steel structure costs due to competitive bidding for the AC Collector lines.

These net decreases are slightly offset by the following scope changes:

4. Increase of $6.0M to the construction costs for the installation of the dead end tower footings. Final design was not complete at the time of the contract award; additional towers were required resulting in higher construction costs.
5. Increase of $3.6M for scope changes in the project (several in small amounts) now incorporated.
6. Increase of $2.8M to the construction costs as there was a change in strategy from internal resources to external contracts for the high voltage cable installations and steel modification work at Long Spruce GS, primarily due to the lack of internal resources and expertise for the given scope.
7. Increase of $2.4M for the incorporation of secondary communications link between the Keewatinohk CS and Henday CS.
8. Increase of $1.6M in construction costs as there was a change in strategy from internal resources to external contract for the steel assembly, erection, switch installation and bus modifications at Henday CS, due to the lack of availability of internal resources.

Justification (This section is required for all addendums).

A third 500kV HVdc transmission line with converter stations will provide for increased reliability to the Manitoba Hydro system, due to the critical risk to the Province and the Corporation of a Dorsey Converter

Justification (This section is required for all addendums).

Station outage or an Interlake (Bipole I and II) corridor outage. It will also provide an increase in southern power due to reduced line losses on the existing Bipoles I and II (approximately 76MW in normal steady state operation prior to the addition of new generation into the northern collector system).

The DC converter rating was increased from 2000MW to 2300MW. The additional 300MW converter rating is a pre-investment to allow for economical transmission options for future generation development and to maintain adequate HVDC spare capacity to cover the valve group outage, the most frequently occurred events based on operation experience.

ANALYSIS OF ALTERNATIVES: (This section is be filled out only if there is a change to which alternative is being recommended).

Economic Analysis		
Discount Rate	% For current corporate rates see G911	For clarification on hurdle rates, contact Economic Analysis Department

Recommended Option	**NPV Benefits/(Costs)**
No change.	
Other Alternatives Considered	**NPV Benefits/(Costs)**
N/A	

Risk Analysis – (This section is be filled out only if there is a change to the project risk).

The risk & contingency methodology outlined at the NFAT for Keeyask & Conawapa Projects has been applied to the revised Bipole III Project estimate. The estimate includes a recommended Collector Lines project contingency at a P75 confidence level to address remaining areas of uncertainty, and has decreased from the previously approved contingency.

Inclusion of a Management Reserve for this portion of the Bipole III Project is not considered necessary at this time.

The Collector Line components require a reduced contingency amount of $1M from [redacted] to [redacted] in contingency as the project components are further along in construction and reflect remaining risks.

Remaining significant risks identified include:

- $3.2M for potential market rates for the Electrode Lines and R49R Sectionalization.
- $3.0M for potential weather delays increasing construction costs.
- $2.0M for skywire replacement with buried grounding conductor outside of Henday CS to accommodate new overhead lines.
- $2.0M for additional modifications to the Gas Insulated Switchgear at Long Spruce GS.
- $2.0M for additional crews at Long Spruce GS and Henday CS to support the overhead work.
- $1.0M for potential additional costs for 500kV line crossings.
- $1.0M for potential additional costs associated with the installation of the High Voltage cables at Long Spruce GS.
- $0.7M for potential additional construction support from design groups.

Total Budget – (This section is required for all Addendums).

The impact on annual budget requirements is as follows (in thousands of dollars):

Fiscal Year	Prev. Approved CPJ/Addendum	Proposed CPJ Addendum	Increase (Decrease)
Prev. Actuals	$ 33,120	$ 33,120	$ -
2014/15	$ 58,432	$ 34,218	$ (24,214)
2015/16	$ 75,516	$ 63,240	$ (12,277)
2016/17	$ 51,722	$ 60,752	$ 9,030
2017/18	$ 36,708	$ 33,974	$ (2,733)
2018/19	$ 4,653	$ 21,264	$ 16,612
Total	$ 260,150	$ 246,568	$ (13,583)

Proposed Schedule (This section is be filled out only if there is a change to the project schedule).

No change to the in-service date of July 2018.

Related Projects (This section is be filled out only if changed).

No change.

1.5.2.1.1.1 Bipole III Project – Transmission Line
1.5.2.1.2.1 Bipole III Project – Converter Stations
1.5.2.1.7.1 Bipole III Project – Community Development Initiative

Reference Documents (This section is be filled out only if changed).

No change.

1. System Planning Department Report on Bipole III Rating, 2012 11 02
2. System Planning Department Report on Integrated Transmission Plan for Keeyask and Conawapa Generation, 2012 07 06

D1876(A)

APPROVED BY MHEB
MINUTE # 872.07

DATE: 2016 10 26
Financial Planning

CAPITAL PROJECT JUSTIFICATION ADDENDUM FOR

BIPOLE III PROJECT
COMMUNITY DEVELOPMENT INITIATIVE
Addendum Number 08d

REVIEWED BY:
(Requesting Dept Manager) Adele Poulin 2016/10/19

NOTED BY:
(if applicable) Oct 20/2016

Responsible Division: 2016/10/19

Constructing Division:

Financial Department:
(if over $1 million) Oct. 19/16.

RECOMMENDED FOR IMPLEMENTATION:

Requesting Div. Manager: 2016/10/19

Business Unit V.P.: A. Bailey 2016/10/20

PREV. APPROVED BUDGET $: (Use $ value from approved CPJ or last approved CPJ Addendum)	$61,954,000
REVISED BUDGET $: (Total Net Cost)	$56,647,000
START DATE: (1st Cost Flow)	2014 03
PREV. APPROVED ISD: (Use In-service Date from approved CPJ or last approved CPJ Addendum)	2018 07
REVISED ISD: (Last Major In-service Date)	2018 07
RISK MATRIX/ BUSINESS CASE TIER: (Optional)	N.A.
INVESTMENT REASONS: (Optional)	

PRIMARY JUSTIFICATION:
Indicate key project driver(s):

- ☐ Safety
- ☐ System Supply
- ☒ System Reliability
- ☐ Customer Service
- ☐ Efficiency
- ☐ Environmental

NERC COMPLIANCE*: ☒ YES ☐ NO

*Determine if the project requires compliance with North American Electric Reliability Corporation (NERC) CIP Cyber Security Standards.

REQUESTING DIVISION:	Transmission Construction & Line Maintenance
I.M. NODE NUMBER:	1.5.2.1.7.1
W.B.S. NUMBERs:	P:21948
MAJOR ITEM ☒	**DOMESTIC ITEM** ☐
PREPARED BY:	
DATE PREPARED:	2016 10 dd
REPORT NUMBER:	
FILE NUMBER (Optional):	

ADDENDUM NUMBER	DATE (yyyy mm dd)	REVISION	REVISED BY	APPROVED BY
07d	2014 10 21	Inclusion of Community Development Initiative ("CDI") fund for Manitoba Hydro to provide benefits to communities in vicinity of the Bipole III Project	Alastair Fogg / Adele Poulin	Executive Committee (Minute #1503.02)
	2001 06 13	Original CPJ	E.R. Kristjanson	Executive Committee (Minute #1145.03)

MANITOBA HYDRO
CAPITAL PROJECT JUSTIFICATION ADDENDUM

Project Name (This section is required for all Addendums).

Bipole III Project – **COMMUNITY DEVELOPMENT INTITIATIVE (CDI)**

Recommendation (This section is required for all Addendums).

Total cost has decreased from $62 million to $56.7 million from the last approved CPJ addendum. [redacted] These costs are now captured in 1.5.2.1.1.1 Transmission Line (in P:04221).

Project Scope (This section is be filled out only if there is a change to the scope).

No change.

Background (This section is be filled out only if there is information relevant to the recommendation).

The total decrease of $5.3 million is as a result of a revaluation of the Present Value of the payments, [redacted] These costs are now captured in 1.5.2.1.1.1 Transmission Line (in P:04221).

Justification (This section is required for all addendums).

The CDI program remains inclusive of a variety of interests; is required as part of Bipole III; and will be an effective means of promoting community support for hosting the Bipole III project facilities

ANALYSIS OF ALTERNATIVES: (This section is be filled out only if there is a change to which alternative is being recommended).

Economic Analysis

Discount Rate	% For current corporate rates see G911	For clarification on hurdle rates, contact Economic Analysis Department

Recommended Option	**NPV Benefits/(Costs)**
No Change.	

Other Alternatives Considered	**NPV Benefits/(Costs)**
N.A.	

Risk Analysis – (This section is be filled out only if there is a change to the project risk).

No Change.

Total Budget – (This section is required for all Addendums).

The impact on annual budget requirements is as follows (in thousands of dollars):

Fiscal Year	Prev. Approved CPJ/Addendum	Proposed CPJ Addendum	Increase (Decrease)
Prev. Actuals	$ 53,863	$ 53,863	$ -
2014/15	$ 2,291	$ 2,065	$ (226)
2015/16	$ 1,979	$ (5,470)	$ (7,449)
2016/17	$ 1,787	$ 2,588	$ 801
2017/18	$ 1,581	$ 2,698	$ 1,117
2018/19	$ 453	$ 903	$ 450
Total	$ 61,954	$ 56,647	$ (5,307)

Proposed Schedule (This section is be filled out only if there is a change to the project schedule).

No Change.

Related Projects (This section is be filled out only if changed).

No Change.
1.5.2.1.1.1 Bipole III Project – Transmission Line
1.5.2.1.2.1 Bipole III Project – Converter Stations
1.5.2.1.3.1 Bipole III Project – Collector Lines

Reference Documents (This section is be filled out only if changed).

No change.

PUB MFR 157
Bipole III

Provide the performance guarantee specifications that the HVDC converter equipment proponents are required to meet. Provide a summary description of these specifications.

Public disclosure of the response to this MFR (or portions thereof) would result in the release of information considered to be confidential and commercially sensitive. As directed by the PUB, Manitoba Hydro will be filing a letter seeking confidential treatment of the redacted information contained in this response pursuant to Rule 13.

There are four technical "performance guarantees" for the HVDC contract for Bipole III:

- Guaranteed availability and forced outages;
- Guaranteed power transmission rating;
- Guaranteed losses; and,
- Guaranteed thyristor and capacitor failure rates.

Demonstration of performance to ensure the guarantees are being met occurs for the first three years after the in-service date of the HVDC converter equipment. Should any guarantee not be met after the first three years due to one or more issues requiring corrective action, one or two additional years of monitoring of the performance guarantees will be undertaken to ensure sufficient reliability of the solution has been demonstrated. Should any of the guarantees fail to be achieved at the end of the performance guarantee period and any granted extensions, the residual performance guarantee gaps will be addressed through liquidated damages.

Guaranteed Availability and Forced Outages:

Availability and forced outages are the two metrics used to monitor the overall reliability of the HVDC converter equipment. Availability is measured by comparing total available energy (power) transmission capacity over a given service period (usually a year) to the nominal energy transmission capacity over that same service period, and generally expressed as a percentage. [redacted] The forced outage rates are measured by number of outages

over a service period (usually a year) by type of system – valve group, pole or bipole. [redacted]

[redacted]

The method of categorizing outages and calculating availability is based on the methods described in CIGRE (International Council on Large Electrical Systems) Document 346 "Protocol for Reporting the Operational Performance of HVDC Transmission Systems", which is widely recognized and utilized in the HVDC industry as the means of monitoring, measuring, and reporting HVDC system performance.

Guaranteed Power Transmission Rating:

The specified nominal power transmission capability of Bipole III, including the specified 15% continuous overload rating, is guaranteed as 2300MW. As part of this guarantee, the contractor is required to demonstrate the power transmission capacity on a per-pole basis for a minimum 12 hour continuous period without interruption or disturbance. This is a generally accepted method of demonstrating maximum equipment capacity ratings and falls in line with methods used for factory acceptance testing some individual converter components.

Guaranteed Losses:

[redacted]

[redacted]

Losses are evaluated based on the methodology in standard IEC 61803 for HVDC converter stations.

Guaranteed Thyristor and Capacitor Failure Rates:

[redacted]

[redacted]

These rates are established based on industry experience and contractor knowledge of performance of components on other past projects. The values represent the guaranteed maximum average annual failure rate over the guarantee period for the installed device of each type.

PUB MFR 161
Bipole III

Provide a table comparing HVDC converter equipment proposals with any engineer's or third party estimates

Public disclosure of the response to this MFR (or portions thereof) would result in the release of information considered to be confidential and commercially sensitive. As directed by the PUB, Manitoba Hydro will be filing a letter seeking confidential treatment of the redacted information contained in this response pursuant to Rule 13.

The following table outlines the HVDC converter equipment proposal prices against Manitoba Hydro's reference estimates for the HVDC converter equipment. In order to provide an appropriate comparison to Manitoba Hydro's reference estimate the HVDC converter proposals have been adjusted to 2014/15 dollar amounts, i.e. addressing escalation and interest costs built into the bid prices.

Additionally, it should be noted there is not a perfect alignment between the definition of each "cost item" between the bid amounts and the reference estimates. For example, the CIGRE reference estimates incorporates spare equipment costs into the "Design & Supply of HVDC Converters and Associated Equipment" cost item whereas this is shown as a separate cost item for the HVDC converter equipment bid amounts.

The table is included on the next page.

Note: The basis estimates outlined are for LCC technology as all bids received on the HVDC converter equipment proposal were for LCC technology. These basis values were not Manitoba Hydro's estimates for the HVDC converter equipment at the time the bids were received. At the time of bid Manitoba Hydro's project estimate included an HVDC converter equipment cost estimate based on VSC technology. This value is therefore not included below as a basis/reference value against the LCC technology based HVDC converter equipment proposal prices.

Table 1 - HVDC Proposal Comparison (2014/15$)					
Cost Item	**PV of Siemens Bid Price**	**PV of ABB Bid Price**	**PV of Alstom Bid Price**	**MH Basis Estimate (CIGRE Standard)**	**MH Basis Estimate (Vendor Budgetary Proposals - LCC)**
System Engineering & System Studies	[redacted]				
Design & Supply of HVDC Converters and Associated Equipment					
Design and Supply of Civil Works					
Construction and Installation					
Testing and Commissioning					
Project Management Services & Performance Bond					
Mandatory & Recommended Spare Equipment					
TOTAL					

PUB MFR 164 (Revised)

Bipole III

Provide the Rashwan Consultant report on the Bipole III cost estimate. [previously filed as CSI in 2015/16 GRA PUB/Manitoba Hydro-II-11c]

Public disclosure of the response to this MFR (or portions thereof) would result in the release of information considered to be confidential and commercially sensitive. As directed by the PUB, Manitoba Hydro will be filing a letter seeking confidential treatment of the redacted information contained in this response pursuant to Rule 13.

Please see attached for the Rashwan Consultant report on the Bipole III cost estimate.

A Review of Manitoba Hydro Cost Estimates for Bipole III Converter Stations and Associated Facilities

Prepared for:

Mr. R. B. Brennan
President and CEO, Manitoba Hydro

Prepared by:

Mohamed Rashwan
Rashwan Consultant

Dan Lorden
Energy Initiatives Group, LLC

Brad Railing
Cross Sound Cable Company LLC

Report R1101.01.01

February 18, 2011

Disclaimer

This report was prepared by Mohamed Rashwan, Dan Lorden, and Brad Railing, whose responsibility is limited to the scope of work as shown herein. The authors disclaim responsibility for the work of others incorporated or referenced herein. This report has been prepared exclusively for Manitoba Hydro and must not be reused or modified without the prior written authorization of the authors.

Revisions

Project Name:	Manitoba Hydro Bipole III
Document Title:	Review of Manitoba Hydro Cost Estimates for Bipole III Converter Stations and Associated Facilities
Document Type:	Final draft report
Document No.:	R1101.01.01
Last Action Date:	February 18, 2011

Rev. No.	Status	Prepared By	Checked By	Date	Comments
01	IFC	M. Rashwan D. Lorden B. Railing		February 2, 2011	Release of draft report for comments.
02	IFA	M. Rashwan D. Lorden B. Railing		February 18, 2011	Release of final draft report for approval.

Legend of Document Status:

Approved by Client:	ABC
Draft for Comments:	DFC
Issued for Comments:	IFC
Issued for Approval:	IFA
Issued for Information:	IFI
Returned for Correction:	RFC
Approval not Required:	ANR

Table of Contents

Executive Summary **1**
1. Introduction **2**
2. Scope of Work **2**
3. Manitoba Hydro documents reviewed **3**
4. Analysis of Manitoba Hydro cost estimates **4**
4.1. Converter station estimate 4
4.1.1. Comments on the converter station mini-specification 4
4.1.2. Converter station market costs 4
4.2. Riel Synchronous condensers 5
4.3. Keewatinoow AC switchyard 5
4.4. Site development 5
4.5. Interfaces, test equipment & communications for converter stations 5
4.6. Property for electrodes and Keewatinoow site; Electrode sites 5
4.7. Project & Construction management; Engineering planning studies and consultants 6
4.8. Keewatinoow electrode line 6
4.9. Keewatinoow converter station construction power 6
4.10. Keewatinoow collector lines 6
4.11. Riel AC switchyard 6
4.12. Riel electrode line 6
4.13. Summary -- Converter stations and associated facilities 7
5. Analysis and Discussion **8**
6. Project delivery strategy **10**
7. Possible deferral of expenditure **10**
8. Project staging **10**
9. Recommendation **11**
1. Appendix 1 ..... **12**
2. Appendix 2 ..... **24**
3. Appendix 3 ..... **26**
4. Appendix 4 ..... **27**

Executive Summary

This report is a review of Manitoba Hydro cost estimates for the 2,000 MW Bipole III converter stations and associated facilities. Associated interest expense, environmental assessment, construction camps, cost of most property -- as well as all DC transmission line costs -- are not included. All of our cost estimates are in Canadian dollars.

In summary, an "apples-to-apples" comparison between the Manitoba Hydro cost estimate and our cost estimate for the Bipole III converter stations and associated facilities is as follows:

	Base Cost Estimate	Contingency and Escalation Estimate	Total Cost Estimate
MH Cost Estimate:	1,516 M$	763 M$	**2,279 M$**
Our Cost Estimate:	1,351 M$	107 M$	**1,458 M$**

Manitoba Hydro's base cost estimate is 1,516 M$ while our base cost estimate is 1,351 M$. The difference (which is not very significant) is primarily due to the difference in the estimated cost of the converter stations and the AC switchyards which we have assumed a portion of could be integrated into the converter station scope of supply.

The principal difference between our cost estimates is escalation and contingency. First, we believe that the converter station and associated facilities costs will not be subject to appreciable escalation as we understand Manitoba Hydro would enter into definitive and binding contracts in 2013/14. Second, we believe that Manitoba Hydro's estimates for contingency are too high, unnecessarily conservative, and not supportable.

In addition, we believe that Manitoba Hydro can defer the construction and integration of the two DC transmission lines between Dorsey and Riel and Henday and Keewatinoow until Conawapa is in service as they would not be needed until that generation resource is available. This would defer an expenditure of approximately 91 M$ for several years which should offer appreciable savings. It may also be possible to defer two of the Riel synchronous condensers until Conawapa comes on line. By doing so, Manitoba Hydro can also defer approximately 125 M$ of project investment until that generation resource is available.

We recommend that Manitoba Hydro exploit the opportunities for cost reduction and risk mitigation afforded by turnkey, engineer-procure-construct ("EPC") contract structures to the maximum extent possible.

Finally, please note that converter station scope and associated price estimates do not impact cost estimates for the DC transmission line between the Keewatinoow converter station and the Riel converter station nor does it impact any issue associated with routing the DC transmission line between the two converter stations (i.e., the "west DC transmission route" v. the "east DC transmission line route").

1. Introduction

This report is a review of Manitoba Hydro cost estimates for Bipole III converter stations and associated facilities. The review was conducted by Mohamed Rashwan, Dan Lorden, and Brad Railing. All of our cost estimates are in Canadian dollars.

2. Scope of Work

The scope of work is as follows:

1. Review cost estimates prepared by Manitoba Hydro for a 2,000 MW bipole;
2. Establish whether the cost estimates are reasonable and consistent with industry prices;
3. Establish whether the contingencies are reasonable;
4. Identify possible project staging opportunities; and
5. Recommend actions to Manitoba Hydro for consideration.

We have defined the converter station and associated facilities to be the:

1. Keewatinoow converter station and ground electrode system;
2. Keewatinoow AC switchyard;
3. Keewatinoow-Henday AC transmission lines;
4. Keewatinoow-Long Spruce AC transmission lines;
5. Riel converter station and ground electrode system;
6. Portion of Riel AC switchyard not part of the Riel Sectionalization Project; and
7. Riel synchronous condensers.

Other costs associated with these facilities under our review include:

1. Site development;
2. Project management;
3. Construction management;
4. Engineering and studies; and
5. Interfaces, communications and test equipment.

The following items are excluded from the scope of work:

1. DC transmission line from the Keewatinoow converter station to the Riel converter station;
2. DC transmission line from the Keewatinoow converter station to the Henday converter station;
3. DC transmission line from the Riel converter station to the Dorsey converter station;
4. Construction camps;
5. Environmental approvals and any stakeholder consultation; and
6. Property acquisition (with small exception of ground electrode system).

We are also not in a position to review Manitoba Hydro's Bipole III interest expense calculations as they are a function of cash flow assumptions and Manitoba Hydro's cost of capital.

Finally, please note that converter station scope and associated price estimates do not impact cost estimates for the DC transmission line between the Keewatinoow converter station and the Riel converter station nor does it impact any issue associated with routing the DC transmission line between the two converter stations (i.e., the "west DC transmission route" v. the "east DC transmission line route").

3. Manitoba Hydro documents reviewed

Manitoba Hydro provided the following documents for our review:

1. HVDC converter stations re-estimate (July 2010) – (Appendix 1)
2. Construction management
3. Engineering support, planning and consultants
4. Project management
5. Budgetary pricing request for Bipole III
6. ABB response to the mini specification
7. Areva (Alstom Grid) response to the mini specification
8. Siemens response to the mini specification
9. Bipole III converter station project pre-design and estimate report
10. Calculation of CPJ addendum amounts -- (Appendix 2)
11. Spreadsheets showing the base cost estimates -- (Appendix 3)

4. Analysis of Manitoba Hydro cost estimates

A portion of the Manitoba Hydro costs estimates for converter stations and associated facilities was supplied by the Power Supply Business Unit (see Appendix 1) and a smaller portion was supplied by the Transmission and Distribution Business Unit (see Appendix 2 and Appendix 3).

4.1. Converter station estimate

Manitoba Hydro estimated 558 M$ for the Keewatinoow converter station and Riel converter station based on budgetary prices from converter station suppliers who responded to a mini specification issued in 2009.

The lowest supplier estimate was 480 M$. Manitoba Hydro added 70 M$ to cover items not quoted by the supplier and another 8 M$ to cover items not in the mini specification for a total of 558 M$.

The converter station cost estimate per kW is 279 $/kW for two converter stations (i.e., 558,000,000 $ ÷ 2,000,000 kW) and, according to the mini specification, does not include ac circuit breakers.

4.1.1. Comments on the converter station mini-specification

We believe that converter station suppliers should be provided with design flexibility and that Manitoba Hydro should pursue developing a "functional" as opposed to a "detailed" technical specification. Certain requirements in the mini-specification would indicate that Manitoba Hydro currently intends to pursue developing a "detailed" technical specification and we recommend against that. Again, we believe that it is to Manitoba Hydro's benefit not to take detailed ownership of the converter station design and by doing so will result in a more cost effective solution.

In addition, we recommend Manitoba Hydro consider "packaging" as much of the Keewatinoow AC switchyard and Riel AC switchyard into the converter station scope of work as possible. This would benefit Manitoba Hydro as the AC switchyard equipment technical requirements will largely be determined by the converter station supplier. This will eliminate any risk with the converter station to AC switchyard interface, and -- if sourced on a turnkey EPC contract basis -- we believe would result in a lower overall cost.

4.1.2. Converter station market costs

Turnkey, EPC converter station market prices are currently between 175 $/kW and 250 $/kW and would include the following comprehensive converter station scope of work:

- Technical studies; system design; component / equipment specification and procurement
- Station layout and detailed design;
- Civil works;
- Converter equipment and buildings;
- AC switchyard;
- DC switchyard;
- Control and protection hardware and software engineering;
- Off-Site testing and QA monitoring;
- Logistics;
- DC and AC system installation and commissioning; and
- Documentation.

Also, Cigre technical brochure number 388 WG B2/B4/C1-17 (2009) provides guidance for estimating converter stations and indicates that the cost for a 2,000 MW system should be approximately 173 $/kW. The Cigre figures are based on quotes from suppliers provided to the working group and therefore -- as

these are relatively "generic" cost estimates -- need to be applied carefully. However, Cigre's cost estimates provide a good "sanity check".

So, using the current market prices of 175 $/kW to 250 $/kW, the cost estimate for the converter stations should be between 350 M$ and 500 M$. Therefore, to be conservative, we propose 500 M$ for the base converter station cost estimate.

4.2. Riel Synchronous condensers

Four (4) 250 MVAr synchronous condensers are required at the Riel AC point-of-interconnection for proper operation of Bipole III. Manitoba Hydro has based their cost estimate on quotations and meetings with the limited number of suppliers. Manitoba Hydro's estimate is 255 M$ for the four machines based on an EPC contract which would include the machines, their unit transformers and the associated circuit breakers. We believe that this cost estimate is on the conservative side and propose it remain at 255 M$ for the base synchronous condenser cost estimate.

4.3. Keewatinoow AC switchyard

The Keewatinoow AC switchyard would require 18 circuit breaker positions. Manitoba Hydro's cost estimate is 73 M$ which we concur with. However, for the purpose of this review, we have assumed that circuit breakers associated with the converter station equipment (i.e., 4 converter transformers and 4 filter banks) are included in the converter station cost estimate. Therefore, assuming that approximately 40% of the switchyard cost is included in the converter station contract, we propose that the adjusted base Keewatinoow AC switchyard cost estimate be (73 M$ • 60%) or 45 M$.

4.4. Site development

Manitoba Hydro's cost estimate for Keewatinoow site development is 54.5 M$, Riel site development is 28.7 M$, for a total site development cost estimate of 83 M$.

Manitoba Hydro's definition of site development includes: (i) geotechnical engineering tests, site improvements, transportation access, fence, infrastructure development, etc.; and (ii) converter transformer access and change out infrastructure and additional buildings and other which would not be typically included in a converter station EPC contract. The first component of site development scope would be considered typical for a converter station while the second component of site development costs might be considered discretionary or otherwise specific to Manitoba Hydro. We are not in a position to comment one way or another on these requirements and, therefore, Manitoba Hydro's cost estimate.

We propose that the base site development cost estimate remain at 83 M$, but, encourage Manitoba Hydro to revisit its requirements for site development to determine if this cost could be optimized.

4.5. Interfaces, test equipment & communications for converter stations

Manitoba Hydro's cost estimate for Keewatinoow and Riel interfaces, communication systems, and test equipment is 26 M$. We have assumed that this scope of work is included in the converter station EPC contract (which it typically is). Therefore, we recommend that this cost estimate be adjusted to 0 M$.

4.6. Property for electrodes and Keewatinoow site; Electrode sites

We have no comment on Manitoba Hydro's cost estimate and recommend that the base cost estimate for these two items remain at 15 M$.

4.7. Project & Construction management; Engineering planning studies and consultants

Manitoba Hydro's estimate for these three management and engineering activities is 189 M$ which we believe is too high. Typically we would expect 10% to15% of the total cost estimate be budgeted for this scope of work which would put this figure between 100 M$ and 150 M$. Regardless, not being familiar with Manitoba Hydro's internal cost structure and management/oversight philosophy, we assume that the base cost estimate for these services would remain unchanged at 189 M$.

4.8. Keewatinoow electrode line

Manitoba Hydro's estimate for the Keewatinoow electrode line is 4.7 M$. We believe this to be reasonable and recommend that the base cost estimate remain unchanged at 4.7 M$.

4.9. Keewatinoow converter station construction power

Manitoba Hydro's cost estimate for converter station construction power is 23.4 M$. We believe this to be reasonable and recommend that the base cost estimate remain unchanged at 23.4 M$.

4.10. Keewatinoow collector lines

Manitoba Hydro's cost estimate for the five (5) Keewatinoow 230 kV AC transmission lines (a.k.a. "collector lines") is 70.9 M$. We believe this to be reasonable and recommend that the base cost estimate remain unchanged at 70.9 M$.

4.11. Riel AC switchyard

Manitoba Hydro's cost estimate for the Riel AC switchyard is 133.5 M$. Again, for the purpose of this review, we have assumed that a portion of the Riel AC switchyard equipment would be integrated into the converter station EPC contract. Maintaining the same assumption that 40% of the Riel AC switchyard would be associated with the converter station, we propose that the adjusted base Riel AC switchyard cost estimate be 80 M$.

4.12. Riel electrode line

Manitoba Hydro's estimate for the Riel electrode line is 3.5 M$. We believe this to be reasonable and recommend that the base cost estimate remain unchanged at 3.5 M$.

4.13. Summary -- Converter stations and associated facilities

Table 1 provides a summary of Manitoba Hydro's cost estimates (including contingency and escalation) for converter stations and associated facilities. The items included in "Subtotal 1" were derived from -- and formatted in accordance with -- Appendix 1. The items included in "Subtotal 2" were derived from Appendix 2 and Appendix 3. Contingency (which includes so-called "Management Reserve") was derived from Appendix 3.

Scope	MH Base Estimate M$	MH Contingency Estimate M$	MH Escalation Estimate M$	MH Total Estimate M$
HVDC Converter Stations	558	483	181.6	1,222.6
Synchronous Condensers (4 Syncs)	255	0	0	255.0
230kV AC Switchyard (Keewatinoow only)	73	30	9.4	112.4
Site Development	83	0	0	83
Interfaces, Test Equipment & Comm. for C.S	26	0	0	26
Property for Electrodes Sites and Keewatinoow	15	0	0	15
Construction Management	77	0	0	77
Camp (North) & Construction Facilities (*)	81	0	0	81
Engineering, Planning Studies & Consultants	72	0	0	72
Project Management	40	0	0	40
Subtotal 1	**1,280**	**513**	**191**	**1,984**
Keewatinoow electrode line	4.7	1.6	0.3	6.6
Keewatinoow construction power	23.4	5.5	1.3	30.2
Keewatinoow collector lines (5 lines)	70.9	9.0	6.5	86.4
Riel 230 kV switch yard development	133.5	25	8.0	166.5
Riel electrode line	3.5	1.2	0.3	5
Subtotal 2	**236**	**42.3**	**16.4**	**294.7**
Total	**1,516**	**555.3**	**207.4**	**2,279**

(*) Not included in our review.

Table 1 -- Manitoba Hydro estimate including contingency and escalation

5. Analysis and Discussion

Table 2 provides an "apples-to-apples" comparison summary of our cost estimates for the same scope packages.

Scope	Our Base Estimate M$	Our Contingency Estimate M$	Our Escalation Estimate M$	Our Total Estimate M$
HVDC Converter Stations	500	50	0	550
Synchronous Condensers (4 Syncs)	255	25.5	0	280.5
230kV AC Switchyard (Keewatinoow only)	45	4.5	0	49.5
Site Development	83	8.3	0	91.3
Interfaces, Test Equipment & Comm. for C.S	0	0	0	0
Property for Electrodes Sites and Keewatinoow	15	0	0	15
Construction Management	77	0	0	77
Camp (North) & Construction Facilities (*)	81	0	0	81
Engineering, Planning Studies & Consultants	72	0	0	72
Project Management	40	0	0	40
Subtotal 1	**1,168**	**88.3**	**0**	**1,256.3**
Keewatinoow electrode line	4.7	0.5	0	6.6
Keewatinoow construction power	23.4	2.3	0	30.2
Keewatinoow collector lines (5 lines)	70.9	7.1	0	86.4
Riel 230 kV switch yard development	80	8.0	0	166.5
Riel electrode line	3.5	0.4	0	5
Subtotal 2	**182.5**	**18.3**	**0**	**200.8**
Total	**1,350.5**	**106.6**	**0**	**1,458**

(*) Not included in our review.

Table 2 – Review Team estimate including contingency and escalation

We believe that a "Big Picture" presents itself when comparing Manitoba Hydro's converter station and associated facilities cost estimates and our cost estimates. For all intent and purposes, the base cost estimates are the same. As previously discussed, our converter station cost estimate is a little lower and we have assumed that portions of the two AC switching stations would be integrated into the converter station EPC contract. Moreover, we assumed that the converter station EPC contract would include the associated interface equipment, communication equipment and test equipment. Bottom line, we are in general agreement with Manitoba Hydro's "Base Cost Estimate". The principal difference lies within our estimates for Contingency and Escalation.

We have systematically applied a 10% contingency to all "hard" scope components (i.e., equipment as opposed to services). We believe that 10% is typical for such large capital projects and especially justified as, in most all cases, we believe that the base estimates are on the high-side of the range. For example, one might argue that our converter station cost estimate already has "embedded contingency" as we applied the highest current market price of 250 $/kW. Moreover, the absolute value of our estimated contingency of 107 M$ is a significant amount of money which we believe can be actively managed by Manitoba Hydro's risk control systems. Manitoba Hydro's estimated contingency (inc. management reserve) is 555 M$ which is 35% of its base cost estimate or approximately equal to the value of two complete 2,000 MW converter stations. We believe this estimated contingency is too high, unnecessarily conservative, and not supportable.

We also believe that the converter station and associated facilities costs will not be subject to appreciable escalation as we understand Manitoba Hydro would enter into definitive and binding contracts in 2013/14. This is the time that actual costs will be known and to most extent fixed. Moreover, we have not witnessed any significant change in converter station, synchronous machine, or switchyard equipment costs over the past several years. Manitoba Hydro has estimated 207 M$ (14% of its base cost estimate) for escalation cost which, again, is too high, unnecessarily conservative, and not supportable.

Budgetary converter station cost estimates will be subject to some currency exchange and commodity price risk. Converter station suppliers functionally "denominate" the EPC contract price in their respective European-based currencies (i.e., Euro or Krona). Moreover, suppliers typically stipulate that commodity (i.e., copper, steel, etc.) price risk be borne by its customer. Therefore, for budgetary price purposes, these risks are placed with Manitoba Hydro. However, these are subject to negotiation with potential suppliers and these risks will pass when a definitive EPC contract is executed. Moreover, financial hedging strategies are available to Manitoba Hydro to help mitigate and certainly define the price for mitigating these risks.

Finally, we have not estimated nor commented on Manitoba Hydro's cost estimate for interest expense. This is a financially-driven calculation based on cash flow, Manitoba Hydro's average cost of capital, and other accounting rules. Having said that, once a final cost estimate and associated cash flow has been established and approved, the calculation of interest expense would be programmatic, straight-forward, and should not subject to interpretation.

6. Project delivery strategy

We recommend that the "Big Five" components which comprise the scope of the converter station and associated facilities "i.e., (a) Keewatinoow converter station; (b) Keewatinoow AC switchyard; (c) Riel converter station; (d) Riel AC switchyard; and (e) Riel synchronous condensers" be packaged, functionally specified, procured, and managed by Manitoba Hydro on a turnkey EPC contract basis. This is certainly the trend, if not the rule, in converter station procurement as evidenced by the project list in Appendix 4.

In addition, we recommend that Manitoba Hydro consider packaging the converter station and associated facilities in possibly no more than two principal EPC Contracts. For example, we believe that the Keewatinoow AC switchyard, Keewatinoow converter station, Riel Converter station, and Riel AC switchyard could be packaged in one EPC Contract and the Riel synchronous condensers be packaged in a second EPC contract. In our opinion, if properly structured, this will minimize interface risk and benefit Manitoba Hydro.

Converter station suppliers are accustomed to negotiating for and providing the following technical and commercial protections:

1. Firm, fixed-price contract amount;
2. Extended equipment warranties;
3. Schedule guarantee with associated liquidated damages;
4. Transmission capacity performance guarantee with associated liquidated damages
5. Transmission loss performance guarantee with associated liquidated damages; and
6. Reliability and availability guarantees with associated liquidated damages.

Bottom line, this converter station contracting strategy is currently the norm, is understood by lenders and insurance underwriters and, we believe would provide Manitoba Hydro with manageable risk.

7. Possible deferral of expenditure

We believe that there may be two possibilities to defer project investment until such time as the Conawapa generation resource comes on line post 2020.

1. We believe that the: (i) 72 km DC transmission line between the Dorsey converter station and the Riel converter station and the: (ii) 27 km DC transmission line between the Keewatinoow converter station and the Henday converter station can be deferred until Conawapa comes on line. By doing so, Manitoba Hydro can defer approximately 91 M$ of project investment until post 2020.

2. It may also be possible to defer two of the Riel synchronous condensers until Conawapa comes on line. By doing so, Manitoba Hydro can also defer approximately 125 M$ of project investment until post 2020.

8. Project staging

Finally, there may also be net benefits by "staging" the Bipole III converter stations over time and there could be two potential staging options:

Option 1 – Three stages (similar to Bipole II development):

1. Stage 1: 1,000 MW bipolar operation at ± 250 kV DC voltage;
2. Stage 2: 1,500 MW bipolar operation at +500 kV / -250-kV DC voltage; and
3. Stage 3: 2,000 MW bipolar operation at ± 500 kV DC voltage.

Option 2 – Two stages:

1. Stage 1: 1,000 MW monopolar metallic return operation at + 500 kV DC voltage; and
2. Stage 2: 2,000 MW bipolar operation at ±500 kV DC voltage.

In both cases, the DC transmission line between the Keewatinoow converter station and the Riel converter station would initially be constructed for full 2,000 MW, ±500 kV DC voltage capability.

Either of these two options would increase converter station EPC costs but defer certain of these costs in time. Also, overall complexity, losses, outage requirements and other factors need to be considered to determine if indeed net benefits exist.

We do not necessarily recommend that Manitoba Hydro consider this staging concept further but are simply highlighting the opportunity.

9. Recommendation

In conclusion, we recommend that Manitoba Hydro:

1. Review and possibly apply certain of our modified cost estimates;
2. Consider adjusting estimated contingency and escalation costs;
3. Employ EPC contracts for the converter stations, AC switchyards and synchronous condensers;
4. Consider deferring Keewatinoow to Henday DC transmission line construction;
5. Consider deferring Riel to Dorsey DC transmission line construction;
6. Consider deferring two of the Riel synchronous condensers; and
7. Evaluate whether any Bipole III staging strategy would be beneficial and efficacious.

Appendix 1
HVDC Converter Stations Re-estimate (July 2010)

This estimate has been modified to reflect the repackaging of the BPIII Complex as per memo dated 2010 06 23 from KRF Adams and TE Tymofichuk. Only the items managed by Power Supply are shown.

REVISED ESTIMATE (2009$) in Millions				
ITEM	**DIRECTS**	**2000MW (ISD 2017)**	**2000MW + 500MW (ISD 2017)**	**2500MW (ISD 2022)**
D1	HVDC Converter Station	558	642	20
D2	Synchronous Condensers (4 Syncs)	255	255	148
D3	230kV AC Switchyard (Keewatinoow only)	73	73	5
D4	Site Development	83	85	5
D5	Interfaces, Test Equipment & Comm. for C.S	26	26	0
D6	Property for Electrodes and Keewatinoow Site	10	10	0
D8	Electrode Sites	5	6	0
	Subtotal - DIRECTS	1,010	1,097	178
ITEM	**INDIRECTS**	**2000MW (ISD 2017)**	**2000MW + 500MW (ISD 2017)**	**2500MW (ISD 2022)**
I1	Construction Management	77	77	11
I2	Camp (North) & Construction Facilities	81	81	0
I3	Engineering, Planning Studies & Consultants	72	72	9
I4	Project Management	40	40	5
	Subtotal - INDIRECTS	270	270	25
	TOTAL- BASE ESTIMATE	1,280	1,367	203

	2000MW (ISD 2017)	**2000MW + 500MW (ISD 2017)**	**2500MW (ISD 2022)**
Base Estimate:	**1,280**	**1,367**	**203**
Contingency (based on 50% confidence):	350	367	50
Interest and Escalation:	519	558	N/A
Management Reserve (High probability):	163	163	25**
CONVERTER STATION PROJECT TOTAL COST:	**2,312**	**2,455**	**253**

D1 - HVDC Converters

Budgetary Estimate

2000MW 2017 ISD: $558 Million (2009 estimate)

2000MW + 500MW Future Option 2017 ISD (incremental): $642 Million (+$84 Million)
(Immediate purchase of Spare Converter transformers @ 4x $6M is recommended until a formal risk analysis has been performed)

Converter 2500MW Capacity (@ 2000MW Operational Rating) Benefits:
1. The 2500MW capacity would increase reliability as follows:

Capacity	Post Loss of VG Availability	Post Loss of Pole Availability	Largest single contingency (excluding lines)
2000MW	1500MW (0.75)	1000MW (0.50)	1000MW
2500MW	1875MW (0.9375)	1250MW (0.625)	750MW
2500MW + 10% continuous overload	2000MW (1.0)	1375MW (0.6875)	625MW

2. This should be considered when performing the risk analysis of deferring the spare converter transformers

Expansion from 2000MW to 2500MW 2022 ISD: $20 Million
- $15Million for an additional 200MVar AC Filter at Keewatinoow
- $5Million approximate estimate for additional Engineering, System Planning Studies and Commissioning

Budgetary estimates are based on responses to mini-specs received from HVDC suppliers (Q1 2009). Estimates for options and items not quoted by supplier were prepared by [redacted]

	2009$M		
	[redacted]	[redacted]	[redacted]
Base Cost Provided by Supplier 2000MW	480	590	556
Base Cost Provided by Supplier 2500MW	554	630	616
Base Cost Multiplier to increase to 2500MW	1.15	1.08	1.11
Est. for Options and Items Not Quoted by Supplier (2000MW)	70	54	28
Subtotal Cost (2000MW)	550	644	584
Additional HVDC items outside scope of mini-spec for (2000MW)	8	8	8
Total Cost 2000MW Option	**558**	**652**	**592**
Total Cost 2500MW Option (2000MW x Multiplier)	**642***	**704**	**657**
Incremental 2500MW Dollar Increase	**84**	**52**	**65**

Note 1: From CIGRE 186 WG 14.20, cost of converter transformers is approx. 22% of total cost, therefore, each unit is approx. $6M
Note 2: Additional HVDC items outside scope of mini-spec for 2000MW include NERC and SPS
Note 3: Estimate for Options and Items Not Quoted by Supplier include Continuous Overload, F3 tornado rating and 3D drawings as well as spare thyristors and VH HVAC for [redacted] only.

Management Reserve

2000MW
Lowest price estimate of $558 was selected for the 2000MW budgetary estimate. HVDC suppliers [redacted] and [redacted] are considered to be industry leaders in the HVDC transmission world market and [redacted] is considered to have less experience. Management reserve of $102M (difference between average base price of industry leaders and lowest vender price and associated $10M for other related costs) has been allotted for vender uncertainty and to secure a more experienced vender.

2500MW
The [redacted] price estimate of $642 is selected for the 2500MW budgetary estimate. HVDC suppliers [redacted] and [redacted] are considered to be industry leaders in the HVDC transmission world market and [redacted] is considered to have less experience. Management reserve of $80M (difference between average base price of industry leaders and lowest vender price and associated $10M for other related costs) has been allotted for vender uncertainty and to secure a more experienced vender.

2500MW Upgrade Requirements Description:

Valves:
Immediate (must be upgraded to protect 2500MW option):
- Thyristor size will increase for 2500A, size increase from 4" to 5"
- Saturable Core Reactors, Snubber components would increase
- Valve Hall buswork will increase
- Larger Air Handling requirements for additional heat dissipation
- Larger Valve Cooling equipment could be added later

Converter Transformer:
Immediate (must be upgraded to protect 2500MW option):
- Size increase from approximately 170MVA to 210MVA
- BPII units are approximately 250MVA, therefore BPIII units should be within transport limits
- Mini Specification Pricing included 4 Spare units
- Purchase of spare units should not be deferred until a risk analysis is completed

Smoothing Reactors:
Immediate (must be upgraded to protect 2500MW option):
- Size increase from 2000A to 2500A

AC Filters:
Immediate (2 x 100MVar, 2 x 200Mvar): Future (1 x 200MVar)
- Increase from 600MVar to 800MVar total per station
- Additional Filter required

DC Switchyard and Filters:
Immediate (must be upgraded to protect 2500MW option):
- Size increase of Buswork, Switch Capacity from 2000A to 2500A and DC Filtering
- Size for 2500MW now to eliminate future HVDC outage requirements for an upgrade

D2 - Synchronous Condensers

Budgetary Estimate

2000MW 2017 ISD: $255 Million (Adjusted from 2009 estimate of $305 Million)

2000MW + 500MW Future Option 2017 ISD (incremental): $255 Million ($0)

Expansion from 2000MW to 2500MW 2022 ISD: $148 Million
$128 Million for additional 2 machines plus $20 Million Indirect Costs

Budgetary estimates are based on responses to mini-specs received from HVDC suppliers (Q1 2009) and on information received during recent vendor meetings. Estimates for items not quoted by supplier were prepared by [redacted].

	2009$M			
	[redacted]	[redacted]	[redacted]	[redacted]
Base Cost Provided by Supplier (4 syncs)	219	70 Machine Only	250	203
Machine Only Costs from supplier	TBD	70	-	85
BOP and auxiliaries from supplier	TBD	TBD	-	118
Est. for Items Not Quoted by Supplier	86	TBD	-	NA
Total Cost (4 synchs)	305	TBD	250	**203**
Total Cost (6 synchs)	457.5	TBD	375	**304.5**

[redacted] Proposal dated December 22, 2009 was quite detailed and included the unit transformer, building and civil works. The proposal was based on four 250MVar machines, so the cost could be scaled up for the 2500MW option to meet the six machine requirement.

[redacted] has indicated that they would prefer to supply the existing 300Mvar Machine design in service at Dorsey. The supply of 300MVar machines could allow for a reduction of the required machines for 2500MW from six to five.

With the above new information, we recommend carrying the average between the three most detailed estimates [redacted] of $255 Million and keeping the previous contingency.

[redacted], [redacted] and [redacted] are supplying a hydrogen cooled machine, while [redacted] is a larger air cooled unit. The existing contingency will be kept since [redacted] manufacturing capabilities must be assessed. A more detailed budgetary price from [redacted] is required to validate the Hydrogen cooled machine pricing, which may allow us to reduce the required contingency.

Management Reserve

2000MW
No management reserve was allotted to synchronous condensers.

2500MW
No management reserve was allotted to synchronous condensers

D3 - 230kV AC Switchyard (Keewatinoow only)

Budgetary Estimate

2000MW 2017 ISD: $73 Million (2009 estimate +Updated costs)

2000MW + 500MW Future Option 2017 ISD (incremental): $73 Million ($0)

Expansion from 2000MW to 2500MW 2022 ISD: $5 Million
This is an approximate estimate for additional Engineering, System Planning Studies and Commissioning. Additional Bay costs would be the responsibility of the corresponding new generation facility project.

Budgetary estimates are based on AIS estimates compiled internally by Manitoba Hydro (Q1 2009).

	230kV AC SWITCHYARDS (2009$M)			
	Riel		Keewatinoow	Base Cost
	Phase A	Phase B		
	TBU	TBU	73	73*
Total	TBU			

Riel works are managed by Transmission Construction and Line Maintenance Division (**TCLM**) and are included in their TBU estimate.

Northern works are managed by New Generation Construction Division (**NGCD**).

The 2009 AIS Estimate of $49 Million for Keewatinoow was based on a 32 breaker bay; however the System Planning SLD shows 24 breakers for a 2017 ISD. Scaling down to 24 breakers, the cost is approx $45 Million. An additional $15 Million is added to account for PM and CM costs (typically 17%-18% based on Wuskwatim and Keeyask SAP reports + 10% for Site Management performed by an EPC Vendor as identified from CIGRE 186 WG 14.20). This $60 Million dollar figure used previously is consistent with the TCLP 2009 cost estimate report.

The $73 million used in this estimate was obtained from TBU.

2500MW Option:
The Riel Sectionalization Project has designed the AC switchyard to protect the 2500MW option. There are minimal differences between the Converter Station AC Switchyards for a 2500MW option and the costs associated with terminating future lines will be the responsibility of the corresponding new generation facility project.

Management Reserve

AIS option has been recommended, $15M allotted to the Keewatinoow Switchyard to account for aggressive estimating as per direction from the Working Group.

D4 - Site Development

Budgetary Estimate

2000MW 2017 ISD: $83 Million (2009 estimate)

2000MW + 500MW Future Option 2017 ISD (incremental): $85 Million (+$2 Million)
Additional $2 Million for Keewatinoow size increase to support an additional AC Filter

Expansion from 2000MW to 2500MW 2022 ISD: $5 Million
This is an approximate estimate for additional engineering and civil works.

Budgetary estimates are based on estimates compiled internally by Manitoba Hydro (Q1 2009).
Riel (Phase A) - TCLM
Riel (Phase B) & North - NGCD

	SITE DEVELOPMENT (2009$M)			
	Riel		Keewatinoow	Base Cost
	Phase A	Phase B		
	TBU	28.7	54.5	83*
TOTAL	TBU + 28.7			

Riel Phase A works are managed by the TCLM as part of the Sectionalization Project and represent costs associated with overall Riel site development. Phase B works are part of the BPIII Converter Station Complex and represent the site development directly related to synchronous condensers and HVDC converters.

Northern works are also part of the BPIII Converter Station Complex and are solely for the HVDC Converter Station.

Site development costs include all works associated with site development and can be subdivided as follows:

ITEM	% of Site Development Cost
Civil Site Improvements	42%
Mechanical Buildings and Systems	43%
Auxiliary Buildings	8%
Fire Protection	7%

2500MW Option:
Since there are minimal differences in site development for a 2500MW option, we recommend carrying the previous figures.

Management Reserve
The current estimate is based on using the optimum location at the Keewatinoow site. However, the Conawapa area exhibits poor site conditions in many locations. Management reserve of $12M has been allotted to Site Development if a site with unfavorable soil conditions is required to be selected based on Conawapa GS interfacing, system operational requirements or direction from an external organization.

NOTE: Questions have been raised about the relative cost difference between the Riel and Keewatinoow Stations. Riel includes $49.4M (Phase A & B works) under Power Supply, and $20.7M (Phase A works) under Transmission for a total of $70.1M. The total cost of Keewatinoow Site Development is $54.5M.

D5 & D6

No changes are perceived, see the estimate summary table.

D7 – Construction Power for Keewatinoow CS

This is being managed by TCLM, and now forms part of the TBU estimate.

D8 - Electrode Sites

Budgetary Estimate

2000MW 2017 ISD: $5 Million (2009 estimate + $1.5M)
This increase is based on a revised electrode site selection field program.

2000MW + 500MW Future Option 2017 ISD (incremental): $6 Million (+ $1.0 Million)

Scenario A - Candidate sites can support a 2750dcA option
- $0.5M - Increased electrode size North
- $0.5M - Increased electrode size South

Scenario B - Candidate sites cannot support a 2750dcA option
- $2.5M to site a 2500MW electrode in North
- $1.5M to site a 2500MW electrode in South
- $10.4M - additional line distance North
- $7M - additional line distance South
- $0.5M - Increased electrode size North
- $0.5M - Increased electrode size South

Expansion from 2000MW to 2500MW 2022 ISD: $0
Add $24.4 Million to Management reserve for worst case scenario B above.

Budgetary estimates are based on estimates compiled internally by NGCD (Q1 2009).

ELECTRODE SITES (2009$M)		
Riel	**Keewatinoow**	**Base Estimate**
2	3	5

2500MW Option:
We are assuming a worst case additional cost of $24.4 Million

Management Reserve
Management reserve of $20M has been allotted for Electrode Sites if mitigation of adverse effects of electrode sites is directed. The main drivers of mitigation requirements are adverse effects related to the communities surrounding the Electrode Sites.

In addition to this, $24.4 Million must be added in case candidate sites cannot support a 2750dcA option.

I1 - Construction Management

Budgetary Estimate

2000MW 2017 ISD: $77 Million (2009 estimate)

2000MW + 500MW Future Option 2017 ISD (incremental): $77 Million ($0)

Expansion from 2000MW to 2500MW 2022 ISD: $11 Million
Estimated using the ratio of I1 to total direct costs for the 2000MW and applying this ratio to the total directs for 2500MW.

Budgetary estimates are based on estimates compiled internally by NGCD (Q1 2009).

	INDIRECTS	Riel	North	Base Cost
I1	**Construction Management**	**35**	**42**	**77***
	Site Management	25	26	51
	Services, Supplies and Equipment	10	16	26

2500MW Option:
Since there are minimal differences in construction management for a 2500MW option, we recommend carrying the previous figures. The costs associated with terminating future lines will have to be estimated.

Management Reserve
5% of all Construction Management hours (equating to $4M) were removed from the Base Estimate and allotted to Management Reserve. This more aggressive estimating practice was completed as per direction from the Working Group to reduce the Base Estimate.

I2 - Camp (North) & Construction Facilities

Budgetary Estimate

2000MW 2017 ISD: $81 Million (2009 estimate)

2000MW + 500MW Future Option 2017 ISD (incremental): $81 Million ($0)

Expansion from 2000MW to 2500MW 2022 ISD: $0
No camp costs are required since the additional synchronous Condensers are in the south.

Budgetary estimates are based on estimates compiled internally by NGCD (Q1 2009).

	INDIRECTS	Riel	North	Base Cost
I2	**Camp (North) & Construction Facilities**	**7**	**74**	**81***
	Construction Facilities	2.7	39.1	41.8
	Camp Services Contract	-	19.2	19.2
	Electric Power & Communications for Construction	3.1	7.0	10.1
	Labour and Material Provisions	-	7.8	7.8
	Transportation and Stores	1.3	0.5	1.8

2500MW Option:
Since there are minimal differences in camp and construction facilities for a 2500MW option, we recommend carrying the previous figures. The cost of a camp to terminate future lines is outside the scope of the converter stations.

Management Reserve
A 5% reduction was applied to select activities in Camp (North) & Construction Facilities (equating to $4M). The $4M was removed from the Base Estimate and allotted to Management Reserve. This more aggressive estimating practice was completed as per direction from the Working Group to reduce the Base Estimate.

I3 - Engineering Support, Planning Studies & Consultants

Budgetary Estimate

2000MW 2017 ISD: $72 Million (2009 estimate with updated System Planning studies estimate)

2000MW + 500MW Future Option 2017 ISD (incremental): $72 Million ($0)

Expansion from 2000MW to 2500MW 2022 ISD: $9 Million
Estimated using the ratio of I3 to total direct costs for the 2000MW and applying this ratio to the total directs for 2500MW.

Budgetary estimates are based on estimates compiled internally by NGCD (Q1 2009).

	INDIRECTS	Riel	North	Base Cost
I3	**Engineering Support, Planning Studies & Consultants**	**45**	**27**	**72***
	Engineering Support and Consultants	29.5	19.9	49.4
	Major Consultants	13.0	7.4	20.4
	System Studies	2.2	0.1	2.3

2500MW Option:
Since the 2500MW option studies are in progress and preliminary engineering has not commenced, we recommend carrying the previous figures. The costs associated with the studies required to expand from 2000MW to 2500MW are based on previous ratios.

Management Reserve
5% of all Engineering Support, Planning Studies & Consultant hours (equating to $4M) were removed from the Base Estimate and allotted to Management Reserve. This more aggressive estimating practice was completed as per direction from the Working Group to reduce the Base Estimate.

I4 - Project Management

Budgetary Estimate

2000MW 2017 ISD: $40 Million (2009 estimate)

2000MW + 500MW Future Option 2017 ISD (incremental): $40 Million ($0)

Expansion from 2000MW to 2500MW 2022 ISD: $5 Million
Estimated using the ratio of I4 to total direct costs for the 2000MW and applying this ratio to the total directs for 2500MW.

Budgetary estimates are based on estimates compiled internally by NGCD (Q1 2009).

	INDIRECTS	Riel	North	Base Cost
I4	**Project Management**	**18**	**22**	**40***
	Project Management - NGC	13.5	13.4	26.9
	Insurance, JRS & HPMA	4.5	8.1	12.6

2500MW Option:
Since there are minimal differences in project management for a 2500MW option, we recommend carrying the previous figures. The costs associated with Project Management required to expand from 2000MW to 2500MW are based on previous ratios.

Management Reserve
5% of all Project Management hours (equating to $2M) were removed from the Base Estimate and allotted to Management Reserve. This more aggressive estimating practice was completed as per direction from the Working Group to reduce the Base Estimate.

Cost Impact Analysis (All Costs are High Level Estimates)

A) Savings and Cost to Defer 1 Synchronous Condenser
Deferring one synchronous Condenser is not recommended as the components of the BPIII Converter Station Project are planned to be designed to an N-2 redundancy. It is understood that this is an operating and power sales requirement.

B) Cost and Savings to defer one pole (Pole 5 or Pole 6) of Bipole III
Deferring one Pole is not recommended as the components of the BPIII Convertor Station Project are planned to be designed to an N-2 redundancy. As well a 50% savings would not be observed if one pole is deferred due to shared costs, and it would cost more than 50% of current estimate to construct the remaining pole after the project ISD.

C) N-1 or N-2
All components of the BPIII Convertor Station Project are planned to be designed to an N-2 redundancy. It is understood that this is an operating and power sales requirement.

- D1 - Convertor Stations
  - It is assumed that both poles of the Bipole III Converter Stations are required to meet the N-2 redundancy.
  - The Convertor Stations require 2-valve groups per pole to meet the N-2 redundancy. The 2009 [redacted] estimate identifies a 5-10% cost difference between 2-valve groups per pole vs. 1-valve group per pole (approx $55M)
- D2 - Synchronous Condensers
  - 4 syncs are required to meet the N-2 redundancy.
- D3 & D4 - Site Development and Switchyards
  - Riel Sectionalization works which include the Site Development and the 230kV Switchyard are proceeding with an N-2 redundancy.
  - Keewatinoow Site Development works and the 230kV Switchyard are planned for an N-2 redundancy.

D) Gold Plating Report

The following items will be identified in a "Gold Plating" report which was not available at the time of this estimate:

1) Spare HVDC Converter Transformer staging
2) Synchronous Condenser estimate change
3) Oil spill containment design
4) Relay buildings water requirements
5) Road requirements
6) Contracting strategies
7) Transformer moving system

Item 1 needs a formal risk assessment prior to deferring the purchase of spare transformers.
Item 2 has been incorporated into this estimate.
Items 3 - 7 are not anticipated to have any significant impact on this estimate.

Appendix 2

Bipole III - Western Routed HVdc T/L and 2000MW Converters
Calculation of CPJ Addendum Amounts based on the Revised Estimate (Summer 2010)
(In thousands of dollars)

Prepared by: Transmission BU

IM Node / WBS	COMPLEX DESCRIPTION FOR CEF / Project Description	REVISED ESTIMATE Summer 2010 Total Net (In-service Cost)	Increase (Decrease) vs. APPROVED BUDGET [Amount to explain under each CPJ Addendum] Base *	Contingency	Int. & Esc	Total Net (In-service Cost)
1.5.2.1.1.1	**BIPOLE III - LICENSING & PROPERTIES**					
P:04221	Licensing & Environmental Assessment					
P:14363	Property - Riel Converter Station					
P:14518	Property - BPIII Transmission Line					
P:15533	Property - Keewatinoow Converter Station					
P:15537	Property - Keewatinoow Collector Lines					
P:15696	Property - Keewatinoow Electrode Line & Station					
P:15697	Property - Riel Electrode Line & Station					
1.5.2.1.2.1	**BIPOLE III - TRANSMISSION LINE**					
P:10155	Western Route 500kV Transmission Line					
P:04218	Eastern Route 500kV T/L (sunk costs)					
1.5.2.1.3.1	**KEEWATINOOW CONVERTER STATION**					
P:15540	Keewatinoow Converter Station					
P:15542	Keewatinoow Electrode Line					
1.5.2.1.4.1	**KEEWATINOOW AC COLLECTOR SYSTEM**					
P:15535	Keewatinoow C.S.-Construction Power					
P:15536	Keewatinoow 230kV Collector Lines					
P:15544	Keewatinoow 230kV AC Switchyard					
1.5.2.1.5.1	**RIEL CONVERTER STATION**					
P:15541	Riel Converter Station					
P:14364	Riel C.S. & 230kV AC Switchyard Site Development					
P:15534	Riel R49R T/L Sectionalization					
P:15543	Riel Electrode Line					
TOTAL for BIPOLE III		**4,107,057**	**739,553**	**688,482**	**432,187**	**1,859,222**

Notes:
- Scope for Bipole III does not include Riel Sectionalization, Riel 230kV Outlet Lines or Protecting for a 2500MW Option
- Revised Estimate Total Net figures include interest and escalation to the 2017 in-service as calculated for that year's CERs

N:\Riel BPIII Proj Mgmt Section\BP III Complex\Estimates\2010\Estimate History by WBS.xls 2010.10.05

Bipole III - Western Routed HVdc T/L and 2000MW Converters
Proposed Treatment for CEF10
(in thousands of dollars)

Prepared by: Transmission BU

IM Node / WBS	COMPLEX DESCRIPTION FOR CEF / Project Description	APPROVED BUDGET Summer 2007 Total Net (In-service Cost)	Current Responsibilities by Project: Proj Owner	Current Responsibilities by Project: Proj Manager	Proposed Responsibility for CPJ Addendums
1.5.2.1.1.1	**BIPOLE III - LICENSING & PROPERTIES**	[redacted]			**Transmission**
P:04221	Licensing & Environmental Assessment		Trans-TP&D	Trans-TC&LM	
P:14363	Property - Riel Converter Station		Trans-TC&LM	F&A-CorpServ	
P:14518	Property - BPIII Transmission Line		Trans-TC&LM	F&A-CorpServ	
P:15533	Property - Keewatinoow Converter Station		PS-NGC	F&A-CorpServ	
P:15537	Property - Keewatinoow Collector Lines		Trans-TC&LM	F&A-CorpServ	
P:15696	Property - Keewatinoow Electrode Line & Station		PS-NGC	F&A-CorpServ	
P:15697	Property - Riel Electrode Line & Station		PS-NGC	F&A-CorpServ	
1.5.2.1.2.1	**BIPOLE III - TRANSMISSION LINE**				**Transmission**
P:10155	Western Route 500kV Transmission Line		Trans-TP&D	Trans-TC&LM	
P:04218	Eastern Route 500kV T/L (sunk costs)		Trans-TP&D	Trans-TC&LM	
1.5.2.1.3.1	**KEEWATINOOW CONVERTER STATION**				**Power Supply**
P:15540	Keewatinoow Converter Station		PS-NGC	PS-NGC	
P:15542	Keewatinoow Electrode Line		PS-NGC	Trans-TC&LM	
1.5.2.1.4.1	**KEEWATINOOW AC COLLECTOR SYSTEM**				**Power Supply**
P:15535	Keewatinoow C.S.-Construction Power		PS-NGC	Trans-TC&LM	
P:15536	Keewatinoow 230kV Collector Lines		Trans-TP&D	Trans-TC&LM	
P:15544	Keewatinoow 230kV AC Switchyard		PS-NGC	PS-NGC	
1.5.2.1.5.1	**RIEL CONVERTER STATION**				**Power Supply**
P:15541	Riel Converter Station		PS-NGC	PS-NGC	
P:14364	Riel C.S. & 230kV AC Switchyard Site Development		Trans-TP&D	Trans-TC&LM	
P:15534	Riel R49R T/L Sectionalization		Trans-TP&D	Trans-TC&LM	
P:15543	Riel Electrode Line		PS-NGC	Trans-TC&LM	
TOTAL for BIPOLE III for CEF10 (unchanged from CEF09, CEF08 & CEF07)		**2,247,835**			

Notes:
- Scope for Bipole III does not include Riel Sectionalization, Riel 230kV Outlet Lines or Protecting for a 2500MW Option
- Approved Budget Total Net figures include interest and escalation to the 2017 in-service as calculated for that year's CERs.

N:\Riel BPIII Proj Mgmt Section\BP III Complex\Estimates\2010\Estimate History by WBS.xls

Appendix 3

Bipole III - Western Routed HVdc T/L and 2000MW Converters
Calculation of CPJ Addendum amounts based on the revised estimate as of Summer 2010
(in thousands of dollars)

TABLE 1 - SAP BREAKDOWN OF ESTIMATE:
NOTE: Values are taken from version DAP in SAP

IM node	WBS	Complex Description for CEF / Project Description	Estimate Responsibility	Revised Estimate Summer 2010 Total Net (in service cost)	Base	Contingency	Management Reserve	Interest	Escalation
1.5.2.1.1.1		**BIPOLE III - LICENSING AND PROPERTIES**		$					
	P:04221	Licensing & Environmental Assessment	T	$					
	P:14363	Property - Riel Converter Station	T	$					
	P:14518	Property - BPIII Transmission Line	T	$					
	P:15533	Property - Keewatinoow Converter Station	PS	$					
	P:15537	Property - Keewatinoow Collector Lines	T	$					
	P:15696	Property - Keewatinoow Electrode Line & Station	PS	$					
	P:15697	Property - Riel Electrode Line & Station	PS	$					
1.5.2.1.2.1		**BIPOLE III - TRANSMISSION LINE**		$					
	P:10155	Western Route Route 500kV Transmission Line	T	$					
	P:04218	Eastern Route 500kV T/L (sunk costs)	T	$					
1.5.2.1.3.1		**KEEWATINOOW CONVERTER STATION**		$					
	P:15540	Keewatinoow Converter Station	PS	$					
	P:15542	Keewatinoow Electrode Line	T	$					
1.5.2.1.4.1		**KEEWATINOOW AC COLLECTOR SYSTEM**		$					
	P:15535	Keewatinoow C.S. - Construction Power	T	$					
	P:15536	Keewatinoow 230 kV Collector Lines	T	$					
	P:15544	Keewatinoow 230 kV AC Switchyard	PS	$					
1.5.2.1.5.1		**RIEL CONVERTOR STATION**		$					
	P:15541	Riel Converter Station	PS	$					
	P:14364	Riel C.S. & 230 kV Ac Switchyard Development	T	$					
	P:15534	Riel R49R T/L Sectionalization	T	$					
	P:15543	Riel Electrode Line	T	$					

TABLE 2 - TOTAL POWER SUPPLY & TRANSMISSION COSTS:
(In thousands of dollars)

	Total Net (in-service cost)	Base Estimate	Contingency	Management Reserve	Interest	Escalation
Transmission	$ 1,794,948	$ 1,146,630	$ 175,482	$ -	$ 347,017	$ 125,819
Power Supply	$ 2,312,109	$ 1,279,831	$ 350,000	$ 163,000	$ 328,025	$ 191,253
TOTAL	$ 4,107,057	$ 2,426,461	$ 525,482	$ 163,000	$ 675,042	$ 317,072

NOTE: Base dollars contain both Directs & Indirects

Appendix 4

Sample EPC Contracts

Project Name	Client name	Contract start	Contract end	Scope / Description
New Zealand Pole 3	Trans Power	10/2009	06/2012	Monopolar 700 MW
Adani	Adani Power, Ahmedabad , India	04/2009	12/2011	Bipolar 2500 MW +/- 500 kV
China Guangdong	CSG	2007	End 2009	Bipolar 5000 MW, +/- 800 kV
China Xiangjjaba	SGCC	12/2008	03/2011	Bipolar 6400 MW, 800 kV DC
China DEBAO	SGCC	06/2008	03/2010	Bipolar 3000 MW, 500 kV
China Ningdong	SGCC	2009	2012	Bipolar 4000 MW, 660 kV
Trans Bay Cable LLC	Babcock&Brown and Pattern Energy	03/2007	03/2010	400 MW IGBT VSC Based +/-200 kV
Cometa	Red Electrica de Espana	10/2007	07/2011	2x 200 MW bipolar , 250 kV DC
Britned	National Grid / Tennet	05/2007	05/2010	1000 MW bipolar cable transmission, 450 kV DC Cable
Stoerebaelt	Energinet DK	05/2007	03/2010	600 MW monopolar operation, 400 kV DC, Sea Cable, LTT
Neptune HVDC Project	Neptune RTS	07 / 2005	07 / 2007	Monopole 660 MW
Gui Guang II	State Power South Company (SPSC)	05/2005	01/2008	Bipole 3000MW + / - 500 kV DC
Bass Link	Basslink PTY Limited	contract received 2000, authority approval 2002	end of 2005	Monopole 500 MW
Gui Guang I	State Power South Company (SPSC)	10 / 2001	10 / 2004	Bipole 3000MW + / - 500 kV DC
East South Interconnector	Power Grid Corporation of India	03 / 2000	2003	Bipole 2000 MW, DC + / - 500 kV

Project Name	Client name	Contract start	Contract end	Scope / Description
Moyle Interconnector	Moyle Interconnector Ltd. (MIL)	09 / 1999	11 / 2001	Monopoles 2 x 250 MW, both DC 250 kV, LTT
Thailand - Malaysia	Electricity Generating Authority of Thailand (EGAT) / Tenega Nasional Berhad (TNB)	1997	2001	Monopole 300 MW, DC 300 kV
Tianshengquio - Guangzhou	State Power South Company (SPSC)	1997	2000	Bipole 1800 MW, DC + / - 500 kV
Kontiskan - pole 1	Denmark	April 2003	September 2006	
Agra	India	To be awarded		6000 MW, +/- 800 kV
Skagerrak 4	Denmark-Norway	To be awarded	2014	700 MW, 500 kV
NorNed 2	Norway-Netherlands	To be awarded	2015/2016	1200 MW, 450 kV
South Korea-Cheju Island	South Korea	April 2009	February 2012	400 MW
Rio Madeira 1&2	Brazil	2009	1st. bipole 2012 2nd. Bipole 2013	2X3150 MW +/- 600 kV
Hydro Quebec to New England	Canada/USA		Multi=terminal 1992 in service	2250 MW,

Sample EPC Contracts

PUB MFR 165
Bipole III

For every expense category related to the Bipole III project, provide a summary comparing the forecast costs underpinning the $3.28 billion Bipole III capital cost estimate with those underpinning the $4.65 billion control budget. Explain all variances between the two cost estimates.

Public disclosure of the response to this MFR (or portions thereof) would result in the release of information considered to be confidential and commercially sensitive. As directed by the PUB, Manitoba Hydro will be filing a letter seeking confidential treatment of the redacted information contained in this response pursuant to Rule 13.

Please find a summary of the Bipole III project costs in CEF11 and CEF14 by category and an explanation of variances below.

BPIII Project (in millions of dollars)	**CEF11**	**CEF14**	**Variance**
Material	$373.49	$302.62	($70.87)
Consulting Services	$89.98	$133.80	$43.81
Construction Services	$1,509.83	$2,400.90	$891.07
Other expenses	$122.34	$384.32	$261.98
Internal Labour	$240.86	$353.64	$112.78
Interest	$575.30	$568.00	($7.29)
Escalation	$220.43	$147.60	($72.84)
Contingency	$147.65	$361.69	$214.03
Total	**$3,279.88**	**$4,652.56**	**$1,372.67**

Material

- Decrease in Transmission Line materials primarily based on actual vendor pricing

Construction Services

Changes to scope to include:

- Revised line length of final preferred route,
- Increased converter rating to 2300 MW,
- 230kV AC Switchyard indirect and interface costs,
- Site development costs previously assumed to be shared with Conawapa,
- Addition of 2 more temporary collector lines

- Addition of the Keewatinohk construction power substation.
- Inclusion of Synchronous Condensers
- Updated HVDC Converter Equipment costs

Other Expenses

- Changes in preferred final route and right-of-way, updated land values
- Increased Camp Operations costs due to extension of In-Service Date
- [redacted]

Internal Labour

- Increased to reflect project requirements, extension of a year to In Service Date (2017 to 2018) and greater requirements, in part related to license conditions and monitoring.

Interest & Escalation

- Decrease due to lower interest rates and changes in cash flows

Contingency

- Allocation of P50 Project Contingency

Copies of the CPJ Addendums for 2011 ($3.28B), 2014 ($4.65B), and 2016 ($5.04B) were included in the attachment to PUB MFR 155.

For additional detail, the following summarizes the costs related to the previous $4.65 billion control budget and the revised $5.04 billion control budget by category:

BPIII Project (in millions of dollars)	**CEF14**	**CEF16**	**Variance**
Material	$302.62	$343.90	$41.28
Consulting Services	$133.80	$151.87	$18.08
Construction Services	$2,400.90	$2,842.01	$441.11
Other expenses	$384.32	$350.21	($34.11)
Internal Labour	$353.64	$360.61	$6.98
Interest	$568.00	$466.58	($101.43)
Escalation	$147.60	$52.86	($94.74)
Contingency	$361.69	$473.62	$111.94
Total	**$4,652.56**	**$5,041.66**	**$389.10**

Material

- Incorporation of additional materials required for CEC prescribed southern route changes, anticipated incorporation of Nav Canada re-route additional materials, delays in material supply, premiums to accelerate materials and associated engineering.
- Decrease in steel structure costs due to competitive bidding for the AC Collector lines.

Construction Services

- Incorporation of actual construction costs and awarded contract values as a result of higher market rates for anchor and foundations as well as tower assembly erection and stringing contracts than planned and incorporation of delay claims (weather and material) experienced.
- Additional costs included for Keewatinohk External Infrastructure work Including Provincial Road Upgrades (PR 280 and PR 290) and Conawapa Access Road Upgrades which were not included in the original scope of CPJ Addendum 7b.
- Decrease in accommodation costs for the following projects: Long Spruce and Henday AC station modifications, and the AC Collector lines.
- Increase to the construction costs for the installation of the dead end tower footings for the AC Collector Lines. Final design was not complete at the time of the contract award; additional towers were required resulting in higher construction costs.

Other Expenses

[redacted]

Internal Labour

- Incorporation of greater material management costs, project management and construction management.

Interest & Escalation

- Decrease due to lower interest rates and changes in cash flows

Contingency

- Increase in contingency levels to a P75 confidence level to better address project risks to the completion of the work. Previous contingency was based on a P50 confidence level. Management Reserve included in $4.65M budget depleted for actual award and market conditions realized on contracts.

PUB MFR 166
Bipole III

For every contract related to the construction of Bipole III, provide a summary of the forecast contract values underpinning the $4.65 billion Bipole III capital cost, actual expenditures to date, and forecast expenditure at completion. Explain all variances between the forecast contract values and the forecast expenditures at completion.

Public disclosure of the response to this MFR would result in the release of information considered to be confidential and commercially sensitive. As directed by the PUB, Manitoba Hydro will be filing a letter seeking confidential treatment of the information contained in this response pursuant to Rule 13.

The tables below summarize the forecast contract values and construction segment estimates that underpinned the $4.65 billion Bipole III capital cost (previously approved Capital Project Justification Addendum), actual expenditures to date and forecast at completion.

The forecast expenditures at completion include contingency amounts designated in the control budget to address unforeseen risks that have not yet materialized (or been issued to the contractors). Forecast contract values in CEF14 do not include any allocations made from the control budget contingency.

Table 1 provides a summary for the Transmission and Collector Lines and Table 2 for the Converter Stations.

Table 1. Summary for the Bipole III Transmission & Collector Lines

Summary of Forecasted Contract Values
for the Bipole III Transmission & Collector Lines
As of April 30, 2017
(in millions of dollars)

Construction Segment and Material Costs	Forecast Value (CEF14)
N1 Construction	[redacted]
N2 Construction	
N3 Construction	
N4 Construction	
C2 Construction	
S1 & S2 Construction	
C1 Construction	
Material	
Collector Line Construction	

Contract Description & Vendor	Actual Costs to April 30, 2017	Forecast Expenditures at Completion
Clearing / Foundation & Anchor - Hugh Munro Construction Ltd.	[redacted]	
Foundation & Anchor - Valard Construction (Manitoba) Ltd.		
Clearing - Iron North/Interlake Power		
Clearing - Muskeko Joint Venture		
Foundations - Interlake Power		
Foundations -Muskeko Joint Venture		
Clearing - Metis N4 Joint Venture*		
Clearing - Metis N4 Construction Inc.		
Foundation & Anchor - Muskeko Joint Venture		
Clearing - Pine Creek First Nation Joint Venture		
Foundation & Anchor - Metis N4 Interlake Power Joint Venture		
Clearing - Westside/Sawridge Joint Venture		
Foundation & Anchor - Tri-Core Projects Manitoba Ltd.		
Clearing - Swan Lake First Nation Joint Venture		
All Construction Activities - Forbes Bros Ltd.		
All Construction Activities - Rokstad Power Corporation		
Tower Supply - Jyoti*		
Tower Supply - Locweld Inc.		
Tower Supply - SA-RA Enerji		
Tower Supply - SAE Towers Ltd.		
Conductor Supply - Southwire Canada		
All Construction - Iron North/Interlake Power Joint Venture		

The estimating strategy in CEF14 for the Transmission and Collector Lines was based on construction segments and type of work. Actual contracts were awarded across multiple segments and in combination of types of work. As a result, a direct comparison of the estimate to the forecast at completion and variance analysis by contract is not possible for this component of the Bipole III Project. It should be noted that the forecast at complete estimates above were provisioned for in the last approved CPJA 08 (2016).

Table 2. Summary for the Bipole III Converter Stations

Summary of Forecasted Contract Values for the Bipole III Converter Stations
As of April 30, 2017
(in millions of dollars)

Contract Description & Vendor	Forecast Contract Value (CEF14)	Actual Costs to April 30, 2017	Forecast Expenditures at Completion
BPIII CS Owner's Engineer Phase II-V - Teshmont Consultants	[redacted]		
BPIII KCS Lagoon Construction - Sigfusson Northern			
Riel Expansion Electrical & Overhead Construction - Valard			
HVDC Converter Equipment - Siemens & Mortenson			
Keewatinohk 230kV AC Switchyard - SNC-Lavalin			
Keewatinohk Auxiliary & Process Buildings - PCL			
Keewatinohk Pre engineered Buildings - PCL			
Keewatinohk Camp Construction - Outland Camps			
Keewatinohk Camp Operations Services - Fox Lake & Sedexo			
Keewatinohk Electrode - Fox Lake & Newton Mechanical			
Keewatinohk Site Development - Sigfusson Northern			
Manufacturing and Delivery of Standard Dorms - Maple Leaf Home			
Protection, Control and Metering System - Schneider Electric			
Synchronous Condensers - Voith Hydro & Stuart Olson			
[redacted]			

[redacted]

[redacted]

PUB MFR 167
Bipole III

Provide a summary of the Bipole III contingency, management reserve, and escalation reserve original budget, draw-down, remaining, and allocated amounts. Provide details of the draw-down and allocation amounts by indicating to which contract they are assigned and for what purpose.

Public disclosure of the response to this MFR (or portions thereof) would result in the release of information considered to be confidential and commercially sensitive. As directed by the PUB, Manitoba Hydro will be filing a letter seeking confidential treatment of the redacted information contained in this response pursuant to Rule 13.

Table 1. Bipole III Contingency Allocation Schedule

Bipole III Contingency Allocation Schedule as at June 9, 2017 *(in millions of dollars)*					
Item	**Budget**	**Draw Down**	**Remaining**	**Allocated**	**Description of Drawdown**
Converter Stations					
Riel 230 KV Expansion Allocation					
Road & Rail External Infrastructure Allocation					
HVDC Converter Commodity Escalation Allocation					
Keewatinohk BNA Labour Retention Bonus Allocation					
Camp Services Extension Allocation					
Keewatinohk Surveying					
Keewatinohk Site Development					
Keewatinohk Auxiliary & Process Buildings					
Keewatinohk Concrete Batch Plant					
Keewatinohk 230KV AC Switchyard					
Safe Engineering Services					
Keewatinohk Electrode					

Bipole III Contingency Allocation Schedule
as at June 9, 2017
(in millions of dollars)

Item	Budget	Draw Down	Remaining	Allocated	Description of Drawdown
Keewatinohk Camp Operations Services					
Manufacturing & Delivery of Stnd Dorms					
Keewatinohk Pre-engineered Buildings					
Synchronous Condensers					
Electrode Design Consulting					
HVDC Converter Equipment					
Riel Expansion Electrical					
Other Allocated Contract Contingency Amounts					
Unallocated Contingency					
Total Converter Stations					

Transmission Line

Forbes					
Rokstad					
Relationship management & agreements					
Material and A&F Contingency					
Biosecurity / acceleration / route change					
Other Allocated Contingency Items					

Bipole III Contingency Allocation Schedule as at June 9, 2017 *(in millions of dollars)*					
Item	**Budget**	**Draw Down**	**Remaining**	**Allocated**	**Description of Drawdown**
Bipole III T/L Unallocated Contingency	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Transmission Line	[redacted]	[redacted]	[redacted]	[redacted]	
Collector Lines					
Riel R49R Sectionalization	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
AC Collector Lines	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Long Spruce Cable & Station Modification	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Henday Station Modification	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Keewatinohk Electrode Line	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Riel Electrode Line	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Breaker Replacements	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Limestone to KCP U/G Fibre	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Unallocated Contingency	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Collector Lines	[redacted]	[redacted]	[redacted]	[redacted]	

PUB MFR 168
Bipole III

Provide details and justification for any revised contingency, escalation, and interest amounts included in the revised $5 billion Bipole III project cost. Provide contingency and reserve amounts for P50, P90, and P95 probability levels.

Public disclosure of the response to this MFR (or portions thereof) would result in the release of information considered to be confidential and commercially sensitive. As directed by the PUB, Manitoba Hydro will be filing a letter seeking confidential treatment of the redacted information contained in this response pursuant to Rule 13.

The $536 million of contingency included in the revised $5.04B Bipole III project cost was established based on a 2014 contingency analysis with an updated review of the project risks. The revised estimate incorporates an increase in contingency levels to a P75 confidence level to better address project risks to the completion of the work. The 2014 estimate was based on P50 confidence level. As more than 90% of the projects contracts had been awarded since the 2014 estimate, the new evaluation also incorporated a majority of the project's contract costs and scope updates.

Figure 1. Bipole III P75 Contingency Breakdown

Bipole III Project P75 Contingency Break-down *(billions of dollars)*	
Base Contingency	0.509
Interest & Escalation	0.027
Total Contingency	0.536

Total contingency addresses potential cost and schedule risks still present in the project such as:

- weather-related schedule remediation costs;
- transmission line route alteration costs;
- additional infrastructure upgrade commitments (e.g. roads, etc.);
- commodity escalation;

- biosecurity measures;
- helicopter erection and stringing; and
- Contract claims and close-out costs.

Interest and escalation were updated based on the revised base contingency cash flow, updated Interest Capitalization Rates and escalation rates for the Corporation.

The management reserve included in the previous estimates was based on uncertainty in transmission line construction pricing. As those contracts have now been awarded and the management reserve expended, it was determined that there was no further requirement to include a management reserve.

The contingency amounts for the P50, P75, P90 and P95 probability levels are summarized in **Figure 2**.

Figure 2. Bipole III Contingency Summary - 2016 Estimate

Bipole III Project
Contingency Summary - 2016 Estimate
(in billions of dollars, excluding Interest & Escalation)

Probability Levels	**P50**	**P75**	**P90**	**P95**
Contingency	0.279	0.509	[redacted]	[redacted]

PUB MFR 169
Bipole III

a) **If Manitoba Hydro developed one, provide the risk registry for the Bipole III Project detailing the risks to the Bipole III project and Manitoba Hydro's mitigation actions.**
b) **Identify and explain whether any of the risks in the registry with an impact score of Very High have materialized, how Manitoba Hydro addressed the risks, and what the impact of the risk has been and is expected to be on the total project cost and project schedule.**
c) **Identify whether any of the risks in the registry with impact scores other than Very High have materialized but which have had a financial impact of greater than $20 million or a schedule impact of greater than 6 months. Explain how Manitoba Hydro attempted to mitigate the risks, and what Manitoba Hydro has done or continues to do to manage the impact of the risk.**

Public disclosure of the attachment to this response would result in the release of information considered to be confidential and commercially sensitive. As directed by the PUB, Manitoba Hydro will be filing a letter seeking confidential treatment of the information contained in the attachment to this response pursuant to Rule 13.

a) Manitoba Hydro has developed and maintained a risk registry for the Bipole III Project for each of the key project elements. The key project elements are identified as follows:
    i. Converter Stations
    ii. Transmission Line
    iii. Collector Lines

    The risk registries for each element are included in the attachment to this response, which is confidential in its entirety.

    Attachment 1 outlines all risks that are presently open or that have transitioned to active issues (i.e. realized risks that are actively being managed). Risks that are not included are closed (either not realized and no longer open, or were realized but have been resolved and closed out). However, all risks including those now closed

were considered for reporting purposes under the parameters of parts b) and c) below, of which none that were closed were found to qualify.

b) Table 1. Bipole III Project Very High Risks Realized

Section	**Materialized Very High Risk**	**Mitigation Undertaken**	**Impact to Project Costs** >$300M Threshold	**Impact to Project Schedule** >1 Year Threshold
Converter Stations	None			
Transmission Line	None			
Collector Lines	None			

c) Table 2. Bipole III Project Risks Realized > $20 million or Schedule > 6 months

	Materialized Risk	**Mitigation Undertaken**	**Impact to Project Costs**	**Impact to Project Schedule**
Converter Stations	Unforeseen geotechnical conditions in the HDVC Converter area & obstructions encountered during the installation of the AC switchyard area at Keewatinohk Converter Station led to the changes to the pile foundation designs on HVDC and	For HVDC, detailed geotechnical analysis and design reviews were completed and the piles were redesigned and successfully installed. For the AC switchyard, additional drilling and excavation was implemented to ensure successful	A potential impact of up to $23 million due to contractor claims for unforeseen ground conditions and the resulting costs/measures taken to ensure successful installation of compliant foundations	Mitigated

	additional installation measures on the AC switchyard to ensure technically compliant foundations war installed	installation of the piles		
Transmission Line	None			
Collector Lines	None			

PUB MFR 186
GNTL

Provide the Capital Project Justification for the GNTL and any addenda.

Public disclosure of the response to this MFR (or portions thereof) would result in the release of information considered to be confidential and commercially sensitive. As directed by the PUB, Manitoba Hydro will be filing a letter seeking confidential treatment of the redacted information contained in the attachment to this response pursuant to Rule 13.

Please refer to the attached CPJ for the Great Northern Transmission Line Project.

ROUTING SLIP FOR APPROVAL OF A

CPJ or CPJ ADDENDUM for a MAJOR item

FINANCE CONTACT: Kyle Ibbetson

DATE: August 16, 2016

PROJECT/COMPLEX NAME: Great Northern Transmission Line Project

PROJECT/COMPLEX - I.M. NODE NUMBER:	*WBS NUMBER(S):*
1.3.1.1.1.36	P-21491

OWNING DIVISION FOR PROJECT/COMPLEX: Power Sales & Operations

COORDINATING DIVISION FOR PROJECT/COMPLEX: Power Sales & Operations

INSTRUCTIONS:

1) Review attached CPJ and associated CER(s) belonging to this project and/or complex and follow the ADDITIONAL INSTRUCTIONS, if applicable.

If you wish to request changes:

2a) Circle YES under the CHANGES REQUIRED column next to your name and enter a description of the change(s) in the space provided below.

2b) Return the document/package immediately to the person listed next to the red "Return document/package to:" below.

If you wish to indicate your approval of the Project/Complex:

2a) Circle NO under the CHANGES REQUIRED column and follow the ADDITIONAL INSTRUCTIONS, if applicable.

2) *Forward the document/package to the next person on the list.*

	CHANGES REQUIRED?	SIGNATURE	ADDITIONAL INSTRUCTIONS	
Reviewed by Project Manager 1 Scott Sage	YES / NO		*CPJ:* INITIAL the title page, 'Prepared By:'	*CER(s):* INITIAL 'Prepared by'
Reviewed by Coordinating Section Head 2	YES / NO		*CPJ:* INITIAL the title page: Coordinating Division	*CER(s):* not applicable
Reviewed by Coordinating Manager. 3	YES / NO		*CPJ:* INITIAL the title page: Coordinating Division	*CER(s):* not applicable
Reviewed by Owning Manager: 4 Daryl Maxwell	YES / NO	[signature] 2016 08 18	*CPJ:* SIGN and DATE the title page, Owning Dept Manager	*CER(s):* Initial Owning Division box
Approved by Coordinating Division Manager: 5	YES / NO		*CPJ:* SIGN and DATE the title page, Coordinating Division Manager	*CER(s):* SIGN and DATE the Coordinating Division box
Approved by Owning Division Manager: 6 David Cormie	YES / (NO)	[signature]	*CPJ:* SIGN and DATE the title page, Owning Division Manager	*CER(s):* Sign and Date the Owning Division box
Finance: 7 Kyle Ibbetson	YES / NO		*CPJ:* SIGN and DATE the title page, Financial Department	*CER(s):* not applicable

Return document/package to: Kyle Ibbetson

COMMENTS:

Please remember to also approve the MC-04 Copperleaf workflow to provide online tracking of the CPJ.

Please pass this folder on to the next person on the list above.

continue on reverse if necessary

These documents are time-sensitive. Your soonest attention would be appreciated.

D1878(A)

CAPITAL PROJECT JUSTIFICATION ADDENDUM FOR

Great Northern Transmission Line Project

Addendum Number 1

REVIEWED BY:
(Requesting Dept Manager) 2016 08 18

NOTED BY:
(if applicable)
Responsible Division: 2016 08 19

Constructing Division:

Financial Department:
(if over $1 million) 2016/08/18

RECOMMENDED FOR IMPLEMENTATION:
Requesting Div. Manager: David Cormie

Business Unit V.P.: Lorne Midford 2016 08 19

PREV. APPROVED BUDGET $: (Use $ value from approved CPJ or last approved CPJ Addendum)	$541,615,000
REVISED BUDGET $: (Total Net Cost)	[redacted]
START DATE: (1st Cost Flow)	2012 12
PREV. APPROVED ISD: (Use In-service Date from approved CPJ or last approved CPJ Addendum)	2020 06
REVISED ISD: (Last Major In-service Date)	2020 06
RISK MATRIX/ BUSINESS CASE TIER: (Optional)	
INVESTMENT REASONS: (Optional)	

PRIMARY JUSTIFICATION:
Indicate key project driver(s):

- ☐ Safety
- ☐ System Supply
- ☐ System Reliability
- ☒ Customer Service
- ☐ Efficiency
- ☐ Environmental

NERC COMPLIANCE*: ☐ YES ☒ NO

*Determine if the project requires compliance with North American Electric Reliability Corporation (NERC) CIP Cyber Security Standards.

REQUESTING DIVISION:	Power Sales and Operations
LM. NODE NUMBER:	1.3.1.1.1.36
W.B.S. NUMBERs:	P:21491
MAJOR ITEM ☒	**DOMESTIC ITEM** ☐
PREPARED BY:	Kyle Ibbetson
DATE PREPARED:	2016 08 10
REPORT NUMBER:	
FILE NUMBER (Optional):	

ADDENDUM NUMBER	DATE (yyyy mm dd)	REVISION	REVISED BY	APPROVED BY
1	2016 08 10	Increased project budget [redacted]	Kyle Ibbetson	

MANITOBA HYDRO
CAPITAL PROJECT JUSTIFICATION ADDENDUM

Project Name (This section is required for all Addendums).

Great Northern Transmission Line Project

Recommendation (This section is required for all Addendums).

To increase the Great Northern Transmission Line's (GNTL) total project budget by [redacted] $CDN to a total of [redacted] $CDN.

Project Scope (This section is be filled out only if there is a change to the scope).

Manitoba Hydro (MH) and Minnesota Power (MP) entered into a 250 MW System Power Sale and an Energy Exchange Agreement on May 19, 2011 to provide for the export of 250 MW of capacity and energy and to provide MH the ability to import up to 250 MW of energy. The Power Sale Agreements require MP to construct a 230 kV transmission line in the U.S. in order provide for the delivery of power commencing June 1, 2020 and that by mutual agreement MH and MP may increase the transfer capability and enter additional agreements with other persons for the new US transmission line.

As part of MH's Preferred Development Plan, MH has been negotiating additional sales with Wisconsin Public Service, or WPS, and others that will be dependent upon the construction of a new hydraulic generation and additional transmission capacity beyond that possible from the 230 kV line MP is required to construct. A new 500 kV line is expected to increase firm southbound transmission capacity by 883 MW and firm northbound by 698 MW..

The following lists the significant activities/items where changes have occurred from the initial GNTL estimate to the budget for MH subsidiary (6690271 Manitoba Ltd.) portion of the Facilities Construction Agreement (FCA):

Subsidiary 6690271 54% portion of increased costs
[redacted]

Capital Project Justification Addendum

Background (This section is be filled out only if there is information relevant to the recommendation).

6690271 Manitoba Ltd. is a Manitoba Incorportated company that is 100% owned by Manitoba Hydro.

6690271 Manitoba Ltd., Minnesota Power and the Midcontinent Independent System Operator Inc. executed a FCA in which MP and 6690271 Manitoba Ltd. agreed as Transmission Line Payers to pay their allocated portion (MP - 46%, 6690271 Manitoba Ltd. - 54%) of the certification and construction costs of the GNTL project.

The FCA contained an initial estimate of $676.9 million (2013US$), excluding interest and escalation, for the GNTL project based on preliminary engineering, a proxy route and typical construction costs for the transmission line and associated substation facilities. In addition, the FCA requires the capital estimate to be revised upon approval of the route permit by the Minnesota Public Utilities Commission (MPUC).

Pursuant to the FCA, 6690271 Manitoba Ltd. and MP are also parties to a Construction Management Agreement (CMA) dated April 12, 2016 that appointed MP as the Construction Manager for the GNTL project. The CMA requires the Construction Manager to prepare a pre-construction estimated project budget (budget) for review and approval by the Management Committee appointed pursuant to the CMA.

On April 11, 2016, the Minnesota Public Utilities Commission granted Minnesota Power (MP) a route permit for the GNTL. Pursuant to the Construction Management Agreement, the Construction Manager has now prepared and recommended for approval by the Management Committee a budget of [redacted], excluding capitalized interest and escalation costs. This budget represents an increase of [redacted] from the initial FCA estimate to reflect escalation from 2013US$ to 2016US$, and adjustments for the approved GNTL route and additional engineering, design and construction details that have been since developed by the Construction Manager. 6690271 Manitoba Ltd.'s portion (54%) of the budget equates to [redacted]

Justification (This section is required for all addendums).

Acceptance of this revised capital estimate is justified as it is the best estimate of the cost to construct the GNTL as it reflects the final approved route and associated additional engineering, design and construction details that have been developed by the Construction Manager. The previous estimate included in the FCA was based on preliminary engineering, a proxy route and typical construction costs for the transmission line and associated substation facilities.

Approval of the budget of [redacted] will align with MP's estimate to ensure consistency between the parties with respect to any public disclosures.

MP has indicated that they consider the budget as a "not to exceed" estimate and that there is a high likelihood that the project's actual cost will be lower.

A new 500kV transmission line to the US is justified as follows:

- It is an integral part of MH's Development Plan.
- The Needs For and Alteratives To (NFAT) report to the Province of Manitoba recommended that MH proceed with the 500 kV US transmission project and the government subsequently accepted the recommendation

ANALYSIS OF ALTERNATIVES: (This section is be filled out only if there is a change to which alternative is being recommended).

Economic Analysis		
Discount Rate	% For current corporate rates see G911	For clarification on hurdle rates, contact Economic Analysis Department

Recommended Option	NPV Benefits/(Costs)
N/A	

Other Alternatives Considered	NPV Benefits/(Costs)

Risk Analysis – (This section is be filled out only if there is a change to the project risk).

As with any construction estimate, actual project costs will differ from the estimate as final engineering, design and construction details are not yet complete, no construction contracts have been signed and the project is still four years from in-service.

Total Budget – (This section is required for all Addendums).

The impact on annual budget requirements is as follows (in thousands of dollars):

Fiscal Year	Prev. Approved CPJ/Addendum	Proposed CPJ Addendum	Increase (Decrease)
Prev. Actuals	$ 33,128	$ [redacted]	$ [redacted]
2016/17	$ 59,455	$ [redacted]	$ [redacted]
2017/18	$ 121,800	$ [redacted]	$ [redacted]
2018/19	$ 182,384	$ [redacted]	$ [redacted]
2019/20+	$ 144,848	$ [redacted]	$ [redacted]
Total	$ 541,615	$ [redacted]	$ [redacted]

Proposed Schedule (This section is be filled out only if there is a change to the project schedule).

Related Projects (This section is be filled out only if changed).

Capital Project Justification Addendum

Reference Documents (This section is be filled out only if changed).

PUB MFR 187
GNTL

Provide updates to NFAT Exhibits Manitoba Hydro-139 (items 1-4) and Manitoba Hydro-168 related to the GNTL capital and operating cost responsibilities of Manitoba Hydro and Minnesota Power.

Public disclosure of the response to this MFR (or portions thereof) would result in the release of information considered to be confidential and commercially sensitive. As directed by the PUB, Manitoba Hydro will be filing a letter seeking confidential treatment of the redacted information contained in this response pursuant to Rule 13.

Table 1A below provides a summary of 6690271 Manitoba Ltd funding responsibilities for the capital expenditures to develop and construct the Great Northern Transmission Line (US portion of the new 500 kV transmission interconnection) which were utilized in preparing IFF16.

Table 1A

	GNTL – Investment Distribution		
Row #	Description	% of Capital Investment	Comments
1	MP 250MW of 883MW	28.3%	Per Multi-Party Facilities Construction Agreement
2	MP Additional Capital Investment	17.7%	
3	6690271 MB Ltd. Capital Investment	54.0%	
4	Total	100%	

Row # 1 represents MP's investment in transmission associated with the 250MW System Power Sale Agreement with Manitoba Hydro (250 MW / 883 MW = 28.3%).

Row # 2 represents MP's additional investment opportunity in the Great Northern Transmission Line.

Row #3 represents 6690271 Manitoba Ltd's investment in the Great Northern Transmission Line for the residual.

Table 1B below provides a summary of Manitoba Hydro's and 6690271 Manitoba Ltd's funding responsibilities for post in-service costs which were included in preparing IFF 16.

Table 1B

	GNTL Post In-Service Cash Flows		
Row #	Description	% of Operating & Maintenance Costs	Comments
1	MP 250MW	33.3%	Per Multi-Party Facilities Construction Agreement
2	Manitoba Hydro - MP Revenue Requirement	17.7%	
3	6690271 MB Ltd.	49.0%	
	Total	100.0%	

Row #1 represents MP's responsibility for post in-service costs associated with the 250 MW System Power Sale Agreement with Manitoba Hydro that is based on the original expected southbound firm transmission capacity of the GNTL (250 MW / 750 MW = 33.3%).

Row #2 represents Manitoba Hydro's reimbursement of the annual revenue requirement for Minnesota Power's additional 17.7% capital investment and 17.7% of forty years' worth of expected Great Northern Transmission Line operating costs over a 20 year period.

Row #3 represents 6690271 Manitoba Ltd's responsibility to fund 49% of forty years' worth of expected Great Northern Transmission Line operating costs over a 20 year period.

Table 2 below provides Manitoba Hydro's Post In-service Costs with respect to the GNTL.

Table 2

Row #	Description	2016 CND $'s (millions)	Comments
1	Manitoba Hydro - MP Revenue Requirement	$472	Associated with Row #2 in Table #1B
2	6690271 MB Ltd	$315	Associated with Row #3 in Table#1B
	Total	$787	

Table 3 provides Manitoba Hydro's Combined Capital and Post In-Service Costs with respect to the GNTL.

Table 3

Row #	Description	2016 CND $'s (millions)	Comments
1	6690271 MB Ltd. Capital Investment	[redacted]	Associated with Row #3 in Table #1A
2	Manitoba Hydro –MP Revenue Requirement	$472	Per Row 1 in Table #2
3	6690271 MB Ltd	$315	Per Row #2 in Table #2
4	Total Post In-Service Costs = Row 2 + Row 3	$787	

Table 4 provides a Reconciliation of Capital Costs for the GNTL.

Table 4

Row #	Capital Costs	Reference Dollar Year	(Millions of $)
1	Base Estimate (Per NFAT Exhibit #139 Table #4)	2012	$633 USD
2	Escalation & Budget Revision	2016	[redacted]
3	GNTL Project Budget per Construction Management Agreement	2016	[redacted]
4	6690271 MB Ltd Portion (54%)	2016	[redacted]
5	Row 4 Converted to CND $	2016	[redacted] CDN
6	6690271 MB Ltd Internal Costs	2016	$20 CDN
7 (Rows 5+6)	6690271 MB Ltd Capital Cost	2016	[redacted] CDN

PUB MFR 188
GNTL

Provide the GNTL facilities construction agreement between Manitoba Hydro or its subsidiary and Minnesota Power.

Public disclosure of the response to this MFR (or portions thereof) would result in the release of information considered to be confidential and commercially sensitive. As directed by the PUB, Manitoba Hydro will be filing a letter seeking confidential treatment of the redacted information contained in the attachment to this response pursuant to Rule 13.

Please refer to the attached Multi-Party Facilities Construction Agreement for the GNTL. Exhibit A1 "Overall CUU One Line Diagram" on Original Sheet No. 71 has been removed as it is confidential.

Original Sheet No. 1

MULTI-PARTY

FACILITIES CONSTRUCTION AGREEMENT

entered into among:

Midcontinent Independent System Operator, Inc.,

and

Minnesota Power, an operating division of ALLETE, Inc.,

and

6690271 Manitoba Ltd.,
and

Minnesota Power, an operating division of ALLETE, Inc.

on the 25 day of September, 2014

THIS MULTI-PARTY FACILITIES CONSTRUCTION AGREEMENT (sometimes hereinafter referred to as the "Agreement") is made and entered into this 25 day of September, 2014, among:

Midcontinent Independent System Operator, Inc.,
(a non-profit, non-stock corporation organized and existing under the laws of the State of Delaware sometimes hereinafter referred to as the "**Transmission Provider** or **"MISO"**),

and

Minnesota Power, an operating division of ALLETE, Inc.,
(a Minnesota corporation sometimes referred to as "**MPM**"),

and

6690271 Manitoba Ltd, a wholly owned subsidiary of Manitoba Hydro
(a Manitoba corporation sometimes referred to as "**6690271**"),

and

Minnesota Power, an operating division of ALLETE, Inc.,
(a Minnesota corporation sometimes referred to as "**MP**"),

(6690271 and MPM may be collectively referred to as the "**Transmission Line Payers**" or individually as a "**Transmission Line Payer**", MP and 6690271 may be collectively referred to as the "**CUU Transmission Owners**" or individually as a "**CUU Transmission Owner**" and the Transmission Line Payers, the CUU Transmission Owners and the Transmission Provider each may be individually referred to as a "**Party**" or collectively as the "**Parties**.")

RECITALS

WHEREAS, Minnesota Power, an operating division of ALLETE, Inc. is the owner and operator of electric generation and transmission facilities in the United States and is engaged in generation, transmission, distribution, and/or sale of electric power and energy;

WHEREAS, when MPM is referred to in this Agreement it refers to the obligations being entered pursuant to this Agreement on behalf of Minnesota Power, an operating division of ALLETE, Inc.'s marketing and sales functions;

WHEREAS, when MP is referred to in this Agreement it refers to the obligations being entered into pursuant to this Agreement on behalf Minnesota Power, an operating division of ALLETE, Inc.'s transmission functions;

WHEREAS, The Manitoba Hydro-Electric Board ("**MH**") is the owner and operator of electric generation and transmission facilities in Canada and is engaged in generation, transmission, distribution, and/or sale of electric power and energy;

WHEREAS, 6690271 is a wholly owned subsidiary of MH;

WHEREAS, Wisconsin Public Service Corporation ("**WPSM**") is the owner and operator of electric generation facilities in the United States and is engaged in generation, distribution, and/or sale of electric power and energy;

WHEREAS, when WPSM is referred to in this Agreement it refers to Wisconsin Public Service Corporation's marketing and sales functions;

WHEREAS, MH's marketing and sales division ("**MHEM**") has filed transmission service requests pursuant to Reservation Request Numbers 79429002, 79258492, 79258646, and 79258668 for north bound service totaling 883 MW;

WHEREAS, WPSM has filed a transmission service request pursuant to Reservation Request Number 79258364 for south bound service totaling 200 MW;

WHEREAS, MPM has filed a transmission service request pursuant to Reservation Request Numbers 76703672 and 79258361 for south bound service totaling 383 MW;

WHEREAS, MHEM has filed transmission service requests pursuant to Reservation Request Number 80142548, 80142558, and 80142561 for south bound service totaling 300 MW;

WHEREAS, MP has functional control of the operations of the Transmission System, as defined herein, and is responsible for providing transmission and transmission service on the transmission facilities under its control;

WHEREAS, MISO has agreed with MPM that upon completion of the Common Use Upgrades that MISO will provide MPM with 250 MW of south bound Firm Transmission Service and 133 MW of south bound Firm Transmission Service in accordance with Service Agreements entered into by MISO and MPM on the Effective Date;

WHEREAS, MISO has agreed with WPSM that upon completion of the Common Use Upgrades that MISO will provide WPSM with 200 MW of south bound Firm Transmission Service in accordance with the Service Agreement entered into by MISO and WPSM on the Effective Date;

WHEREAS, MISO has agreed with MHEM that upon completion of the Common Use Upgrades that MISO will provide MHEM with 300 MW of southbound Firm Transmission Service in accordance with the Service Agreements entered into by MISO and MHEM on the Effective Date;

WHEREAS, MISO has determined that only 698 MW of northbound Firm Transmission Service will be available upon completion of the Common Use Upgrades and MISO has agreed with MHEM that upon completion of the Common Use Upgrades that MISO will provide MHEM with a total of 698 MW of northbound Firm Transmission Service in accordance with Service Agreements entered into by MISO and MHEM on the Effective Date;

WHEREAS, MPM, WPSM and MHEM in their capacity as the entities that will receive Firm Transmission Service may be collectively referred to as the "**CUU Transmission Customers**" or individually as a "**CUU Transmission Customer**");

WHEREAS, as set out in Table 2 of Appendix A each Transmission Line Payer has agreed to accept the financial responsibility for payment of the allocated cost of the Common Use Upgrades for the CUU Transmission Customers' transmission service requests that are identified in Table 2(A) and Table 2(B) for that Transmission Line Payer (the "**Transmission Line Payers Associated TSR**");

WHEREAS, the Parties acknowledge that if a Transmission Line Payer defaults under the provisions of this Agreement and its participation in this Agreement is terminated in accordance with the provisions of this Agreement, the Transmission Line Payers Associated TSR will also be withdrawn and the applicable CUU Transmission Customer will not be entitled to receive its respective Firm Transmission Service;

WHEREAS, MP and 6690271 have jointly agreed to design, own and construct the Common Use Upgrades as tenants in common;

WHEREAS, the CUU Transmission Owners as of the In-Service Date will be MISO Transmission Owners; and

WHEREAS, the Transmission Line Payers have requested, and the Transmission Provider and CUU Transmission Owners have agreed, to enter into this Agreement with the Transmission Line Payers for the purpose of facilitating construction of the CUU and to enable the Transmission Provider to provide WPSM, MPM and MHEM, as CUU Transmission Customers, with the Firm Transmission Service referred to herein for such CUU Transmission Customer.

NOW, **THEREFORE,** in consideration of and subject to the mutual covenants contained herein, it is agreed:

ARTICLE 1

DEFINITIONS

Wherever used in this Agreement with initial capitalization, the following terms shall have the meanings specified or referred to in this Article 1. Terms used in this Agreement with initial capitalization not defined in this Article 1 shall have the meanings specified in the Tariff:

1.1 "**Applicable Laws and Regulations**" shall mean all duly promulgated applicable federal, state, and local laws, regulations, rules, ordinances, codes, decrees, judgments, directives, or judicial or administrative orders, permits, and other duly authorized actions of any Governmental Authority having jurisdiction over the Parties, their respective facilities, and/or the respective services they provide.

1.2 "**Applicable Reliability Council**" shall mean the reliability council of NERC applicable to the Local Balancing Authority of the Transmission System in which the CUU is located.

1.3 "**Breach**" shall mean the failure of a Party to perform or observe any material term or condition of this Agreement and shall include, but not be limited to, the events described in Article 9.1.

1.4 "**Breaching Party**" shall mean a Party that is in Breach of this Agreement.

1.5 "**Common Use Upgrades**" or "**CUU**" shall collectively mean all of the Transmission Facility, Network Upgrade, System Protection Facility, or any other classified additions, alterations, or improvements on the Transmission System of MP and on the Transmission Systems of the other Transmission Owners identified in Table 1 of Appendix A (not classified under Attachment FF as a Baseline Reliability Project, Market Efficiency Project, or Multi-Value Project) that are needed to accommodate MHEM's Reservation Request Numbers, 79258492, 79258646, 79258668 (partial service) and 79429002 for 698 MW of north bound service and 80142548, 80142558, and 80142561 for 300 MW of south bound service, WPSM's Reservation Request Number 79258364 for 200 MW of south bound service, MPM's Reservation Request Numbers 76703672 and 79258361 for 383 MW of south bound service as more particularly set out in Appendix A (the Transmission Service Requests are collectively referred to as the "**Transmission Customers' TSRs**" and individually as the "**Transmission Customer's TSR**").

1.6 "**Confidential Information**" shall mean any proprietary or commercially or competitively sensitive information, trade secret, or information regarding a plan, specification, pattern, procedure, design, device, list, concept, policy, or compilation relating to the present or planned business of a Party, or any other information as specified in Article 12, which is designated as confidential by the Party supplying the information, whether conveyed orally, electronically, in writing, through inspection, or otherwise, that is received by another Party.

1.7 "**Default**" shall mean the failure of a Breaching Party to cure its Breach in accordance with Article 9 of this Agreement.

1.8 "**Effective Date**" shall have the meaning set forth in Section 2.1.

1.9 "**Executive Officer**" shall mean such officer designated by each Party from time to time.

1.10 "**FERC**" shall mean the Federal Energy Regulatory Commission, also known as the "Commission," or its successor.

1.11 "**Firm Transmission Service**" shall mean firm Point-To-Point Transmission Service provided under Module B of the Tariff and firm Network Integration Transmission Service under Module B of the Tariff and shall include all rights conveyed to the Transmission Customer, including but not limited to energy and capacity market congestion rights, as defined in the Tariff.

1.12 "**Force Majeure**" shall mean an event or circumstance that prevents or delays one Party from performing its obligations under this Agreement and that is not within the reasonable control of, nor the result of the negligence of, the claiming Party, and that, by the exercise of Good Utility Practice, the claiming Party is unable to overcome or avoid or cause to be avoided, including but not restricted to, acts of God, floods, droughts, earthquakes, storms, fires, lightning, tornados, strikes, lockouts and other labor disturbances, epidemics, pandemic, war (whether or not declared), blockades, acts of public enemies, acts of sabotage or terrorism, civil insurrection, riots or civil disobedience, any situation where delivery or acceptance will endanger a Party's facilities or endanger that Party's system operations, explosions, acts or omissions of any Governmental Authority taken on or after the Effective Date, (including the adoption or change in any law or regulation or environmental constraints lawfully imposed by such Governmental Authority) but only if, and to the extent that, such action or inaction by such Governmental Authority prevents or delays performance and/or renders the Party unable, despite due diligence, to obtain any license, permit, or approval required by any Governmental Authority, and the issuance of any order, injunction, or other legal or equitable decree to the extent that any of the foregoing prevents or delays the performance of a Party's obligations hereunder. A Force Majeure event does not include intentional wrongdoing by the Party claiming Force Majeure.

1.13 "**Good Utility Practice**" shall mean any of the practices, methods, and acts engaged in or approved by a significant portion of the electric industry during the relevant time period, or any of the practices, methods, and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business

practices, reliability, safety, and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region.

1.14 "**Governmental Authority**" shall mean any federal, state, local, or other governmental, regulatory, or administrative agency, court, commission, department, board, or other governmental subdivision, legislature, rulemaking board, tribunal, or other governmental authority having jurisdiction over the Parties, their respective facilities, or the respective services they provide, and exercising or entitled to exercise any administrative, executive, or taxing authority or power; provided, however, that such term does not include any Transmission Line Payer, any Transmission Provider, any CUU Transmission Owner, any CUU Transmission Customer, or any Affiliate thereof.

1.15 "**In-Service Date**" shall mean the date that the 500 kV Line that is a component of the CUU is commissioned and comes into service, presently scheduled to be June 1, 2020.

1.16 "**Local Balancing Authority**" shall mean an operational entity or a Joint Registration Organization which is (i) responsible for compliance with the subset of NERC Balancing Authority Reliability Standards defined in the Balancing Authority Agreement for their local area within the Transmission Provider Balancing Authority Area, (ii) a Party to Balancing Authority Agreement, excluding MISO, and (iii) shown in Appendix A to the Balancing Authority Agreement.

1.17 "**Loss**" shall mean any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demands, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from the other Party's performance, or non-performance of its obligations under this Agreement on behalf of the indemnifying Party, except in cases of gross negligence or intentional wrongdoing, by the indemnified Party.

1.18 "**NERC**" shall mean the North American Electric Reliability Corporation, or its successor organization.

1.19 "**Non-Breaching Party**" shall mean a Party that is not in Breach of this Agreement with regard to a specific event of Breach by a Party and "Non-Breaching Parties" shall mean all of the Parties that are not in Breach of this Agreement with regard to a specific event of Breach by a Party.

1.20 "**Northbound Transmission Service**" shall mean any transmission service the Transmission Provider will grant contingent on construction of the CUU which is to be

utilized for the delivery of energy from within the Transmission Provider region to the interface between MH and the Transmission Provider region.

1.21 "**Reasonable Efforts**" shall have the meaning as provided in the Tariff.

1.22 "**Tariff**" shall mean the Transmission Provider's Tariff through which open access transmission service and Interconnection Service are offered, as filed with the Commission, and as amended or supplemented from time to time, or any successor tariff.

1.23 "**Total Transmission Service Capacity**" means the total of the capacities associated with all transmission service to be granted by the Transmission Provider contingent on the construction of the CUU.

1.24 "**Transmission System**" shall mean the facilities owned by MP and controlled or operated by Transmission Provider or MP that are used to provide Transmission Service or Wholesale Distribution Service under the Tariff.

ARTICLE 2
TERM OF AGREEMENT

2.1 **Effective Date.** This Agreement shall become effective on the date on which this Agreement is made and entered into by the Parties (the "**Effective Date**").

2.2 **Term.**

2.2.1 **General.** This Agreement shall become effective as provided in Article 2.1 and shall continue in full force and effect until the earlier of (i) the design, procurement, construction, and installation of the Common Use Upgrades; (ii) the Parties agree to mutually terminate this Agreement; (iii) earlier termination as permitted or provided for under Appendix A of this Agreement; and (iv) Transmission Line Payers have mutually agreed to terminate this Agreement after providing Transmission Provider and CUU Transmission Owners with written notice at least sixty (60) Calendar Days prior to the proposed termination date, provided that all of the Transmission Line Payers have no outstanding contractual obligations to Transmission Provider or CUU Transmission Owners under this Agreement as of the termination date. No purported termination of this Agreement shall be effective until the Parties have complied with all Applicable Laws and Regulations applicable to such termination. The term of this Agreement may be adjusted upon mutual agreement of the Parties.

2.2.2 Termination Upon Default. In the event of a Default by a Party, the Non-Breaching Party or Parties shall have the termination and removal rights described in Article 9.2 and in addition, if one or more Transmission Line Payers (but not all) are in Default, the CUU Transmission Owners or the Transmission Provider may terminate the participation of the defaulting Transmission Line Payer(s) without terminating this entire Agreement; provided, however, if an event described in part (a) or (c) of Article 9.1 has not occurred, and provided the Default does not pose a threat to the reliability of the Transmission System, if a Transmission Line Payer is the Breaching Party then neither the Transmission Provider nor the CUU Transmission Owners may terminate the participation of such Transmission Line Payer, if such Transmission Line Payer (i) has undertaken, in accordance with Article 9.2, to cure the Breach that led to the Default and has failed to cure the Breach for reasons other than Transmission Line Payer's failure to diligently commence reasonable and appropriate steps to cure the Breach within the thirty (30) Calendar Days allowed by Article 9.2, and (ii) compensates the Transmission Provider or the CUU Transmission Owners, as applicable, within thirty (30) Calendar Days for the amount of damage billed to such Transmission Line Payer by the Transmission Provider or the CUU Transmission Owners, as applicable, for any damages, including costs and expenses, incurred by the Transmission Provider or the CUU Transmission Owners, as applicable, as a result of such Default. In the event of an occurrence described in part (a) or (c) of Article 9.1**,** and provided the Default does not pose a threat to the reliability of the Transmission System, the Non-Breaching Party or Parties shall not terminate participation of the defaulting Transmission Line Payer(s) provided that the Breaching Party provided an assurance of payment acceptable to the Non-Breaching Party or Non-Breaching Parties, and pays any applicable damages. Notwithstanding the foregoing, Default by one or more Transmission Line Payers shall not provide the other Transmission Line Payers either individually or in concert, with the right to terminate the entire Agreement. The Non-Breaching Parties may, in concert, initiate the removal of a Transmission Line Payer that is a Breaching Party from this Agreement as described in Article 9.2. The Transmission Provider shall not terminate this Agreement or the participation of any Transmission Line Payer without provision being made for the CUU Transmission Owners to be fully reimbursed for all of their costs incurred under this Agreement. The Parties acknowledge that if a Transmission Line Payer defaults under the provisions of this Agreement and its participation in this Agreement is terminated in accordance with the provisions of this Agreement, the Transmission Line Payer's Associated TSR will also be withdrawn and the applicable CUU Transmission Customer will not be entitled to receive the Firm Transmission Service.

2.2.3 Consequences of Termination. In the event of a termination by or of any Party, other than a termination by the Transmission Line Payer(s) due to a Default by the CUU Transmission Owners, each Transmission Line Payer whose participation in this Agreement is terminated must pay to the CUU Transmission Owners the Transmission Line Payer's proportionate share of all amounts still due and payable for construction and installation of the CUU (including, without limitation, any equipment ordered related to such construction), plus all out-of-pocket expenses incurred by the CUU Transmission Owners in connection with the construction and installation of the CUU, through the date of termination and, in the event of the termination of the entire Agreement, any actual costs which the CUU Transmission Owners (A) reasonably incur in winding up work and construction demobilization (including previously incurred capital costs, penalties for early termination, removal and site restoration) and (B) reasonably incur to ensure the safety of persons and property and the integrity and safe and reliable operation of the Transmission System.

The Parties acknowledge that this Article 2.2.3 and such payments do not restrict the right of any Non-Breaching Party pursuant to any other provision of this Agreement or any other agreement or Applicable Laws and Regulations to make a claim against the Transmission Line Payer whose participation in this Agreement or the entire Agreement was terminated due its Default.

The performance assurance of a terminated Transmission Line Payer will be applied to the terminated Transmission Line Payer's proportionate share of the cost of the CUU. A Transmission Line Payer's performance assurance will not be refunded in the event the Transmission Line Payer is terminated from this Agreement, unless otherwise provided for in Article 6.8. Other Transmission Line Payers remaining as parties to the Agreement will share, subject to the provisions of this Agreement, the remaining CUU costs according to the portion of the Total Transmission Service Capacity, excluding Northbound Transmission Service, which is associated with the Transmission Line Payer or as otherwise agreed to by the Parties.

2.2.4 Material Adverse Change. In the event of a material change in law or regulation that adversely affects, or may reasonably be expected to adversely affect a Party's material rights and/or material obligations under this Agreement, the Parties shall negotiate in good faith any amendments to this Agreement necessary to adapt the terms of this Agreement to such change in law or regulation, and the Transmission Provider shall file such amendments with FERC. If, within sixty

(60) Calendar Days after the occurrence of any event described in this Article 2.2.4, the Parties are unable to reach agreement as to any necessary amendments, the Parties may proceed under Article 14 to resolve any disputes related thereto. The Transmission Provider and/or the CUU Transmission Owners shall have the right to make a unilateral filing with FERC to modify this Agreement pursuant to Section 205 or any other applicable provision of the Federal Power Act and FERC's rules and regulations thereunder, and the Transmission Line Payer shall have the right to make a unilateral filing with FERC to modify this Agreement pursuant to Section 206 or any other applicable provision of the Federal Power Act and FERC's rules and regulations thereunder; provided that a Party shall have the right to protest any such filing by another Party and to participate fully in any proceeding before FERC in which such modifications may be considered. If a Party is unable to fully perform this Agreement due to the occurrence of an event described in this Article 2.2.4 and such inability is not based on economic reasons, such Party shall not be deemed to be in Default of its obligations under this Agreement, provided that such Party is seeking dispute resolution under Article 14 or before FERC, to the extent that (i) such Party is unable to perform as a result of such an event; and (ii) such Party acts in accordance with its obligations under this Article 2.2.4. A material change in law or regulation affecting a Transmission Line Payer's ability to perform under this Agreement will not suspend any other Transmission Line Payer's obligations to perform under this Agreement.

2.2.5 Transmission Provider's Option to Add New Transmission Service Requests and Restudy. In addition to the Transmission Provider's right to make a unilateral filing with FERC to modify this Agreement with respect to any rates, terms and conditions, charges, classifications of service, rule or regulation under Section 205 or any other applicable provision of the Federal Power Act and FERC's rules and regulations thereunder, the Transmission Provider may, at its sole option after reasonable consultation with the CUU Transmission Owners, add a transmission line payer or transmission line payers as parties to this Agreement at any time, provided that: (i) the transmission customer or transmission customers TSR(s) associated with such transmission line payer(s) impacts the same CUU; (ii) the inclusion of that party or parties to this Agreement is consistent with Good Utility Practice; (iii) the addition is made prior to the completion of the CUU; (iv) the CUU scope, completion schedule and cost is not changed; (v) there are no material changes to the CUU unless the change is mutually agreed to by all the Parties, with such agreement not to be unreasonably withheld or delayed. The addition of such other party or parties to this Agreement will result in the reallocation of costs among the Transmission Line Payers and

may result in the need for a restudy as provided under this Article 2.2.5. Each new transmission line payer must meet the creditworthiness requirements pursuant to Article 6.1. As a condition of executing this Agreement, each Transmission Line Payer agrees that an additional party or parties may be added to this Agreement without the renegotiation or prior consent of the Transmission Line Payers, provided that such addition is consistent with other provisions of this Agreement, including that if a new Transmission Service Request is added, which is not Northbound Transmission Service, the costs will be reallocated to the Transmission Line Payers according to the portion of the Total Transmission Service Capacity, excluding Northbound Transmission Service, which is associated with the Transmission Line Payer or as otherwise agreed to by the Parties and if a new Transmission Service Request is added which is Northbound Transmission Service, costs will not be reallocated. This provision does not affect each Transmission Line Payer's right to seek dispute resolution under Article 14 or to make a unilateral filing with FERC to modify this Agreement pursuant to Section 206 or any other applicable provision of the Federal Power Act and FERC's rules and regulations thereunder.

Subject to Section 2.2.2 in the event one or more Transmission Line Payers either withdraws from this Agreement, in accordance with the provisions of this Agreement or fails to cure a Breach, it will result in the termination of that Transmission Line Payer as a party to this Agreement and the Parties acknowledge that the Transmission Line Payers Associated TSR(s) will also be withdrawn and the applicable CUU Transmission Customer will not be entitled to receive Firm Transmission Service. The Transmission Provider shall attempt to add similarly situated Transmission Service Request(s), pursuant to this Article 2.2.5, to replace the withdrawn or terminated Transmission Service Request(s) with a new transmission customer or transmission customers. If the Transmission Provider is unable to identify similarly situated Transmission Service Request(s), and the Transmission Provider deems it likely that another CUU would be more prudent, the Transmission Provider may, in its sole discretion after reasonable consultation with the CUU Transmission Owners, declare a restudy. If one or more Transmission Line Payers either withdraws from the Agreement or fails to cure a Breach resulting in termination of that Transmission Line Payers Associated TSR(s) and the Transmission Line Payer as a party to this Agreement and the Transmission Provider does not replace it, the Transmission Provider will provide the remaining Transmission Line Payers with an analysis stating whether or not the same CUU is needed and the re-allocated proposed costs for which each Transmission Line Payer is responsible and the provisions of Article 6 will also apply. If the Transmission Provider is able to add a similarly situated

Transmission Service Request upon withdrawal or termination, the CUU costs shall be reallocated according to the portion of the Total Transmission Service Capacity, excluding Northbound Transmission Service, which is associated with the Transmission Line Payer or as otherwise agreed to by the Parties.

2.2.6 Termination of Transmission Line Payer. If a Transmission Line Payer is terminated from this Agreement, the CUU Transmission Owners will retain the performance assurance of the terminated Transmission Line Payer and all remaining Transmission Line Payers, and the Transmission Provider will determine whether to add a new transmission line payer or transmission line payers as parties to this Agreement pursuant to Article 2.2.5. Additionally, whether or not a new transmission line payer or transmission line payers are added to this Agreement, the Transmission Provider shall adjust the proportionate share of the costs to be borne by the remaining Transmission Line Payers when a Transmission Line Payer has been terminated from this Agreement in accordance with the provisions of this Agreement. If the addition of a new transmission line payer or transmission line payers to the Agreement results in a reduction of cost estimates, the cost estimates of all remaining Transmission Line Payers will be reduced proportionately subject to the provisions of this Agreement. It is expressly understood that a Transmission Line Payers' proportionate share of the responsibility for the costs of the CUU may increase or decrease. If such cost adjustment causes the cost estimate for any of the remaining Transmission Line Payers to increase by more than twenty-five (25%) percent above the cost estimate set forth in Appendix A, any such Transmission Line Payer whose proportionate share of the cost estimate increases by more than twenty-five (25%) percent may withdraw from the Agreement within thirty (30) Calendar Days of the date that the Transmission Provider notifies the Transmission Line Payer of the redetermination of its proportionate share of the cost responsibility. If a Transmission Line Payer withdraws pursuant to this option, the unused portion of its performance assurance will be released or refunded and the Transmission Line Payers Associated TSR will also be withdrawn and the applicable CUU Transmission Customer will not be entitled to receive Firm Transmission Service. If a Transmission Line Payer's withdrawal under this option causes the cost estimate for any of the remaining Transmission Line Payers to increase by more than twenty-five (25) percent from the estimate in Appendix A, that Transmission Line Payer may also withdraw pursuant to this Article 2.2.6.

2.3 Regulatory Filing. In accordance with Applicable Laws and Regulations, Transmission Provider shall file this Agreement, and any amendment to this Agreement with FERC as a service agreement under the Tariff. Subject to

Section 2.2.4 each Transmission Line Payer that has executed this Agreement or any amendment to this Agreement, shall not protest this Agreement or the amendment, shall reasonably cooperate with Transmission Provider with respect to such filing, and shall provide any information, including the rendering of testimony or pleadings, as applicable, reasonably requested by Transmission Provider to the extent reasonably needed to comply with applicable regulatory requirements.

2.4 Survival. The applicable provisions of this Agreement shall continue in effect after expiration, cancellation, or termination hereof to the extent necessary to provide for final billings, billing adjustments, and the determination and enforcement of liability and indemnification obligations arising from acts or events that occurred while this Agreement was in effect.

ARTICLE 3
CONSTRUCTION OF COMMON USE UPGRADES

3.1 Construction.

3.1.1 CUU Transmission Owners Obligations. The CUU Transmission Owners shall (or shall cause such action to) design, procure, engineer, construct, install and commission the Common Use Upgrades and the Transmission Line Payers shall pay, consistent with Article 3.2, the cost of the CUU in accordance with Appendix A. The Parties acknowledge that Appendix A provides that the construction of the CUU shall proceed in two distinctive phases and the obligations of the Parties under each phase is set out in Appendix A. The CUU designed, procured, constructed, installed and tested by the CUU Transmission Owners pursuant to this Agreement shall satisfy all requirements of applicable safety and/or engineering codes, including those requirements of the CUU Transmission Owners and the Transmission Provider, and shall include all additions, modifications and upgrades required to be made to certain facilities of the Transmission System in order to accommodate the Transmission Customers' TSRs, and shall comply with Good Utility Practice, and further, shall satisfy all Applicable Laws and Regulations.

3.1.2 Right to Suspend Due to Inadequate Funding. The CUU Transmission Owners reserve the right, upon written notice to Transmission Line Payers, to suspend, at any time, work by the CUU Transmission Owners and the incurrence of additional expenses associated with the construction and installation of the CUU, upon the occurrence of a Default by a Transmission Line Payer, including a

Default caused by a Transmission Line Payer's failure to provide performance assurance pursuant to Article 6.1 that the remaining Transmission Line Payer(s) does not (do not) cure pursuant to Article 9. Any form of suspension by the CUU Transmission Owners shall not be barred by Articles 2.2.2 or 2.2.3 nor shall it affect the CUU Transmission Owners' right to terminate the work or this Agreement pursuant to Article 9. In such events, the Transmission Line Payers shall be responsible for costs which the CUU Transmission Owners incur as set forth in Article 2.2.3.

3.1.3 Construction Status. The CUU Transmission Owners shall keep the Transmission Line Payers and the Transmission Provider advised periodically as to the progress of its respective design, procurement, engineering, construction, installation and commissioning efforts as described in Appendix A. A Transmission Line Payer may, at any time, request a progress report from the CUU Transmission Owners, with a copy to be provided to all other Parties. If, at any time, a Transmission Line Payer determines that the completion of the CUU will not be required until after the specified In-Service Date, such Transmission Line Payer may provide written notice to all other Parties of such requested later date for the completion of the CUU. The CUU Transmission Owners may delay the In-Service Date accordingly, but only if agreed to in writing by all other Transmission Line Payers.

3.1.4 Timely Completion. The CUU Transmission Owners shall use Reasonable Efforts to design, procure, engineer, construct, install, and commission the CUU in accordance with the schedule set forth in Appendix A, which schedule may be revised from time to time by mutual agreement of the Parties. If any event occurs that will affect the time for completion of the CUU, or the ability to complete any component of the CUU, the CUU Transmission Owners and/or the Transmission Provider shall promptly notify all other Parties. In such circumstances, the Transmission Provider shall, within fifteen (15) Calendar Days of such notice, convene a technical meeting with the Transmission Line Payers and the CUU Transmission Owners to evaluate the alternatives available to the Transmission Line Payers. The CUU Transmission Owners and/or the Transmission Provider shall also make available to the Transmission Line Payers all studies and work papers related to the event and corresponding delay, including all information that is in the possession of the Transmission Provider or the CUU Transmission Owners that is reasonably needed by the Transmission Line Payers to evaluate alternatives. The CUU Transmission Owners shall, at any Transmission Line Payer's request and expense, use Reasonable Efforts to accelerate their work under this Agreement to meet the schedule set forth in Appendix A, provided that:

(i) Transmission Line Payers jointly authorize such actions; (ii) such authorizations to be withheld, conditioned or delayed by a given Transmission Line Payer only if it can demonstrate that the acceleration would have a material adverse effect on it; and (iii) the requesting Transmission Line Payer funds the incremental costs associated therewith.

3.2 Transmission Service Costs and Credits

3.2.1 Costs.

The Transmission Line Payers shall pay to the CUU Transmission Owners the costs (including taxes) associated with seeking and obtaining all necessary approvals and of designing, engineering, constructing, and commissioning the Common Use Upgrades, as identified in and in accordance with the cost recovery method set forth in Appendix A of this Agreement.

3.2.1.1 Lands of Other Property Owners.

If any part of the CUU is to be installed on property owned by persons other than CUU Transmission Customers, or Transmission Line Payers or CUU Transmission Owners, the CUU Transmission Owners shall at the Transmission Line Payers' expense use efforts, similar in nature and extent to those that it typically undertakes on its own behalf or on behalf of its Affiliates, including use of its eminent domain authority to the extent permitted and consistent with Applicable Laws and Regulations, to procure from such persons any rights of use, licenses, rights of way and easements that are necessary to construct, operate, maintain, test, inspect, replace or remove the CUU upon such property.

3.2.1.2 Rights not Relinquished. Notwithstanding any other provision of this Agreement, nothing herein shall be construed as relinquishing or foreclosing any rights, including but not limited to firm transmission rights, capacity rights, transmission congestion rights, or transmission credits, that each Transmission Line Payer as well as each CUU Transmission Customer shall be entitled to, now or in the future under any other agreement or tariff as a result of, or otherwise associated with, the transmission capacity, if any, created by the CUU, including the right to obtain refunds or transmission credits for transmission service.

3.3 Taxes.

3.3.1 Indemnification for Contributions in Aid of Construction. The Parties intend that any payments made by a Transmission Line Payer to a CUU Transmission

Owner for the installation of the CUU shall be non-taxable contributions to capital under Internal Revenue Code Sec. 118 to the extent the payments meet the safe harbor requirements of IRS Notice 2001-82 and IRS Notice 88-129. All CUU Transmission Owners and all Transmission Line Payers covered by this Agreement agree to cooperate in good faith to meet the intent of Section 3.3.1 in that any payments made by a Transmission Line Payer to a CUU Transmission Owner for construction of the CUU shall be treated as non-taxable contributions to capital to the extent allowed under Applicable Laws and Regulations.

With regard to any such contribution, the CUU Transmission Owner receiving the contribution shall not include a gross-up for income taxes for the amount the Transmission Line Payer is to pay pursuant to this Agreement for the installation of the CUU unless: (i) the CUU Transmission Owner and the Transmission Line Payer have determined, in good faith, that the payments or property transfers made by the Transmission Line Payer should be reported as income subject to taxation by that CUU Transmission Owner; or (ii) the Internal Revenue Service ("IRS") concludes that the contribution payments or property transfers are income subject to taxation as the result of a final settlement with the IRS, a closing agreement or accepted offer in compromise, which resolves the liability for taxes with respect to the contributions to capital or as a result of the filing of a private letter ruling request and the receipt of such ruling ("**IRS Final Determination**") (the CUU Transmission Owner that has made such determination pursuant to (i) above or has been required by the IRS to report such payments or property as income in accordance with (ii) above, referred to as the "**Affected CUU Transmission Owner**"). The Transmission Line Payer shall reimburse the Affected CUU Transmission Owner for the tax liability on the applicable amount of the capital contributions on a fully grossed up basis in the manner set out below.

If a gross-up payment for income taxes is required pursuant to this Section 3.3.1, the gross-up amount will be determined by multiplying the gross-up rate by the capital contributions that are subject to tax (the "Gross-Up Amount"). The gross-up rate is calculated as follows: (1/(1 - Combined Tax Rate)) - 1. The Combined Tax Rate is the sum of the rates for the U.S. federal corporate income tax (net of the Minnesota state tax deduction benefit) and the Minnesota Income and Franchise Taxes imposed by Chapter 290 of the Minnesota Statutes (to the extent imposed on or measured by net income). For the purposes of example the Combined Tax Rate in 2014 is 41.37%. The federal and Minnesota income tax rates used in this calculation of the Combined Tax Rate will be the rates in effect or reasonably expected to be in effect when the Affected CUU Transmission

Owner is required to pay tax on the capital contributions. If it has been determined in advance that the applicable capital contribution payments will be taxable, the Gross-Up Amounts on such capital contributions made during that tax year shall be due and payable by the Transmission Line Payer to the Affected CUU Transmission Owner within ninety (90) Calendar Days of such capital contribution. Within sixty (60) Calendar Days of the IRS Final Determination of the tax payable in any applicable year by the Affected CUU Transmission Owner, a report of such payment and accounting shall be prepared and forwarded by the Affected CUU Transmission Owner to the Transmission Line Payer together with any overpayment in the Gross-Up Amount. Any shortfall on the Gross-Up Amount paid shall be paid by the Transmission Line Payer within thirty (30) Calendar Days of the receipt of such report. If the tax liability is determined in a tax year after the original capital contribution has been made, the Gross-Up Amount is due within ninety (90) Calendar Days of the IRS Final Determination of taxability.

Following the payment of any Gross-Up Amount, commencing in the first fiscal year in which the CUU is placed in-service and for each successive fiscal year thereafter, the Affected CUU Transmission Owner shall within ninety (90) Calendar Days of its fiscal year end remit to the Transmission Line Payer the combined federal and Minnesota tax benefit of the tax depreciation from the taxable capital contribution received by the Affected Transmission Line Owner plus the corresponding federal and Minnesota tax benefit of the additional tax deduction for such payment to such Transmission Line Payer, at the Federal and Minnesota corporate tax rates in effect in the tax year of the tax depreciation deduction ("**Tax Depreciation Credit**"). For greater certainty, the Tax Depreciation Credit will be determined for each fiscal year by multiplying the tax depreciation from the taxable capital contribution for such fiscal year by the depreciation credit rate. The depreciation credit rate is calculated as follows: (1/(1 - Combined Tax Rate)) - 1.

The indemnification obligation set forth above shall terminate at the earlier of (1) the expiration of the ten-year testing period and the applicable statute of limitation, as it may be extended by a CUU Transmission Owner, upon request of the IRS, to keep these years open for audit or adjustment, but only if notice is given to the Transmission Line Payer within sixty (60) days of the statute extension; or (2) the occurrence of a subsequent taxable event and the payment of any related indemnification obligations as contemplated by this Article 3.3.1.

As described above, to the extent that the receipt of capital contributions by a CUU Transmission Owner is determined by the IRS and/or the Minnesota Department of Revenue ("**Taxation Authority**") to constitute income by a CUU Transmission Owner subject to taxation, the Transmission Line Payer shall protect, indemnify, and hold harmless such CUU Transmission Owner and its Affiliates, from all claims by any such Taxation Authority for any tax, interest and/or penalties associated with such determination. Upon receiving written notification of such determination from the Taxation Authority, such CUU Transmission Owner shall provide the Transmission Line Payer with written notification within thirty (30) Calendar Days of such determination and notification. Such CUU Transmission Owner, upon the timely written request by the Transmission Line Payer and at the expense of the Transmission Line Payer, shall appeal, protest, seek abatement of, or otherwise oppose such determination. Such CUU Transmission Owner reserves the right to make all decisions with regard to the prosecution of such appeal, protest, abatement or other contest, including the compromise or settlement of the claim; provided that such CUU Transmission Owner shall cooperate and consult in good faith with the Transmission Line Payer regarding the conduct of such contest. If requesting the action, the Transmission Line Payer shall advance to such CUU Transmission Owner on a periodic basis as requested by such CUU Transmission Owner the estimated cost of prosecuting such appeal, protest, abatement or other contest. The Transmission Line Payer shall not be required to pay such CUU Transmission Owner for the tax, interest and/or penalties prior to the seventh (7th) Calendar Day before the date on which such CUU Transmission Owner (i) is required to pay the tax, interest and/or penalties or other amount in lieu thereof pursuant to a compromise or settlement of the appeal, protest, abatement or other contest; (ii) is required to pay the tax, interest and/or penalties as the result of a final, non-appealable order by a Taxation Authority; or (iii) is required to pay the tax, interest and/or penalties as a prerequisite to an appeal, protest, abatement or other contest. In the event such appeal, protest, abatement or other contest results in a determination that such CUU Transmission Owner is not liable for any portion of any tax, interest and/or penalties for which the Transmission Line Payer has already made payment to such CUU Transmission Owner, the CUU Transmission Owner shall promptly refund to the Transmission Line Payer any payment attributable to the amount determined to be non-taxable, plus any interest or other payments such CUU Transmission Owner receives or to which such CUU Transmission Owner may be entitled with respect to such payment.

3.3.2 Private Letter Ruling and Other Cooperation. At the request of a Transmission Line Payer, a CUU Transmission Owner may and shall file with the IRS a request

for a private letter ruling as to whether any property transferred or sums paid, or to be paid, by such Transmission Line Payer to such CUU Transmission Owner under this Agreement are subject to federal income taxation. In that event, the Transmission Line Payer will prepare the initial draft of the request for a private letter ruling and will bear the expense of such ruling request. The CUU Transmission Owner and the Transmission Line Payer shall cooperate in good faith with respect to the submission of such request.

3.3.3 Other Taxes. Any Transmission Line Payer making a contribution to a CUU Transmission Owner shall cooperate in good faith to appeal, protest, seek abatement of, or otherwise contest any tax (other than federal income tax and Minnesota income taxes) asserted or assessed against such CUU Transmission Owner for which such Transmission Line Payer may be required to reimburse such CUU Transmission Owner under the terms of this Agreement.

ARTICLE 4
FORCE MAJEURE

4.1 Force Majeure. No Party shall be in breach or liable for any delay or failure in its performance under this Agreement to the extent such performance is prevented or delayed due to a Force Majeure event or circumstance, provided that:

(a) the non-performing Party shall give the other Parties notice promptly (and within forty-eight (48) hours if possible) after the non-performing Party's knowledge of the commencement of the Force Majeure, with written confirmation to be supplied within ten (10) calendar days after the commencement of the Force Majeure further describing the particulars of the occurrence of the Force Majeure;

(b) the delay in performance due to the Force Majeure shall be of no greater scope and of no longer duration than is directly caused by the Force Majeure;

(c) the Party whose performance is delayed or prevented: (i) shall proceed with Reasonable Efforts to overcome the Force Majeure which is preventing or delaying performance; and (ii) shall provide weekly written progress reports to the other Party during the period that performance is delayed or prevented describing actions taken and to be taken to remedy the consequences of the Force Majeure, the schedule for such actions and

the expected date by which performance shall no longer be affected by the Force Majeure; and

(d) when the performance of the Party claiming the Force Majeure is no longer being delayed or prevented, that Party shall give the other Parties notice to that effect.

ARTICLE 5
INFORMATION REPORTING

5.1 Information Reporting Obligations. Each Party shall, in accordance with Good Utility Practice, promptly provide to the other Parties all relevant information, documents, or data regarding the Party's facilities and equipment which may reasonably be expected to pertain to the reliability of any other Party's facilities and equipment and which has been reasonably requested by any other Party.

5.2 Non-Force Majeure Reporting. A Party shall notify the other Parties when it becomes aware of its inability to comply with the provisions of this Agreement for a reason other than Force Majeure. The Parties agree to cooperate with each other and provide necessary information regarding such inability to comply, including, but not limited to, the date, duration, and reason for the inability to comply, and corrective actions taken or planned to be taken with respect to such inability to comply. In the event of Force Majeure, a Party unable to comply with the provisions of this Agreement shall notify the other Parties in accordance with the provisions of Article 4.

ARTICLE 6

CREDITWORTHINESS, BILLING, AND PAYMENTS

6.1 Creditworthiness.

The CUU Transmission Owners will review the creditworthiness of the Transmission Line Payers to determine if performance assurance is required. If the Transmission Line Payer maintains a senior unsecured bond rating or corporate credit rating from Standard & Poor's of "BBB" or better and/or Moody's of "Baa2" or better and/or DBRS Limited's of "BBB(med)" or better (if such Party maintains multiple credit ratings, for the purposes of this Article 6.1 the lower of such credit ratings shall be utilized) and has a total asset size exceeding $1 billion (confirmed through audited financial statements) then performance assurance will not be required. If the CUU Transmission Owners determine

that performance assurance is required in accordance with Article 6.1 of this Agreement, then the following applies:

Thirty (30) Calendar Days prior to the due date for the Transmission Line Payer's first payment under the payment schedule specified in Appendix A, each Transmission Line Payer shall provide the CUU Transmission Owners with performance assurance either in the form of cash deposited into an escrow account, a parental guarantee, letter of credit, surety bond or another form of performance assurance and is reasonably acceptable to the CUU Transmission Owners as an adequate assurance of creditworthiness for the Transmission Line Payer's share of responsibility for CUU costs as set out in Appendix A. The amount of performance assurance required to be provided to the CUU Transmission Owners will be as stipulated in Appendix D Subsection 1. This amount of performance assurance will remain in place up to the day that is 20 Business Days after the last of the MPM Certification Phase Conditions Precedent and the MPM Construction Phase Conditions Precedent have been satisfied or waived by MPM.

By no later than 20 Business Days after all of the MPM Certification Phase Conditions Precedent and MPM Construction Phase Conditions Precedent have been satisfied or waived by MPM, each Transmission Line Payer shall provide the CUU Transmission Owners with performance assurance as stipulated in Appendix D Subsection 2.

By no later than the 20 Business Days after all of the MPM Construction Phase Conditions Precedent and the 6690271 Certification Phase Conditions Precedent and the 6690271 Construction Phase Conditions Precedent have been satisfied or waived by the respective Party, the amount of performance assurance required by the CUU Transmission Owners from the Transmission Line Payers will be determined by the CUU Transmission Owners based on the CUU Transmission Owners' projected cost to complete the CUU facilities multiplied by the percentage of the CUU that is required to be funded by such Transmission Line Payer minus any amount of its performance assurance held by the CUU Transmission Owner remaining from Appendix D Subsections 1 and 2.

If performance assurance is in the form of a parental guarantee or surety bond, it must be made by an entity that meets the creditworthiness requirements of the CUU Transmission Owners, as set out above, have terms and conditions reasonably acceptable to the CUU Transmission Owners and guarantee payment of the amount specified in Article 6.3. The surety bond must be issued by an insurer reasonably acceptable to the CUU Transmission Owners, specify a reasonable expiration date and shall provide that the maximum amount assured under the bond shall reduce on a quarterly basis.

If the performance assurance is in the form of a letter of credit, it must be issued by a bank reasonably acceptable to the CUU Transmission Owners, specify a reasonable expiration date and may provide that the maximum amount available to be drawn under the letter of credit shall reduce on a quarterly basis based on payments received by the CUU Transmission Owners from such Transmission Line Payer.

If the performance assurance is a cash escrow account, then the maximum amount available to be drawn under the escrow account shall reduce on a quarterly basis based on payments received by the CUU Transmission Owner from such Transmission Line Payer.

After the CUU has been placed in service and until the Transmission Line Payers have fully compensated the CUU Transmission Owners for construction of the CUU, each Transmission Line Payer shall, subject to the standards of this Article 6.1, maintain a parental guarantee, surety bond, letter of credit, or some other credit assurance sufficient to meet its monthly payment obligation under Article 3.2.1. Each Transmission Line Payer's estimated liability under Article 3.2.1 is stated in Appendix A. If a Transmission Line Payer provides the entire payment it must remit under the payment schedule as of the date of first payment, it need not provide additional performance assurance unless cost allocation changes pursuant to this Article 6.1 or additional funds are required by the CUU Transmission Owners to complete the CUU and allocated among the Transmission Line Payers according to Article 3.2.

A Transmission Line Payer's performance assurance will not be returned or refunded in the event a Transmission Line Payer is terminated from the Agreement, except as provided in this Article 6.1 and Article 6.8.

The CUU Transmission Owners may draw on the performance assurance in full or in part, acting reasonably, upon any Default, early termination or suspension in order to fund any costs and liabilities owing by such Transmission Line Payer to the CUU Transmission Owners pursuant to this Agreement. The amount of performance assurance required by or available to CUU Transmission Owners is based on estimates of costs and liabilities and shall not limit the damages that are otherwise required to be paid by Transmission Line Payers hereunder, if any. In the event the performance assurance drawn by or paid to CUU Transmission Owners is not sufficient to cover all amounts due to CUU Transmission Owners from such Transmission Line Payer under the terms of this Agreement, Transmission Line Payer shall be required to pay the full amount of the deficiency to CUU Transmission Owners.

6.2 **Failure to Provide Performance Assurance.** If a Transmission Line Payer fails to provide acceptable performance assurance pursuant to Article 6.1, the Transmission Line

Payer can be terminated from this Agreement by the CUU Transmission Owners and the Transmission Line Payers Associated TSR will also be withdrawn and the applicable CUU Transmission Customer will not be entitled to receive Firm Transmission Service.

When a Transmission Line Payer withdraws from the Agreement as a result of an increase of more than twenty-five (25%) percent in its cost estimate pursuant to Article 2.2.6, the Transmission Provider will notify all other Parties to the Agreement of the withdrawal and will provide a revised cost estimate of each Transmission Line Payer's responsibility for the cost of the CUU within thirty (30) Calendar Days. Within thirty (30) Calendar Days of receiving such notification, each remaining Transmission Line Payer(s) must either withdraw or submit additional assurance necessary to cover its revised cost responsibility, if applicable. Failure to provide such additional performance assurance, if applicable, will be a Breach of the Agreement and subject to Article 9, any Transmission Line Payer that does not provide additional performance assurance within thirty (30) Calendar Days of receiving the cost allocation notice can be withdrawn from this Agreement by the CUU Transmission Owners and if such Transmission Line Payer is withdrawn, the Transmission Line Payer's Associated TSR will also be withdrawn and the applicable CUU Transmission Customer will not be entitled to receive Firm Transmission Service. If such cost adjustment causes the cost estimate for any of the remaining Transmission Line Payers to increase by more than twenty-five (25%) percent above the cost estimate provided in response to the prior withdrawal, the Transmission Provider will perform a restudy of the CUU unless the remaining Parties agree to proceed without a restudy.

6.3 **Monthly Invoice.** The CUU Transmission Owners shall submit to each Transmission Line Payer, on a monthly basis, invoices of amounts due, if any, for the preceding month. Each invoice shall state the month to which the invoice applies and fully describe the services and equipment provided. The Parties may discharge mutual debts and payment obligations due and owing to each other on the same date through netting, in which case all amounts a Party owes to another Party under this Agreement, including interest payments or credits, shall be netted so that only the net amount remaining due shall be paid by the owing Party. The Parties may by mutual consent adjust the invoicing procedures. These procedures could include but are not limited to construction advances by the Transmission Line Payers to the CUU Transmission Owners.

6.4 Payment. Invoices shall be rendered to the paying Party at the address specified by the Parties. The Party receiving the invoice shall pay the invoice within thirty (30) Calendar Days of receipt. All payments shall be made in immediately available funds payable to the other Party, or by wire transfer to a bank named and account designated by the invoicing Party. Payment of invoices by a Party will not constitute a waiver of any rights or claims that Party may have under this Agreement.

6.5 Final Invoice. Within six (6) months after completion of the construction of the CUU, unless otherwise agreed to under Appendix A, the CUU Transmission Owners shall provide an invoice of the final cost of the construction of the CUU and shall set forth such costs in sufficient detail to enable each Transmission Line Payer to compare the actual costs with the estimates and to ascertain deviations, if any, from the cost estimates. The CUU Transmission Owner shall refund, with interest (calculated in accordance with 18 C.F.R. Section 35.19a(a)(2)(iii)), to each Transmission Line Payer any amount by which the actual payment by the Transmission Line Payer for estimated costs exceeds the actual costs of construction within thirty (30) Calendar Days of the issuance of such final construction invoice.

6.6 Interest. Interest on any unpaid amounts shall be calculated in accordance with Section 7 of the Tariff.

6.7 Payment During Dispute. In the event of a billing dispute among the Parties, the CUU Transmission Owners shall continue to construct the CUU as long as each Transmission Line Payer: (i) continues to make all payments not in dispute; and (ii) pays to the Transmission Provider or the CUU Transmission Owners or into an independent escrow account the portion of the invoice in dispute, pending resolution of such dispute. If any Transmission Line Payer fails to meet these two requirements, then the Transmission Provider may or, at the CUU Transmission Owners' request upon a Transmission Line Payer's failure to pay the CUU Transmission Owners, shall provide notice to such Transmission Line Payer of a Default pursuant to Article 9. Within thirty (30) Calendar Days after the resolution of the dispute, the Party that owes money to another Party shall pay the amount due with interest calculated in accordance with the methodology set forth in 18 C.F.R. Section 35.19a(a)(2)(iii).

6.8 Return of Excess Performance Assurance. Excess performance assurance will be refunded or released if any funds remain when the CUU is placed in service or if the Transmission Provider determines that the CUU is no longer needed. The amount of excess performance assurance to be refunded or released will be determined net of any performance assurance required by the CUU Transmission Owners for any amounts still due and payable for construction and installation of the CUU (including, without limitation, any equipment ordered related to such construction), plus all out-of-pocket expenses incurred by the CUU Transmission Owners in connection with the construction and installation of the CUU, any actual costs which the CUU Transmission Owners (A) reasonably incur in winding up work and construction demobilization (including previously incurred capital costs, penalties for early termination, removal and site restoration) and (B) reasonably incur to ensure the safety of persons and property and the integrity and safe and reliable operation of the Transmission System, through the In-

Service Date or date the Transmission Provider determines that the CUU is no longer required.

ARTICLE 7
ASSIGNMENT

7.1 Assignment. This Agreement may be assigned by any Party only with the written consent of the other Parties; provided that a Party may assign this Agreement without the consent of the other Parties to any Affiliate of the assigning Party with an equal or greater credit rating and with the legal authority and operational ability to satisfy the obligations of the assigning Party under this Agreement. In addition 6690271 may assign its interest, rights and obligations in or arising out of this Agreement: (i) as a CUU Transmission Owner to MP without the consent of MP or any other Party to this Agreement; or (ii) as a CUU Transmission Owner and/or Transmission Line Payer to Great River Energy or an Affiliate of Great River Energy (the "Assignee") with the consent of MP and without the consent any other Party to this Agreement provided that the Assignee has the legal authority and operational ability to satisfy the obligations of 6690271 as the assigning party under this Agreement, and without restricting the generality of the foregoing, if such assignment is in respect of 6690271 interests, rights and obligations as a Transmission Line Payer, the Assignee must meet or satisfy the creditworthiness provisions of Article 6. Any attempted assignment that violates this Article 7.1 is void and ineffective and shall not relieve any Party of its obligations under this Agreement. No Party's obligations shall be enlarged, in whole or in part, by reason of an assignment. Where required, consent to assignment will not be unreasonably withheld, conditioned or delayed.

ARTICLE 8
INDEMNITY

8.1 General. To the extent permitted by law, a Party (the "**Indemnifying Party**") shall at all times indemnify, defend, and hold the other Parties (each an "**Indemnified Party**") harmless from Loss, only as provided in the Tariff.

8.1.1 Indemnified Party. If an Indemnified Party is entitled to indemnification under this Article 8 as a result of a claim by a third party, and the Indemnifying Party fails, after notice and reasonable opportunity to proceed under Article 8.1, to assume the defense of such claim, such Indemnified Party may at the expense of the Indemnifying Party contest, settle or consent to the entry of any judgment with respect to, or pay in full, such claim.

8.1.2 Indemnifying Party. If an Indemnifying Party is obligated to indemnify and hold any Indemnified Party harmless under this Article 8, the amount owing to the Indemnified Party shall be the amount of such Indemnified Party's actual Loss, net of any insurance or other recovery.

8.1.3 Indemnity Procedures. Promptly after receipt by an Indemnified Party of any claim or notice of the commencement of any action or administrative or legal proceeding or investigation as to which the indemnity provided for in Article 8.1 may apply, the Indemnified Party shall notify the Indemnifying Party of such fact. Any failure of or delay in such notification shall not affect a Party's indemnification obligation unless such failure or delay is materially prejudicial to the Indemnifying Party.

The Indemnifying Party shall have the right to assume the defense thereof with counsel designated by such Indemnifying Party and reasonably satisfactory to the Indemnified Party. If the defendants in any such action include one or more Indemnified Parties and the Indemnifying Party and if the Indemnified Party reasonably concludes that there may be legal defenses available to it and/or other Indemnified Parties which are different from or additional to those available to the Indemnifying Party, the Indemnified Party shall have the right to select separate counsel to assert such legal defenses and to otherwise participate in the defense of such action on its own behalf. In such instances, the Indemnifying Party shall only be required to pay the fees and expenses of one additional attorney to represent an Indemnified Party or Indemnified Parties having such differing or additional legal defenses.

The Indemnified Party shall be entitled, at its expense, to participate in any such action, suit, or proceeding, the defense of which has been assumed by the Indemnifying Party. Notwithstanding the foregoing, the Indemnifying Party (i) shall not be entitled to assume and control the defense of any such action, suit, or proceedings if and to the extent that, in the opinion of the Indemnified Party and its counsel, such action, suit, or proceeding involves the potential imposition of criminal liability on the Indemnified Party, or there exists a conflict or adversity of interest between the Indemnified Party and the Indemnifying Party, and in such event the Indemnifying Party shall pay the reasonable expenses of the Indemnified Party, and (ii) shall not settle or consent to the entry of any judgment in any action, suit or proceeding without the consent of the Indemnified Party, which shall not be unreasonably withheld, conditioned, or delayed.

8.2 Consequential Damages. In no event shall any Party be liable to any other Party under any provision of this Agreement for any losses, damages, costs or expenses for any special, indirect, incidental, consequential, or punitive damages, including but not limited to loss of profit or revenue, loss of the use of equipment, cost of capital, cost of temporary equipment or services, whether based in whole or in part in contract, in tort, including negligence, strict liability, or any other theory of liability; provided, however, that damages for which a Party may be liable to another Party under another agreement will not be considered to be special, indirect, incidental, or consequential damages hereunder.

ARTICLE 9
BREACH, CURE AND DEFAULT

9.1 Events of Breach. A Breach of this Agreement shall include:

(a) The failure to pay any amount when due;

(b) The failure to comply with any material term or condition of this Agreement, including but not limited to any material Breach of a representation, warranty or covenant made in this Agreement;

(c) If a Party (i) is adjudicated bankrupt; (ii) files a voluntary petition in bankruptcy under any provision of any federal or state bankruptcy law or shall consent to the filing of any bankruptcy or reorganization petition against it under any similar law; (iii) makes a general assignment for the benefit of its creditors; or (iv) consents to the appointment of a receiver, trustee or liquidator;

(d) Assignment of this Agreement in a manner inconsistent with the terms of this Agreement;

(e) Failure of a Party to provide information or data to another Party as required under this Agreement, provided the Party entitled to the information or data under this Agreement requires such information or data to satisfy its obligations under this Agreement; or

(f) Failure of a Party to provide the performance assurance required pursuant to Article 6.1.

9.2 Notice of Breach, Cure and Default. Upon the occurrence of an event of Breach, any Party aggrieved by the Breach, when it becomes aware of the Breach, shall give written notice of the Breach to the Breaching Party and to any other person representing a Party to this Agreement identified in writing to the other Parties in advance. Upon receiving written notice of a Breach hereunder, the Breaching Party shall have a period to cure such Breach (sometimes hereinafter referred as "Cure Period") which shall be thirty (30) Calendar Days unless such Breach is due to an occurrence under Article 9.1(a) or (c) in which case the cure period will be five (5) Calendar Days. Such notice shall set forth, in reasonable detail, the nature of the Breach, and where known and applicable, the steps necessary to cure such Breach.

9.2.1 Upon the occurrence described in part (c) of Article 9.1, the Party experiencing such occurrence shall notify the other Parties in writing within seven (7) Calendar Days after the commencement of such occurrence.

9.2.2 If the Breach is such that it cannot be cured within the Cure Period, the Breaching Party will commence in good faith all steps as are reasonable and appropriate to cure the Breach within such Cure Period and thereafter diligently pursue such action to completion. In the event the Breaching Party fails to:

(A) cure the Breach, or to commence reasonable and appropriate steps to cure the Breach, within the Cure Period; or

(B) completely cure the Breach within sixty (60) Calendar Days if the Breach occurs pursuant to Article 9.1(b), (d), (e) or (f),

the Breaching Party shall be in Default of this Agreement and the Non-Breaching Parties may, at their option: (1) act in concert to amend the Agreement to remove a Transmission Line Payer that is in Default from this Agreement for cause and to make other changes as necessary; or (2) either in concert or individually, take whatever action at law or in equity as may appear necessary or desirable to enforce the performance or observance of any rights, remedies, obligations, agreement, or covenants under this Agreement. Alternatively, if a Transmission Line Payer is the Breaching Party and the Breach results from a failure to provide payments or performance assurance under Article 9.1, the other Transmission Line Payers, either individually or in concert, may cure the Breach by paying the amounts owed or by providing adequate performance assurance, without waiver of contribution rights against the Transmission Line Payer in Default with the right to receive an assignment of all rights the CUU Transmission Owners had in respect of such Breach. Such cure for the Breach of a Transmission Line Payer is

subject to the reasonable consent of the Transmission Provider and CUU Transmission Owners. The CUU Transmission Owners may also cure such Breach by funding the proportionate share of the CUU costs related to the Breach of the Transmission Line Payer. CUU Transmission Owners must notify all Parties that it will exercise this option within thirty (30) Calendar Days of notification that a Transmission Line Payer has failed to provide payments or performance assurance under Article 9.1.

9.3.1 Rights in the Event of Default. Notwithstanding the foregoing, upon the occurrence of an event of Default, any Non-Breaching Party shall be entitled to exercise all rights and remedies it may have in equity or at law.

ARTICLE 10
TERMINATION OF AGREEMENT

10.1 Expiration of Term. Except as otherwise specified in this Article 10, the Parties' obligations under this Agreement shall terminate at the conclusion of the term of this Agreement.

10.2 Termination. In addition to the termination provisions set forth in Article 2.2, a Party may terminate this Agreement upon the Default of another Party in accordance with this Agreement. Subject to the limitations set forth in Article 10.3, in the event of a Default, a Non-Breaching Party may terminate this Agreement only upon the later of: (i) its giving written notice of termination to the other Parties; and (ii) the filing of a notice of termination for this Agreement.

10.3 Disposition of Facilities Upon Termination of Agreement Due to Default.

10.3.1 Transmission Provider and CUU Transmission Owners Obligations.
Upon termination of this Agreement due to Default, unless otherwise agreed by the terms of this Agreement, the CUU Transmission Owners:

(a) shall, prior to the construction and installation of any portion of the CUU described in Appendix A and to the extent possible, cancel any pending orders of, or return, such equipment or material for the CUU;

(b) may keep in place any portion of the CUU already constructed and installed; and

(c) shall perform such work as may be necessary to ensure the safety of persons and property and to preserve the integrity of the Transmission System.

10.3.2 Transmission Line Payer Obligations. Upon billing by the CUU Transmission Owners, each Transmission Line Payer shall reimburse the CUU Transmission Owners for its share of any costs incurred by the CUU Transmission Owners in performance of the actions required or permitted by Article 10.3.1. The CUU Transmission Owners and the Transmission Provider shall use Reasonable Efforts to minimize costs and shall offset the amounts owed by any salvage value of facilities, if applicable. Each Transmission Line Payer shall pay these costs pursuant to Article 6.3 of this Agreement.

10.3.3 Pre-construction or Installation. Upon termination of this Agreement and prior to the construction and installation of any portion of the CUU, the CUU Transmission Owners may, at their option, retain any portion of the CUU not cancelled or returned in accordance with Article 10.3.1(a), in which case the CUU Transmission Owners shall be responsible for all costs associated with procuring the CUU. To the extent that the Transmission Line Payers have already paid the CUU Transmission Owners for any or all of such costs, the CUU Transmission Owners shall refund such amounts to the Transmission Line Payers within six (6) months. If the CUU Transmission Owners elect to not retain any portion of such facilities, and one or more of the Transmission Line Payers wish to purchase such facilities, the CUU Transmission Owners shall convey and make available to the applicable Transmission Line Payer(s) such facilities as soon as practicable after receiving payment for such facilities and the CUU Transmission Owners shall account to the other Transmission Line Payer(s) for such payment.

10.4 Survival of Rights. Termination or expiration of this Agreement shall not relieve any Party of any of its liabilities and obligations arising hereunder prior to the date termination becomes effective, and each Party may take whatever judicial or administrative actions as appear necessary or desirable to enforce its rights hereunder. The applicable provisions of this Agreement will continue in effect after expiration or early termination hereof to the extent necessary to provide for (A) final billings, billing adjustments and other billing procedures set forth in this Agreement; (B) the determination and enforcement of liability and indemnification obligations arising from acts or events that occurred while this Agreement was in effect; and (C) the confidentiality provisions set forth in Article 12.

ARTICLE 11
SUBCONTRACTORS

11.1 Subcontractors. Nothing in this Agreement shall prevent a Party from utilizing the services of subcontractors, as it deems appropriate, to perform its obligations under this Agreement; provided, however, that each Party shall require its subcontractors to comply with all applicable terms and conditions of this Agreement in providing such services and each Party shall remain primarily liable to the other Parties for the performance of such subcontractor.

11.1.1 Responsibility of Principal. The creation of any subcontract relationship shall not relieve the hiring Party of any of its obligations under this Agreement. In accordance with the provisions of this Agreement, each Party shall be fully responsible to the other Parties for the acts or omissions of any subcontractor it hires as if no subcontract had been made. Any applicable obligation imposed by this Agreement upon a Party shall be equally binding upon, and shall be construed as having application to, any subcontractor of such Party.

11.1.2 No Third-Party Beneficiary. Except as may be specifically set forth to the contrary herein, no subcontractor or any other party is intended to be, nor will it be deemed to be, a third-party beneficiary of this Agreement.

11.1.3 No Limitation by Insurance. The obligations under this Article 11 will not be limited in any way by any limitation of any insurance policies or coverages, including subcontractor's insurance.

ARTICLE 12
CONFIDENTIALITY

12.1 Confidentiality. Confidential Information shall include, without limitation, all information relating to a Party's technology, research and development, business affairs, and pricing, and any information supplied by a Party to another Party prior to the execution of this Agreement.

Information is Confidential Information only if it is clearly designated or marked in writing as confidential on the face of the document, or, if the information is conveyed orally or by inspection, if the Party providing the information orally informs the Party receiving the information that the information is confidential. The Parties shall also maintain as confidential any information that is provided and identified by a Party as Critical Energy Infrastructure Information ("**CEII"**), as that term is defined in 18 C.F.R. Section 388.113(c).

Such confidentiality will be maintained in accordance with this Article 12. If requested by the receiving Party, the disclosing Party shall provide in writing, the basis for asserting that the information referred to in this Article warrants confidential treatment, and the requesting Party may disclose such writing to the appropriate Governmental Authority. Each Party shall be responsible for the costs associated with affording confidential treatment to its information.

12.1.1 Term. During the term of this Agreement, and for a period of three (3) years after the expiration or termination of this Agreement, except as otherwise provided in this Article 12 or with regard to CEII, each Party shall hold in confidence and shall not disclose to any person Confidential Information. CEII shall be treated in accordance with Commission policies and regulations.

12.1.2 Scope. Confidential Information shall not include information that the receiving Party can demonstrate: (1) is generally available to the public other than as a result of a disclosure by the receiving Party; (2) was in the lawful possession of the receiving Party on a non-confidential basis before receiving it from the disclosing Party; (3) was supplied to the receiving Party without restriction by a non-Party, who, to the knowledge of the receiving Party after due inquiry, was under no obligation to the disclosing Party to keep such information confidential; (4) was independently developed by the receiving Party without reference to Confidential Information of the disclosing Party; (5) is, or becomes, publicly known, through no wrongful act or omission of the receiving Party or Breach of this Agreement; or (6) is required, in accordance with Article 12.1.7 of this Agreement, to be disclosed by any Governmental Authority or is otherwise required to be disclosed by law or subpoena, or is necessary in any legal proceeding establishing rights and obligations under this Agreement. Information designated as Confidential Information will no longer be deemed confidential if the Party that designated the information as confidential notifies the receiving Party that it no longer is confidential.

12.1.3 Release of Confidential Information. No Party shall release or disclose Confidential Information to any other person, except to its Affiliates (limited by the Standards of Conduct requirements), subcontractors, employees, agents, consultants, or to non-parties who may be or are considering providing financing to the Transmission Line Payers, or to potential purchasers of the Transmission Line Payer, on a need-to-know basis in connection with this Agreement, unless such person has first been advised of the confidentiality provisions of this Article 12 and has agreed to comply with such provisions. Notwithstanding the foregoing, a Party providing Confidential Information to any person shall remain

primarily responsible for any release of Confidential Information in contravention of this Article 12.

12.1.4 Rights. Each Party retains all rights, title, and interest in the Confidential Information that it discloses to the receiving Party. The disclosure by a Party to the receiving Party of Confidential Information shall not be deemed a waiver by the disclosing Party or any other person or entity of the right to protect the Confidential Information from public disclosure.

12.1.5 No Warranties. By providing Confidential Information, no Party makes any warranties or representations as to its accuracy or completeness. In addition, by supplying Confidential Information, no Party obligates itself to provide any particular information or Confidential Information to another Party nor to enter into any further agreements or proceed with any other relationship or joint venture.

12.1.6 Standard of Care. Each Party shall use at least the same standard of care to protect Confidential Information it receives as it uses to protect its own Confidential Information from unauthorized disclosure, publication, or dissemination. Each Party may use Confidential Information solely to fulfill its obligations to another Party under this Agreement or its regulatory requirements.

12.1.7 Order of Disclosure. If a court or a Governmental Authority or entity with the right, power, and apparent authority to do so requests or requires any Party, by Freedom of Information Act request, subpoena, oral deposition, interrogatories, requests for production of documents, administrative order, or otherwise, to disclose Confidential Information, that Party shall provide the disclosing Party with prompt notice of such request(s) or requirement(s) so that the disclosing Party may seek an appropriate protective order or waive compliance with the terms of this Agreement. Notwithstanding the absence of a protective order or waiver, the Party may disclose such Confidential Information which, in the opinion of its counsel, the Party is legally compelled to disclose. Each Party will use Reasonable Efforts to obtain reliable assurance that confidential treatment will be accorded any Confidential Information so furnished.

12.1.8 Termination of Agreement. Upon termination of this Agreement for any reason, each Party shall, within ten (10) Calendar Days of receipt of a written request from another Party, use Reasonable Efforts to destroy, erase, or delete (with such destruction, erasure, and deletion certified in writing to the requesting Party) or return to the requesting Party any and all written or electronic

Confidential Information received from the requesting Party, except that each Party may keep one copy for archival purposes, provided that the obligation to treat it as Confidential Information in accordance with this Article 12 shall survive such termination.

12.1.9 Remedies. The Parties agree that monetary damages would be inadequate to compensate a Party for another Party's Breach of its obligations under this Article 12. Each Party accordingly agrees that the disclosing Party shall be entitled to equitable relief, by way of injunction or otherwise, if the receiving Party Breaches or threatens to Breach its obligations under this Article 12, which equitable relief shall be granted without bond or proof of damages, and the breaching Party shall not plead in defense that there would be an adequate remedy at law. Such remedy shall not be deemed an exclusive remedy for the Breach of this Article 12, but shall be in addition to all other remedies available at law or in equity. The Parties further acknowledge and agree that the covenants contained herein are necessary for the protection of legitimate business interests and are reasonable in scope. No Party, however, shall be liable for direct, indirect, incidental or consequential or punitive damages of any nature or kind resulting from or arising in connection with this Article 12 except to the extent of any and all gains wrongfully acquired, directly or indirectly, from unauthorized disclosure of any Confidential Information covered by this Agreement.

12.1.10 Disclosure to FERC, Its Staff, or a State. Notwithstanding anything in this Article 12 to the contrary, and pursuant to 18 C.F.R. § 1b.20, if FERC or its staff, during the course of an investigation or otherwise, requests Confidential Information from a Party that is otherwise required to be maintained in confidence pursuant to this Agreement, the Party shall provide the requested Confidential Information to FERC or its staff, within the time provided for in the request for information. In providing the Confidential Information to FERC or its staff, the Party must, consistent with 18 C.F.R. § 388.112, request that the Confidential Information be treated as confidential and non-public by FERC and its staff and that the Confidential Information be withheld from public disclosure. To the extent provided by applicable law, the Parties are prohibited from notifying the other Parties to this Agreement prior to the release of the Confidential Information to FERC or its staff. The Party shall notify the other Parties to the Agreement when it is notified by FERC or its staff that a request to release Confidential Information has been received by FERC, at which time any of the Parties may respond before such information would be made public, pursuant to 18 C.F.R. §388.112. Requests from a state regulatory body

conducting a confidential investigation shall be treated in a similar manner if consistent with applicable law.

12.1.11 Subject to the exception in Article 12.1.10, any information that a disclosing Party claims is competitively sensitive, commercial or financial information under this Agreement shall not be disclosed by the receiving Party to any person not employed or retained by the receiving Party, except to the extent disclosure is (i) required by law; (ii) reasonably deemed by the disclosing Party to be required to be disclosed in connection with a dispute between or among the Parties, or the defense of litigation or dispute; (iii) otherwise permitted by consent of the disclosing Party, such consent not to be unreasonably withheld; or (iv) necessary to fulfill its obligations under this Agreement or as the Regional Transmission Organization or a Local Balancing Authority operator including disclosing the Confidential Information to a regional or national reliability organization. The Party asserting confidentiality shall notify the receiving Party in writing of the information that Party claims is confidential. Prior to any disclosures of that Party's Confidential Information under this subparagraph, or if any non-Party or Governmental Authority makes any request or demand for any of the information described in this subparagraph, the Party who received the Confidential Information from the disclosing Party agrees to promptly notify the disclosing Party in writing and agrees to assert confidentiality and cooperate with the disclosing Party in seeking to protect the Confidential Information from public disclosure by confidentiality agreement, protective order or other reasonable measures.

ARTICLE 13
INFORMATION ACCESS AND AUDIT RIGHTS

13.1 Information Access. Each Party shall make available to the other Parties information necessary to verify the costs incurred by the other Parties for which the requesting Party is responsible under this Agreement and carry out obligations and responsibilities under this Agreement, provided that the Parties shall not use such information for purposes other than those set forth in this Article 13.1 and to enforce their rights under this Agreement.

13.2 Audit Rights. Subject to the requirements of confidentiality under Article 12 of this Agreement, the accounts and records related to the design, engineering, procurement, construction, installation and commissioning of the CUU shall be subject to audit during the period of this Agreement and for a period of twenty-four (24) months following the CUU Transmission Owners' issuance of a final invoice in accordance with Article 6.4.

The Transmission Line Payers may jointly or individually, at the expense of the requesting Party or Parties, during normal business hours and upon prior reasonable notice to the other Parties, audit such accounts and records, provided, however, that the CUU Transmission Owners shall not be required to cooperate with more than one audit per quarter (accordingly, if more than one Transmission Line Payer wishes to conduct an audit within a given calendar quarter, they must do so jointly). Any audit authorized by this Article 13.2 shall be performed at the offices where such accounts and records are maintained and shall be limited to those portions of such accounts and records that relate to obligations under this Agreement.

ARTICLE 14
DISPUTES

14.1 Submission. Any claim or dispute which a Party may have against another Party or Parties, arising out of this Agreement that concerns Tariff related matters shall be submitted for resolution in accordance with the dispute resolution provisions of the Tariff. All matters arising out of this Agreement concerning the Transmission Provider shall be submitted for resolution in accordance with the dispute resolutions of the Tariff. All other claims or disputes shall be resolved in accordance with the following provisions of this Article 14.

14.2 Condition Precedent to Arbitration. Prior to initiation of arbitration, any controversy, claim or dispute between any of the Parties shall be first referred in writing to the Executive Officers of the Parties to the dispute for review and decision. Any decision by the Executive Officers to resolve a controversy, claim or dispute must be unanimous. If the controversy, claim or dispute is not resolved within thirty (30) Calendar Days after referral to the Executive Officers, any of the Parties to the dispute may proceed to arbitration.

14.3 Initiation. Arbitration proceedings must be initiated within one hundred and twenty (120) Calendar Days of the date the controversy, claim or dispute was first referred to the Executive Officers and shall be initiated by written notice to the other Party or Parties to the dispute setting forth the point or points in dispute. Unless otherwise agreed to in writing by the Parties to the dispute, failure to initiate arbitration within such one hundred and twenty (120) day period shall be deemed a waiver of the right to arbitrate that controversy, claim or dispute. Provided however, that any such waiver shall not preclude a Party from initiating arbitration proceedings in respect of a similar claim, controversy or dispute based on facts that arise subsequent to the date the controversy, claim or dispute was first submitted to the Executive Officers.

14.4 Arbitration Proceedings. Subject to Article 14.1 above, any and all controversies, claims

or disputes between the Parties arising out of or relating to this Agreement or an alleged breach thereof, shall be settled by arbitration. For greater clarity and certainty, arbitration shall not be available to anyone who is not a Party to this Agreement, and the aforesaid requirement to arbitrate shall not preclude a Party or Parties to the dispute from seeking contribution, indemnification or damages from another Person in proceedings instituted by third parties in courts of competent jurisdiction. Unless otherwise provided in this Article, the arbitration shall be conducted before three arbitrators and shall be conducted in accordance with the International Commercial Arbitration Act (Ontario), RSO 1990, c.I9 and the UNCITRAL model Law on International Commercial Arbitration as amended and then in effect. If there are two Parties to the dispute, each Party shall select one arbitrator, and the two selected arbitrators shall jointly agree, within 30 Calendar Days after the last of the two arbitrators have been appointed, on a third arbitrator who shall chair the arbitration. If there are more than two Parties to the dispute the Parties shall jointly appoint three arbitrators provided that if the Parties are unable to reach agreement on the appointment of the three arbitrators one arbitrator shall be appointed in accordance with the International Commercial Arbitration Act (Ontario), RSO 1990, c.I9 and the UNCITRAL model Law on International Commercial Arbitration as amended and then in effect. All arbitrators shall be competent by virtue of education and experience in the particular matter subject to arbitration. Before proceeding with the first hearing, each arbitrator shall take an oath of office. The arbitrators shall require witnesses to testify under oath administered by a duly qualified person. The arbitrators shall have jurisdiction and authority only to interpret, apply or determine compliance with the provisions of this Agreement insofar as shall be necessary to determine the particular matter subject to arbitration. The arbitrators shall not have jurisdiction or authority to add to, detract from, or alter the provisions of this Agreement or any applicable law or rule of civil procedure. The arbitrators shall have the power to order specific performance under any and all provisions of this Agreement and no Party can avoid specific performance based on an argument that the other Party or Parties to the dispute has or have an adequate remedy at law. All arbitrations shall be held in or near St. Paul, Minnesota.

14.5 Jurisdiction. The arbitrators may rule on their own jurisdiction, including any objections with respect to the existence or validity of this Agreement. For that purpose, this Article shall be treated as an agreement independent of the terms of the balance of this Agreement. A decision by the arbitrators that this Agreement is null and void shall not entail ipso jure the invalidity of this Article. If a Party disputes the authority or jurisdiction of the arbitrators, it shall notify the other Party or Parties to the dispute as soon as the matter alleged to be beyond the authority or jurisdiction of the arbitrators is raised during the arbitration proceedings. The arbitrators may rule on the issue as to whether or not they have the authority or jurisdiction in dispute, either as a preliminary question or in an award on the merits.

14.6 Continuation of Performance. Pending the final decision of the arbitrators, the Parties to the dispute agree to diligently proceed with the performance of all obligations, including the payment of all sums required by this Agreement. Payment of any interest shall be as determined by the arbitrator.

14.7 Costs. All fees, costs and expenses of the arbitrators incurred in connection with the arbitration shall be allocated among the Parties to the dispute by the arbitrators. The nature of the dispute and the outcome of the arbitration shall be factors considered by the arbitrators when allocating such fees, costs, and expenses. Each Party to the dispute shall be responsible for the fees, costs, and expenses of its own employees, expert consultants and attorneys, and for the costs of exhibits and other incidental costs.

14.8 Enforcement. Any decision (including orders arising out of disputes as to the scope or appropriateness of a request for, or a response to, discovery) of an arbitrator may be enforced in a court of competent jurisdiction with all costs, including court costs and attorney's fees and disbursements, paid by the Party or Parties to the dispute found to be in error. Judgment upon the award rendered by the arbitrators may be entered in any court of competent jurisdiction and may be enforced in accordance with the Convention on the Recognition and Enforcement of Foreign Arbitral Awards.

14.9 Correction and Interpretation of Award. Within thirty (30) Calendar Days after receipt of an arbitration award, a Party, with notice to the other Party or Parties to the dispute, may request the arbitrators to correct in the award any errors in computation, any clerical or typographical errors or any errors of similar nature, or may request the arbitrators to give an interpretation of a specific point or a part of the award. If the arbitrators consider the request to be justified, they shall make the correction or give the interpretation within thirty (30) Calendar Days after receipt of the request. The interpretation shall form part of the award. The arbitrators may correct any error as herein-before referred to on their own initiative within thirty (30) calendar days after the date of award. In addition, within thirty (30) Calendar Days after receipt of an award, a Party with notice to the other Party or Parties to the dispute may request the arbitrators to make an additional award as to claims presented in the arbitration but omitted from the award. If the arbitrators consider the request to be justified, they shall make an additional award within sixty (60) Calendar Days after receipt of the request. The arbitrators may extend, at their sole discretion if necessary, the period of time within which they shall make a correction, interpretation or an additional award.

14.10 Rights under the Federal Power Act. Nothing in this Article 14 shall restrict the rights of any Party to file a complaint with FERC under relevant provisions of the Federal Power Act.

14.11 Equitable Remedies. Nothing in this Article shall prevent a Party from pursuing or seeking any equitable remedy available to it under Applicable Laws and Regulations, at any time, before a Governmental Authority.

ARTICLE 15
NOTICES

15.1 General. Except for notice required pursuant to Article 6, any notice to be provided to a Transmission Line Payer shall also be provided to the CUU Transmission Customers. Any notice, demand or request required or permitted to be given by a Party to another Party and any instrument required or permitted to be tendered or delivered by a Party in writing to another Party may be so given, tendered, or delivered, as the case may be, by depositing the same with the United States Postal Service with postage prepaid, for transmission by certified or registered mail, addressed to the Parties, or personally delivered to the Parties, at the address set out below:

Transmission Provider:

USPS mailing address:
Midcontinent ISO
Attn: Director, Transmission Access Planning
P.O. Box 4202
Carmel, IN 46082-4202

For overnight deliveries:
Midcontinent ISO
Attn: Director, Transmission Access Planning
720 City Center Drive
Carmel, IN 46032

To CUU Transmission Owners:

Minnesota Power
30 West Superior
Street Duluth, MN
55802
Attention: Vice President – Transmission and Distribution

6690271 Manitoba Ltd.

6690271 Manitoba Ltd.
Attention: Lorne Midford- President

Post Office Box 1886
Winnipeg, Manitoba
R3C 3R2
Fax 204-360-6138

with copies to: 6690271 Manitoba Ltd.
Attention: H.D. Maxwell – General Manager
Post Office Box 1886
Winnipeg, Manitoba
R3C 3R2
Fax 204-360-6137

To Transmission Line Payers:

Minnesota Power
30 West Superior
Street Duluth, MN
55802
Attention: Transmission Marketing Manager

66902771 Manitoba Ltd.

6690271 Manitoba Ltd.
Attention: Lorne Midford- President
Post Office Box 1886
Winnipeg, Manitoba
R3C 3R2
Fax 204-360-6138

with copies to: 6690271 Manitoba Ltd.
Attention: H.D. Maxwell- General Manager
Post Office Box 1886
Winnipeg, Manitoba
R3C 3R2
Fax 204-360-6137

To CUU Transmission Customers:

Manitoba Hydro
Attention: David Cormie, Division Manager Power Sales
& Operations

Post Office Box 815
Winnipeg, Manitoba
R3C 2P4
Fax: (204) 360-6137

Minnesota Power
Attention: Cindy Hammarlund, Transmission Marketing Manager
30 West Superior Street
Duluth, MN 55802
Fax: (218) 723-3955

Wisconsin Public Service Corporation
Attention: Jody C Arendt, General Manager - Energy Supply & Control
700 N Adams St
Green Bay WI 54301
Fax: 920-433-4986

15.2 Billings and Payments. Billings and payments shall be sent to the addresses shown in Article 15.1 unless otherwise agreed to by the Parties.

Transmission Provider:

USPS mailing address:
Midcontinent ISO
Attn: Director, Transmission Access Planning
P.O. Box 4202
Carmel, IN 46082-4202

For overnight deliveries:
Midcontinent ISO
Attn: Director, Transmission Access Planning
720 City Center Drive
Carmel, IN 46032

To CUU Transmission Owners:

Minnesota Power
30 West Superior Street Duluth, MN 55802
Attention: Vice President – Transmission and Distribution

6690271 Manitoba Ltd.

6690271 Manitoba Ltd.
Attention: Lorne Midford- President
Post Office Box 1886
Winnipeg, Manitoba
R3C 3R2
Fax 204-360-6138

with copies to: 6690271 Manitoba Ltd.
Attention: H.D. Maxwell - General Manager
Post Office Box 1886
Winnipeg, Manitoba
R3C 3R2
Fax 204-360-6137

To Transmission Line Payers:

Minnesota Power
30 West Superior
Street Duluth, MN
55802
Attention: Transmission Marketing Manager

6690271 Manitoba Ltd.

6690271 Manitoba Ltd.
Attention: Lorne Midford- President
Post Office Box 1886
Winnipeg, Manitoba
R3C 3R2
Fax 204-360-6138

with copies to: 6690271 Manitoba Ltd.
Attention: H.D. Maxwell – General Manager
Post Office Box 1886
Winnipeg, Manitoba
R3C 3R2
Fax 204-360-6137

15.3 Alternative Forms of Notice. Any notice or request required or permitted to be given by a Party to another Party and not required by this Agreement to be given in writing

may be so given by telephone, facsimile or email to the telephone numbers and email addresses set out below:

Transmission Provider:

Voice telephone – (317) 249-5700
Facsimile telephone – (317) 249-5358
Email address –misotap@misoenergy.org or
MISOTransmissionAccessPlanning@misoenergy.org

To CUU Transmission Owners:

Minnesota Power
Phone: (218) 355-2695
Fax: (218) 723-3955
Email address: cfleege@mnpower.com

6690271 Manitoba Ltd.

Voice telephone - (204) 360-7002
Facsimile telephone - (204) 360-6138
Email address: lemidford@hydro.mb.ca

To Transmission Line Payers:

Minnesota Power
Phone: (218) 355-3970
Fax: (218) 723-3955
Email address: chammarlund@mnpower.com

6690271 Manitoba Ltd.
Voice telephone - (204) 360-7002
Facsimile telephone - (204) 360-6138
Email address: lemidford@hydro.mb.ca

To CUU Transmission Customers:

Manitoba Hydro
Phone: (204) 360-3405
Fax: (204) 360-6137
Email address: bmukanik@hydro.mb.ca

Minnesota Power
Phone: (218) 355-3970
Fax: (218) 723-3955
Email address: chammarlund@mnpower.com

Wisconsin Public Service Corporation
Voice telephone: (920) 433-1090
Fax: 920-433-4986
Email address: jcarendt@wisconsinpublicservice.com

15.4 Notification of In-Service Date. CUU Transmission Owners will serve to Transmission Provider a copy of Appendix B as forwarded to Transmission Line Payers on the same day to the address shown in Article 15.1, and by facsimile telephone to the numbers set out below:

To Transmission Provider:

Facsimile telephone - (317) 249-5703

And copy to
Midcontinent Independent System Operator, Inc.
Attn: Director, Transmission Access Planning

P.O. Box 4202
Carmel, IN 46082-4202

for overnight deliveries:
720 City Center Drive
Carmel, IN 46032

ARTICLE 16
MISCELLANEOUS

16.1 Waiver. Except as otherwise provided for in this Agreement, the failure of any Party to comply with any obligation, covenant, agreement, or condition herein may be waived by the Parties entitled to the benefits thereof only by a written instrument signed by the Parties granting such waiver. Any waiver at any time by a Party of its rights with respect to a Default under this Agreement, or with respect to any other matters arising in connection with this Agreement, shall not be deemed a waiver or continuing waiver with respect to any subsequent Default or other matter.

16.2 Governing Law. The validity, interpretation and performance of this Agreement and each of its provisions shall be governed by the laws of the state where the CUU is located, without regard to its conflicts of law principles

16.3 Headings Not to Affect Meaning. The descriptive headings of the various Sections and Articles of this Agreement have been inserted for convenience of reference only and shall in no way modify or restrict any of the terms and provisions hereof.

16.4 Amendments and Rights Under the Federal Power Act. Transmission Provider shall have the right to make a unilateral filing with FERC under Section 205 or any other applicable provision of the Federal Power Act and FERC's rules and regulations thereunder to modify this Agreement with respect to any rates, terms and conditions, charges, classifications of service, rule or regulation; provided that Transmission Provider may not exercise this unilateral filing right to alter capital cost responsibility of the Transmission Line Payers under the Agreement in a manner other than as provided under Article 2.2.5 or in a FERC order. The CUU Transmission Owners and Transmission Line Payers shall have the right to make a unilateral filing with FERC to modify this Agreement pursuant to Section 206 or any other applicable provision of the Federal Power Act and FERC's rules and regulations there under; provided, however, that each Party shall have the right to protest any such filing and to participate fully in any proceeding before FERC in which such modifications may be considered. Notwithstanding the foregoing, Transmission Provider agrees that (a) at least thirty (30) days prior to making any unilateral filing with FERC to modify this Agreement, it shall provide the Parties with a copy of the proposed modification(s) to this Agreement and the reasons why Transmission Provider believes that such modification(s) are necessary and shall afford the Parties an opportunity to discuss whether such modification(s) are necessary or whether alternative modifications are in the best interests of all of the Parties; and (b) if at the time of the filing all of the Parties are not in agreement with the Transmission Provider's proposed modification(s), the Transmission Provider will include in its unilateral filing with FERC an alternative proposal supported by the CUU

Transmission Owners and Transmission Line Payers, to be considered by FERC contemporaneously with the Transmission Provider's proposed modification(s). Nothing in this Agreement shall limit the rights of the Parties or of FERC under Sections 205 or 206 of the Federal Power Act and FERC's rules and regulations there under, except to the extent that the Parties otherwise mutually agree as provided herein.

16.5 Entire Agreement. This Agreement, together with all the appendices and exhibits, constitutes the final and entire written agreement among the Parties hereto with reference to the subject matter hereof, and is a complete and exclusive statement of those terms and conditions and supersedes all prior negotiations, representations or agreements, either written or oral, with respect to the specific subject matter of this Agreement. No change or modification as to any of the provisions hereof shall be binding on any Party unless reduced to writing and approved by the duly authorized officer or agent of each of the Transmission Line Payers, each of the CUU Transmission Owners, and the Transmission Provider.

16.6 Counterparts. This Agreement may be executed in any number of counterparts, and each executed counterpart shall have the same force and effect as an original instrument.

16.7 Binding Effect. This Agreement and the rights and obligations hereof, shall be binding upon and shall inure to the benefit of the Parties hereto and their successors and assigns. No person or party shall have any rights, benefits or interests, direct or indirect, arising from this Agreement except the Parties hereto, their successors and authorized assigns. The Parties expressly disclaim any intent to create any rights in any person or party as a third party beneficiary to this Agreement.

16.8 Conflicts. In the event of a conflict between the body of this Agreement and any attachment, appendix or exhibit hereto, the terms and provisions of the body of this Agreement shall prevail and be deemed to be the final intent of the Parties except in respect of Appendix A where in the event of conflict with the body of this Agreement the provisions of Appendix A shall prevail and be deemed to the final intent of the Parties.

16.9 Regulatory Requirements. Each Party's obligations under this Agreement shall be subject to its receipt of any required approval or certificate from one or more Governmental Authorities in the form and substance satisfactory to the receiving Party, or the Party making any required filings with, or providing notice to, such Governmental Authorities, and the expiration of any time period associated therewith. Each Party shall in good faith seek these other approvals as soon as is reasonably practicable.

16.10 Trial by Jury. Each Party hereby irrevocably waives to the fullest extent permitted by applicable law, any and all rights it may have to trial by jury with respect to any legal proceeding arising out of or relating to this Agreement and any agreement executed or contemplated to be executed in conjunction with this Agreement. This provision is a material inducement to each of the Parties for entering into this Agreement. Each Party hereby waives any right to consolidate any action, proceeding, or counterclaim arising out of or in connection with this Agreement and any other agreement executed or contemplated to be executed in conjunction with this Agreement, or any matter arising hereunder or thereunder in which a jury trial has not or cannot be waived.

16.11 Enurement. This Agreement shall be binding upon and its benefits enure to the Parties and their permitted successors and assigns. This Agreement shall not create the relationship between any of the Parties of a joint venture or a partnership.

16.12 Conditions Precedent. The obligation of the CUU Transmission Owners and the Transmission Line Payers to complete all or a portion of the matters referenced in this Agreement shall be subject to and contingent upon the fulfillment of the conditions precedent set out in Appendix A in accordance with the provisions of Appendix A.

16.13 Recitals. The recitals hereto shall form an integral part of this Agreement.

ARTICLE 17

REPRESENTATIONS AND WARRANTIES

17.1 General. Each Party hereby represents, warrants and covenants as follows with these representations, warranties, and covenants effective as to the Party during the full time this Agreement is effective:

17.1.1. Good Standing. Such Party is duly organized or formed, as applicable, validity existing and in good standing under the laws of its jurisdiction of organization or formation, and is in good standing under the laws of the respective jurisdictions(s) of their organization as stated in the preamble of this Agreement.

17.1.2 Authority. Such Party has the right, power and authority to enter into this Agreement, to become a party hereto and to perform its obligations hereunder, and this Agreement is a legal, valid and binding obligation of such Party, enforceable against such Party in accordance with its terms.

17.1.3 No Conflict. The execution, delivery and performance of this Agreement does not violate or conflict with the organizational or formation documents, or bylaws or operating agreement, of such Party, or any judgment, license, permit or order or material agreement or instrument applicable to or binding upon such Party or any of its assets.

17.1.4 Consent and Approval. That it has sought or obtained, or, in accordance with this Agreement will seek or obtain, each consent, approval, authorization or order of, or acceptance of a filing with, or notice to, any Governmental Authority with jurisdiction concerning this Agreement, in connection with the execution, delivery and performance of this Agreement.

17.1.5 Solvency. That such Party is financially solvent.

IN WITNESS WHEREOF, the Parties have executed this Agreement in multiple originals, each of which shall constitute and be an original effective Agreement among the Parties as of the day and year first above written.

Midcontinent Independent System Operator, Inc.

By: Jennifer Curran JCB 9/25/14

Name: Jennifer Curran
JENNIFER CURRAN
Vice President
System Planning & Seams Coordination

Title: Vice President, System Planning and Seams Coordination

Minnesota Power – CUU Transmission Owner

By: _____

Name: Alan R. Hodnik

Title: Chairman, President and Chief Executive Officer

6690271 Manitoba Ltd. –CUU Transmission Owner

By: _____

Name: Lorne Midford

Title: President

Minnesota Power -Transmission Line Payer

By: _____

Name: Alan R. Hodnik

Title: Chairman, President and Chief Executive Officer

6690271 Manitoba Ltd. –Transmission Line Payer

By: _____

Name: Lorne Midford

Title: President

IN WITNESS WHEREOF, the Parties have executed this Agreement in multiple originals, each of which shall constitute and be an original effective Agreement among the Parties as of the day and year first above written.

Midcontinent Independent System Operator, Inc.

By:_____

Name: Jennifer Curran

Title: Vice President, System Planning and Seams Coordination

Minnesota Power – CUU Transmission Owner

By:_____

Name: Alan R. Hodnik

Title: Chairman, President and Chief Executive Officer

6690271 Manitoba Ltd. –CUU Transmission Owner

By:_____

Name: Lorne Midford

Title: President

Minnesota Power -Transmission Line Payer

By:_____

Name: Alan R. Hodnik

Title: Chairman, President and Chief Executive Officer

6690271 Manitoba Ltd. –Transmission Line Payer

By:_____

Name: Lorne Midford

Title: President

IN WITNESS WHEREOF, the Parties have executed this Agreement in multiple originals, each of which shall constitute and be an original effective Agreement among the Parties as of the day and year first above written.

Midcontinent Independent System Operator, Inc.

By:_____

Name: Jennifer Curran

Title: Vice President, System Planning and Seams Coordination

Minnesota Power – CUU Transmission Owner

By: _____
Name: Alan R. Hodnik
Title: Chairman, President and Chief Executive Officer

6690271 Manitoba Ltd. –CUU Transmission Owner

By: 
Name: Lorne Midford
Title: President

Minnesota Power -Transmission Line Payer

By: _____
Name: Alan R. Hodnik
Title: Chairman, President and Chief Executive Officer

6690271 Manitoba Ltd. –Transmission Line Payer

By: 
Name: Lorne Midford
Title: President

Multi-Party Facilities Construction Agreement

APPENDIX A

THE CUU, COST ESTIMATES AND RESPONSIBILITY, CONSTRUCTION SCHEDULE AND PAYMENT SCHEDULE

This Appendix A is an integral part of the Multi-Party Facilities Construction Agreement between the Transmission Line Payers, the CUU Transmission Owners, and the Transmission Provider (the "**Agreement**"). Terms used in this Appendix A with initial capitalization not defined in this Appendix A shall have the meaning set out in the Agreement.

1.0 Common Use Upgrades.

The Transmission Provider's TSR study disclosed that the CUU Transmission Customers' TSRs caused transmission line constraints requiring the Common Use Upgrades as more particularly set out in this Appendix A. Due to the extensive permitting and regulatory efforts, the significant financial obligations and the complex scheduling needed to construct and install the CUU, the CUU Transmission Owners have developed a two (2) phase approach to assist in meeting the In-Service Date. The two (2) phases are comprised of: (i) Certification Phase; and (ii) Construction Phase. Each phase has its own separate financial, regulatory and construction obligations and milestones and certain conditions and provisions applicable only to such phase as set out in this Appendix A. The CUU Transmission Owners shall provide quarterly progress reports to the Parties. The GNTL progress reports shall be issued no later than 30 days after each calendar quarter.

1.1 Certification Phase.

1.1.1 The certification phase will consist of the CUU Transmission Owners developing, filing and securing approvals of all major permits (the "**Major Permits**") required for the Common Use Upgrades to proceed in the United States after all Certification Phase Conditions Precedent are satisfied or waived (the "**Certification Phase**"). The Major Permits are identified in Section 1.1.4 of this Appendix A. The Certification Phase will include strategic planning, communications, agency coordination related to state and federal permits, routing, stakeholder and public involvement, field studies and surveys, preparation of permit applications, support of regulatory review processes, preliminary engineering design and legal services. Permitting activities will continue to overlap with additional engineering and construction activities during the Construction Phase.

1.1.2 The Certificate of Need and Route Permit referenced in Section 1.1.4 are required by the State of Minnesota and are issued by the Minnesota Public Utilities Commission. A Certificate of Need and a Route Permit are anticipated to be separately approved by the Minnesota Public Utilities Commission, within two and one-half years after submittal of the first application.

1.1.3 The Presidential Permit and Section 404 Wetland Permit referenced in Section 1.1.4 are Federal approvals and are issued by the US Department of Energy and U.S. Army Corps of Engineers respectively. The approval process for these two Major Permits includes a federally led environmental impact assessment. The Presidential Permit is anticipated to be issued within one and one-half years after submittal of the application for this permit. The Section 404 Wetland Permit is anticipated to be issued within one year after submittal of the application.

1.1.4 The Major Permits required for the Common Use Upgrades, referred to in Sections 1.1.2 and 1.1.3, as well as their anticipated durations of review and approval based on the review of relevant projects and the various assumptions identified, are listed below:

	Administering Agency	Anticipated Start Date (or Submittal of Application)	Anticipated End Date
Presidential Permit	U.S. Department of Energy	April 2014	December 2015
Certificate of Need	Minnesota Public Utilities Commission	October 2013	May 2015
Route Permit	Minnesota Public Utilities Commission	April 2014	December 2015
Section 404 Wetlands Permit	U.S. Army Corps of Engineers	January 2015	October 2015

1.1.5 Upon approval of the Route Permit by the Minnesota Public Utilities Commission the CUU Transmission Owners shall begin certain preliminary construction related activities deemed necessary by the CUU Transmission Owners in order to achieve the In-Service Date. These activities are comprised of the engagement of land agents, land surveys and research, land acquisition and clearing as well as initial procurement of long lead time materials such as conductors and towers and such other matters as the CUU Transmission Owners and Transmission Line

Payers may mutually agree upon. The CUU Transmission Owners acknowledge and agree that such activities will not include obtaining easements before March 31, 2016, unless the CUU Transmission Owners and Transmission Line Payers mutually agree to an earlier date. The Transmission Line Payers are to provide additional performance assurance for this activity if required by Article 6.1 of this Agreement.

1.1.6 Completion of the Certification Phase will be achieved when all of the Major Permits are obtained and all Construction Phase Conditions Precedent have been satisfied or waived. It is estimated that the Certification Phase will continue until the second half of 2016. During the Certification Phase additional state and federal approvals will also be obtained but unlike the Major Permits such approvals are not required prior to proceeding to the Construction Phase.

1.1.7 The Transmission Line Payers acknowledge that MP on behalf of and with the consent of the CUU Transmission Owners has begun the Certification Phase prior to the execution date of this Agreement and that these activities and associated cost, charges and expenses were required to ensure timely completion of the Certification Phase in order to meet the In-Service Date presently scheduled as June 1, 2020 ("**Pre-Certification Phase Expenses**"). Each Transmission Line Payer agrees to pay to the CUU Transmission Owners for the share of the costs, charges and expenses of the Certification Phase component as set out in the CUU Cost Allocation Summary Table (Table 2(B) below) including the Pre-Certification Phase Expenses after netting such amounts against payment made for such costs, charges and expenses prior to the Effective Date. A current detailed schedule of anticipated payment obligations arising from Table 2(B) shall be provided by the CUU Transmission Owners on request from a Transmission Line Payer. The costs, charges and expenses consist of internal labor expenses, travel expenses, and costs and charges of outside consultants, engineering services, regulatory expenses, and outside legal counsel and shall be limited to those incurred in accordance with Good Utility Practice. Subject to Articles 1.1.8 and 1.8 of this Appendix A, payments in respect of the Certification Phase payments will be made by the Transmission Line Payers upon submission by the CUU Transmission Owners of: (i) invoices to the Transmission Line Payers for their share of Pre-Certification Phase Expenses; and (ii) monthly invoicing to the Transmission Line Payers for expenses following the execution of this Agreement, as more particularly set out in Table 3.

1.1.8 The Parties acknowledge in accordance with Article 1.8 of this Appendix A that the obligations of each Transmission Line Payer to make its payments as set out

in Article 1.1.7 of this Appendix A and to fulfill its other obligations in respect of the Certification Phase are subject to and contingent upon the satisfaction of the Certification Phase Conditions Precedent.

1.2 Construction Phase.

1.2.1 The Construction Phase will consist of that component of the Common Use Upgrades needed for the granting of the interconnection of the Transmission Customers' TSRs after all Major Permits are secured and all Construction Phase Conditions Precedent are satisfied or waived (the "**Construction Phase**").

1.2.2 The Construction Phase will include the construction of a new 500 kV transmission line in Minnesota from the United States/Canadian border to the Minnesota Power Blackberry Substation in the Grand Rapids, Minnesota area (the "**500 kV Line**"), an associated 500 kV substation and a 500 kV series compensation station. The 500 kV Line will be approximately 220 miles in length and will be constructed on a 200 foot wide right of way. The 500 kV Line will be part of a new 500 kV international transmission interconnection (the "**500 kV Interconnection**"). Manitoba Hydro will be constructing the Canadian portion of the 500 kV Interconnection which is not part of this Agreement.

1.2.3 A detailed design for the 500 kV Line has not been prepared at this time. Conceptual structure configurations have been prepared for use during the routing process. Following the identification of a route, a detailed design will be prepared that incorporates and complies with the design criteria. As the detailed design is prepared, the preliminary design criteria in the Minnesota Power Great Northern 500kV Transmission Line Project Facilities Study will be expanded, as needed, to include the criteria and parameters established for the detailed design.

Several structure types and configurations were developed for the preliminary design of the 500 kV Line, including: a lattice guyed-V structure, a self-supporting lattice structure, a lattice guyed delta structure, and a self-supporting lattice delta structure. The type of structure in any given section of transmission line will be dependent on land type and land use.

The 500 kV Line will be designed to meet or exceed the applicable clearances recommended in the National Electrical Safety Code (NESC). The preliminary design criteria for the Project assumed a minimum conductor-to-ground clearance of 40 feet.

For the purpose of budgetary estimates, it has been assumed that, each phase of the 500 kV Line will consist of three 1,192.5kcmil ACSR 45/7 conductors, codename "Bunting", the sub-conductors will be arranged in an 'inverted delta' triangular bundle with 18" spacing and the structures will be designed to support two 48-fiber optical ground wires (OPGW). Detailed design of the 500 kV line will begin during the Certification Phase and continue into the Construction Phase.

1.2.4 The 500 kV Line will terminate at a new substation ("**Blackberry 500 kV Substation**") located on the same site as Minnesota Power's existing Blackberry 230/115 kV Substation. The Blackberry 500 kV Substation will be located adjacent to and east of the existing substation, and will be designed to accommodate the new 500 kV line, 500/230 kV transformation, existing 230 kV lines, and all associated 500 kV and 230 kV equipment.

The CUU will also require a new 500kV series compensation station ("**500 kV Series Compensation Station**"), which will be located within or adjacent to the final approved route. The 500 kV Series Compensation Station will include the 500 kV series capacitor banks necessary for the reliable operation and optimal performance of the CUU, and all associated 500 kV equipment.

The arrangement of the Blackberry 500 kV Substation is designed to accommodate the CUU and facilitate possible future expansion. The 500kV transformer breaker required for the Project will be located such that the 500kV yard can ultimately be arranged in a "ring bus" configuration. The 230kV breakers required for the CUU will be arranged in what is known as a "breaker-and-a-half" configuration. Space outside of the fence will be reserved for the 500kV expansion as well as a future 345kV yard. The appearance of the new substation will be similar to the appearance of existing substation of a similar size, including the existing Blackberry and Forbes substations nearby. The tallest structures in the substation will be the 500kV and 230kV dead-end structures, which are approximately 125 to 135 feet tall (500kV) and 70 feet tall (230kV). Exhibit A1 provides a preliminary one line drawing for the Blackberry 500 kV Substation. The site of the 500 kV Series Compensation Station has not yet been identified at this time, but for budgetary purposes, it has been assumed that the series compensation station will be a separate substation located along the line. This assumption is reflected in the preliminary one-line shown in Exhibit A1. The location of the series compensation equipment and whether it will be located in a separate station or located within the Blackberry 500 kV Substation will be determined in the final design of the 500 kV Line.

The estimate also assumes that a new permanent all weather access road approximately 500 feet in length will be constructed to the site from County Road 434. This is required to provide access for personnel, material deliveries, vehicles, trucks, heavy equipment, low-boy tractor trailer rigs (used for moving large transformers), and ongoing maintenance activities at the site.

1.2.5 The Parties acknowledge in accordance with Article 1.8 of this Appendix A that the obligations of each Transmission Line Payer to make its payments in respect of the Construction Phase and to fulfill its other obligations in respect of the Construction Phase are subject to and contingent upon: (i) the satisfaction of the Construction Phase Conditions Precedent applicable to that Transmission Line Payer; and (ii) notice being received from the CUU Transmission Owners that the Certification Phase has been successfully completed.

1.3 Cost Estimates

The Transmission Line Payers hereby acknowledge and agree that the costs, expenses and charges for the two (2) phases of the CUU set out in Table 1 are only an estimate and that the Transmission Line Payers shall pay the CUU Transmission Owners for their allocated percentages in accordance with Table 2(B) for all costs, expenses and charges, as determined pursuant to Article 3.2 of this Appendix A and subject to this Appendix A.

The total estimated costs, expenses and charges for the CUU are $676,947,930 in 2013 dollars. The estimate does not include escalation or the Tax Gross-Up Amount. Transmission Line Payers are responsible for the actual costs subject to IRS Revenue Procedures 2005-35. The Parties acknowledge that this estimate is based on a preferred route for the 500 kV Line and this estimate will be revised upon approval of the Route Permit by the Minnesota Public Utilities Commission which is anticipated to occur in the time frame described in Articles 1.1.2 and 1.1.4 of this Appendix. A detailed cost estimate updated at the end of the preceding month shall be provided to the Transmission Line Payers by the CUU Transmission Owners on request from a Transmission Line Payer.

Table 1 - CUU Cost Summary

	Certification Phase	Construction Phase	Total Project
Certification Expenses-Permitting	$22,896,300		$22,896,300
Certification Expenses-Preliminary Construction Activities	$55,253,400		$55,253,400
Line Construction		$457,336,420	$457,336,420
Blackberry Substation		$ 42,994,380	$42,994,380
GNTL Series Compensation Station		$ 49,258,220	49,258,220
Minnesota Power System Upgrades		$ 4,579,210	$ 4,579,210
Capitalize Property Taxes 1/		$ 44,200,000	$ 44,200,000
Network Upgrades to Other Systems Which Will Require Execution of Additional Facility Construction Agreements with Other Transmission Owners			
ATC Kewaunee – Point Beach Rating Increase		$ 250,000	$ 250,000
GRE-Benton County Rating Increase		$ 65,000	$ 65,000
MP-Mud Lake Rating Increase		$ 65,000	$65,000
OTP-Browns Valley-Hankinson Rating Increase		$ 50,000	$50,000
Totals	**$78,149,700**	**$598,798,230**	**$ 676,947,930**

1/ Capitalize Property Taxes were not included in the Facilities Study Estimate but were added as a line item by the CUU Transmission Owners

1.4 Cost Responsibility

The Parties have agreed that the cost allocation methodology for the construction of the CUU referenced in the Agreement shall be determined independently from traditional cost allocation methodology of pro rata cost allocation based on TSR requested amounts. The Parties further agree that the financial responsibility for funding the CUU assets will fall entirely on the Transmission Line Payers. The Transmission Line Payer financial responsibility ratio is stated in Table 2(B) below. Notwithstanding the Transmission Line Payer financial responsibility ratio, the Parties have also agreed that as of the Effective Date the ownership

share of the CUU assets as tenants in common shall be as stated in Table 2(C) below:

Table 2(A) - CUU TSR's and Associated Transmission Line Payers

TSR	CUU Transmission Customer	TSR Amount	Transmission Line Payer
76703672	Minnesota Power	250	Minnesota Power
79258361	Minnesota Power	133	Minnesota Power
79258364	Wisconsin Public Service	200	6690271 Manitoba Ltd.
80142548	Manitoba Hydro	100	6690271 Manitoba Ltd.
80142558	Manitoba Hydro	100	6690271 Manitoba Ltd.
80142561	Manitoba Hydro	100	6690271 Manitoba Ltd.
		883 south	

TSR	CUU Transmission Customer	TSR Amount	Transmission Line Payer
79258492	Manitoba Hydro	133	6690271 Manitoba Ltd.
79258646	Manitoba Hydro	200	6690271 Manitoba Ltd.
79258668	Manitoba Hydro	115 (partial service)	6690271 Manitoba Ltd.
79429002	Manitoba Hydro	250	6690271 Manitoba Ltd
		698 north	

Table 2(B) - CUU Cost Allocation Summary

TSR	TSR Customer	TSR Amounts	Transmission Line Payer	CUU Capital Cost Allocation
76703672	Minnesota Power	250 south	Minnesota Power	28.3 %
79258361		133 south	Minnesota Power	17.7 %
79258364	Wisconsin Public Service	200 south	6690271 Manitoba Ltd.	21.6 %
80142548	Manitoba Hydro	100 south	6690271 Manitoba Ltd.	
80142558	Manitoba Hydro	100 south	6690271 Manitoba Ltd.	32.4%

80142561	Manitoba Hydro	100 south	6690271 Manitoba Ltd.	
79258492	Manitoba Hydro	133 north	6690271 Manitoba Ltd	N/A
79258646	Manitoba Hydro	200 north	6690271 Manitoba Ltd	N/A
79258668	Manitoba Hydro	115 north (partial) 250 north	6690271 Manitoba Ltd	N/A
79429002	Manitoba Hydro		6690271 Manitoba Ltd	N/A

Table 2(C) - CUU Ownership Summary

CUU Transmission Owner	**Percentage Ownership Share of CUU Assets**
Minnesota Power	51%
6690271 Manitoba Ltd.	49%

1.5 First Equipment Order. Will be dependent on final permitting approval.

1.6 Construction Schedule. Construction of the CUU is scheduled under Table 3-FCA Milestones and will be periodically updated as necessary.

1.7 Payment Schedule.

1.7.1 Timing of and Adjustments to Transmission Line Payers' Payments and Performance Assurance. Notwithstanding the requirements of Article 6.1 of the Agreement, the Transmission Line Payers shall make the advance payments, or if a Transmission Line Payer cannot provide advance payments because Governmental Authority approvals have not yet been granted, provide performance assurance, to the CUU Transmission Owners as set forth in the schedule in Table 3 in Section 1.7.2 of this Appendix A. The CUU Transmission Owners shall not be required to send to the Transmission Line Payers an invoice or notice for such initial payments or performance assurance; rather, such payment (or performance assurance) shall be provided by the Transmission Line Payers by the date specified in Table 3 below. Subsequent payments shall

be pursuant to invoices issued by the CUU Transmission Owners in accordance with Section 1.7.2.

1.7.2 Payment Schedule. The Transmission Line Payers' payment schedule is as follows.

Certification Phase Payments

Initial payments shall be made pursuant to Table 3 (1-A) below. Failure by any Transmission Line Payer to provide payments (or performance assurance acceptable to the CUU Transmission Owners, where applicable) by the due date in the table below to the CUU Transmission Owners is a Breach pursuant to Article 9 of the Agreement. Following the initial payment, the CUU Transmission Owners will invoice the Transmission Line Payers monthly for all expenses incurred in accordance with Table 3 (1-B) after crediting the Transmission Line Payers for any payments made prior to the Effective Date

Construction Phase Payments

Funding for the Construction Phase will utilize a construction account which the CUU Transmission Owners can access to pay all Construction Phase payments. It is expected that the CUU Transmission Owners will be requesting a two (2) month forward looking requirement be placed into the construction escrow account with monthly reconciliation and reporting. CUU Transmission Owners will provide a calculation of the interest from an interest bearing escrow account which will be used to reduce the amount of the funding request.

If, at any time during the course of the CUU Transmission Owners' work on the CUU, they become aware that the payments they have received and performance assurance they then hold will not be sufficient to fully fund the work, the CUU Transmission Owners shall submit invoices to the Transmission Line Payers for their proportionate shares of the additional funds needed. Each Transmission Line Payer shall pay the full amount of the invoice (or, if a Transmission Line Payer cannot provide advance payments because Governmental Authority approvals have not yet been granted, provide performance assurance for the full amount) within thirty 30 Calendar Days of receipt. A Transmission Line Payer's failure to make any such payment (or provide acceptable performance assurance, where

applicable) when due shall constitute a Breach by such Transmission Line Payer.

A Transmission Line Payer that fails to make payments when due will be given a Breach notice. Unless the Breach is cured in accordance with Article 9 of the Agreement, the CUU Transmission Owners are relieved from performing under this Agreement. Failure by any Transmission Line Payer to comply with Article 9.2.2(A) or 9.2.2(B) relative to such Breach may, pursuant to Article 2.2.2 of the Agreement, result in termination of the Agreement as to that Transmission Line Payer.

Table 3 FCA Milestones (Transmission Line Payer share of payments will be based on Table 2(B))

NO.	MILESTONES	PAYMENT SCHEDULE
1	The CUU Transmission Owners begin the Certification Process and Transmission Line Payers to provide to CUU Transmission Owners a guarantee, letter of credit, cash escrow account or other form of performance assurance for the Certification Phase, if required pursuant to this Agreement (Article 6.1 of the Agreement).	Required performance assurance due 30 Calendar Days after the Effective Date.
1-A	CUU Transmission Owners will submit invoices to the Transmission Line Payers for their proportional share of Pre-Certification Phase Expense pursuant to Section 1.1.7 of this Appendix A.	30 Calendar Days after the Effective Date.
1-B	CUU Transmission Owners begin monthly invoicing to the Transmission Line Payers for all other expenses for the Certification Phase.	Invoices will be submitted by the CUU Transmission Owners on the 15th of every month, beginning the month following the Effective Date.
1-C	CUU Transmission Owners notifies the Transmission Line Payers that all Major Permits have been received and all of MPM's Certification Phase Conditions Precedent and	Required performance assurance due 20 Business Days after notification by the CUU

	MPM's Construction Phase Conditions Precedent have been satisfied or waived and the CUU Transmission Owners shall begin Preliminary Construction Activities and the Transmission Line Payers to provide to CUU Transmission Owners performance assurance, if required pursuant to this Agreement (Article 6.1).	Transmission Owners.
2	Upon notification by the CUU Transmission Owners that the Certification Process has been successfully completed and all Construction Phase Conditions Precedent have been satisfied and or waived, the construction of the CUU will commence in accordance with the Construction Phase component subject to Section 1.8 of this Appendix A. The Transmission Line Payers to provide to CUU Transmission Owners performance assurance, if required pursuant to this Agreement (Article 6.1).	The Construction Phase will commence subject to Section 1.8 of this Appendix A. Required performance assurance due no later than 20 Business Days after notification by the CUU Transmission Owners.
2-A	The CUU Transmission Owner shall request the first two month advance of expected construction expenditures and the CUU Transmission Line Payer shall provide the advance. Additional requests shall be made by the CUU Transmission Owner by the 15th of each month. The Transmission Line Payers have 30 Calendars Days to satisfy the advance request.	Not later than 30 Calendar Days after the Construction Phase begins.
3	CUU Transmission Owners to complete acceptance testing and complete the Construction Phase.	In-Service Date (Expected June 1, 2020)
4	CUU Transmission Owners to provide final report to the Transmission Line Payers (Article 6.5 of this Agreement)	180 days after In-Service Date

1.7.3 When applicable, each Transmission Line Payer shall pay any difference between actual costs and actual payments in accordance with this Agreement, no later than thirty (30) Calendar Days after receipt of the CUU Transmission Owner' final construction invoice. If agreed in writing by the Parties, payments may be made in accordance with a revised schedule.

1.7.4 All costs will be paid for on a proportional basis as set out herein.

1.7.5 Any refund shall be allocated on a proportional basis as set out herein.

1.8 Conditions Precedent.

MPM

1.8.1 MPM's Certification Phase Conditions Precedent.

The obligations of MPM to complete the matters referenced herein in respect of the Certification Phase shall be subject to and contingent upon the fulfillment of the following conditions ("**MPM's Certification Phase Conditions Precedent**") to the satisfaction of MPM, as certified or waived in writing by MPM, by the dates specified:

(a) MP obtaining approval of the Board of Minnesota Power, an operating division of ALLETE, Inc. within thirty (30) days of the Effective Date approving MP entering into this Agreement.

1.8.2 MPM's Construction Phase Conditions Precedent.

The obligations of MPM to complete the matters referenced herein in respect of the Construction Phase shall be subject to and contingent upon the fulfillment of the following conditions ("**MPM's Construction Phase Conditions Precedent**") to the satisfaction of MPM, as certified or waived in writing by MPM, by the dates specified:

(a) MPM obtaining approval of its Board of Directors by July 1, 2016 approving MPM proceeding to fund its proportionate share of costs of the CUU pursuant to the Construction Phase of this Agreement;

(b) All conditions precedent to the 250 MW System Power Sale Agreement between MHEM and MPM, dated May 19, 2011 being satisfied or waived by July 1, 2016, or by such other date (if any) as the Transmission Line Payers and CUU Transmission Owners may mutually upon;

(b) The Transmission Line Payers and CUU Transmission Owners executing a Project Development Agreement, an Operations and Maintenance Agreement, a Transmission Capacity Exchange Agreement, and if deemed applicable by the Transmission Provider, an Interconnection Agreement, by June 30, 2015 and all conditions precedent to such agreements being satisfied by September 30, 2015,

or by such other date (if any) as the Transmission Line Payers and CUU Transmission Owners may mutually agree upon;

(c) All required FERC filings and authorizations related to this Agreement are accepted by FERC on or before July 1, 2016, including acceptance by FERC under Section 205 of the Federal Power Act; and

(e) Conditional approval by the Transmission Provider by June 30, 2015 of the MPM transmission service request pursuant to Reservation Number 76703672 of 250 MW south and Reservation Number 79258361 of 133 MW south on conditions acceptable to MPM.

6690271 Manitoba Ltd.

1.8.3 6690271's Manitoba Ltd. Certification Phase Conditions Precedent.

The obligations of 6690271 to complete the matters referenced herein in respect of the Certification Phase shall be subject to and contingent upon the fulfillment of the following conditions ("**6690271's Certification Phase Conditions Precedent**") (MPM's Certification Phase Conditions Precedent and 6690271's Certification Phase Conditions Precedent are collectively referred to the "**Certification Conditions Precedent**") to the satisfaction of 6690271 as certified or waived in writing by 6690271 by the dates specified:

(a) MH obtaining an Order in Council of the Lieutenant Governor (Manitoba) within ninety (90) days of the Effective Date approving 6690271 entering into this Agreement.

1.8.4 6690271's Construction Phase Conditions Precedent.

The obligations of 6690271 to complete the matters referenced herein in respect of the Construction Phase shall be subject to and contingent upon the fulfillment of the following conditions ("**6690271's Construction Phase Conditions Precedent**") (MPM's Construction Phase Conditions Precedent and 6690271's Construction Phase Conditions Precedent are collectively referred to the "**Construction Conditions Precedent"**) to the satisfaction of 6690271 as certified or waived in writing by the dates specified:

(a) 6690271 obtaining approval of its Board of Directors by October 31, 2016 approving 6690271 proceeding to fund its share of costs of the CUU pursuant to the Construction Phase of this Agreement;

(b) MH obtaining an Order in Council of the Lieutenant Governor (Manitoba) within ninety (90) days of the Effective Date approving 6690271 entering into this Agreement;

(c) MH obtaining the final non-appealable order of the National Energy Board ("**NEB**") on conditions acceptable to MH, in its sole and absolute discretion, by October 31, 2016 or by such other date (if any) as the Transmission Line Payers and CUU Transmission Owners may mutually agree upon, authorizing: (i) the construction and operation of the component of the 500 kV Interconnection in the province of Manitoba; and (ii) the modification of the component of any existing transmission interconnection in the province of Manitoba that pursuant to the laws applicable to the NEB is an international power line and that MH, in its sole and absolute discretion, determines is necessary to be modified in conjunction with the construction of the component of the 500 kV Interconnection in the province of Manitoba;

(d) MH obtaining the final non-appealable license from the Province of Manitoba, on conditions acceptable to MH, in sole and absolute discretion, authorizing MH to commence construction of the Canadian component of the 500 kV Interconnection by October 31, 2016, or such other date (if any) as the Transmission Line Payers and CUU Transmission Owners may mutually agree upon;

(e) All conditions precedent to the 250 MW System Power Sale Agreement between MHEM and MPM, dated May 19, 2011 being satisfied or waived by the dates set out in the 250 MW System Power Sale Agreement, or by such other date (if any) as the Transmission Line Payers and CUU Transmission Owners may mutually upon;

(f) The Transmission Line Payers and CUU Transmission Owners executing a Project Development Agreement, an Operations and Maintenance Agreement, a Transmission Capacity Exchange Agreement, and if deemed applicable by the Transmission Provider, an Interconnection Agreement by June 1, 2015 and all conditions precedent to such agreement being satisfied by September 30, 2015 or by such other date (if any) as the Transmission Line Payers and CUU Transmission Owners may mutually agree upon;

(g) Conditional approval by MHEM's transmission provider by June 30, 2015 of the MHEM transmission service request pursuant to Reservation Number 76703161,

79622800, 79622805, 79622810 for a minimum of 698 MW north on conditions acceptable to MHEM;

(h) Conditional approval by MHEM's transmission provider by June 30, 2015 of the MHEM transmission service request pursuant to Reservation Number 76703213, 76703216, 79622799 of 883 MW south on conditions acceptable to MHEM;

(i) Conditional approval by the Transmission Provider by June 30, 2015 of the MHEM transmission service request pursuant to Reservation Number 79429002, 79258492, 7928646, 79258668 for a minimum of 698 MW north on conditions acceptable to MHEM; and

(j) Conditional approval by the Transmission Provider by June 30, 2015 of the MHEM transmission service requests pursuant to Reservation Number 80142548, 80142558 and 80142561 of up to 300 MW south on conditions acceptable to MHEM.

1.8.5 Reasonable Assistance.

The CUU Transmission Owners and Transmission Line Payers agree to provide reasonable assistance to another Party, if requested, in order to assist that Party to obtain any approval associated with its condition precedent.

1.8.6 Conditions Precedent Notices and Termination.

Each Party shall notify the other Parties as soon as practicable following the satisfaction or waiver or the failure to satisfy or waive its condition precedent. The CUU Transmission Owners shall provide notice to all Parties when the Certification and Construction Phases have begun. The Parties acknowledge:

(a) If MPM's conditions precedent applicable to the Certification Phase or Construction Phase are not satisfied or waived in accordance with this Section 1.8: (i) MPM shall be terminated as party to the Agreement; (ii) MPM's Transmission Line Payers Associated TSR's shall be withdrawn from the Transmission Provider's transmission queue; and (iii) the Transmission Line Payers whose conditions precedent were satisfied or waived shall enter into negotiations with the CUU Transmission Owners and the Transmission Provider to amend the Agreement on mutually acceptable terms and if such amendments are not agreed to the Agreement shall terminate; and

(b) If 6690271 conditions precedent applicable to the Certification Phase or Construction Phase are not satisfied or waived in accordance with this

Section 1.8: (i) 6690271 shall be terminated as a party to this Agreement; (ii) 6690271's Transmission Line Payers Associated TSR's shall be withdrawn from the Transmission Provider's transmission queue; and (iii) the Transmission Line Payers whose conditions precedent were satisfied or waived shall enter into negotiations with the CUU Transmission Owners and the Transmission Provider to amend the Agreement on mutually acceptable terms and if such amendments are not agreed to the Agreement shall terminate.

Multi-Party Facilities Construction Agreement
APPENDIX B
NOTIFICATION OF COMPLETED CONSTRUCTION

This Appendix B is a part of the Multi-Party Facilities Construction Agreement among Transmission Line Payers, CUU Transmission Owners, and Transmission Provider. When CUU Transmission Owners have completed construction of the CUU, CUU Transmission Owners shall send notice to Transmission Line Payers, the CUU Transmission Customers and the Transmission Provider, in substantially the form following:

[Date]

MISO, Inc.

Attn: Director, Transmission Access Planning

P.O. Box 4202

Carmel, IN 46082-4202

for overnight deliveries:

720 City Center Drive

Carmel, IN 46032

Transmission Line Payer and CUU Transmission Customer contact information: please see Article 15 of the Agreement.

Re: Completion of Common Use Upgrades ("CUU")

Dear [Name or Title]:

This letter is sent pursuant to the Multi-Party Facilities Construction Agreement among [CUU Transmission Owners], [Transmission Line Payers], and the MISO, dated _____, 20___.

On [Date], CUU Transmission Owners completed to their satisfaction all work on the CUU described in the _____, 20__ Multi-Party Facilities Construction Agreement by and among _____. Further, CUU Transmission Owners confirms that the CUU have been placed "in service."

Thank you.

[Signature]

[CUU Transmission Owners Representative]

Multi-Party Facilities Construction Agreement

APPENDIX C

This Appendix C is a part of the Multi-Party Facilities Construction Agreement among Transmission Line Payers, CUU Transmission Owners, and Transmission Provider.

The following exhibits are part of this report and are attached at the end of this document.

Exhibit A1: Overall CUU One Line Diagram

Exhibit A2: 500 kV CUU Transmission Line Route Map

Exhibit A3: Draft CUU Project Schedule

Exhibit A1 Overall CUU One Line Diagram

CEII MATERIAL

Exhibit A2 500 kV CUU Transmission Line Route Map

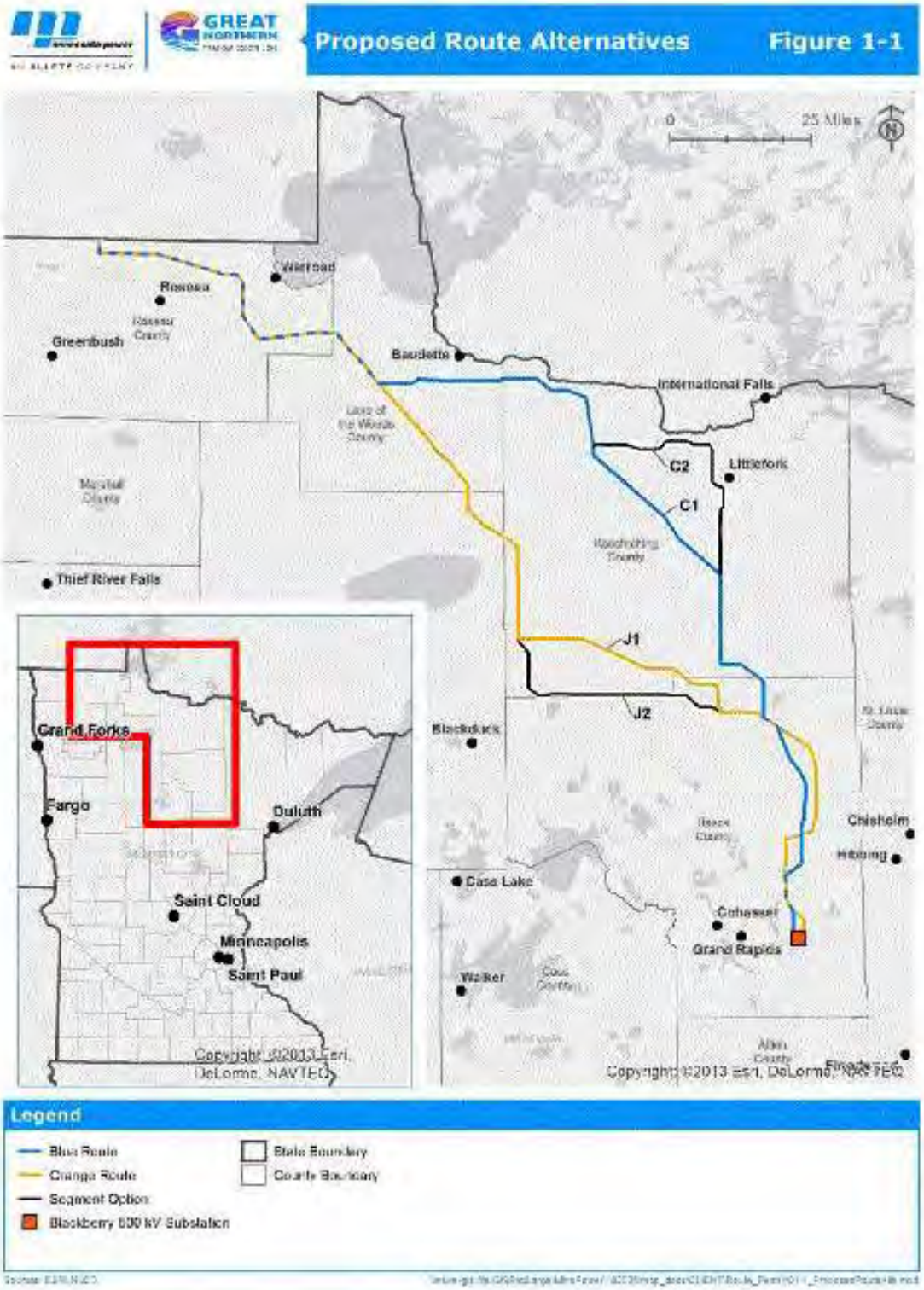
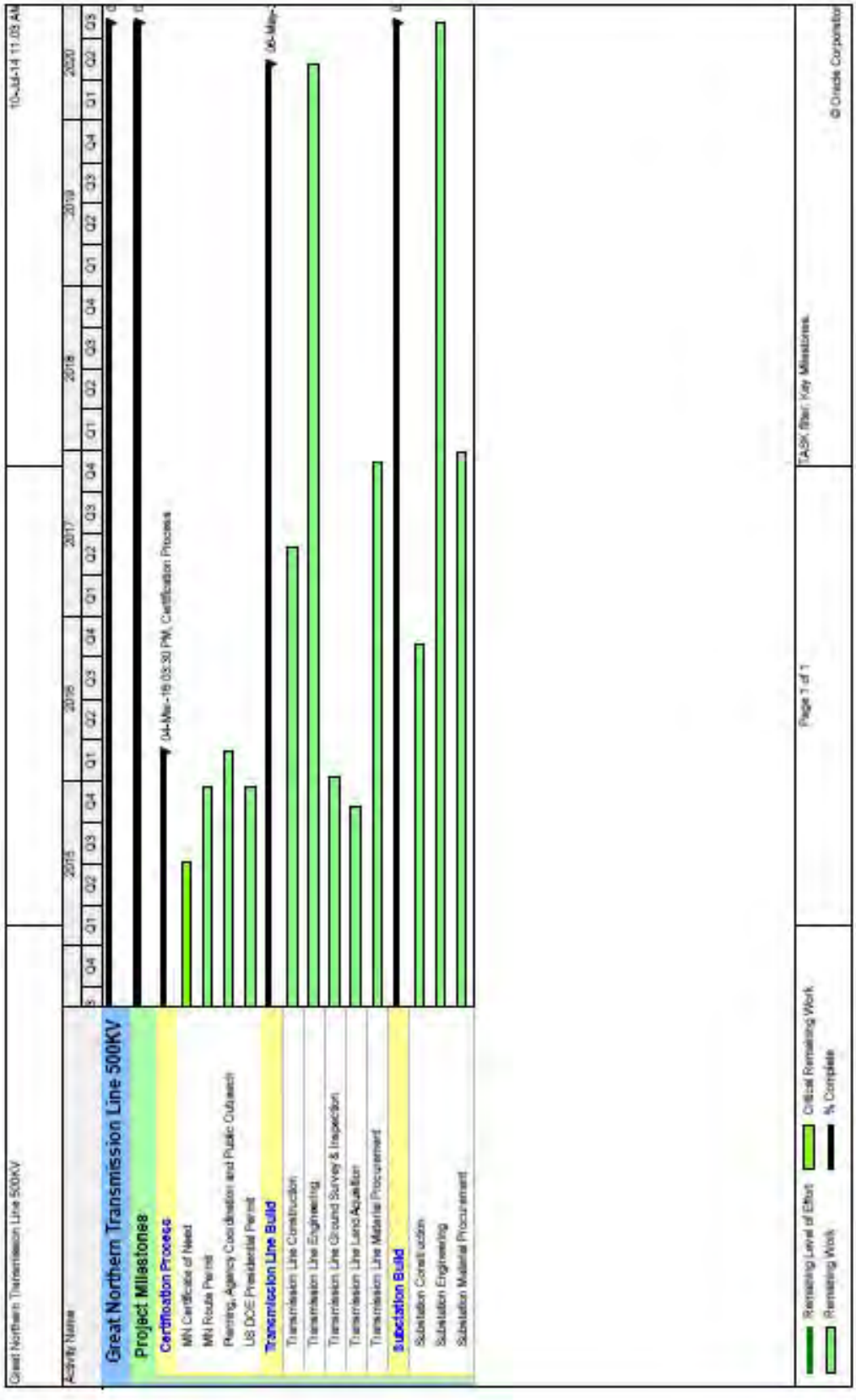


Exhibit A3 Draft CUU Project Schedule



APPENDIX D
PERFORMANCE ASSURANCES

Transmission Line Payers that are required to post performance assurance in accordance with Section 6.1, shall be responsible for providing performance assurance in accordance with the following:

Subsection 1

Transmission Line Payer will be required to post performance assurance in the amount based on the CUU Transmission Owners projected remaining costs to the day that is 20 Business Days after the last of the MPM Certification Phase Conditions Precedent and the MPM Construction Phase Conditions Precedent have been satisfied or waived by MPM (which amount is estimated to be $16 million as of the Effective Date) multiplied by the percentage of the CUU facilities that are required to be funded by such Transmission Line Payer.

Subsection 2

Transmission Line Payer will be required to post performance assurance in the amount based on the CUU Transmission Owners projected remaining costs to the day that is 20 Business Days after all of the MPM Construction Phase Conditions Precedent and the 6690271 Certification Phase Conditions Precedent and the 6690271 Construction Phase Conditions Precedent have been satisfied or waived by the respective Party (which amount is estimated to be $55 million as of the Effective Date) multiplied by the percentage of the CUU facilities that are required to be funded by such Transmission Line Payer minus any amount of its performance assurance held by the CUU Transmission Owner remaining from Subsection 1.

ASSIGNMENT OF MULTI-PARTY FACILITIES CONSTRUCTION AGREEMENT

THIS ASSIGNMENT made as of the 12th day of April, 2016.

BETWEEN:

6690271 MANITOBA LTD.

- and –

MINNESOTA POWER, AN OPERATING DIVISION OF ALLETE INC.

WHEREAS:

A. Minnesota Power, an operating division of ALLETE, Inc., in its capacity as a CUU Transmission Owner ("**MP**"), 6690271 Manitoba Ltd. in its capacity as a CUU Transmission Owner and its capacity as a Transmission Line Payer, and Minnesota Power, an operating division of ALLETE, Inc., in its capacity as a Transmission Line Payer ("**MPM**") together with the Midcontinent Independent System Operator, Inc., are parties to a Multi-Party Facilities Construction Agreement dated September 25, 2014 ("**FCA**"), whereby MP and 6690271 Manitoba Ltd. agreed as CUU Transmission Owners to own as tenants in common and to (or shall cause such action to) design, procure, engineer, install and commission the CUU in two distinct phases, consisting of the Certification Phase and the Construction Phase.

B. MPM and 6690271 Manitoba Ltd. agreed as Transmission Line Payers pursuant to the FCA to pay their allocated portion of the costs of the CUU during the Certification Phase and the Construction Phase.

C. 6690271 Manitoba Ltd. is in its capacity as a CUU Transmission Owner assigning to MP pursuant to this Assignment of Multi-Party Facilities Construction Agreement ("**Agreement**") all of its interests, rights and obligations in or arising out of the FCA as one of the CUU Transmission Owners.

NOW THEREFORE THIS AGREEMENT WITNESSETH that in consideration of the premises and the sum of One (US $1.00) U.S. Dollar (the receipt whereof is hereby acknowledged):

1. The preamble to this Agreement forms an integral part hereof and is incorporated herein.

2. 6690271 Manitoba Ltd. in its capacity as a CUU Transmission Owner does hereby assign to MP pursuant to this Agreement all of its interests, rights and obligations in or arising out of the FCA as one of the CUU Transmission Owners.

3. 6690271 Manitoba Ltd. in its capacity as a CUU Transmission Owner covenants with the MP that:

(a) it has the right to enter into this Agreement; and

(b) it has not previously assigned its interests, rights and obligations in or arising out of the FCA as one of the CUU Transmission Owners.

4. MP covenants with 6690271 Manitoba Ltd. in its capacity as a CUU Transmission Owner that:

(a) it has the right to enter into this Agreement; and

(b) it accepts the assignment from 6690271 Manitoba Ltd. pursuant to this Agreement and will observe and perform all of the covenants of 6690271 Manitoba Ltd. in its capacity as a CUU Transmission Owner pursuant to the FCA.

5. The parties hereto (6690271 Manitoba Ltd. and MPM in their capacities as Transmission Line Payers are parties to this Agreement only for the purposes of this acknowledgment) acknowledge that notwithstanding such assignment:

(a) 6690271 Manitoba Ltd. will continue to be obligated, in its capacity as a Transmission Line Payer, to pay under the FCA its allocated portion of the costs of the CUU during the Certification Phase and the Construction Phase whether incurred before or after such assignment; and.

(b) 6690271 Manitoba Ltd. will continue in its capacity as a Transmission Line Payer to have the rights and obligations under the FCA arising from being a Participant.

6. Terms used in this Agreement with initial capitalization not defined in this Agreement shall have the meaning specified in the FCA.

7. The provisions hereof shall enure to the benefit of and be binding upon each of the parties hereto, and their respective heirs, executors, administrators, successors or assigns, and the singular and masculine shall be read and construed as the plural, or the feminine or neuter wherever the context so requires.

8. This Agreement may be executed in or one more counterparts, all of which shall be read and construed as one document and any facsimile signature hereto shall be deemed to be an original signature.

IN WITNESS WHEREOF Minnesota Power, an operating division of ALLETE, INC., has executed this Agreement at the City of Duluth, in the State of Minnesota as of the date first written above and 6690271 Manitoba Ltd. has executed this Agreement at the City of Winnipeg, in the Province of Manitoba as of the date first written above.

6690271 MANITOBA LTD.-CUU TRANSMISSION OWNER

BY: _____

NAME: LORNE MIDFORD

TITLE: PRESIDENT

MINNESOTA POWER, AN OPERATING DIVISION OF ALLETE, INC.-CUU TRANSMISSION OWNER

BY: _____

NAME: BRADLEY W. OACHS

TITLE: CHIEF OPERATING OFFICER -MP

6690271 MANITOBA LTD.- TRANSMISSION LINE PAYER

BY: _____

NAME: LORNE MIDFORD

TITLE: PRESIDENT

MINNESOTA POWER, AN OPERATING DIVISION OF ALLETE, INC.-TRANSMISSION LINE PAYER

BY: _____

NAME: BRADLEY W. OACHS

TITLE: CHIEF OPERATING OFFICER-MP

PUB MFR 195

MB-SK Transmission Project

Provide the Capital Project Justification for the MB-SK Transmission Project including addenda.

Public disclosure of the attachment to this MFR (or portions thereof) would result in the release of information considered to be confidential and commercially sensitive. As directed by the PUB, Manitoba Hydro will be filing a letter seeking confidential treatment of the redacted information contained in the attachment pursuant to Rule 13.

The Capital Project Justification for the MB-SK Transmission Project is attached.

D1876

APPROVED BY EXECUTIVE COMMITTEE
MINUTE # 1543.04

DATE: 2015 10 01
Financial Planning

CAPITAL PROJECT JUSTIFICATION FOR

Manitoba – Saskatchewan Transmission Project

REVIEWED BY:
(Owning Dept Manager)
Kayn Scarfone 09/15/2015

NOTED BY:
(if applicable)

Coordinating Division: Power Sales & Operation

Constructing Division:

Financial Department:
(if over $1 million) 09/13/2015

RECOMMENDED FOR IMPLEMENTATION:

Owning Div. Manager: David Cormie

Business Unit V.P.: 2015 09 18

PRIMARY JUSTIFICATION:
Indicate key project driver(s):

- ☐ Safety
- ☐ System Supply
- ☐ System Reliability
- ☒ Customer Service
- ☐ Efficiency
- ☐ Environmental

NERC COMPLIANCE*: ☐ YES ☐ NO

*Determine if the project requires compliance with North American Electric Reliability Corporation (NERC) CIP Cyber Security Standards.

BUDGET $: (Total Net Cost)	$57,043,673
START DATE: (1st Cost Flow)	2015 09
IN-SERVICE DATE: (Last Major In-service Date)	2021 06
RISK MATRIX/ BUSINESS CASE TIER: (Optional)	
INVESTMENT REASONS: (Optional)	

OWNING DIVISION:	Power Sales & Operations
I.M. NODE NUMBER:	1.5.2.6.2.1
W.B.S. NUMBERs:	P:25848 and P:25840
MAJOR ITEM ☒	**DOMESTIC ITEM** ☐
PREPARED BY:	S. Amorim Dew/B. Mukanik
DATE PREPARED:	2015 09 04
REPORT NUMBER:	
FILE NUMBER (Optional):	

MANITOBA HYDRO
CAPITAL PROJECT JUSTIFICATION

Project Name

Manitoba – Saskatchewan Transmission Project

Recommendation

Approve construction of the Manitoba – Saskatchewan Transmission project required to supply the SaskPower 100 MW System Power Sale.

Project Scope

Based on a 2012 Facilities Study completed by System Planning, the following Network Upgrades are required in Manitoba:

- Adding a new 44 km 230 kV transmission line between Birtle South (Manitoba) to the Manitoba-Saskatchewan border;
- Termination at Birtle South station;
- Re- tensioning of the MH section of the P52E line to 100°C design rating; and
- 230 kV line B69R current transformer (CT) ratio change at Birtle South station.

Background

MH and SPC executed a Term Sheet on June 26, 2015 for a twenty year System Power Sale commencing June 1, 2020. The capacity amount will be for a minimum of 100 MW.

The sale will require the construction of a new 230 kV interconnection between Birtle, Manitoba and Tantallon, Saskatchewan involving 44 km in Manitoba and 36 km in Saskatchewan and additional miscellaneous upgrades to the transmission grid in both provinces. The cost of the line and transmission enhancements in Manitoba is estimated at [redacted] in interest and escalation. [redacted]

In February 2012, System Planning completed a Facilities Study for 2-50 MW transmission service requests, which identified the scope of this transmission project. Transmission service requests are currently being studied to provide updated results for this project.

Approval for the Term Sheet and required transmission upgrades received approval by MH's Executive on June 9, 2015 and by MH's Board of Directors on June 24, 2015 (Board minute 860-15-04).

JUSTIFICATION—BUSINESS CASE ANALYSIS (SUMMARY):

Justification and Link to Corporate/Business Unit Goals

This transmission project will allow for a twenty year 100 MW system power sale which will provide MH with a fixed revenue stream estimated at [redacted] from 2020 to 2040. At the end of this sale contract term, the likelihood of future sales to SaskPower is high given that a new interconnection is being built and SaskPower has growing supply needs that they cannot meet on their own. There is also the potential for additional surplus sales in the off peak which would increase the revenue projections as a result of this project being completed.

JUSTIFICATION—BUSINESS CASE ANALYSIS (SUMMARY):

Justification and Link to Corporate/Business Unit Goals

In addition to the sale, the new interconnection to Saskatchewan will also expand and diversify MH's market access and customer base.

This project supports the Corporate Financial goal to "Aggressively pursue a balanced portfolio of domestic and profitable export sales to provide the highest financial benefits to ratepayers and all Manitobans over the long term".

ANALYSIS OF ALTERNATIVES:

Economic Analysis

Discount Rate	For current corporate rates see G911 %	For clarification on hurdle rates, contact the Economic Analysis Department

Recommended Option	NPV Benefits (Costs)
Name the recommended option and provide its Net Present Value (NPV).	NPV is usually negative in a "cost minimization" project where the justification is other than economic or financial i.e., safety, environment etc.

Other Alternatives Considered	NPV Benefits/(Costs)
List each alternative considered as well as its calculated NPV.	

Risk Analysis

The following are some potential risks that have been identified with this project:

Delay in ISD – The current in-service date has been set as June 2021, which is a year later than what is required to serve the new sale to SaskPower which is set to commence June 1, 2020. There is a risk for a further delay of another year. The parties have agreed in the Term Sheet that they will use alternative short-term transmission arrangements until the new transmission line is available which mitigates this risk.

Transmission Cost Increases - There is a risk that the interconnection costs could increase, although the numbers included in this CPJ have been increased from the estimates provided in the 2012 Facilities Study and are deemed to be sufficient.

Termination of the sale to SaskPower - The risks related to signing the Power Purchase Agreement with SaskPower are low, as the parties have negotiated nearly all of terms and conditions that will be included in

Risk Analysis

the final agreement in the Term Sheet. In addition, the final agreement will be subject to approval by the Executive Committee, the MH Board and an Order in Council of the Lieutenant Governor (Manitoba) and the transmission project will not be initiated until all of these approvals are sought.

Capital Budget Estimate

The annual net budget requirements are as follows (in thousands of dollars):

Fiscal Year	Proposed Budget	
Prev. Actuals	$	-
2015/16	$	691
2016/17	$	2,433
2017/18	$	3,795
2018/19	$	2,232
2019/20	$	18,937
2020/21	$	18,063
2021/22	$	10,893
Total	$	57,044

Proposed Schedule

Related Projects

P:25840 Sask Power 230KV line [redacted]

Reference Documents

Facilities Study prepared by System Planning, February 29, 2012.

CER(1) Rev. 97 12

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

Title	Investment Management Node:
Manitoba - Saskatchewan Transmission Pro	1.5.2.6.2.1
Owning Division Power Sales & Operations	**Coordinating Division** Power Sales & Operations — **Project Number:** P-25848

DESCRIPTION
Approve construction of the Manitoba and Saskatchewan Transmission project required to supply the SaskPower 100 MW System Power Sale.

Scope:

Based on a 2012 Facilities Study completed by System Planning, the following Network Upgrades are required in Manitoba:

-Adding a new 44 km 230 kV transmission line between Birtle South (Manitoba) to the Manitoba-Saskatchewan border;

-Termination at Birtle South station;

-Re- tensioning of the MH section of the P52E line to 100°C design rating; and

-230 kV line B69R current transformer (CT) ratio change at Birtle South station.

JUSTIFICATION
This transmission project will allow for a twenty year 100 MW system power sale which will provide MH with a fixed revenue stream estimated at [redacted] from 2020 to 2040. At the end of this sale contract term, the likelihood of future sales to SaskPower is high given that a new interconnection is being built and SaskPower has growing supply needs that they cannot meet on their own. There is also the potential for additional surplus sales in the off peak which would increase the revenue projections as a result of this project being completed.

In addition to the sale, the new interconnection to Saskatchewan will also expand and diversify MH's market access and customer base.

This project supports the Corporate Financial goal to "Aggressively pursue a balanced portfolio of domestic and profitable export sales to provide the highest financial benefits to ratepayers and all Manitobans over the long term".

IN SERVICE DATES						Base estimate 2015/04/01 CLASS 3
2021/06/30	48612					Work start date 2015/09/01
PREV.AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	[redacted]	TOTAL NET COST
Actual cost to date:						
(Over)under expend.						
V-CPJ TOTAL						
REV. AMOUNTS:						
Actual cost to date:						
(Over)under expend:						
Auth 2015/16	672	10	9			691
Req 2016/17	2268	68	97			2433
2017/18	3360	170	265			3795
2018/19	1680	120	432			2232
2019/20	18420	1547	970			18937
2020/21	14400	1672	1991			18063
2021/22	1600	208	653			2461
V-HLD TOTAL	40400	3795	4417			48612

Prepared by	yy mm dd	Approved by	yy mm dd	Approved by	yy mm dd	Approved by	yy mm dd
	15 09 15	OWNING DIVISION		COORDINATING DIVISION		VICE-PRESIDENT	15 09 15

2015/09/15 08:39AM

CER(1) Rev. 97 12

ITAL EXPENDITURE REVISION

FORECAST HISTORY (In thousands of dollars)

ProjectNumber P:25848

Approved yy mm	TOTAL AMOUNT	COMMENTS

Forecasted Mthly Exp.		GROSS	ESCALATION	INTEREST CAP.	[redacted]	SALVAGE	TOTAL NET COST	YTD Accumulated
2015/16	Apr							
	May							
	Jun							
	Jul							
	Aug							
	Sep	68	1				69	69
	Oct	105	1				106	175
	Nov	100	1	1			102	277
	Dec	100	1	1			102	379
	Jan	100	2	2			104	483
	Feb	95	2	2			99	582
	Mar	104	2	3			109	691
TOTAL		672	10	9			691	691
2016/17	Apr	185	4	3			192	192
	May	195	4	4			203	395
	Jun	195	5	5			205	600
	Jul	185	5	6			196	796
	Aug	204	6	7			217	1013
	Sep	185	5	8			198	1211
	Oct	185	6	9			200	1411
	Nov	195	6	9			210	1621
	Dec	175	6	11			192	1813
	Jan	185	7	11			203	2016
	Feb	175	7	11			193	2209
	Mar	204	7	13			224	2433
TOTAL		2268	68	97			2433	2433

2015/09/15 08:39AM

CER(1) Rev 97 12

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

Title		Investment Management Node:
Sask Power 230KV line [redacted]		15262401
Owning Division VP Generation Operations Administration	Coordinating Division Power Sales & Operations	ProjectNumber: P:25840

DESCRIPTION:
MH will [redacted] of the new transmission interconnection required in Saskatchewan for the 100 MW System Power Sale to SaskPower. [redacted]

JUSTIFICATION:
MH and SaskPower will be building a new interconnection from Manitoba to Saskatchewan which will allow for a twenty year 100 MW system power, providing MH with a fixed revenue stream estimated at [redacted] from 2020 to 2040. There is also the potential for additional sales on the new interconnection.

Each party is responsible for costs related to construction of the interconnection in their respective provinces. [redacted]

IN SERVICE DATES			Base estimate 2015/04/01 CLASS 3 Work start date 2021/06/01

PREV AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	[redacted]	TOTAL NET COST
Actual cost to date: (Over)under expend:						
V-CPJ TOTAL						
REV. AMOUNTS: Actual cost to date: (Over)under expend. Auth 2021/22 Req.:					[redacted]	[redacted]
V-HLD TOTAL					[redacted]	[redacted]

Prepared by	yy mm dd	Approved by	yy mm dd	Approved by	yy mm dd	Approved by	yy mm dd
[signature]	5 09 11	OWNING DIVISION		COORDINATING DIVISION		VICE-PRESIDENT	11 07 15

2015/09/11 09:44AM

CER(1) Rev. 97 12

PITAL EXPENDITURE REVISION

FORECAST HISTORY (in thousands of dollars)

ProjectNumber P:25840

Approved yy mm	TOTAL AMOUNT	COMMENTS

Forecasted Mthly Exp.		GROSS	ESCALATION	INTEREST CAP.	[redacted]N	SALVAGE	TOTAL NET COST	YTD Accumulated
2015/16	Apr							
	May							
	Jun							
	Jul							
	Aug							
	Sep							
	Oct							
	Nov							
	Dec							
	Jan							
	Feb							
	Mar							
TOTAL								
2016/17	Apr							
	May							
	Jun							
	Jul							
	Aug							
	Sep							
	Oct							
	Nov							
	Dec							
	Jan							
	Feb							
	Mar							
TOTAL								

2015/09/11 09:44AM

PUB MFR 196

MB-SK Transmission Project

Provide the economic justification, including NPV, IRR, and revenue requirement analyses, that demonstrates that the MB-SK Transmission Project is favourable to ratepayers.

Public disclosure of the attachment to this MFR (or portions thereof) would result in the release of information considered to be confidential and commercially sensitive. As directed by the PUB, Manitoba Hydro will be filing a letter seeking confidential treatment of the redacted information contained in the attachment pursuant to Rule 13.

Please refer to the attached Saskatchewan Power 100/140 MW Sale Evaluation, which has been provided as an attachment to this response.

SASKATCHEWAN POWER 100/140 MW SALE EVALUATION

Resource Planning Department
Power Planning Division

PREPARED BY:

R ELDERS
D GILLICH
B HINTON
B JOHNSON
S KRAUT
C KREUTZER
D MARINELLI

APPROVED BY:

NOTED BY:

DATE: JAN 5 2016
REPORT: **PPD 16/01**

Manitoba Hydro

CONFIDENTIAL

This report is intended for internal use by Manitoba Hydro only. External requests for information contained herein should be referred to Power Planning Division.

This page is intentionally blank.

The purpose of this report is to detail the key assumptions and provide a supply and economic evaluation of the draft contract dated November 26, 2015 for a 100 MW sale to Saskatchewan Power Corporation ("SaskPower").This analysis also considers that the sale could be up to 140 MWs and evaluates the impact of adding an additional 40 MWs to the sale.

1 OVERVIEW

SaskPower has agreed to purchase 100 MW of Manitoba Hydro system power for a 20 year period from June 1, 2020 to May 31, 2040; and is considering the option of adding an additional 40 MWs to the sale. This report is based on preliminary transmission studies which provide indications for costs related to 100 MWs and 140 MWs of transmission interconnection. Under the agreement firm energy deliveries will be scheduled on a 6 x 16 basis and capacity must be sourced from Manitoba Hydro system resources.

This sale provides a long-term fixed revenue stream, reducing uncertainty related to future market price. Entering into long-term firm sales is a key component of the business case made during the 2013-14 Needs For and Alternatives to process for proceeding with Keeyask; including a 500KV transmission US-Can interconnection and Demand Side Management programming.

This Resource Planning evaluation compares the sale to a potential range of capital costs, potential alternative sale options, and system benefits. [redacted] The construction of a new East/West transmission line for export provides additional benefit beyond the contract period. Although recent transmission studies have confirmed 90 MW of firm transmission can be made available on the existing system between Manitoba and Saskatchewan starting in 2020, SaskPower has indicated [redacted] SaskPower maximizes its use of the existing 45 MW firm transmission for shorter term purchases from Manitoba Hydro and [redacted] The evaluation concludes the sale provides benefits (on a net present value basis) compared to development plans without

the sale [redacted] The evaluation indicates the 100 MW to 140 MW sales are economic.

2 KEY SALE TERMS

SaskPower has agreed to purchase at least 100 MWs and up to 140 MWs of Manitoba Hydro system power for a 20 year period from June 1, 2020 to May 31, 2040. Under the agreement firm energy deliveries will be scheduled on a 6 x 16 basis. Capacity supplied under this agreement must be sourced from Manitoba Hydro system capacity resources. Manitoba Hydro has the right, but not the obligation, to source the energy provided from this agreement from third party purchases and/or markets available to Manitoba Hydro.

3 TRANSMISSION

Manitoba Hydro and SaskPower have agreed to construct a new 230 kV interconnection between Birtle, Manitoba and Tantallon, Saskatchewan involving 44 km in Manitoba and 36 km in Saskatchewan and additional upgrades to the transmission grid in both provinces. The line will provide at least 100 MWs and up to 140 MWs of firm transmission service to export the firm energy and capacity from Manitoba to Saskatchewan. Manitoba Hydro will own and be responsible for the cost to construct and operate the Manitoba portion of the interconnection and SaskPower will own and be responsible for the cost to construct and operate the Saskatchewan portion of the interconnection. For the 100 MW sale, the cost of the line and transmission enhancements in Manitoba is estimated between $38-58 million (2015$). For the 140MW sale, there are additional transmission enhancements estimated at $10 million (2015$). [redacted]

Due to the significantly higher capital costs of a two way interconnection, the contract will include an interconnection which will be built to flow only one way from Manitoba to Saskatchewan and no import capability is assumed in the analysis.

Manitoba Hydro's Approval Authority Table also requires both Executive Committee and Board approval for all power purchase agreements greater than 100 MWs which require new generation and/or transmission.

4 RESOURCE REQUIREMENTS

The SaskPower Sale is not contingent on new Manitoba Hydro resources, however adding the 100 MW sale advances the need for additional capacity imports from 2034/35 to 2033/34. Adding an additional 40 MWs [redacted] Based on 2015/16 planning assumptions[1], dependable energy deficits remain the same with the expected Manitoba load requirements in 2036/37. The supply and demand balance includes a one year period in 2034/35, where winter peak capacity shortfalls are assumed to be met through capacity purchases.

Both the 100MW and the 140MW SaskPower Sale increases Manitoba Hydro's capacity demand and advance capacity deficits; and associated need for capacity imports. The sale is not contingent on new Manitoba Hydro resources; and as such can be met by various options expected to be available in the 2032 timeframe as these deficits materialize.

[redacted]

[1] Resource Planning Assumptions & Analysis For 2015/16 Corporate Planning Report, PPD 15/07



5 ENVIRONMENTAL ATTRIBUTES

The sale agreement includes the transfer of the environmental attributes to SaskPower and is included in the price for Supplied Energy.

6 PRICING ANALYSIS

The sale agreement has fixed pricing for both capacity and energy. The pricing analysis compares the projected contract revenue to the expected forecast for the Long Term Dependable Product presented in the 2015 Electricity Export Price Forecast. Conversion from US to Cdn dollars is at a rate of 1: 1.16 as per Manitoba Hydro's October 2015 P911. The Foreign Exchange is used to compare the sale against potential sales into the MISO market.

All values are expressed in 2015 dollars. Future revenue totals have not been discounted.



7 ECONOMIC EVALUATION

The economic evaluation is based on the assumptions of the 2015/16 Resource Planning Assumptions & Analysis[2] which includes Keeyask with an in-service date of 2019 and a new 500 kV US interconnection with an in-service date of 2020 as committed resources common to all development plans. Development plans with a sale to SaskPower include a new 230 kV interconnection between Birtle, MB and Tantallon, SK. The cost of the 44 km line and transmission enhancements in Manitoba is estimated to be $38 million (2015$) for the 100 MW sale and $48 million (2015$) for the 140 MW sale. The System Planning analysis has indicated a static var compensator (SVC) will also be required to serve this sale at an estimated additional cost of $20 million (2015$). A potential alternative to an SVC is the use of Brandon Unit #5 generator as a synchronous condenser to provide voltage support. While this is

[2] Resource Planning Assumptions & Analysis For 2015/16 Corporate Planning Report, PPD 15/07

expected to be a much lower capital cost alternative, the practicality and actual lifecycle cost implications are being reviewed. [redacted]

The following development plans were used in the evaluation:

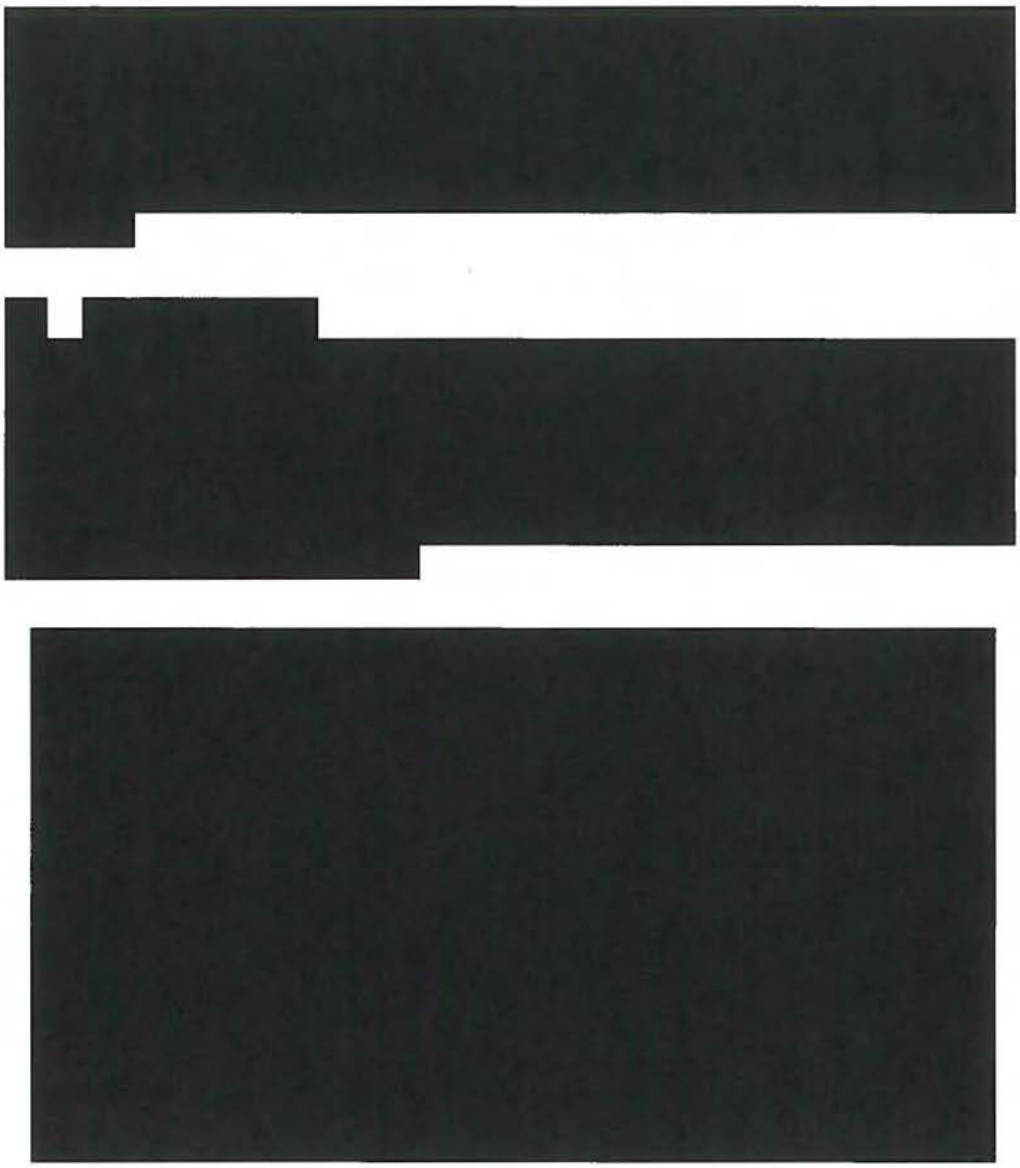
1. 2015/16 All Gas – No 100 MW SaskPower Sale
This plan is used as a base for the analysis to compare against the low capital cost option to provide the resources to meet Manitoba load. The plan includes eight (8) simple cycle gas turbines (SCGT) as required beginning in 2036 and capacity imports in 2034/35. This plan does not include 100 MW SaskPower Sale and is used as base case for comparison to a plan with the sale.

2. Diversity imports/Gas – 100 MW SaskPower Sale
This plan shows the impact of importing capacity resources in years 2033-35 until energy is needed in 2036, when an SCGT is required for the All Gas –100 MW SaskPower Sale. [redacted]

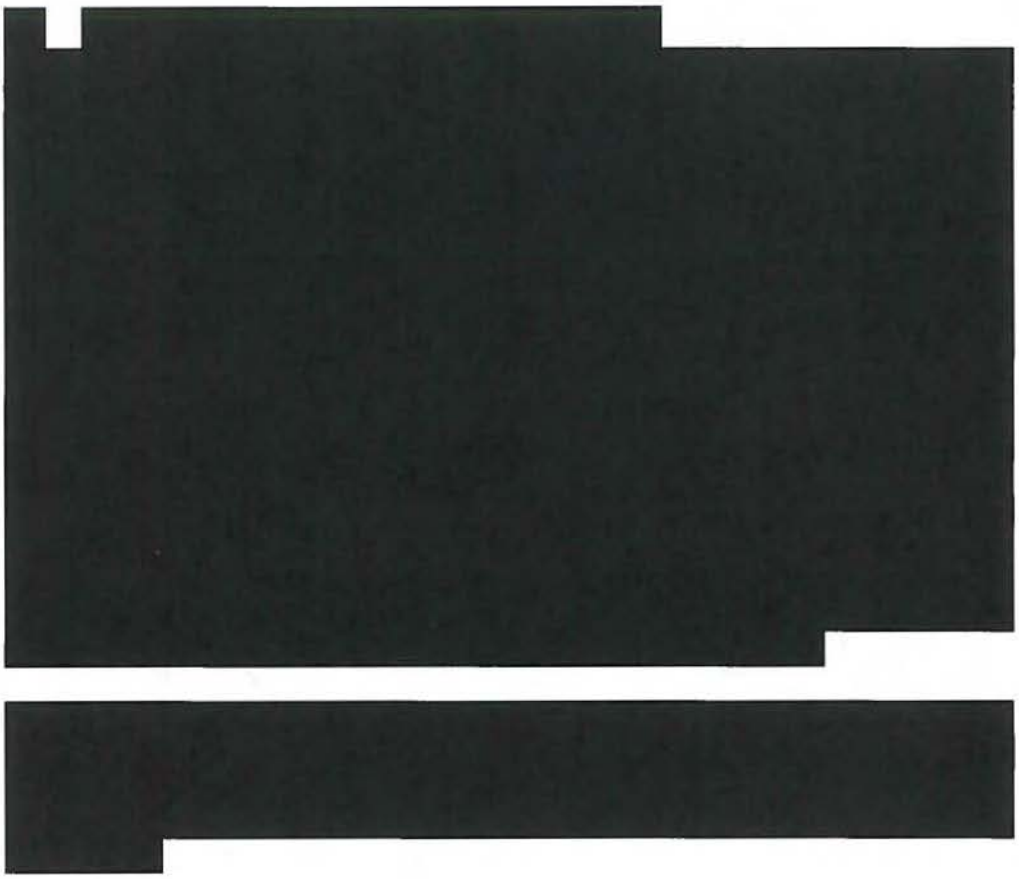
3. Diversity imports/Gas – 140 MW SaskPower Sale
This plan shows the impact of importing capacity resources in years 2032-35, until energy is needed in 2036 when an SCGT is required for the All Gas –140 MW SaskPower Sale. [redacted]

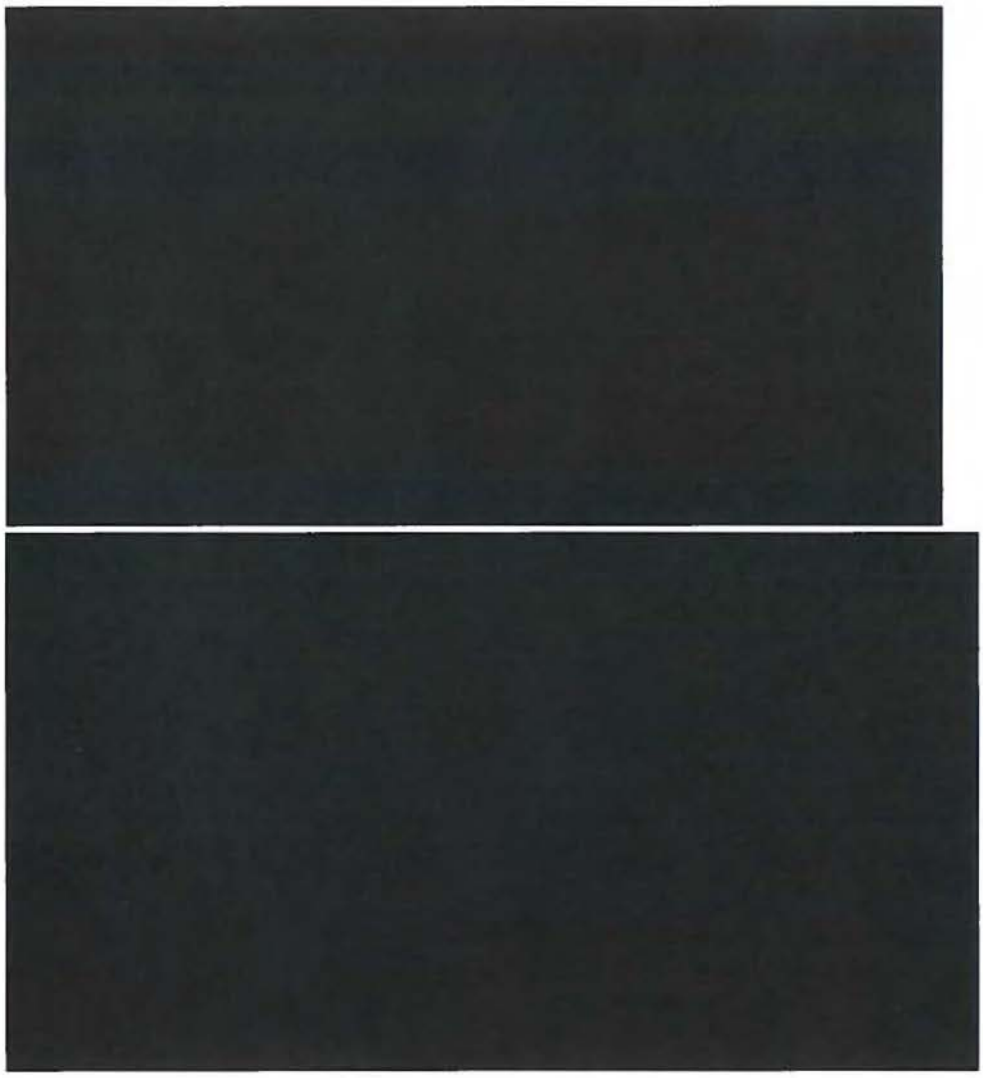
The following tables summarize the results of the economic evaluation [redacted]

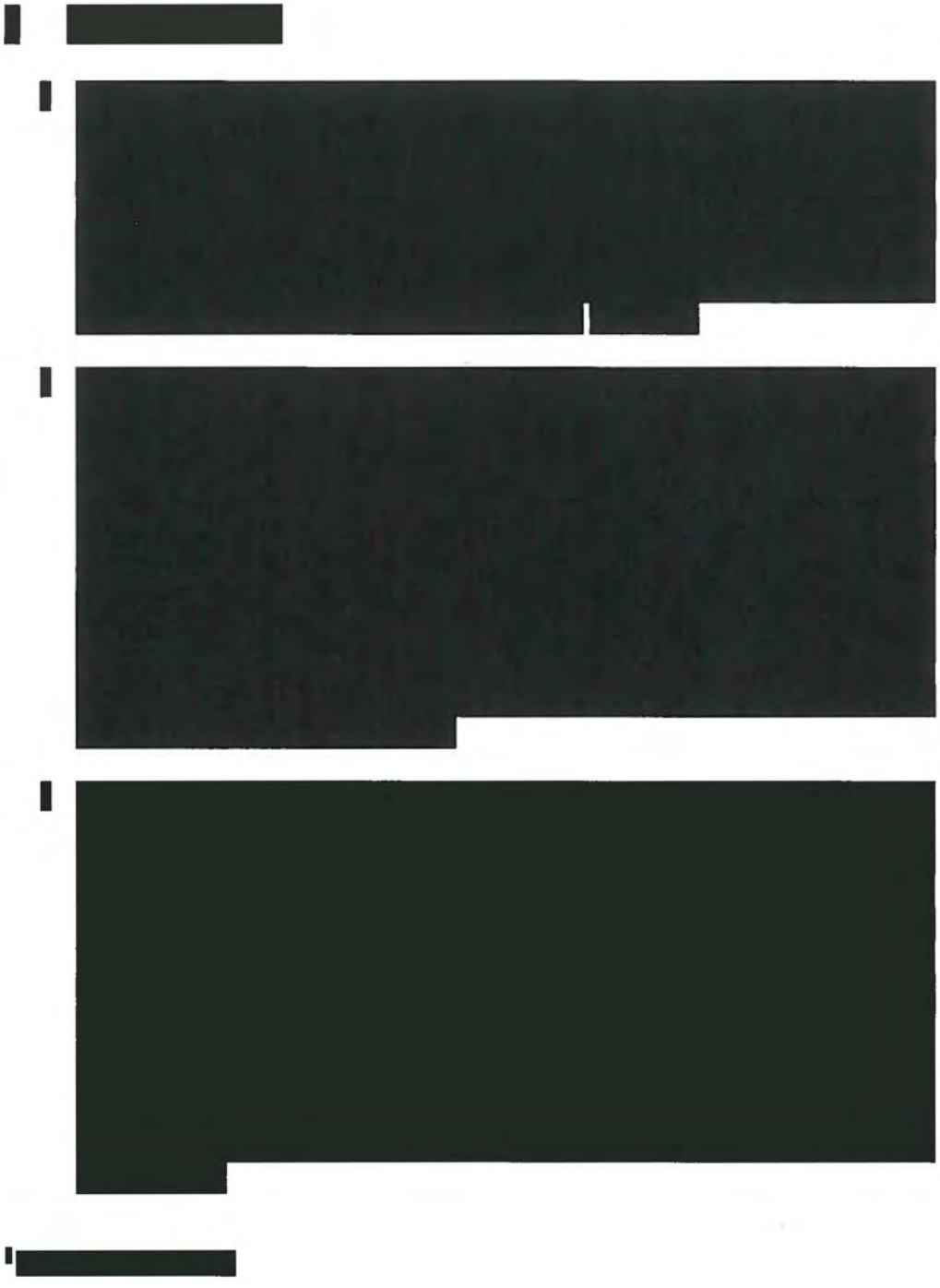
[redacted]













PUB MFR 197

MB-SK Transmission Project

Provide the SaskPower 25MW and 100MW power sale contracts.

Public disclosure of the attachment to this MFR (or portions thereof) would result in the release of information considered to be confidential and commercially sensitive. As directed by the PUB, Manitoba Hydro will be filing a letter seeking confidential treatment of the redacted information contained in the attachment pursuant to Rule 13.

Please find the public version of the SaskPower power sale contracts at the link below:
https://www.hydro.mb.ca/regulatory_affairs/pdf/electric/general_rate_application_2017/mfrs/pub_mfr_197_attachments.pdf

The following is included:

- SaskPower 25 MW:
    1. SaskPower 25 MW System Power Sale Agreement dated 2014 06 30
    2. SaskPower 25 MW amending agreement dated 2016 12 19
    3. SaskPower 25 MW second amending agreement dated 2017 05 01
- SaskPower 100 MW:
    1. SaskPower 2020-2040 System Power Agreement dated 2016 01 29
    2. SaskPower 2020- 2040 amendment dated 2016 12 19

Tab 66

Focused on What Matters Most:

Manitoba's Clean Energy Strategy









Manitoba

7371


FOSSIL FUEL FREE




RED RIVER COLLEGE





MESSAGE FROM THE MINISTER

Manitoba is in the unique position of having the resources, experience and wherewithal to become Canada's renewable energy powerhouse. Already a leader in developing one of the cleanest and greenest electricity systems in the world, Manitoba plans to build on those successes and move farther down the path towards fossil fuel freedom.

To help chart that path our government is pleased to release the Manitoba Clean Energy Strategy. This strategy focuses on made-in-Manitoba solutions to harness our water, wind, solar and biomass resources in ways necessary to help provide electricity to power our homes, businesses and industries; energy to heat our buildings; and fuel to drive our vehicles. This strategy is consistent with the principles behind Tomorrow Now – Manitoba's Green Plan, which focuses on protecting the environment while ensuring a prosperous and environmentally conscious economy.

Not only does energy play a critical role in almost every part of our society, but in Manitoba's case, it has become a major cornerstone of our economy. Plans for new hydroelectric generation and transmission require a bold capital program of $20 billion over the next decade. If they are approved after environmental and economic reviews, these projects will create thousands of jobs, provide us with affordable power well into the future and support our neighbours' needs for clean electricity in the shorter term.

We recognize that fossil fuels like oil and natural gas will continue to be an important part of our society, but our goal is to reduce our reliance on these imported, greenhouse gas emitting and unpredictably priced commodities sooner rather than later. While most jurisdictions can only set 30, 40 or 50 year targets to reduce reliance on fossil fuels, Manitoba has a head start in developing our renewable energy resources in a sustainable way that is good for the economy and benefits the environment.

Our strategy focuses on building new generation hydro; expanding transmission that improves electricity reliability and security; adding more wind power as economics allow; promoting geothermal, biomass and solar for heating needs; developing our biobased fuels; and leading in new cutting edge electric transportation solutions.

Our government will do this in a way that benefits all Manitobans and ensures that our energy is affordable and clean, that it contributes to job creation and business expansion and allows opportunities for greater First Nation partnerships. As Canada's leader in energy efficiency, our government will also continue to balance new energy generation with strong demand side management programs, including Canada's first Pay-As-You-Save, on-meter financing program for efficiency retrofits.

This strategy is all about making energy choices today that will create a stronger economy and a cleaner environment for our future. Is fossil fuel freedom achievable? We're closer than you might think.

Original signed by

Dave Chomiak

Minister of Innovation, Energy and Mines

HIGHLIGHTS

Highlights of Manitoba's Clean Energy Priority Actions include the following.

Building New Hydro

- Ensure that the planning, design, consultations and negotiations necessary for developing substantial new hydroelectric generation, including Keeyask (695 MW) and Conawapa (1485 MW), proceed through environmental and economic review. These new generation hydro projects are being designed to greatly reduce environmental impacts and will be developed in partnership with First Nations.
- Improve Manitoba's transmission system reliability, increase export capabilities, and enhance the development of new hydro and wind energy by constructing a new Bipole lll line, expanding interconnections to the US, strengthening the Dorsey convertor station, adding the new Riel Station and advocating for a stronger east-west Canadian grid.
- Work to eliminate the dependence of northern off-grid communities on diesel generation and ensure all Manitoba communities have access to clean renewable power.
- Maximize the economic benefits and job creation from new hydro and transmission developments through the $30 million Renewable Energy Jobs Fund, a new Energy Opportunities Office, and training support for northern and Aboriginal communities.



Leading Canada in Energy Efficiency

- Through Manitoba Hydro, implement a new On-Meter Financing program that overcomes the high upfront costs that prevent households from implementing energy saving retrofit measures.
- Enhance Manitoba's successful Low Income Energy Efficiency programming, in partnership with social enterprises, to help build community capacity, create jobs and maximize economic benefits.
- Expand The Green Building Policy so that more government funded building construction, renovation and operations are subject to energy efficiency requirements.
- Expedite adoption of National Building Code energy efficiency updates to ensure Manitoba homes and businesses achieve the lowest lifetime costs for energy.
- Advance vehicle-related efficiency through green fleet purchasing policies, support for higher vehicle fuel efficiency standards and promotion of active transportation.
- Support the expansion of voluntary programs to benchmark, rate and label building energy performance. Manitoba will explore and pilot programs that disclose the energy performance of buildings offered for sale or lease.
- Pursue minimum energy efficiency standards for high-energy consuming products where federal standards are deemed inadequate.
- Develop and publish an annual energy efficiency plan that establishes stronger efficiency targets; identifies an expanded range of programming options; sets out costs and benefits; and reports on performance.

Keeping Rates Low

- Place Bill 18 – *The Affordable Utility Rate Accountability Act* – into law to ensure the lowest cost in Canada for a bundle of utility services – that is, the combined rates for electricity for home use, natural gas for home heating and automobile insurance.
- Within the context of *The Affordable Utility Rate Accountability Act*, support predictable, moderate rate increases for Manitoba Hydro over the coming years. The rates should be sufficient to fund the renewal of existing infrastructure; develop new generation, transmission and distribution capacity to serve growing demand; and assure continued reliable service to Manitobans.



Growing Renewable Energy Alternatives

- Continue to develop 1000 MWs of wind power as economically viable. In total, 1,000 MWs is expected to generate $2 billion in new investment and $400 million in lifetime revenues to rural communities.
- Accelerate adoption of geothermal heating and cooling systems through Manitoba's Green Building policy, available financial incentives and by promoting community scale district heating opportunities.
- Grow the province's biomass heat industry by directing revenue from the Emissions Tax on Coal to the Manitoba Biomass Energy Support Program.



- Evaluate new production opportunities and increased biofuels content requirements to pursue reductions in gasoline and diesel imports even beyond the $100 million value currently realized in Manitoba each year.
- Prepare for and accelerate the adoption of electric vehicles in Manitoba by supporting informed decision making by consumers; incorporating electric vehicles into provincial and Crown corporation fleets; providing charging infrastructure support; and expanding electric vehicle demonstration projects.
- Continue to support development of the all-electric battery transit bus and expand the project into a multi-bus and charging demonstration.

Freedom From Fossil Fuels

- Launch a Fossil Fuel Freedom campaign that promotes a path for families to move away from fossil fuel use to clean energy sources for their electricity, heating and transportation needs. This path would help more and more Manitoba families reap the benefits of lower bills, create more local jobs and improve the environment.

TABLE OF CONTENTS

Message from the Minister of Innovation, Energy and Mines 01

Highlights 02

Introduction 06

The Case for Moving Forward and Today's Priority Actions 09

❶ **Building New Hydro** 09
- Today's Hydroelectric Priority Actions 13
- Today's Transmission Priority Actions 15
- Today's Gas, Coal and Import Priority Actions 16
- Today's Off-Grid Community Priority Actions 17
- Today's Energy for Jobs Priority Actions 17

❷ **Leading Canada in Energy Efficiency** 18
- Today's Energy Efficiency Priority Actions 21
- Today's Active Transportation Priority Actions 23
- Today's Auto Efficiency Priority Actions 25
- Today's Heavy Duty Freight Transportation 25

❸ **Keeping Rates Low** 26
- Today's Keeping Rates Low Priority Actions 27

❹ **Growing Renewable Energy Alternatives** 28
- Today's Wind Priority Actions 29
- Today's Geothermal Priority Actions 31
- Today's Wood, Biomass and Solar Priority Actions 33
- Today's Biofuel Priority Actions 35
- Today's Electric Vehicle Priority Actions 37
- Today's Alternative-Powered Bus Priority Actions 38

❺ **Freedom from Fossil Fuels** 39
- Today's Fossil Fuel Freedom Priority Actions 41

Conclusion 42

Appendix I – What is Energy? 43

Appendix II – Energy Abbreviations 44

INTRODUCTION

Energy is critical to contemporary society. How we supply energy and how we use it has a major impact both on the prosperity of our economy and on the future health of our planet.

Since the industrial revolution and the advancement of the coal burning steam engine, the world has relied primarily on fossil fuels – coal, oil and natural gas – to meet its energy needs. Today, recognizing the need to reduce the impacts of climate change and better protect the environment, human health and the well-being of their own economies, more and more countries are committed to reducing their dependence on fossil fuels and developing cleaner energy sources. Manitoba is not a mere follower in this movement, but rather a recognized leader for its efforts to become fossil fuel free.

To build on Manitoba's clean energy successes, an energy strategy must incorporate both a clear plan for the future, while at the same time meeting current needs for electric power, heat and transportation fuels. This strategy charts that path forward for Manitoba, setting out practical, clean energy steps and strengthening our position as a renewable energy powerhouse.

Looking Forward

Manitoba will capitalize on its renewable energy strengths and through innovation, will tap its homegrown clean energy resources allowing more Manitobans to transition to fossil fuel freedom, beginning today, and in the decades to come. It will do this by encouraging more efficient use of energy and by increasing production of clean, renewable energy sources. It will do so while growing its clean energy economy for the benefit of its own citizens as well as neighboring customers.

The Strategic Objectives

- Supply sufficient energy for our needs and deliver it reliably and securely.
- Provide affordable energy, particularly for those in low income, remote or vulnerable situations.
- Produce and use that energy cleanly, sustainably and in ways which reduce our greenhouse gas (GHG) emissions. This means in ways which do not degrade the world, at home or abroad, either today or for future generations.
- Ensure that energy is used efficiently, for environmental and economic reasons.
- Maximize the economic benefits from: constructing and operating energy generation facilities; manufacturing energy related equipment; low rates and improved efficiency; selling energy and expertise abroad; and reducing the economic leakage from the overall Manitoban economy due to imported fossil fuels.
- Increase local control. The value of energy independence and the need for more made-in-Manitoba energy has been made clear by recent decades of volatile energy prices.

Manitoba's clean energy strategy is a focused strategy, one which will demonstrate the government's commitment to build on our underlying and historic comparative advantage in low cost, renewable hydro electricity. It will also build on our newly arrived advantages in ground-source heat pumps, plug-in electric vehicles and other emerging renewable sources. Together, as these energy sources grow, they will offer Manitobans an increasing array of clean, cost effective, non-fossil alternatives for heating our homes, powering industry and fuelling our vehicles. Finally, woven through these power, heating and transportation initiatives is the constant need to increase energy efficiency and reduce the costs of energy waste.

We have the resources. We have the knowledge. We have the infrastructure. And we're already on the move.

Global Challenges

The world's energy supplies have become exceedingly complicated and volatile, with four global forces in particular having significant implications:

1. Oil and natural gas prices have been enormously volatile in the 2000s. For example, natural gas prices fluctuated by as much as 600 per cent in the past decade. The rise of Asia's industrial powerhouses, with their energy needs, make it unlikely that these pressures will lessen in the years to come.

2. Economic leakage from high energy prices has challenged economies globally, with jurisdictions around the world responding by pursuing greater energy independence.

3. Energy security has frayed as grid black-outs, oil blow-outs, wars, hurricanes and tsunamis have threatened energy supplies and repeatedly triggered price spikes.

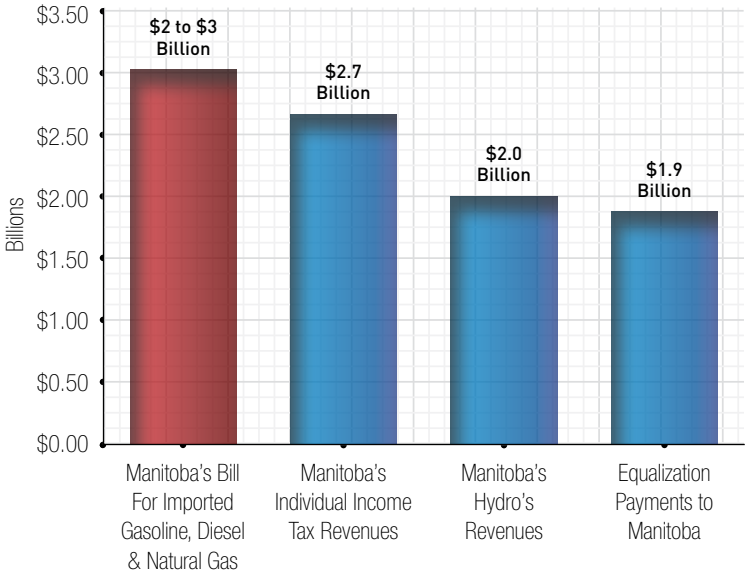
4. Climate change has been accelerated by the GHG emissions from continued fossil fuel use.

Many jurisdictions throughout the world struggle with these forces. While Manitoba has been somewhat insulated because of our strength in renewable hydroelectricity, we all still feel the effects of these forces when it comes time to heat our homes and refuel our vehicles.

Fortunately, at precisely the same time as these global energy forces have arisen, a series of global clean energy tools and innovations have begun to emerge into the mainstream. For example:

- In electricity, the past decade saw more wind-power capacity added in the US and in Europe than new coal, nuclear and hydro combined.
- In transportation, four million hybrid, plug-in hybrid and electric vehicles hit global roads.
- In heating, more than three million heat pumps have been installed globally since 2005.

The Annual High Cost of Manitoba's Gasoline, Diesel & Natural Gas Imports

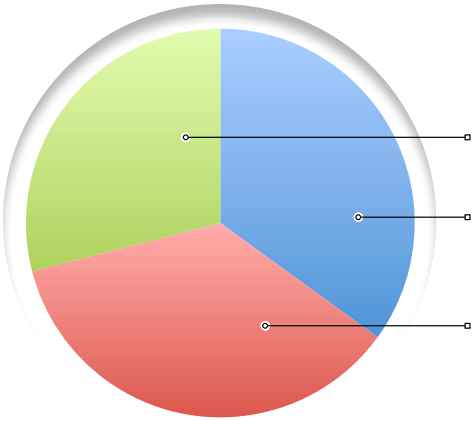


Manitoba has significant oil production in the southwest portion of the province. This oil is not refined in Manitoba but is exported as a commodity for processing. Although this oil is not directly used in Manitoba as an energy source, the industry is a significant contributor to the provincial economy. The industry pays over $100 million annually to private oil and gas rights owners and has seen investment in the province rise to $1 billion annually.



Energy in Manitoba

The following charts provide a snapshot of how we use energy in Manitoba.

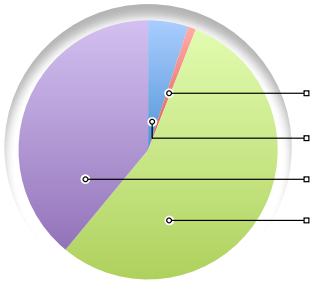


Energy Uses

35% Transportation

36% Heating & Manufacturing

29% Electricity



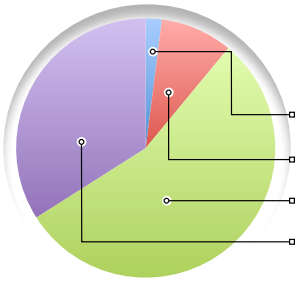
Transportation Fuels

1% Biodiesel

5% Ethanol

39% Diesel

55% Gasoline



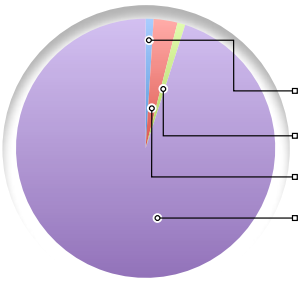
Residential Space Heating

2% Geothermal Heat Pump

9% Other

55% Natural Gas

34% Electric Resistance



Electricity

1% Fossil

1% Other

3% Wind

96% Hydroelectric

Notes: i) "Other" in residential space heating represents a mix of renewable wood/biomass, as well as heating oil and propane. ii) The top chart on Energy Uses reflects overall energy use within Manitoba, as outlined by data from Statistics Canada. iii) The lower charts provide energy source breakdowns for selected application uses only.

Because of extreme climate conditions, a relatively large land area, growing population and significant resource based industries, energy is critical to our way of life. Like other jurisdictions, fossil fuel use is woven into that way of life and will continue to be for decades to come. This is because vehicles, heating systems and buildings have lifespans lasting decades, which makes a too rapid change-out uneconomic. However, this timespan also provides Manitobans with the opportunity to customize the shape and timing of their own personal shifts, allowing them to choose clean energy and fossil fuel free technologies when and as they feel the time is right.

Although fossil fuels will be with us for decades to come and we will continue to maintain access to those fuels, Manitoba is in the enviable position of reducing our dependence on them and becoming a renewable energy powerhouse.

- Manitoba has already taken bold steps to ensure our electricity production is more than 98 per cent renewable using hydro and wind resources.
- Manitoba is a Canadian leader in terms of renewable heat (and cooling) with 11,000 geothermal installations.
- Manitoba took early steps with biofuels in terms of production and use to reduce reliance on imported gasoline and diesel.
- Manitoba consistently rates number 1 in Canada in energy efficiency programs and policies.
- Manitoba is breaking new ground in the electrification of transportation, from hybrid taxis to the first plug-in hybrid conversions through to advanced electric bus designs.
- Manitoba is home to well positioned manufacturing and energy service sectors as well as academic institutions that will help produce the innovative technologies and services needed going forward.

Manitoba will not rest on its past accomplishments, but will focus on five strategic areas that will strengthen our position as a renewable energy powerhouse and move us down the pathway towards fossil fuel-freedom. With so much at stake with our energy future, it is important to understand the case for moving forward.

THE CASE FOR MOVING FORWARD AND TODAY'S PRIORITY ACTIONS

1 BUILDING NEW HYDRO

When Manitoba made the long term, strategic decision to develop its own northern hydroelectric assets – rather than going for the quick fix of expanding the use of low cost, but imported and polluting coal – it faced potentially higher costs, as well as a series of risks that seemed, at the time, insurmountable.

Manitoba Hydro Meets and Overcomes the Challenges

Through innovation and determination, Manitoba Hydro met the challenges and constructed a series of new, northern hydroelectric sites, in the face of some of the world's harshest climates. They opted to develop new technology employing the long, high-voltage, DC transmission lines that reliably deliver Manitoba's power over enormous distances. They produced dependable power from highly variable hydraulic flows. And they managed and financed multi-billion dollar, decade-long megaprojects.

Benefits for Manitobans

The benefits we enjoy today were built on these decades of hard work and innovation. But, at their source, was the long term, strategic decision to build on Manitoba's own renewable resources, rather than consume imported fossil fuels. The benefits of that decision have been many and have risen steadily over the years.

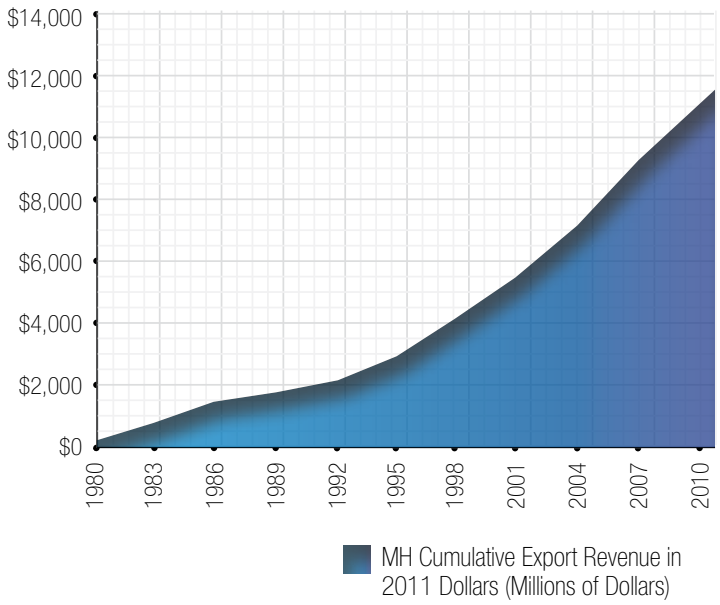
- Manitoba Hydro's rates have been among the lowest on the continent, saving Manitoba families and businesses $13 billion on their bills since 1998, compared to the average Canadian's rates.
- Through its operations, Manitoba Hydro annually creates 16,580 person-years of employment and adds $1.4 billion to Manitoba's GDP.
- More than 98 per cent of Manitoba's electricity is renewable, GHGs have been slashed at home; and electricity exports cut 178 million extra tonnes of GHGs from our neighbours' emissions.



Manitoba Hydro's performance provides strong evidence for the value of a fossil fuel free strategy. Using made-in-Manitoba, renewable energy, the province minimizes the need for fossil fuels to generate electricity, while creating huge economic and environmental benefits.

Manitoba Hydro's exports don't just benefit others. Since 1980, export revenues have risen to more than $11 billion, funds which have helped pay down the costs of the hydro projects themselves and kept rates low for Manitobans. For comparison, this amount is many times the $1.43 billion cost of the Limestone Generating Station, the last large hydro development prior to the Waskwatim dam.

MH Cumulative Export Revenues 1980 to 2011



Why Build New Hydro?

More electric generation is needed to meet Manitoba's rising demand. Even with the addition of the Wuskwatim dam, wind projects and energy efficiency measures, electricity load growth in Manitoba has outpaced the growth of new supply since the Limestone Generating Station came on stream in 1990.

This situation places increasing pressure on Manitoba's hard won energy independence in electricity. It makes us more dependent on fossil fuel imports during droughts and reduces export surpluses even in higher water years.

Manitoba's electricity demand today is growing by approximately 80 MWs per year. This rising demand requires the equivalent of a new Wuskwatim every two and a half years. Given the historic and sustained upsurge in Manitoba's population and housing starts, as well as continued economic growth, the pressure from rising load appears likely to continue. As domestic demand increases, exports are decreased and the revenue derived from exports – that aids in reducing domestic electricity rates – erodes over time.

Many of Manitoba's export customers have also experienced growth in electrical demand, but they too no longer view coal fired generation as a desirable alternative, whereas hydroelectricity from Manitoba is seen to be clean, renewable and stably priced. However, for export customers to be able to buy new hydro in the future, they often require lead times of many years to build the necessary new transmission.

Manitoba needs new generation to supply rising domestic load, while export customers wish to buy new hydro from Manitoba. By advancing the construction of new hydro plants ahead of domestic needs, Manitoba can both earn additional export revenues and expand valuable interconnection transmission, while also building the plants it will need to meet its own future requirements.

Windows of Opportunity

There are limited windows of opportunity within which Manitoba can sign new, long term export contracts, and receive vital new transmission links. If these windows are missed, customers will lock in with other suppliers, new transmission along with its market expansion and domestic reliability benefits will not be built and the window will close and be lost.

The past few years have offered just such a window, with the decision now before Manitoba.

Why Not Fossil Fuels, Like Coal or Natural Gas, Instead?

Decades ago, the largest fuel source used to generate electricity in North America and the world was coal. It was thought North America possessed endless coal reserves at unbeatable low prices. Manitoba Hydro, at the time, took a minority stand in the region with its decision not to use coal to generate most of its electricity. Over the decades, Manitoba's choice of hydroelectricity has proven itself to be the better one – for the environment, the global climate and the economy.

Manitoba Hydro's electricity is made from more than 98 per cent clean, renewable sources.

Today, the use of coal for electricity generation is being replaced by a new fossil fuel source– shale gas. Although coal plants still generate 44 per cent of the electricity in the United States, power generated by natural gas has doubled to 21 per cent. It is now the dominant source of new electricity in the United States and is rising quickly as old coal burning plants are shut down.

As once was said about coal, natural gas is said today to be available in the same near-endless quantities, and at the same unbeatable low prices. Natural gas has even been positioned as a cleaner fossil fuel than coal.

Manitoba's hydroelectric advantages over natural gas - jobs, stability and sustainability

When considering options, Manitoba's hydroelectricity has clear cut advantages over natural gas:

- Construction of new hydro power will create more jobs and more new business activity for Manitoba than natural gas fired imports or local plants.
- New hydro will emit far fewer GHGs than natural gas over its lifetime.
- While a natural gas plant has a life of 25 to 30 years, a key advantage of hydroelectric plants is that, once built, they will generate power for 100 years. For example, a new project like Keeyask, would likely still be generating power in the year 2100.
- Locally generated hydro will provide greater energy security for Manitoba than imported natural gas.

On the other hand: At 2012's natural gas prices of $2 to $3 per gigajoule (GJ), it can be used to produce electric power more cheaply than Manitoba's new hydro plants. But the price of natural gas is extremely volatile – the most volatile of any electricity source, cycling through a range of 600 per cent just over the past decade.

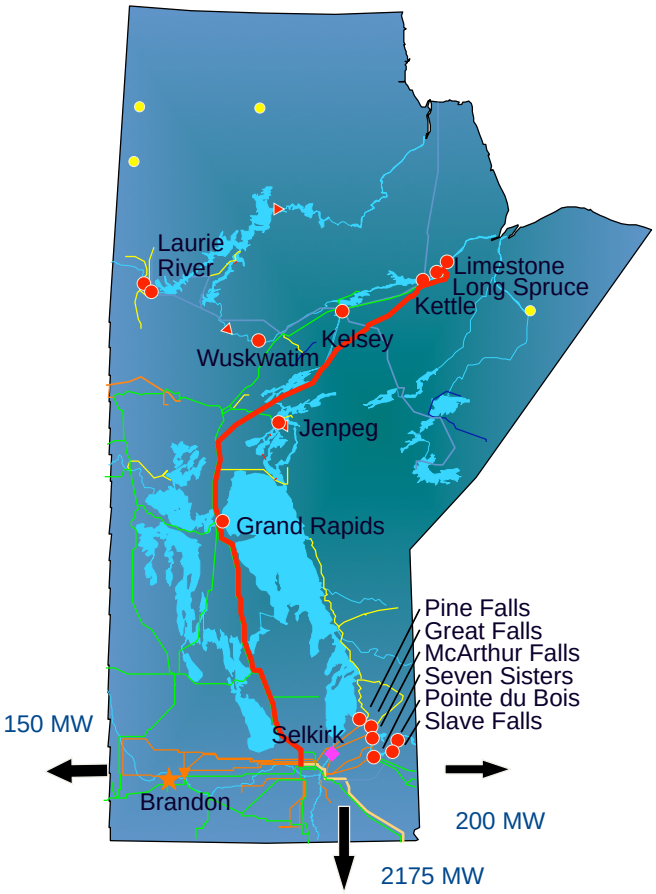


While prices are currently low, natural gas suppliers can't guarantee today's prices for the next 10 years, much less for the next 20 or 30 years or beyond – the years when Manitoba wishes to add new power. The difficulties this poses for long term energy planning in Manitoba can be seen clearly in the forecasts of the major energy planning bodies in North America. These bodies forecast natural gas prices ranging from $5 to $11 per GJ in the coming decades. With today's prices at $2 to $3 GJ, and Manitoba potentially looking at billions of dollars in investments, this uncertainty leaves Manitoba facing the risk of price swings of hundreds of percentage points if it chooses natural gas supplied projects.

Additional uncertainties surrounding natural gas and in particular shale gas include:

- the level of increased demand flowing from natural gas-powered electricity generation, expanded industrial end uses, transportation and Liquefied Natural Gas (LNG) exports
- the accuracy of estimates of shale gas reserves, production and depletion rates
- the long term sustainability of today's exploration and development business model, in the face of extremely low natural gas prices
- GHG emissions from shale gas exploration and production

With Manitoba's next two major hydro projects potentially coming online from 2019 to 2025, and then earning their major revenues in the decades to follow, natural gas prices in 2012 are of less relevance than the prices in 2032 or 2042. In the long term, Manitoba expects that hydroelectricity will continue to be the better option. Hydro's wide and long-lasting range of benefits – lower GHGs, more jobs and business in Manitoba, more stable prices and greater energy security – will still make hydroelectricity the superior choice.



Generating Stations and Interconnections

2011/12 - Energy

80%	Nelson River
9%	Winnipeg River
7%	Saskatchewan River
3%	Wind
1%	Thermal & Imports

- HVDC
- Other Transmission
- Selkirk - Natural Gas
- Brandon - Coal
- Brandon - Gas Combustion Turbine
- Control Structures
- Diesel Sites
- Hydraulic G.S.'s

Today's Hydroelectric Priority Actions

Clean Energy Portfolio

Given the high costs of focusing development on a single new project at a time, Manitoba has made the decision to move a portfolio of diverse, new hydro projects through to the readiness stages. As a result, the province and Manitoba Hydro are taking several projects forward through planning and design, consultation and negotiation with Aboriginal communities, environmental approvals, licensing and permitting.

This means that as and when Manitoba's load or forecast load passes certain thresholds, and as sufficient, firm export contracts are signed, and the economic case moves in favour of approving new supply, Manitoba will be equipped with at least one, and potentially more, projects ready for development. In the same way, if domestic load declines or proposed export contracts are altered or capital costs escalate, Manitoba has the tools to flexibly adapt.

Adopting a Clean Energy Portfolio has also enabled Manitoba to add wind power and other emerging, renewable energies – as well as energy efficiency, improved transmission and the rehabilitation of older hydro projects – to its potential new supply-side projects.

Finally, use of a portfolio approach allows Manitoba to develop its hydro construction in a staged manner that promotes stability of training and employment opportunities for northern and Aboriginal communities. This allows the province to maximize the overall economic and social benefits.

New Generation Hydro

Each new hydro project has been redesigned to better meet the needs in Manitoba's northern communities and also in a way that ensures projects meet and exceed customer expectations not just today, but over the next 40 or more years. Recent years have made clear that changing customer expectations and political debate elsewhere can dramatically impact Manitoba's long term access to export markets. A new hydro project intending to sell into export markets over a period of decades could lose hundreds of millions of dollars – not by failing to meet the legal standards in place when the contract was signed, but by failing to consider long term future issues and trends.



Manitoba export earnings have surpassed $11 billion, keeping rates low and supporting the cost of hydro projects.

With this long term view in mind, Manitoba's New Generation Hydro projects embody two major shifts from historic practices:

1. Aboriginal communities are engaged from the earliest stages of planning, as participants during construction, as well as standing to become long term, financial beneficiaries. Aboriginal people are also consulted through the province's Crown consultation process on any action or decision that might affect an Aboriginal or treaty right.



2. The Manitoba government is responsible for environmental and water licensing processes that outline the responsibilities of Manitoba Hydro to be good stewards of the environment. With that in mind, each project has been redesigned to dramatically reduce its environmental impact. Wuskwatim, for example, experienced just 50 hectares (or half a square kilometre) of additional flooding – a fraction of the size of an average Manitoban farm, while Conawapa will flood an area about the same size as an average farm (500 hectares). Many modern shopping malls, residential developments and energy plants take as much or more land than is lost through a New Generation Hydro project.

The New Generation Hydro components of the Clean Energy Portfolio that are under development or potentially available for development include:

- Wuskwatim – a 200 MW project that saw construction launched in 2008 and began generating power in 2012.
- Keeyask – a 695 MW project awaiting final licensing. Construction could run from 2014 to 2021, with first power potentially flowing in 2019.
- Conawapa – a 1,485 MW project, if approved, would see full project construction run from 2018 to 2026, with first power potentially flowing in 2025.

This expansion, of as much as 2,300 MWs, would be large enough to replace the demand growth of recent decades and to meet the expected domestic demand beyond 2020. It would also provide Manitoba with a surplus large enough to support large long term firm contract sales and to gain other revenues from the opportunity export markets.

The potential economic benefits of the total expansion are as impressive, as in previous generations of hydro development.

- The province is looking at $20 billion in new economic activity over the next decade, with Keeyask and Bipole lll alone expected to create 18,000 person years of direct and indirect employment.
- New export contracts worth over $4 billion are already on offer, with the potential to be added to, if desired. The proceeds will help pay down the cost of the projects, while helping sustain Manitoba's low rates for decades.
- This path offers a reduction in any long term dependency on coal or natural gas, and will reduce long term payments to fossil fuel producers.
- Manitoba's clean, stably priced, hydro exports would add real value to neighbouring systems – being available on-peak if desired, offering greater price stability and reducing their GHG emissions by millions of tonnes a year.

Transmission - Moving Power to Market

Manitoba Hydro's transmission network is large with 11,700 kilometres of transmission lines and 75,000 kilometres of distribution lines. The transmission facilities are developed and operated as an integrated system, with the backbone being two 800-kilometre, high voltage, direct current (HVdc) transmission lines (Bipole I and II). The lines were historically located in a common corridor and transmit over 70 per cent of Manitoba Hydro's annual energy production from its northern hydro stations on the Nelson to southern load centres. The direct current is converted back to alternating current at Dorsey station, northwest of Winnipeg, before being transmitted to the transmission and distribution system, as well as to Ontario, Saskatchewan and the US.

Most of the transmission and distribution facilities are exposed to the elements and can be affected by severe winds, lightning, ice storms and forest fires. The system is planned and built to achieve a high degree of reliability and maintain the delivery of power to its customers.

Manitoba's electric system is dependent on its two backbone HVdc facilities. Should these two facilities suffer a simultaneous catastrophic loss, it could result in extensive, wide spread, lengthy power outages. The number of customers affected, and the duration of their interruption of electrical service, would mainly depend on outside temperatures, with the most severe and extensive power outages occurring during the coldest winter months. Should such a loss occur at the winter peak, Manitoba Hydro has estimated that it could result in a supply interruption of up to 300,000 customers until repairs are completed. As a result, a third HVdc transmission facility, Bipole III, has been proposed to be constructed to assure the reliability of delivery of power to Manitobans.

More widely, new interconnection capacity to electricity markets increases both the reliability of Manitoba's own system, as well as Manitoba's reach into export markets. Should new generation to service additional sales in Minnesota and Wisconsin be approved, new interconnection transmission would be also be required.

Today's Transmission Priority Actions

Manitoba Hydro's transmission work includes developing Bipole III for reliability purposes (expected to be commissioned in 2017), as well as new export transmission interconnections, of different sizes and configurations, to the United States (to be available by 2019.) In addition, strengthening the Dorsey Convertor Station will increase reliability, and developing a new Riel Convertor Station will provide a second delivery point for northern power.

Manitoba has also forged a national leadership position by advancing the idea of a stronger east-west Canadian grid. The timing and size of Manitoba's enhanced, east-west grid interconnections with Saskatchewan and other provinces will ultimately be determined by the results of ongoing power sale talks. Manitoba will continue to advocate for an improved national electrical grid that can transport clean, renewable energy to every region in Canada.

Taken together, these transmission projects will:

- dramatically improve the long term reliability of Manitoba's system in the face of climatic instability and extreme weather
- enhance the development of new northern hydro as well as southern wind development
- reduce the potential cost of imports by achieving greater market access
- boost both the range and the scale of Manitoba's exports
- strengthen Canada's east-west ties

Reducing Coal Fired Power

In recent years, Manitoba closed most of its old, polluting coal fired capacity. Some units were converted to burn natural gas, while two new natural gas generators were installed. In order to reduce GHGs, *The Climate Change and Emissions Reductions Act* stipulated that by 2010, coal fired generation was capped under normal conditions and could only be used in emergency situations. Today, of Manitoba Hydro's 5,500 MWs of capacity, there are 364 MWs of natural gas fired capacity in Selkirk and Brandon, and just 97 MWs of emergency, coal fired backup in Brandon.

Natural Gas to Complement Clean Energies

Manitoba's natural gas based generation is used for a range of purposes: generate power during emergencies and droughts; help during transmission outages; and respond to short term variations in the output of our renewable generation. Used in these complementary ways, natural gas not only helps the system run more smoothly, but can actually increase Manitoba's installed capacity of new hydro and wind energy. By integrating, backing up and stabilizing new hydro or wind, natural gas generation can ultimately allow more renewable energy to be produced here.

Store It Away for Another Day

Manitoba has historically used imported power during droughts. Manitoba Hydro also buys off-peak, imported power at a low cost, stores it, then resells the power back to our trading partners at lower rates than they could make it for themselves – and earns a profit performing the service. This exchange is built on another Manitoba advantage – the large storage capability of our system's reservoirs – an asset which new hydro and new wind also need as they are further developed. The province has also, traditionally, shared these storage and support services with neighbouring utilities, helping the regional grid to run smoothly and supporting wind development in the US. At the same time, Manitoba's first priority moving forward is to use these assets to ensure the development of made-in-Manitoba new hydro and new wind, thus maximizing economic benefits for Manitoba and strengthening its energy security.

Today's Gas, Coal and Import Priority Actions

Coal

The remaining coal fired electricity generator in Brandon will continue to be used only in emergency situations and droughts. The generator will need to be "exercised" on a very limited basis to ensure it is operational when needed in emergencies. Manitoba will also comply with the federal government's new regulations that will phase out the use of conventional coal generation across the country.

Natural Gas

Manitoba's existing natural gas generating capacity continues to play a number of complementary roles in the system and will be maintained. Similarly, new natural gas plants will only be added to respond to short-term variations in renewable output, thus allowing Manitoba to integrate more new hydro and wind – or to augment the complementary roles described. Decisions on whether to add natural gas will also depend on consumer demand, renewable supplies and market conditions.

Imports

Imported power can provide value to Manitoba during droughts and through sales related to peak shifting and similar variations. However, given the limits of Manitoba's system to integrate, store, firm and shape energy, these capabilities will be used in ways which do not inhibit the development of Manitoba's own high priority hydro, wind and other renewable resources.

Off-Grid Diesel Communities

The northern communities of Brochet, Lac Brochet, Shamattawa and Tadoule Lake are currently not connected to the Manitoba Hydro transmission grid. They are supplied by stand alone, diesel generating facilities. For too long, these communities have struggled with high operating costs and the environmental concerns associated with the diesel generation.

All Manitoba communities deserve access to clean, renewable power – especially those in northern Manitoba, the heart of the province's renewable generation. As with many off-grid communities across Canada, the cost of grid connection is very high. However, depending on the local situation and advantages, the addition of small scale renewable energy could potentially help reduce their reliance on diesel generation.

Today's Off-Grid Community Priority Actions

Working closely with the off-grid communities, and the Canadian government and other partners, Manitoba Hydro will reduce dependency on diesel fuel by implementing renewable alternatives to diesel generation and improving energy efficiency. Manitoba will also show national leadership on this complex issue, working with our counterparts in other territories and provinces that have off-grid communities to share best practices and seek solutions.

Energy for Jobs

With the major expansion of hydro generation and transmission over the next decade, new economic opportunities will unfold for Manitoba companies and those looking to invest here. Capital expenditures, estimated at $20 billion by Manitoba Hydro, represent a significant opportunity to increase local job creation – in the construction of new generation and transmission capacity, but also in the supply of equipment, components and construction materials for these projects.

Today's Energy for Jobs - Priority Actions

In April 2012, Manitoba established a $30 million Renewable Energy Jobs Fund to help maximize industrial benefits (including local content and industrial offsets) from these major projects. The fund will provide loans to eligible manufacturers of equipment, components or construction materials used in the generation, or transmission, of renewable energy. This includes hydro, geothermal, wind, next generation biofuels, biomass heating, solar and smart grid technologies.

An Energy Opportunities Office will also be created to work with companies looking to expand, or locate for the first time, in Manitoba. This office will serve as a one-stop business support centre for companies wishing to tap these opportunities, and seek out partnerships with other companies in the renewable energy supply chain. In addition, the Manitoba government and Manitoba Hydro will work together to ensure that northern hydro developments result in good jobs for Aboriginal communities.

Premier Greg Selinger announces the Energy Jobs Fund at Winnipeg-based Crompton Greaves (CG) Power Systems, one of the top electric transformer manufacturers in the world.



❷ LEADING CANADA IN ENERGY EFFICIENCY

Manitoba Leads Canada in Energy-Efficiency

As energy prices began to rise in the early 2000s, the Manitoba government and Manitoba Hydro fast-tracked an expansion of the Power Smart program. They launched new programs to cover all sectors, regions, income groups and fuels. By the end of the decade, 350,000 families, businesses, schools, churches and farms had participated in the newly expanded Power Smart programs. One example is Manitoba Hydro's Power Smart Loan, which provided $267 million in financing to over 65,000 Manitoban customers.

The government launched its new Green Building Policy in 2007. The policy requires that provincially funded new buildings and major renovation projects meet energy and environmental requirements including: a minimum level of energy efficiency that is 33 per cent better than the Model National Energy Code for Buildings (MNECB.) To date, approximately 297,000 square meters (3.2 million square feet) of new construction in Manitoba incorporates green building standards and practices affecting almost 40 per cent of the industrial/ commercial/ institutional construction sector.

Building codes have also been improved on an ongoing basis, provincial energy efficiency standards for gas furnaces have been raised and incentives by the province and Manitoba Hydro helped many thousands of Manitoba families retrofit their homes.

Manitoba's Power Smart Program saved Manitoba families, firms, facilities and farms more than $600 million on their utility bills since it was launched.



7390

Manitoba Seizes # 1 Ranking in Canada

In two short years, Manitoba's energy efficiency programs shot up in the Canadian Energy Efficiency Alliance (CEEA) rankings, from 9th place in 2002 to 1st place in 2004 – a ranking Manitoba has successfully maintained for nearly a decade. In environmental terms, these energy efficiency improvements brought a reduction of 1,350,000 tonnes of GHGs in Manitoba and its export customers, annually. This is equal to taking 250,000 cars off the road.

$600 Million in Bill Savings for Manitobans

Perhaps even more importantly, Manitoba's homes and businesses have achieved direct, energy bill savings which surpassed the $600 million mark in 2011. This amount continues to rise and, in another testament to Manitoba's long term thinking on energy, is expected to exceed $2 billion by the next decade.

Manitoba Hydro's forecast energy and power savings achieved through energy efficiency are included in its planning as a resource option alongside hydro, wind and other resource options. Today, the energy saved by the Power Smart efficiency power plant is more than 575 MWs – equal to that of all the hydro projects on the Winnipeg River.

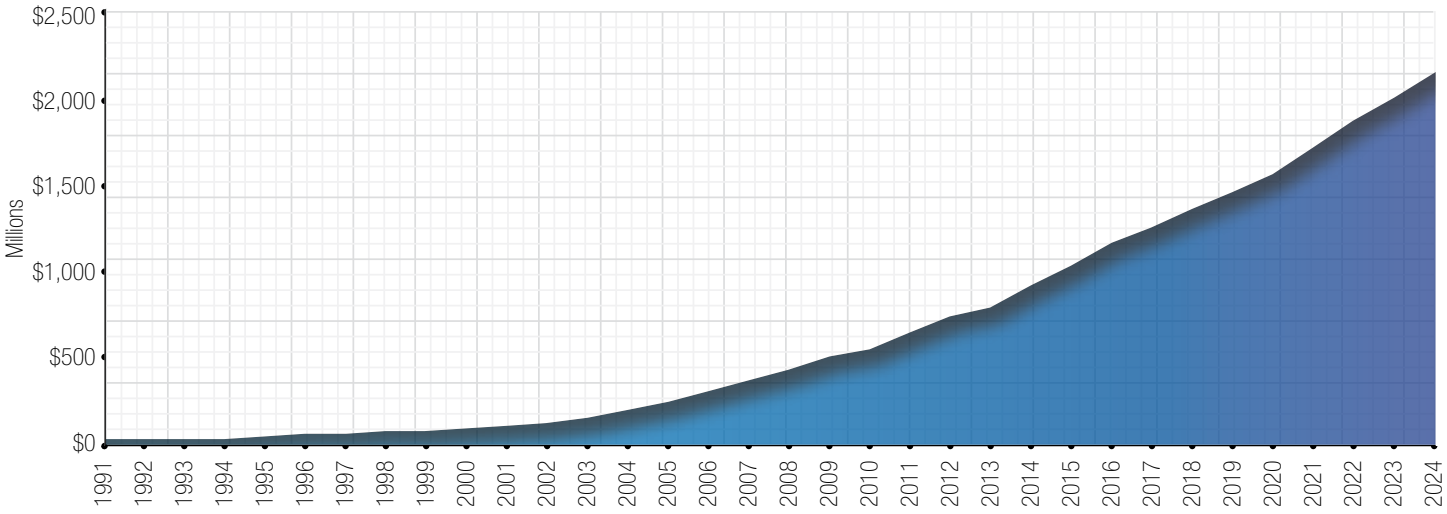
These efficiency savings have cost Manitoba Hydro, on average, just 1.9 ¢/kWh (kilowatt hour), well below the cost of other methods. This saved energy is then resold on the export market by Manitoba Hydro, earning profits and helping keep domestic rates down.

Incentives and Standards Have Cut Manitoba's Natural Gas Use

Manitoba's energy efficiency achievements are also seen in our natural gas sector through the use of incentives for high efficiency gas furnaces and insulation, higher product standards for furnaces and incentives for heat pumps. This effort more than offset any new demand from Manitoba's population increase, so that natural gas use has fallen by 17 per cent in our homes and nine per cent in the commercial sector. As a result, GHGs from residential and commercial natural gas use have fallen by 700,000 tonnes this past decade.

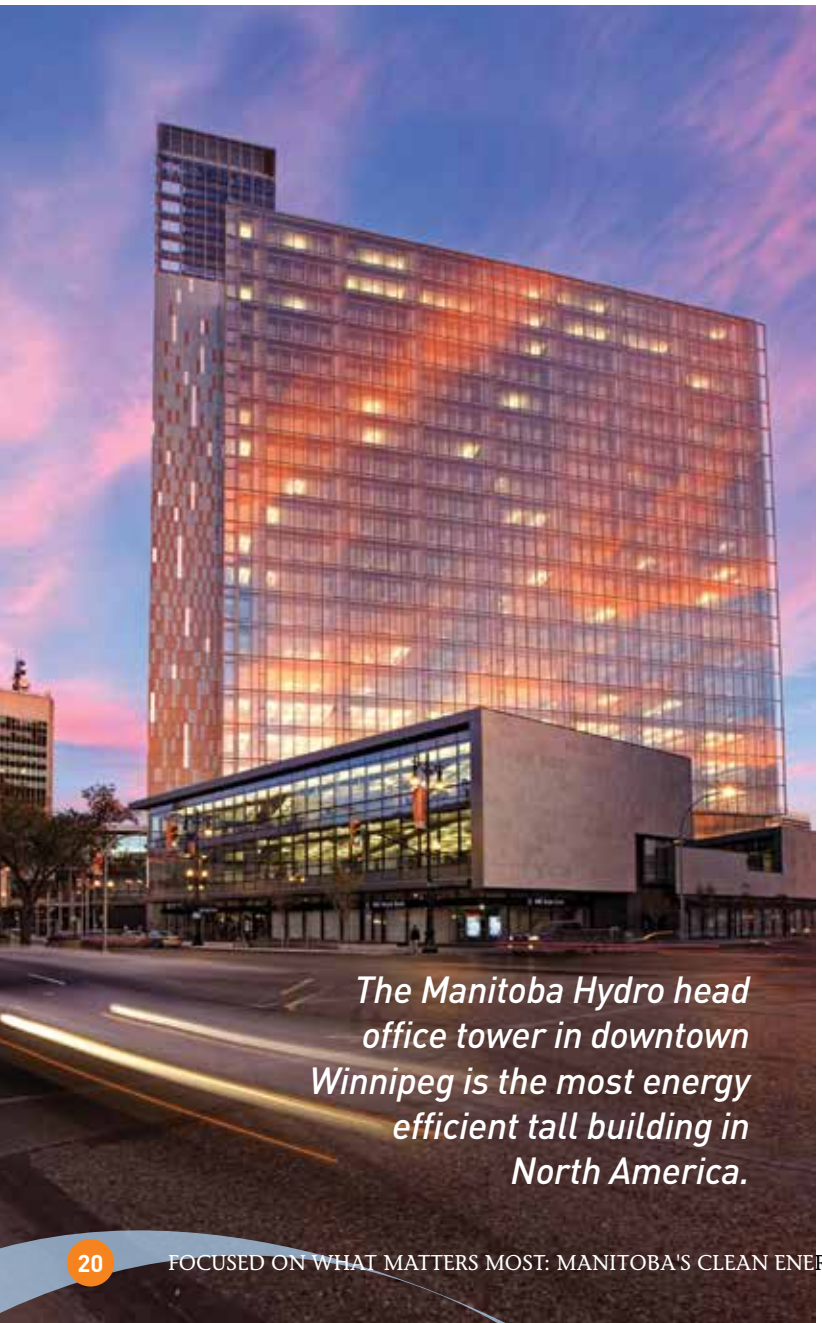
Manitoba ranked number one in Canada for energy efficiency.

Manitoba's Cumulative Bill Savings From Power Smart Programming



Low Income Communities – More Than Meeting the Challenge

Energy efficiency is a major opportunity in low income areas, where homes are often poorly insulated, and energy and water bills take a high share of family income. Social enterprises such as Building Urban Industries for Local Development (BUILD), and the Brandon Energy Efficiency Project (BEEP) in partnership with the Manitoba government and Manitoba Hydro, developed a successful business model that combines social, economic and environmental objectives.



The Manitoba Hydro head office tower in downtown Winnipeg is the most energy efficient tall building in North America.

These enterprises sought not only to address energy waste and unnecessary high bills, but also to employ local people with barriers to employment. Once trained, these employees have conducted the energy and water retrofits in their own neighbourhoods. The benefits have been huge – lowering utility bills for thousands of low income families and providing training and jobs for more than 150 Aboriginal youth and others marginalized from the mainstream labour market.

BUILD's Made-in-Manitoba Model Wins Scotiabank Award for Business Leadership

In 2011, BUILD's made-In-Manitoba model of community development was recognized by Scotiabank and awarded the national EcoLiving Award in Business Leadership. The Manitoba government and Manitoba Hydro backed BUILD and BEEP, and are aiming to raise the bar further by working with the Manitoba Housing Authority on 400 single-family units – each of which is expected to see utility bills cut by $450 a year.

Manitoba Hydro's New Head Office - An Energy Efficient and Architectural Showpiece

Perhaps the high point of the recent decade's efficiency efforts has been Manitoba Hydro's new, 22-storey, head office in downtown Winnipeg. After setting world leading performance targets, Manitoba Hydro challenged Manitoba's architectural, design, engineering and construction sectors to meet them. The result is an edifice that not only has a stunning appearance, but one that uses 70 per cent less energy than a conventional building.

Most of its remaining energy needs are met by heat pumps which draw heat and cooling from 280 bore holes – each drilled 122 metres beneath the site – as well as its many solar features. The new facility has been named North America's most energy efficient tall building. It is also the first large office tower in Canada to receive the LEED® Platinum certification from the Canada Green Building Council.

Today's Energy Efficiency Priority Actions

The Energy Savings Act

Even with significant achievements in energy efficiency, Manitobans are still using large amounts of energy, as a result of our climate, distances and building age. This means efficiency opportunities remain. As a result, Manitoba passed *The Energy Savings Act* (ESA) to ensure that investment in efficiency continues to expand and Manitobans continue to save more.

- **On-Meter Finance**

  The most powerful new tool the ESA enables Manitoba to use is On-Meter Finance. For decades, the number one barrier to energy efficiency savings has been the difficulty of financing the upfront capital costs. Most homes have energy and water savings opportunities. The problem has been that many of these opportunities are not acted upon because of high, upfront costs. Because of this, households paid higher bills than necessary, local retrofit jobs were lost and more money flowed out of Manitoba to pay for fossil fuels.

  The new financial tool developed to overcome this sees energy saving retrofit measures paid for upfront, but by the utility directly. The retrofit cost is then repaid by the residents on their regular utility bill utilizing energy savings to pay for the difference. The ongoing repayments are tied to the meter, not the individuals – thus the name, on-meter financing. This means families can make large and long-lasting efficiency investments, such as in-home insulation or on heat pumps – knowing the investment will be paid off over the measure's lifetime, by whoever is living in the home.

  The program includes plans not just for owner occupied, single family dwellings, but also for the low income sector, rental accommodations and public sector buildings.

More than 350,000 Manitoba families, firms, schools, farms and churches have participated in Power Smart programs.

- **An Energy Efficiency Plan**

  The new ESA requires Manitoba Hydro to set energy efficiency targets for the future. The act will ensure that Manitoba Hydro, the province, industry, community partners and the public are on the same page, by publishing an annual Provincial Energy Efficiency Plan. This plan will include details of stronger efficiency targets for electricity and natural gas use and an expanded range of programs; set out costs and benefits; and report on performance.

- **The Affordable Energy Fund**

  The ESA also extended the Affordable Energy Fund, to make sure all Manitobans, regardless of region, income or fuel source, are able to reap their share of energy and water savings.

Green Building Policy

Manitoba's Green Building Policy will be expanded to include provincially funded residential construction and renovation projects, operation and maintenance of provincially funded existing buildings and government leased accommodations and will include expanded program support.



Low Income Energy Efficiency

Manitoba Hydro's On-Meter Financing program and the Affordable Energy Fund will provide significant support to social enterprises in efforts to make deep retrofits in homes and buildings in low income areas. Manitoba Hydro will work closely with these community groups on a street-by-street approach to retrofit neighbourhoods, rather than one home at a time. Similar to the partnership approach Manitoba Hydro has taken with First Nations on new dam developments (but smaller scale), their partnership with social enterprises will help build community capacity, create jobs and maximize economic benefits.

Green Schools and Education for Sustainability

A centerpiece of the government's longer term energy efficiency efforts is its commitment to make every school a green school. While the Green Building Policy has led the way in building energy savings into new school construction and major renovations, efforts will also be supported to make school grounds green and access energy saving opportunities in school transportation (ex: walk to school, idle-free zones, biodiesel buses). Daily operations of schools are expected to become more energy and water efficient as sustainability school plans, including energy efficiency measures, will be encouraged to be in every school in Manitoba by 2015.



Building Codes

Building codes ensure that homes and businesses achieve the lowest costs for energy over their lifetimes. Subject to completion of consultations and upon final review and approval, Manitoba will adopt the 2011 National Energy Code for Buildings (NECB) to make new construction and major renovations in the commercial and institutional sector more energy efficient. Following this work, Manitoba will review and consider potential adoption of interim amendments to the 2010 National Building Code of Canada (NBC) related to energy and water efficiency in new homes and small buildings.

Net Zero Energy Homes

A growing number of new homes built worldwide are designed to use (or approach) net zero energy. This means they aim to generate as much energy onsite as they draw from the grid. Manitoba supports this direction, but needs to take into consideration our severe climate. The province will promote the design, building and monitoring of net zero energy and near net zero energy homes by Manitobans – for use in Manitoba conditions.

Provincial Buildings Audits

The province owns, controls or funds many public housing units, schools and public buildings, which hold significant opportunities for energy and water savings and renewable heat expansions. Energy and water audits will be encouraged in these buildings to help identify measures to increase energy savings and the use of renewable heating and cooling options such as geothermal.

Disclosure of Energy Performance

Manitoba supports the expansion of voluntary programs to benchmark, rate and label building energy performance. Manitoba will explore and test pilot programs that disclose the energy performance of buildings offered for sale or lease.

Minimum Standards for Energy-using products

Manitoba will pursue minimum energy efficiency standards for high energy consuming products where federal standards are deemed to be insufficient or unlikely.

Active Transportation

The consequences of an ever expanding dependence on car use, and ever increasing vehicle miles travelled, are also seen to be unsustainable over the long term. User friendly alternatives must increasingly be put in place to help support a shift toward reduced travel demand.

Active transportation methods (ex: walking, cycling) can make a real contribution here, while also generating a range of wider benefits. They can improve our quality of life, lower the costs of traffic congestion, enhance our environment and strengthen our economy. They also support Manitoba's energy goals by reducing our reliance on fossil fuels, lowering GHG emissions and helping the overall transport network work more efficiently.

Getting Active - A Smarter Approach

While active transportation embraces several modes of travel, cycling and walking are the most popular. Creating a strong cycling and walking culture, where existing barriers are addressed, convenience is emphasized and safety is vital, is pivotal to advancing Manitoba's active transportation objectives. Manitoba is already making strides by expanding walking trails and cycling paths, putting in better racks and facilities for cyclists, through walk-to-school programs and the Commuter Challenge.

In addition to cycling and walking, Manitobans are using other methods to reduce their fuel use from transportation. And since commuting by car to work each day is the single largest source of GHGs in Manitoba, these actions are often the single largest GHG reduction action individuals can take. Manitoba supports a range of these initiatives:

- car pooling, ride sharing and car sharing through matching and information web sites
- use of Drive Green methods, where drivers learn to reduce sudden accelerations and stops and idling and improve vehicle maintenance
- increased public transit use that has seen Manitoba accelerate its long term investment in transit
- development of technology that supports working from home and telecommuting systems



Today's Active Transportation Priority Actions

Manitoba's three-year action plan, intended to improve the policies, programs and infrastructure that support active transportation, includes the following:

- developing and adopting a provincial active transportation policy including design guidelines for active transportation infrastructure
- launching a new online portal with active transportation resources and an inventory of routes
- working to complete the Borders to Beaches section of the Trans-Canada Trail
- commencing a new active transportation overpass at the north Perimeter Highway in Winnipeg to extend the popular northeast Pioneers Greenway
- providing new funding and technical support to help municipalities integrate active transportation planning, design and use with land use and transportation planning
- working with Manitoba Public Insurance to continue raising awareness of safety issues affecting vulnerable road users (ex: cyclists, pedestrians, children, seniors)



Auto Efficiency

Energy efficiency opportunities extend well outside the home – with one of the greatest opportunities being Manitoba's current fleet of 600,000 to 700,000 light duty vehicles. The fuel consumption of Manitoba's vehicles is relatively high, around 15 litres per 100 kilometres (16 miles per gallon (mpg) US) – about 20 per cent higher than the Canadian average.

This low vehicle efficiency means our drivers pay more for fuel, increased GHG emissions and the Manitoba economy leaks hundreds of millions of extra dollars each year to pay for unnecessary gasoline. While a shift to electric vehicles and plug-in hybrid electric vehicles could potentially change this situation over the longer term, Manitobans' purchase of 40,000 to 50,000 new vehicles each year offers perhaps the fastest way to improve overall fleet efficiency, reduce fuel imports and cut our gasoline bills.

Manitoba Helps Drive North America to Higher Standards

Manitoba decided to help move auto efficiency in the mid-2000s, as consumers were hit by rising prices and oil consuming economies lost billions of dollars to oil producing regions. There had long been debate around increasing auto efficiency standards, but rising oil prices gave more weight to the effort. Since auto manufacturing is integrated continentally, and vehicle standards tend to move hand-in-hand in Canada and the US, Manitoba moved to support a cross-border alliance of states and provinces working toward higher standards.

This alliance won a major victory in 2009, when the US agreed to raise its auto efficiency targets from 25 mpg today to 35.5 mpg by 2016. The arrival and rapid progress of hybrids, EVs and PHEVs has since spurred a further increase, all the way to 54.5 mpg by 2025. The US Government expects that this change will save the average car buyer $8,000 each, and – as Canada shifts its own vehicle standards – will likely save Manitoban drivers a similar amount as they purchase the more efficient models available in years to come.

This doubling of fleet efficiency targets would not have been possible without the growth of hybrids and electric vehicle technologies. Manitoba played a key role, by identifying these technologies as game-changers early on, and launching Canada's first $2,000 consumer-incentive targeting hybrids. The province's taxi companies then put a large number of hybrids to the ultimate test – in Manitoba weather. The Manitoba government also purchased and tested many different models in its own fleet.

In 2010, Canada introduced the Passenger Automobile and Light Truck Greenhouse Gas Emission Regulations, modeled after the US's Corporate Average Fuel Economy standard. The same kind of progressively improved emissions standards will be applied to Canada's cars and light trucks between 2011 and 2016, with efforts to bring in higher standards for 2017. Further efforts regarding heavy duty vehicles are also underway within Canada.

Over time, these higher auto efficiency standards should reduce the amount of fuel used by new cars in Manitoba annually. However, with the province's recent shift to a higher rate of population growth, the number of cars may also rise quickly. As a result, Manitoba is pushing not only for higher auto efficiency standards, but also for a step change away from gasoline and toward electric vehicles over the medium and longer term.

Today's Auto Efficiency Priority Actions

Just as Manitoba helped support the effort for higher vehicle efficiency standards in the past, it will do so in the future. Higher auto efficiency standards will save Manitoba drivers thousands of dollars in the coming years, while reducing GHGs and increasing our energy security. The province will also work to help those Manitobans who wish to take bolder steps toward using more clean energy and moving off fossil fuels, through the rollout of its Fossil Fuel Freedom initiative.

Green Fleet Purchasing

Manitoba will lead by example by implementing a Green Fleet fuel efficiency standard regulation under *The Climate Change and Emission Reduction Act*. The regulation will apply to new vehicles purchased for use by the Manitoba government. Departments will be guided by a Green Fleet procurement manual that will help them achieve efficiency objectives.

Heavy-Duty Freight Transportation

The freight transportation sector, particularly heavy trucking, is a key contributor to Manitoba's economy. This sector depends on energy to transport people and goods to, from and through Manitoba. The sector operates in a tightly meshed North American operational and regulatory context, and has had to rely primarily on conventional diesel as fuel. Although fossil fuels will be a dominant source of the energy needed for heavy, freight transportation into the foreseeable future, fuel efficiency will be critical in reducing GHG emissions and keeping costs down.

Today's Heavy-Duty Freight Transportation Priority Actions

Manitoba will continue to pursue freight fuel efficiency measures which help reduce fossil fuel use and its associated emissions. Manitoba will also evaluate the potential benefits of alternative fuel options to diesel, while ensuring that any alternatives meet the necessary vehicle performance, economic, environmental, jurisdictional as well as infrastructure requirements.



❸ KEEPING RATES LOW

Historically, the cost of electricity in Manitoba has been either the lowest, or among the lowest, in Canada. Manitoba is committed to maintaining this low utility rate advantage.

When Manitoba's Bill 18, *The Affordable Utility Rate Accountability Act*, becomes law, it will include a requirement that Manitoba work to maintain the lowest cost, in Canada, for a bundle of utility services – that is, the combined rates for electricity for home use, natural gas for home heating and automobile insurance.

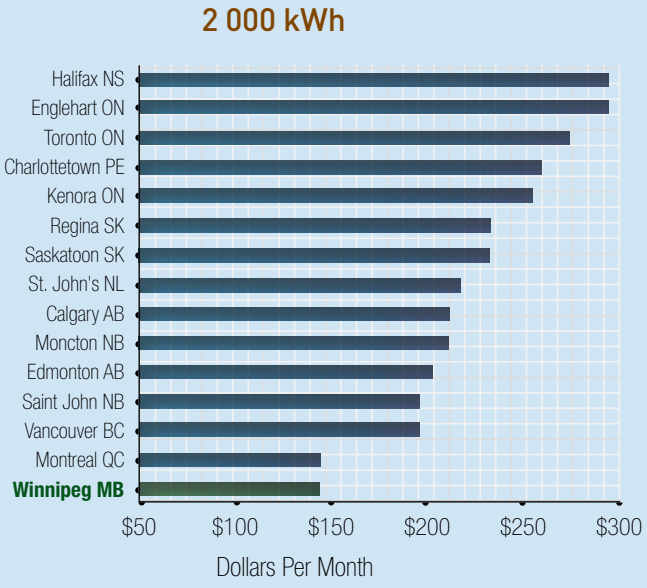


At each fiscal year end, after 2012, the minister of finance must use an independent accounting firm to prepare a report for each province, listing a comparable cost for the same bundle of utility services. For any year in which the cost of the same utility bundle is lower than that of Manitoba, the minister of finance must prepare a plan to return Manitoba to the lowest cost position.

Lowest Rates in Canada

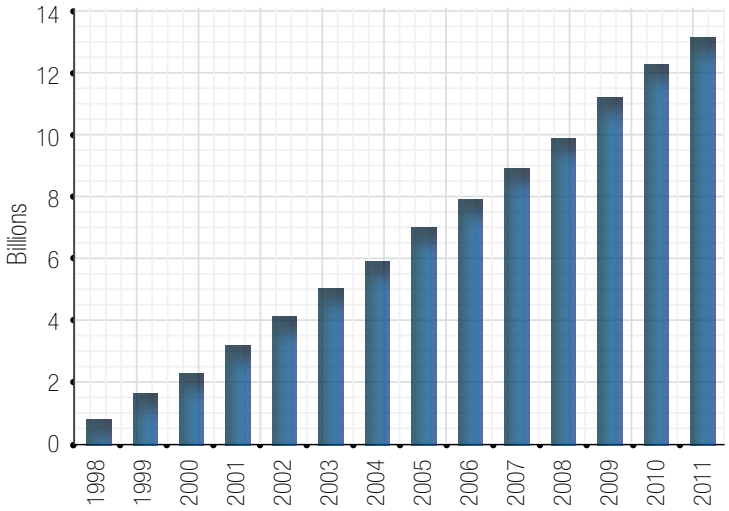
In the past, Manitoba Hydro has used export sales to help finance the cost of large, hydroelectric generating stations. This has helped ensure the low electricity rates Manitobans enjoy today. The average rates in our two neighbouring provinces, Saskatchewan and Ontario, are significantly higher than in Manitoba – approximately 90 per cent higher in Ontario and 40 per cent to 60per cent higher in Saskatchewan, depending on the class of service. In other low cost jurisdictions in Canada, the general average rates are still higher – in Quebec, about eight per cent higher; and in British Columbia, about 17 per cent higher.

Manitobans enjoy some of the lowest electricity rates in Canada and in North America. The chart below shows the comparative monthly cost of service to residential customers in various larger cities in Canada.



The long term benefits to Manitobans of the strategic decisions to invest in hydroelectric power (as well as greater efficiency) include cumulative savings to Manitoba families and businesses of $13 billion on their utility bills, when compared to the average Canadian's rates for the period 1998 to 2011.

Manitoba's Cumulative Hydro Bill Savings 1998-2011 (vs Average Canadian Rates)



Renewal of the Electrical System Assets

Like other electric utilities in Canada, many of Manitoba's electrical system assets were purchased and installed in decades past, and therefore now need to be renewed. However, the system must be renewed and developed at today's costs – which are significantly higher than the capital cost associated with Manitoba Hydro's legacy assets (ex: some of these assets, such as Point du Bois generating station, have been in place for as long as 100 years).

Low electricity rates have provided Manitoba families, firms and farms with savings of $13 billion – more than $10,000 per Manitoban.

Today's Keeping Rates Low Priority Actions

Placing Bill 18 Into Law

Manitoba will move to proclaim Manitoba's Bill 18, *The Affordable Utility Rate Accountability Act*. This act will ensure the provided bundle of combined electricity, natural gas, and automobile insurance rates remains the lowest in Canada.

Predictable Rate Increases

Manitoba Hydro expects it will need predictable and moderate rate increases over the next decade to fund asset renewal, which can still be done in the context of *The Affordability Utility Rate Accountability Act*. These increases will fund the renewal of its existing infrastructure; develop new generation, transmission and distribution infrastructure to serve growing demand; and assure continued reliable service to Manitobans.



4 GROWING RENEWABLE ENERGY ALTERNATIVES

Recent years have seen a range of new, renewable energy technologies emerge globally (ex: wind power, heat pumps, electric vehicles). As these technologies fell in cost and grew in global sales, it became clear that Manitoba not only held a competitive advantage in clean, renewable hydroelectricity, but increasingly, across a broad range of emerging renewable energy sources.

Manitoba's Emerging Clean Energy Portfolio

Manitoba has taken a leadership role in developing emerging energy sources across all three primary energy uses: electricity, heating and transportation:

- In electricity, Manitoba saw two of Canada's larger, and lowest cost, wind farms constructed at St. Leon and St. Joseph.
- In heating, Manitoba became the Canadian leader in heat pumps, installing 11,000 units to date (including the new Manitoba Hydro head office building).
- In transportation, Manitoba led Canada by:
  - building a 130-million-litre ethanol plant in Minnedosa
  - creating one of Canada's first plug in hybrid electric vehicle demonstrations
  - launching world leading hydrogen and electric bus projects

Manitoba's desire to develop its clean energy resources was accelerated by the global fossil fuel price surges of the 2000s, when Manitoba's annual, out of province payments for fossil fuel consumption began to reach into the $2 billion to $3 billion range.

Today, Manitoba has the opportunity to harness its significant breadth and depth of clean, renewable, energy resources and to use them year by year to reduce the province's reliance on expensive, polluting and volatile imported fossil fuels. At the same time, Manitoba can create new, green jobs and business activity at home.

St. Leon and St. Joseph wind farms produce enough energy to meet the needs of 90,000 homes.



Wind Power in Manitoba

Wind power has long been known to emit almost no GHGs, to have stable prices, and – unlike natural gas or coal – to require no payments to outside fuel suppliers. Beginning in the 1990s, when the global wind industry grew by 20 per cent to 30 per cent each year, it drove the cost of wind down from 40 cents per kWh in the 1980s, to five to seven cents per kWh on the Prairies today.

Just a few years after putting up the first monitoring towers, Manitoba's developers built the 103.5 MW St. Leon project in 2005. Within months, St. Leon proved itself to be one of Canada's lowest cost wind farms (and did so without provincial subsidy). Following St. Leon's success, the province established a long term strategic target of 1,000 MWs, equal to 10 per cent of Manitoba Hydro's average annual generation. Since then, Manitoba has developed its second wind farm – the 138 MW St. Joseph project and the St. Leon facility have been expanded by 16.5 MWs.

The results of Manitoba's two wind farms have been stellar, producing benefits by:

- adding 258 MWs of new capacity and producing 880 GWhs of energy annually – more than the Pine Falls hydro plant, Brandon coal plant and Selkirk gas plant combined
- beginning to generate the more than $100 million in royalties and local taxes that will flow to rural landowners and rural municipalities (RMs) over the projects' working lifetimes – more than $10,000 per rural municipality resident
- creating more than 500 new construction jobs in these rural areas
- triggering $586 million in new capital investment

St. Leon and St. Joseph wind farms will provide more than $100 million in local and school taxes and royalties to local farmers and citizens over their lifetimes, $10,000 per person in these rural areas.

Today's Wind Priority Actions

Manitoba's 1,000 MWs of new wind will add almost 3,000 GWhs of dependable energy to the system – a substantial contribution. Economically, developing these 1,000 MWs will generate more than $2 billion in new investment, and $400 million in lifetime revenues to rural communities.

The location, scale and timing of future utility and community scale wind development in Manitoba will be shaped by circumstances such as exchange rates and export prices, federal support, global turbine prices, rural economic conditions and Manitoba Hydro's evaluation of its supply and demand situation.

A single 300-700 MW wind farm would provide the electricity required to shift every Manitoba passenger car and truck from gasoline to electricity.

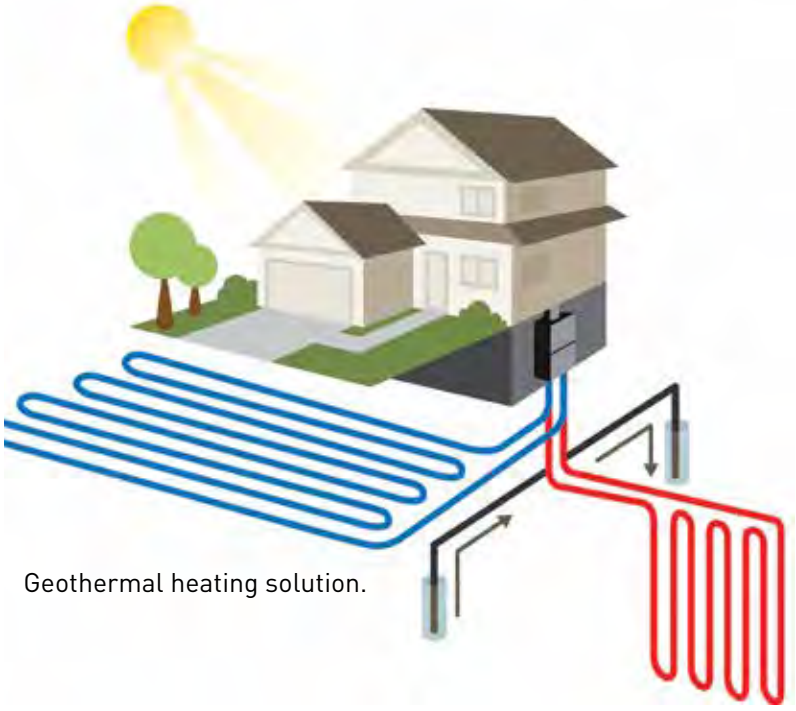


Green Heat

Manitobans in search of clean, low cost, stably priced sources of heating have long faced a dilemma. While natural gas (and propane and heating oil) offered a convenient source for heating space and water, it was also an imported fossil fuel, one which emitted GHGs – and one with highly volatile prices.

While Manitoba Hydro is responsible for most natural gas distribution, it has no direct control over the price of the natural gas itself, which is set outside the province. As a result, 270,000 Manitoban families and businesses pay prices set elsewhere, prices which can be low, but which have also been highly volatile over the past decade.

In fact, $300 million to $600 million leaves the Manitoban economy each year just to pay for natural gas. This money, if redirected and spent locally, would create and support thousands of Manitoba jobs. In addition, the combustion of this fossil fuel results in 2.4 million tonnes of GHG emissions in Manitoba – a full 15 per cent of all the GHGs emitted in the province – and an area needing to be reduced if Manitoba's domestic emissions are to fall.



Geothermal heating solution.

Electric Space and Water Heating – Not the Best Solution

Historically, electric heat was the main alternative for those Manitobans who needed a stably-priced alternative to natural gas. As a result, 130,000 families use all electric heat (especially in rural areas and apartments) today and 230,000 use electric hot water. Even so, using electricity – a high value energy form – to raise air or water temperatures by only a few degrees is considered a wasteful way to create heat. It is often termed, "using a chainsaw to cut butter." As a result, the conversion of buildings heated all-electrically (many of which are in rural areas) to use geothermal heat pumps, biomass or solar sources of renewable energy can produce multiple benefits (ex: lower energy costs, new local jobs, freeing up more electricity for Manitoba Hydro exports).

Heat Pumps– All the Energy You Could Want, Right Beneath Your Feet

Manitobans have increasingly been turning to popular alternatives, often called renewable or "green" heat sources, such as heat pumps, which draw energy from the ground, water or air. A heat pump, for example, can turn one kWh of electricity into three to five kWhs of heat, offering a way to take Manitoba's clean electricity and multiply the benefits. And with almost half of all solar energy reaching the earth being stored in the ground itself, a geothermal heat pump uses the ground beneath our feet to provide a clean, renewable source of heat, or cooling and all at a stable price.

Geothermal Heat Pumps – Once Again, Manitoba Leads the Way in Canada

Beginning in the year 2000, Manitoba began to back this technology and became a Canadian leader by raising its geothermal heat pump installation rate by 400 per cent. Contributing to the industry's rapid growth are innovative policy tools like the province's Green Energy Equipment Tax Credit and Geothermal Grant, the Green Building Policy, support for industry training, quality assurance and education, and Manitoba Hydro's Earth Power loan program.

The result is: as households and businesses had to replace heating systems, more found that their particular circumstances enabled them to invest in heat pumps. There were 11,000 units installed in Manitoba as of 2012. The industry has proven its capabilities by supplying not just family homes, but apartment buildings, arenas, churches, schools, head offices, university residences, credit unions and car dealerships. In particular, Manitoba's pioneering efforts to use heat pumps to supply multi-unit apartments, district systems and commercial projects is opening up a cost effective niche, offering not only lower per unit costs, but long term energy price stability. Today, Manitoba's heat pump industry has annual sales over $35 million, and provides system drilling and installation, design and engineering, component manufacturing and system integration.

Some of the industry's more innovative, showpiece projects in Manitoba include:

- the IKEA store and mall, the largest geothermal installation in Manitoba
- Manitoba Hydro's award winning, 22 storey head office – which has, at its core, 280 heat pump bore holes, each drilled 122 metres beneath the site
- 20 storey, multi-unit apartment towers in Winnipeg
- The Forks Market harnessing heat and cooling from the ground, a well, and a river to heat and cool a central 100 year heritage building, restaurants, offices and retail shops
- Award winning, district geothermal system at Île-des-Chênes, serving the local community centre, arena and fire hall

Moving forward, while individual circumstances and site specific economics will see natural gas fuelled heating systems continued to be installed, a rising percentage of Manitoba's stock of heating systems will likely consist of heat pumps. For those Manitobans, heat pumps offer a tested, made-at-home solution – able to draw on renewable heat and cooling from the ground, water or air; to supply single family homes, apartment blocks and commercial buildings; without emitting GHGs; and all at a stable price.

Today's Geothermal Priority Actions

Manitoba has been accelerating the growth of the geothermal heat pump industry through its Green Building policy, Earth Power Loans and the Green Energy Equipment Tax Credit. The creation of Manitoba Hydro's new On-Meter Finance tool will also provide Manitoba's home and building owners with a new tool to overcome the upfront cost barrier, and to generate a positive cash flow from day one.

The On-Meter financing tool is likely to be of particular value to the 150,000 rural Manitobans who lack access to natural gas and still must rely on fuel oil, propane and all electric heat. Manitoba Hydro estimates that a geothermal heat pump will save these homeowners $750 to $2,500 each year, when compared to these older systems – offering perhaps the single largest energy bill saving available to these families.

Manitoba will continue to provide the popular Green Energy Equipment Tax Credit for geothermal installations throughout the province where equipment is purchased before 2019. It is a refundable tax credit where all Manitobans and eligible corporations can claim this credit, whether tax-paying or tax-exempt (ex: non-profit organizations), to help offset the upfront investment of geothermal.

Recognizing that district heating presents a major opportunity for geothermal and other green heat sources such as biomass, the Manitoba government will work with municipal governments and industry stakeholders to identify and break down barriers to district heating and large scale multi-unit installations, and create a supportive environment that enables community scale and multi-unit biomass and geothermal heating.



The IKEA building is heated and cooled by one of the largest geothermal systems in Manitoba.

Wood

Wood is another renewable heat source widely used in Manitoba, with more than 20,000 homes – especially in rural areas – using wood, often combined with electricity, natural gas, fuel oil or propane. Modern wood stoves have greatly improved their efficiency and now produce more heat with fewer particulates, reducing the volume of wood needed by homeowners as well as the volume of any ash to be disposed.



Biomass – Manitoba's Natural Advantage

Biomass represents a broader and more strategic opportunity for Manitoba, offering the chance to boost economic growth, environmental sustainability and rural diversification. Agricultural residues and forestry waste can be converted into biofuels suitable for heat, electricity or transport. Manitoba has a natural advantage in biomass production with 7.6 million hectares (18.8 million acres) of agricultural land, already producing four million tonnes of biomass each year.

Biomass pellets from wood waste and crop residues have achieved strong growth in Europe, rural eastern Canada and the US, often out competing fuel oil and electricity. Compared to raw wood, pellets are more easily transported, burn more cleanly and produce less ash, create new income streams for farmers, while reducing in-field burning.

The growth of Manitoba's pellet industry will depend on its ability to cut costs along the supply chain – to gather and pack biomass from crop residue or woody debris left after harvest; transform the materials into pellets; install pellet combustion, storage and ash-handling systems in buildings; distribute the pellets; and remove the ash. As a result, the industry is most likely to expand in markets such as on-farm space heating and agricultural drying and processing.

Solar Energy

Solar energy is also on the rise globally, with 200 million buildings now using solar thermal systems for hot water and heat – and solar photovoltaic sales exceeding $90 billion.

In Manitoba, solar thermal heating applications have been found to be most cost effective when built into the design of new buildings (ex: Buhler Versatile tractor manufacturing plant). There, solar energy is captured, stored and transferred throughout the building, to complement other heating sources. Solar walls can also be used to preheat air and have been installed cost effectively at more than 50 Manitoba schools, housing complexes and industrial buildings.



Fred Douglas Place, a multi-unit high rise residential building in the heart of downtown Winnipeg, was retrofitted with a solar thermal wall that compliments its existing exterior brick facade.

47 per cent of solar energy is absorbed by the ground.

Today's Wood, Biomass and Solar Priority Actions

Coal Use Ends in 2014

Manitoba has already established the Emissions Tax on Coal, with revenues being invested to speed the development of systems provided by Manitoba's new, clean energy from biomass industry. Coal was identified because it was the most GHG intensive fossil fuel, but also because many clean energy alternatives were available. Because of the speed at which the few remaining coal burning establishments are converting to cleaner energy, a target end-date on the use of coal for heat has been set for 2014.

Growing Harvest Operations for Biomass Markets

The province's wood and biomass heat industries will continue to grow through the Manitoba Biomass Energy Support Program, which helps develop biomass processing capacity, conversion technology and research and development. Using revenue generated by the Emissions Tax on Coal, Manitoba will support coal users to transition to renewable biomass and work with the forestry and agricultural industries to increase the use of debris from harvesting operations to produce biomass for these emerging markets.

New Technologies Entering Mainstream

Solar will continue to be supported through the Provincial Green Energy Equipment Tax Credit. As wood, biomass and solar technologies move into the mainstream, they will become eligible under Manitoba Hydro's On-Meter Finance program.

Taken together, the shift towards green heat technologies – heat pumps, biomass pellets and solar – should see a growing share of the $300-$600 million that currently leaves the province to pay for natural gas, instead being re-injected at home, creating permanent, new green jobs.

Manitoba's Rural Advantage

Rural Manitoba has been a clear leader in developing new and emerging renewable energy sources. It has not only attracted substantial new investment and created new employment, its entrepreneurs have developed new green businesses and it has shown itself a leader in implementing the new technologies at home and at work.

Examples of this leadership include the exceptional role that local RMs and landowners have taken in partnering with the new wind-farms at St. Leon and St. Joseph (and landing more than $500 million in new investment); the development of Minnedosa's $200 million ethanol plant, including the co-operation of local grain and canola suppliers; the prevalence of heat pumps being installed in rural areas (ex: Île-des-Chênes), as well as the enormous future opportunity On-Meter Finance offers to those using electricity, propane and oil for heat; the rapid conversion off coal by Manitoba's Hutterite colonies; and the research and development work currently going into developing biomass, biofuel and bioproduct applications.



Cleaner Transportation

It is in transportation that fossil fuels have forced Manitobans to pay the greatest cost, with rising global oil prices doubling Manitobans' bills, to $2 billion and more each year. This is money which simply leaves the Manitoban economy. The need for a long term transition off these fossil fuels is particularly underlined by the fact that every 20 cent per litre rise in the price of gasoline and diesel requires Manitobans to pay an extra $500 million – more than Manitoba Hydro's annual export earnings.

By using made-in-Manitoba biofuels and electricity to fuel its vehicles, Manitoba has begun to reclaim the billions of dollars flowing out of province, re-injecting them back into our local economy. Continuing to do so will create thousands of long term, sustainable, local jobs – while enabling more Manitoban families and businesses to regain control over their family budgets.

Homegrown Biofuels

Ethanol – a Cleaner Burning Fuel

Manitoba was home to Canada's first modern ethanol plant, at Minnedosa, in the early 1980s. After 2000, when oil prices rose and ethanol became cheaper to produce, Manitoba worked with industry to create an ethanol strategy designed to help grow local economic opportunities, increase energy security and reduce GHGs. Manitoba has since become a Canadian leader with *The Biofuels Act*, which mandated that 8.5 per cent of gasoline be replaced with ethanol. The province also created an eight year, declining incentive for new ethanol producers, to ensure there would be no impact on drivers at the pumps.

Husky's ethanol plant in Minnedosa produces 130 million litres of ethanol annually.



The results were impressive, and included:

- an investment of $200 million in the construction of Husky's new 130-million litres per year, world class, ethanol plant in Minnedosa
- the creation of a new market for 350,000 tonnes of Manitoba wheat and corn annually.
- the production of 130,000 tonnes of high protein distiller's grain (which livestock producers now use to replace imported soybean meal)
- the re-injection of $100 million that previously leaked away for gasoline payments
- a reduction in transportation emissions of more than 330,000 tonnes of GHG emissions per year

Biodiesel – a Cleaner Burning Fuel

Manitoba developed a strategy for biodiesel in 2005, which led to the creation of a biodiesel testing facility in Selkirk, incentives for producers and demonstration projects in Winnipeg school buses, trucks and underground mines. In 2009, Manitoba again led Canada by introducing its mandate of two per cent biodiesel.

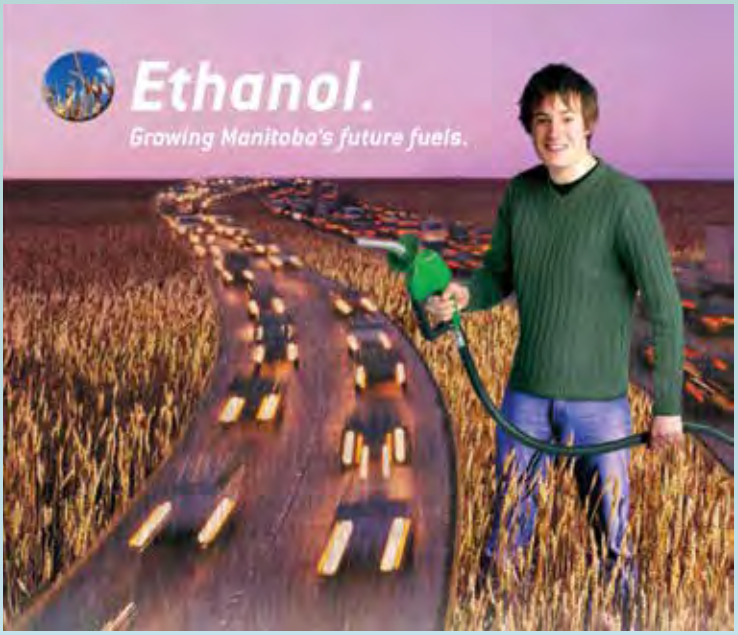
Future Biofuel Technologies

Combined use of these Manitoban biofuels now reduces gasoline and diesel imports by $100 million each year, and cuts GHGs by nearly 400,000 tonnes annually. The next step for the industry is the creation of advanced biofuels from feedstocks such as straw, crop residues, wood waste or algae. There are also new technologies being commercialized today that can produce next generation biodiesel with cold weather properties similar to conventional diesel. Manitoba also now possesses a well equipped biofuel tool kit to help support its development, including fiscal incentives, lab capabilities and mandates.



Today's Biofuel Priority Actions

Manitoba's investment in its biofuel industries over the past decade means that six per cent of our gasoline and diesel fuel is now derived from renewable sources. In the near future, biofuels could grow to supply up to 10 per cent of Manitoba's total liquid fuel consumption. Manitoba, in consultation with stakeholders, will pursue new production opportunities and increased biofuels content requirements. Manitoba will also look for opportunities to increase the production and use of second generation biofuels such as cellulosic ethanol and renewable diesel.



The Electric Transportation Revolution

The electrification of transportation has been described as, potentially, the greatest energy revolution in 100 years. Even though oil still contributes well over 90 per cent of all energy for vehicles and is more energy dense and easier to store, electricity itself has a strong set of advantages:

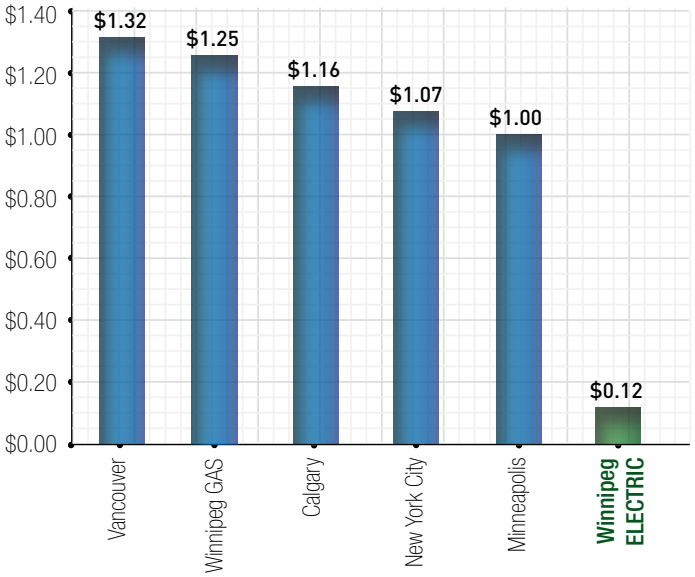
- Electricity can be made from more sources than oil, including from renewable sources.
- Almost every jurisdiction can make its own electricity.
- Electricity costs just a fraction of the price of gasoline.
- When made from renewable sources, electricity emits almost no air pollutants or GHGs.

As a result, electrified transport increasingly offers the world a way out of the energy insecurity, high prices, GHG emissions and economic damage of oil use. Driven in part by these forces, the major automakers have in recent years moved rapidly into this field, making a range of hybrid, plug-in hybrid electric vehicles and all electric vehicles commercially available to the public.

Technological Advances Ongoing

More hybrids and electric vehicles are forecast to be on North American roads in the medium to longer term, with the exact number in any given year heavily influenced by oil prices and battery progress. The major automakers and battery manufacturers have invested tens of billions in developing the new batteries, and have cut prices in half in just the past three years – and with a further halving forecast by 2017 to 2020. This progress means that, with each new model year, more Manitobans will find themselves entering a vehicle sales market with a greater range of hybrid, plug-in and all electric vehicle models, at lower cost and with improved performance. As their personal circumstances dictate, Manitobans who choose to access these vehicles will find the benefits available to them in Manitoba are particularly strong:

The Cost of Vehicle Fuel - At The Pump vs At The Plug



- Manitoban drivers will have North America's lowest-cost vehicle fuel – electricity from Manitoba Hydro – at approximately 12 cents per litre gasoline equivalent
- A young family shifting from two gasoline driven vehicles to two electric ones could therefore expect to save over $100,000 in vehicle fuel payments over their lifetimes.
- For Manitoba as a whole, a shift from gasoline to electricity in the decades to come will:
  - Re-inject a rising share of the $1 billion in gasoline bills back into Manitoba's economy – comparable to Manitobans receiving a $1 billion per year tax cut.
  - Create more than 10,000 new, long term jobs in the economy.
  - Reduce Manitoba's GHG emissions by three million to four million tonnes a year.
  - Convert Manitoba's number one energy weakness (the import of expensive fossil fuel) to its number one strength (its wealth of low cost, renewable electricity)

Switching from gasoline to electricity for vehicles would stop leaks of more than $1 billion from Manitoba's economy each year.

Manitoba's Advantage in Electric Vehicles

This opportunity also stands out for Manitoba because it has such strong assets in this sector:

- The province has an abundance of low cost, clean electricity. For example, given the much higher efficiencies of electric motors versus gasoline engines, a single 300 MW to 700 MW wind farm would provide enough electricity to shift every Manitoba passenger car and truck from gasoline to electricity.
- Manitoba has a prebuilt electric vehicle infrastructure of more than 500,000 plugs in our garages and parking lots. Now used for block heaters, they can also be used for recharging. If Manitoba had to build this infrastructure new (as others do), it would cost $1 billion.
- While others face cultural barriers to plugging in, Manitobans already have a well established plug in culture, driven by the need for block heaters during our winters.

Moving Towards Electrically Powered Vehicles

Manitoba has acted by creating plug in partnerships with automakers like Nissan, Toyota and Mitsubishi, Manitoba Hydro and academic institutions, to better demonstrate plug-in hybrid and electric vehicles under our climatic conditions and ensure that these options are available.

A new Electric Vehicle Technology and Education Centre (EV-TEC) was created at Red River College in Winnipeg, to demonstrate new plug-in hybrids and electric vehicles to Manitobans and train students for the future.

In 2011 Manitoba's Electric Vehicle Road Map identified ways to maximize out-of-the-gate use of Manitoba's $1 billion recharging infrastructure, identified issues around the integration of vehicle charging and the grid, and making links to northern vehicle cold weather testing in Thompson.

Every 20 cent per litre rise in the price of gasoline and diesel drains $500 million from Manitobans.

Today's Electric Vehicle Priority Actions

Building on what we've learned from our early demonstrations, plug in partnerships and work of the Electric Vehicle Advisory Committee – Manitoba will:

- Expand existing, and form new, plug-in partnerships.
- Actively promote at home charging, an option which already exists for 95 per cent of Manitobans; while working with Manitoba Hydro and other partners to ensure parking lots are capable of recharging vehicles, and providing incentives to install some Level-2 recharging systems.
- Expand fleet procurement by the province, the Crowns and others.
- Develop communication strategies to provide objective information to the public and corporations to help make informed electric vehicle purchase and operation decisions in the Manitoba context.
- Launch public participation campaigns to speed the adoption of new generation vehicles, spear headed by the Fossil Fuel Freedom program.

For Manitobans refilling with electricity, it costs just 12 cents for the equivalent of a litre of gasoline.



Hydrogen, Hybrid and Battery Powered Buses

Buses and heavy duty vehicles offer a special opportunity for hydrogen and battery power. This sector is especially significant to Manitoba, as Winnipeg is the bus manufacturing centre of North America. We are home to New Flyer Industries, the leading maker of transit buses, and Motor Coach Industries, the leader in inter city buses. New Flyer has emerged as the number one supplier of alternative fuelled buses, with hybrids, hydrogen, and most recently – in partnership with Mitsubishi Heavy Industries, the Province of Manitoba, Manitoba Hydro, and Red River College – electric buses.

Electric Bus Project – Showcase for North America

The new electric bus project will develop and demonstrate an advanced, battery electric, transit bus plus rapid charge technologies under Manitoba's highly variable climatic conditions. The $3 million project aims to validate the bus's operational capabilities and act as a showcase for potential markets. It has taken one year to develop the prototype bus (including integrating battery technologies from Mitsubishi) that will be followed by two years of operational testing.

Today's Alternative Powered Bus Priority Actions

Manitoba will continue to support development of the electric bus, and work with partners to expand the project into a multi-bus and charging system demonstration. Priority will be placed on seeking value added technology development and component manufacturing. The timing is right for such projects as US transit authorities are considering electric buses in tenders, albeit starting on a small scale. The pathway forward for this ground breaking technology was blazed by hybrid diesel/electric buses, considered cutting edge less than 10 years ago but now making up a significant portion of new bus sales throughout North America.

Hydrogen

In 2003, Manitoba launched its hydrogen strategy, leading to a Winnipeg demonstration of an advanced, fuel cell bus, as well as a bus with a hydrogen hybrid, internal combustion engine. Since then, research partnerships with regions such as Iceland have developed. As well, New Flyer Industries has gained considerable expertise in hydrogen technologies, supplying 20 fuel-cell buses for the 2010 Vancouver Olympics – buses that are still operating today.



7410

❺ FREEDOM FROM FOSSIL FUELS

Over the coming years, a number of Manitobans will be among the first in the industrial world to live their lives without requiring substantial quantities of fossil fuels. Instead, they can meet the vast majority of their three core, daily, energy needs (for electricity, heat and transportation) by using clean, renewable energy and by being energy efficient – not by burning coal, natural gas, gasoline or diesel. These first fossil fuel free Manitobans will be pioneering a path that most nations are hoping their citizens will get to take in future decades – toward a daily life no longer dependent on fossil fuels.

These Manitobans will achieve fossil fuel freedom through a simple three-step process:

1. Their electricity from Manitoba Hydro will already be clean, more than 98 per cent or more fossil fuel free. It will supply their lighting, appliances and other power needs. A clean electricity supply, though difficult to obtain in most other nations, is already here for Manitobans.

2. Their heat will be provided – as it already is for thousands of Manitobans – through clean, renewable, energy systems (ex: heat pumps, biomass, solar), which eliminate the need for fossil fuels like natural gas. While all electric heat is also fossil free, heat pumps use 50 per cent to 70 per cent less electricity, so they're a more efficient choice.

3. The biggest step for most Manitobans will be in transportation. An option chosen by some will be to buy an electric or plug-in hybrid vehicle, which will shift their vehicle energy over to clean electricity, while cutting their gasoline use by 65 per cent to 100 per cent. Others may choose to cut their fossil fuel use by taking public transit, car pooling or ride sharing, while others opt for walking or cycling.



Manitoba currently has more than 500,000 plug in points in garages, parking lots and at businesses. This is a $1 billion infrastructure already in place.

Taken together, these Manitobans will have effectively reduced their use of fossil fuels by more than 90 per cent across the three major energy end uses. They will also have begun to generate a range of benefits for themselves, the environment and the Manitoban economy:

- By moving off gasoline, they will slash their pump price worries and gain the lowest cost vehicle fuel in North America – electricity from Manitoba Hydro at approximately the equivalent of 12 cents per litre.
- By changing to heat pumps and electric and plug-in hybrid vehicles, they will save $3,000 to $5,000 in fuel costs each year. Over a lifetime, this can reach to well over $100,000 per family.
- They will cut their direct GHGs to residual levels (zero to two tonnes.) This can be compared to today's families in North Dakota or Saskatchewan, many of whom emit 15 to 40 tonnes of GHGs a year by using coal fired power, gas heat and gasoline.

When a two gasoline driven vehicle family shifts to using two electric vehicles, they can expect to save more than $100,000 over their lifetimes in vehicle fuel costs.

Fossil Fuel Freedom – A Movement Towards a Healthy Future

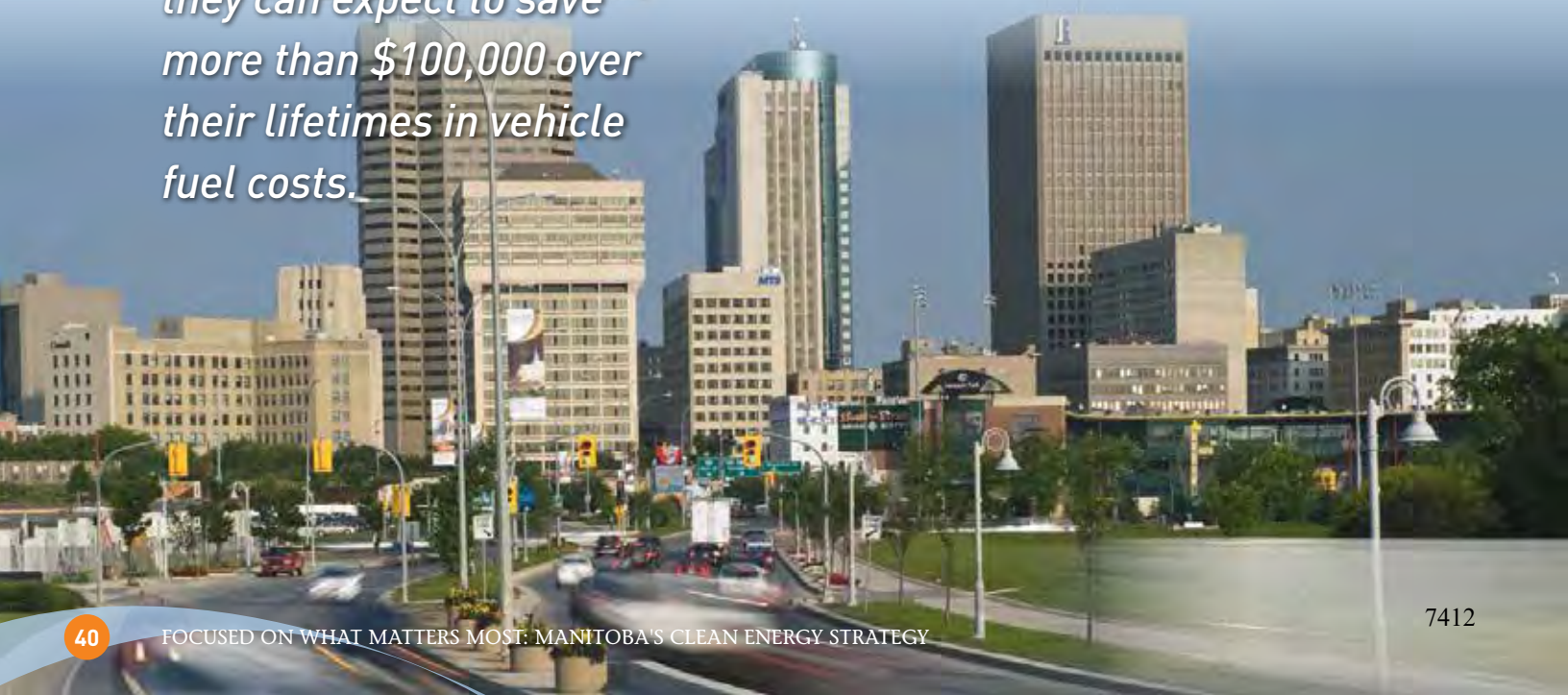
Many nations can only set fossil fuel freedom as a visionary goal, for the years 2040 or 2050.

But in Manitoba, a significant number of its citizens can choose to achieve this freedom today. Any such transition, as we have seen, would require decades to move through a society's energy infrastructure. For example, our vehicle fleets alone requires 15 to 20 years to turn over; our furnaces and heating systems require 20 to 30 years; and our building stock and energy generating infrastructure can last another 50 to 100 years.

Nonetheless, for most Manitobans, the opportunity to move from conventional fossil fuel use to clean energy, and even on to fossil fuel freedom is increasingly a reality. More and more Manitobans are taking the quiet steps they need to ensure that their lives are less exposed to the risks and costs of fossil fuels.

And the reason Manitobans are so well positioned to make this transition, and able to consider it now, in an atmosphere free of any particular energy crisis, is because of the strong clean energy economy and infrastructure which we have come together to create, starting decades ago.

But today's good news is that for Manitobans, the fossil fuel free future starts here…and it starts now.



Today's Fossil Fuel Freedom Priority Actions

The province will support a Fossil Fuel Freedom campaign that will initially focus on families. It is expected that many companies, offices, farms and schools, etc. will want to follow in a similar fashion. The campaign will:

A. Create a public path open to all Manitobans, rather than a program designed just for a few. This will enable more and more families to participate, and reap the full benefits of lower bills, more local jobs and an improved environment.

B. Consist of three simple steps:

Step 1: Use clean electricity – a step Manitoba Hydro has already taken for you.

Step 2: Use a green heating system – such as heat pumps (or biomass or solar).

Step 3: Use clean transport – such as an electric or plug-in hybrid vehicle, public transit, car pooling or ride sharing, or active transportation methods like walking, skating and cycling.

C. Focus on promoting a positive, money saving path forward for households.

- Real world stories of fossil fuel freedom will be communicated to schools and the public, and may include tours as well as special technology demonstrations.

A plug-in hybrid can reduce the number of times you need to refill with gasoline to less than once every two months.

D. Connect to an online fossil fuel free social network, designed to support both early members, as well as to inform and engage those in the next wave who may be interested in joining.

- Families who participate in programs early on may wish to use the network to exchange experiences, discuss the process with experts, engage with those interested but who have not yet joined, and to organize peer-group activities.

E. Support these families through financial incentives and expert help.

- A number of organizations – the Manitoba government, Manitoba Hydro, private suppliers and retailers, universities etc. – already offer incentives and supports. These incentives will brought together (and can be topped up) through the Fossil Fuel Freedom campaign.

- Support from experts is also valuable to people who adopt new technologies early on. The province, Manitoba Hydro and other partners will make sure these families have access to services and expertise in plug-in hybrid and electric vehicles, heat pumps and home retrofits, through in-home visits, expert support and other assistance.

- For those at an earlier stage, partners can provide opportunities to see these new technologies demonstrated, or to speak directly with experts and participants.







CONCLUSION

Our energy future, in many ways, underpins our economic future. Managing the way we source, deliver and use energy in the years ahead will be key to growing our economy, keeping energy affordable, meeting the province's commitments to sustainability and reducing our impact on global climate change. Manitoba's strategic direction is clear – by seizing our own Manitoba domestic energy advantages we can reduce our exposure to fossil fuels while expanding our clean energy resources, all across the electricity, heat and transportation sectors.

Capturing the economic and environmental opportunities this clean energy strategy provides will require innovation and commitment, as well as a willingness to adjust as our energy options evolve. Most importantly, we need to work together to reach our goal.

With the co-operation and participation of the public sector, the private sector, our farms and our schools, industry experts and informed citizens, Manitoba is leading the way into a clean energy, and – for some pioneers – into a fossil fuel free future.

Although the goal of building on our renewable energy advantages is long term in nature, this strategy will be reviewed and updated on a regular basis and progress reports provided annually. As energy technologies evolve, environmental drivers intensify, and market conditions change, it will be important to be flexible enough to adapt as necessary.

It is equally important that Manitobans have an opportunity to provide input into this living strategy and therefore it will remain open to reflect the views of Manitobans.

To provide advice and comments about the Manitoba Clean Energy Strategy please respond in writing to:

Manitoba Innovation, Energy and Mines

Energy Division
1200-155 Carlton Street
Winnipeg, Manitoba, R3C 3H8

www.manitobaenergy.ca

Or by email to:

mbenergy@gov.mb.ca



7414

APPENDIX I – WHAT IS ENERGY?

The term energy comes from the ancient Greek energeia, meaning activity or to cause activity. Literally, energy is what makes things work, and joules (J) are the official units of energy, whatever the form. Abbreviations are used for short form:

1 kilojoule (kJ) = 1,000 J
1 megajoule (MJ) = 1,000,000 J
1 gigajoule (GJ) = 1,000,000,000 J

Power is defined as the flow of energy, and watts (W) are the official units of power.

Watts and joules are related in that:

1 W = 1 J per second

Natural gas is sold in units of cubic metres (m3) (at standard temperature and pressure conditions) with a typical energy content of 37.8 MJ per m3.

Gasoline and diesel liquid fuels are sold in volumetric units of Litres (L) referenced to a standard temperature.

Gasoline typically has an energy content of about 35 MJ/L

Diesel fuel typically has an energy content of about 37 MJ/L

Vehicle fuel consumption is typically expressed in units of Litres per 100 kilometre (L/100 km). Lower numbers are better in this case.

Fuel economy in the United States is expressed in units of miles per U.S. Gallon (MPG). Higher numbers are better in this case. The conversion between L/100 km and MPG is more complicated given they use different units and are inverse. A fuel consumption of 15 L/100 km equates to fuel economy of 16 MPG.

1 U.S. Gallon = 3.78 L

1 mile = 1.6 km

Electricity in terms of energy is sold in units of kilowatthours (kWh). This has been used for convenience and is an official unit for electricity.

There is a simple relationship to official energy units as follows:

1 kWh = 3,600,000 J = 3.6 MJ

APPENDIX II – ENERGY ABREVIATIONS

List of Commonly-used Acronyms

AT	active transportation
BEEP	Brandon Energy Efficiency Project (social enterprise organization)
BUILD	Building Urban Industries for Local Development (social enterprise organization)
CAFE	U.S. Corporate Average Fuel Economy standard
CEEA	Canadian Energy Efficiency Alliance
DC	direct current
ESA	*Energy Savings Act*
EV	electric vehicle
EVTEC	Electric Vehicle Technology and Education Centre (at Red River College)
FFF	fossil-fuel free family
GDP	gross domestic product
GEMTC	Green Energy Manufacturing Tax Credit
GHG	greenhouse gas
GJ	gigajoule

GW	gigawatt
HVdc	high voltage direct current
km	kilometre
kWh	kilowatt-hours
LEED	Leadership in Energy and Environmental Design
LNG	liquefied natural gas
MB	Manitoba
MHI	Mitsubishi Heavy Industries
MNECB	Model National Energy Code for Buildings
MPG	miles per U.S. gallon
MW	megawatt
NBC	National Building Code
NECB	National Energy Code for Buildings
PHEV	plug-in hybrid electric vehicle
PV	(solar) photovoltaic
US	United States



Manitoba Innovation, Energy and Mines
Energy Division

1200-155 Carlton Street
Winnipeg, Manitoba, R3C 3H8
www.manitobaenergy.ca

Aussi disponible en français.

7418

December 2012

Tab 67

Exporting 'Manitoba's oil' down south

HYDROELECTRIC SITE WILL MAKE PROVINCE BILLIONS IN REVENUE

By: Bruce Owen
Posted: **05/26/2011 1:00 AM**

It's called Keeyask and, if all goes according to plan, the cost will be equivalent to building 18 Canadian Museum for Human Rights, but in northern Manitoba, not The Forks.

Or the cost of 29 new football stadiums, but on the Nelson River, not the University of Manitoba.

In other words, it's big.

And it will be built to supply more hydroelectric power to the United States, which because of new environmental laws, are looking north to Manitoba to supply clean energy for years to come.

Keeyask's construction, already years in the works, was put on the front-burner Wednesday when Premier Greg Selinger announced a combined $4 billion deal to sell 475 megawatts of hydro power to Minnesota and Wisconsin starting in 2015.

"This is the largest dollar sale of exports that we've had in the history of Manitoba Hydro in absolute dollar terms," Premier Greg Selinger said at a news conference at Hydro's downtown headquarters. "We like to think of it as Manitoba's oil, but more sustainable and certainly greener as well."

Hydro's export deals will earn the province $21 billion over the next 20 years as clean energy from Manitoba replaces old coal burning plants and as some U.S. states pass laws that the power they use has to come from renewable resources.

The Opposition Progressive Conservatives dismissed the announcement as a rehash of an April 17, 2008 press release by former Premier Gary Doer, and used it to buttress their stance that Bipole III transmission line should not be built down the west side of the province.

"I think it's just further confirmation that the shorter, cleaner, east side route is the way to go," PC Leader Hugh McFadyen said. "Minnesota and Wisconsin are to the south and east of Manitoba. The most direct route to those markets is down the east side by a significant amount."

Selinger said the province has no intention of reversing its stance on bipole as that would open up a big can of worms.

"This would allow us to be identified as a premium product," he said of the province's plan to protect its wilderness. "We don't want to put that at risk by putting a bipole through the boreal forest and the UNESCO World Heritage site. That would generate additional controversy."

He also said Hydro continues to work on another power sale to Wisconsin. If that 500-megawatt deal happens, it would lead to the construction of the Conawapa Generating Station. If approved, it will be Manitoba Hydro's biggest power dam and take at least eight years to build.

Last year Hydro signed a deal worth $3 billion to sell between 375 and 500 megawatts to Xcel Energy of Minneapolis for 10 years starting in 2015.

The Minnesota Power deal comes as Manitoba's Public Utilities Board weighs the risks of Hydro spending $20 billion over the next decade to build Keeyask and Conawapa, plus Bipole III. That hearing continues into next month.

The two dams would add another 1,930 megawatts of electricity to Hydro's system to use in the growing domestic market and to export more to Minnesota and also Wisconsin. Hydro's new $1.3 billion Wuskwatim project on the Burntwood River is to generate 200 megawatts starting next year.

bruce.owen@freepress.mb.ca

What's Keeyask?

IT'S the next hydroelectric generation site to be built under Manitoba Hydro's plan to export more power to the United States and Saskatchewan.

It's 725 kilometres northeast of Winnipeg on the lower Nelson River.

It will cost $5.6 billion to build and will produce 695 megawatts of power, the fourth largest of Hydro's generating stations. (Hydro operates 15 dams).

Work to build it started several years ago, the most important aspect being the signing of the Joint Keeyask Development Agreement May 29, 2009.

It outlines the partnership arrangements for the First Nation's participation: Fox Lake Cree Nation, Tataskweyak Cree Nation, War Lake First Nation and York Factory First Nation.

The Winnipeg Free Press invites you to share your opinion on this story in a letter to the editor. A selection of letters to the editor are **published daily**.

To submit a letter:
• fill out the form **on this page**, or
• email **letters@freepress.mb.ca**, or
• mail *Letters to the Editor, 1355 Mountain Avenue, Winnipeg, Manitoba, R2X 3B6*.

Letters must include the writer's full name, address, and a daytime phone number. Letters are edited for length and clarity.

Tab 68

Market forces weighing on hydro exports

By: Dennis Woodford
Posted: **04/5/2016 4:00 AM**

OPINION

The provincial government likes to describe our hydroelectric resources as "Manitoba's oil," an export commodity that can return dividends from cross-border sales. That has pushed the early construction of hydroelectric plants that will produce power Manitobans won't need until into the 2030s. We are not alone in this, B.C. Hydro is doing the same, with its Site C on the Peace River.

But at what cost to ratepayers? Manitoba Hydro's new Keeyask generating station will produce power at a cost of more than 12 cents per kilowatt-hour. Meanwhile, the average daytime spot-market price of electricity in our export target of Minnesota was recently posted at 2.05 cents per kwh.

Why is the Minnesota electricity spot market price so low? It competes on the market with natural gas, the price of which has been dropping steeply. The average futures price of natural gas last week was US$1.92 per million British thermal units; in 2006, it was more than US$7 per million BTU.

What do we do about this dilemma? Do we push on with Bipole III and Keeyask in anticipation that one year they might become economical? Or, rather, should we halt construction, do a detailed review, and determine whether to put the projects on hold on the possibility that the market will rebound some day?

Bloomberg Business on March 11 reported that in 2007, Canadian natural gas producers met 16 per cent of U.S. demand. In 2014, it had slipped to less than 10 per cent. Given that, it seems spot market electricity prices, affected by natural gas prices, will not increase significantly if at all over the next decade. The falling costs of wind, solar and energy storage will also play a significant role in keeping electricity prices from rising to where they would have to be for Keeyask and Bipole III to be cost effective, any time in the next decade or two.

Manitoba Hydro is working with Minnesota to build a new transmission line into the United States, but mainly with an eye to sell our power south. It may well be more profitable for Hydro ratepayers if it were used to import low-cost Minnesota electricity, so we could put off building Keeyask and Bipole III.

The premiers of Manitoba and B.C. have asserted that sending the hydroelectricity of their new plants into Alberta could replace a lot of the coal-fired power in that province, including to process Fort McMurray's oilsands. But a Canadian Energy Research Institute report in January revealed that Alberta can replace its coal-fired generators with what's called combined-cycle natural gas generators. They would emit half the carbon of the coal generators, at a cost of 5.7 cents/kwh. The same report noted hydroelectricity from Manitoba to Fort McMurray would be 12.4 cents/kwh, and Site C in B.C., at 14 cents/kwh. No wonder Alberta Premier Rachel Notley is not jumping to sign a deal with either province.

There is a new world confronting power producers and buyers, with alternatives emerging to compete with traditional sources of energy, small grids to transmit it and environmental pressures that could change the game. Manitoba Hydro and the provincial government should take a step back, halt the construction of Keeyask and Bipole III and ask for an independent review by experts and determine what's best for Manitobans to keep their hydro rates low.

Dennis Woodford was a transmission planning engineer at Manitoba Hydro for 15 years and now is president of Electranix Corporation.

The Winnipeg Free Press invites you to share your opinion on this story in a letter to the editor. A selection of letters to the editor are **published daily**.

To submit a letter:

• fill out the form **on this page**, or
• email **letters@freepress.mb.ca**, or
• mail *Letters to the Editor, 1355 Mountain Avenue, Winnipeg, Manitoba, R2X 3B6*.

Letters must include the writer's full name, address, and a daytime phone number. Letters are edited for length and clarity.

Tab 69

Terms of Reference - Needs For and Alternatives To (NFAT) Review

NFAT review for Manitoba Hydro's proposed preferred development plan for the Keeyask and Conawapa Generating Stations, their associated domestic AC transmission facilities and a new Canada-USA transmission interconnection

INTRODUCTION

On January 13, 2011, the Government of Manitoba notified Manitoba Hydro (Hydro) of its intention to carry out a public Needs For and Alternatives To (NFAT) review and assessment of the corporation's proposed preferred development plan (Plan) for major new hydro-electric generation and Canada-USA interconnection facilities using an independent body.

On November 15, 2012 the Minister of Innovation, Energy and Mines announced that the Government of Manitoba had asked the Manitoba Public Utilities Board (PUB) to conduct the NFAT for the Keeyask and Conawapa Generating Stations and their associated transmission facilities. This document, including Appendix A, outlines the Terms of Reference for the NFAT.

THE PLAN

Hydro's Plan is intended to meet a growing provincial demand for electricity and take advantage of opportunities to export power to US customer utilities. The Plan includes the Keeyask and Conawapa Generating Stations, their associated domestic AC transmission facilities and a new Canada-USA transmission interconnection. Hydro has stated that its Plan is being brought forward now to take advantage of the proposed Canada-USA interconnection and long-term firm export sale opportunities that occur rather infrequently. Hydro's Plan is dependent upon developing a new transmission interconnection into the USA and entering into long-term firm export sales with US-based electric utilities Minnesota Power and Wisconsin Public Service.

Hydro asserts that the Plan will provide significant benefits to Manitobans. Hydro also asserts that the value proposition of its Plan is justified on a very broad basis, taking into consideration inherent uncertainties that exist over a reasonable range of future possible critical inputs into its business case, and that it is the best development option when compared to alternatives.

MANDATE

The NFAT will be conducted under the authority of Section 107 of *The Public Utilities Board Act* ("The PUB Act"). PUB members designated by the Chair to conduct the NFAT under section 15(6) of The PUB Act will constitute the NFAT Panel (the "Panel"). Panel members will exercise their duty to conduct the assigned NFAT in accordance with The PUB Act and these Terms of Reference.

For greater certainty, in conducting the NFAT, the Panel members who are designated by the Chair to conduct the review:

(a) may hear evidence *in camera* for the purpose of protecting Commercially Sensitive Information as defined in Appendix A, which forms a part of these Terms of Reference;

(b) may exercise discretion over the access of any person to Commercially Sensitive Information; and

(c) shall follow the Rules of Practice and Procedure of the PUB, as amended from time to time, if not otherwise dealt with under these Terms of Reference.

At the completion of its review, the Panel will provide a report to the Minister responsible for the administration of *The Public Utilities Board Act* (currently the Minister of Healthy Living, Seniors and Consumer Affairs) no later than June 20, 2014. The report will include recommendations to the Government of Manitoba on the needs for Hydro's preferred development Plan and an overall assessment as to whether or not the Plan is in the best long-term interest of the province of Manitoba when compared to other options and alternatives.

PUBLIC PARTICIPATION

The public will be encouraged to provide input and comment on the Plan as part of the NFAT.

SCOPE OF THE NFAT REVIEW

The Panel will review and assess the needs for and alternatives to Hydro's Plan. Its assessment will be based upon the evidence submitted by Hydro, intervenors and independent expert consultants used by PUB to assist in the NFAT. The Panel's report to the Minister will address the following items:

1. An assessment as to whether the needs for Hydro's Plan are thoroughly justified, and sound, its timing is warranted, and the factors that Hydro is relying upon to prove its needs are complete, reasonable and accurate. The assessment will take the following factors into consideration:
    a. The alignment of the Plan to Hydro's mandate, as set out in Section 2 of *The Manitoba Hydro Act*.
    b. The alignment of the Plan to Manitoba's Clean Energy Strategy and the Principles of Sustainable Development as outlined in *The Sustainable Development Act*.
    c. The extent to which the Plan is needed to address reliability and security requirements of Manitoba's electricity supply.
    d. The reasonableness, thoroughness and soundness of all critical inputs and assumptions Hydro relied upon for its justification of its needs. This should include Hydro's planning load forecast and future load scenarios, its demand and supply analysis, export expectations and commitments, and demand side management and conservation forecasts.

2. An assessment as to whether the Plan is justified as superior to potential alternatives that could fulfill the need. The assessment will take the following factors into consideration:

    a. If preferred and alternative resource and conservation evaluations are complete, accurate, thorough, reasonable and sound;
    b. The alignment of the Plan and alternatives to Manitoba's Clean Energy Strategy, *The Climate Change and Emissions Reduction Act* and the Principles of Sustainable Development as outlined in *The Sustainable Development Act*;

c. The accuracy and reasonableness of the modeling of export contract sale prices, terms, conditions, scheduling provisions, export transmission costs, and the reasonableness of projected revenues;
d. The reasonableness of forecasted critical inputs including construction costs, opportunity export revenues, future fuel prices, electricity market price forecasts, the determinants of those values, and export volumes;
e. The reasonableness of the scope and evaluation of risks and the benefits proposed to arise from the development and the reasonableness and the reliability of Hydro's interpretation of the most likely future outcomes as a result of climate changes, interest rate fluctuations, export market prices, domestic load fluctuations, droughts, competing technologies, fuel prices, carbon pricing, technology developments, economic conditions, Hydro's transmission positions and other relevant factors;
f. The impact on domestic electricity rates over time with and without the Plan and with alternatives;
g. The financial and economic risks of the Plan and export contracts and export opportunity revenues in relation to alternative development strategies;
h. The socio-economic impacts and benefits of the Plan and alternatives to northern and aboriginal communities;
i. The macro environmental impact of the Plan compared to alternatives;
j. If the Plan has been justified to provide the highest level of overall socio-economic benefit to Manitobans, and is justified to be the preferable long-term electricity development option for Manitoba when compared to alternatives.

Independent Expert Consultants

The Panel shall establish a process for the thorough review of any information that the Panel determines to be relevant to the conduct of the NFAT, including relevant Commercially Sensitive Information, as defined in Appendix A, subject to these Terms of Reference.

The Panel may use one or more independent expert consultant(s) for the purpose of the NFAT. In addition to such other questions and issues as the Panel may determine they should examine, the independent expert consultant(s) shall be expected to critically examine the following:

(a) the high level forecasts of export revenues that are filed by Hydro and whether the forecasts appropriately and accurately reflect the export contracts, including Commercially Sensitive Information.

(b) the accuracy and reasonableness of Hydro's approach to producing an assessment of financial risks (including drought), the assessment of which is derived using Commercially Sensitive Information;

(c) the appropriateness and correct application of methodologies that cannot be publicly disclosed by MH because they contain Commercially Sensitive Information, such as whether Hydro's approach to comparing generation sequences follows sound industry practice;

(d) whether high level summaries filed by Hydro of Net Present Values and Internal Rates of Return which are derived from Commercially Sensitive Information reflect sound assumptions and calculations; and

(e) the accuracy and soundness of Hydro's calculation of a consensus forecast of future market prices for electricity and fuels which is derived from Commercially Sensitive Information.

The PUB shall hire the independent expert consultant(s).

The independent expert consultant(s) shall provide a report(s) to be filed in evidence on the public record, which shall contain their analysis of the submissions filed by Hydro, with sufficient information to satisfy the Panel that the review was conducted with due diligence. The report(s) shall not draw conclusions as to the needs for or alternatives to the Plan, which is the role of the Panel.

The independent expert consultant(s) shall be available for cross-examination at the public hearing, and shall be available as a resource to legal counsel for registered intervenors as deemed necessary by the PUB to prepare for the cross-examination of Hydro witnesses on Commercially Sensitive Information.

The independent expert consultant(s) may also provide such advice to the Panel, and file such report(s) with the Panel *in camera*, that contain, reference, or analyse Commercially Sensitive Information in sufficient detail to satisfy the Panel. Cross-examination of the independent expert consultant(s) on such issues shall be permitted *in camera.*

The independent expert consultant(s) shall not quote in their publicly filed report(s) Commercially Sensitive Information or information that would enable a third party to reverse-engineer Commercially Sensitive Information ("reverse-engineer" means to discover, synthesize or otherwise recreate the Commercially Sensitive Information following a detailed examination). No public cross-examination of the independent expert consultant(s) shall take place with respect to Commercially Sensitive Information. The independent expert consultant(s) will be required to execute a non-disclosure agreement satisfactory to Hydro and the Panel.

NOT IN SCOPE

The following items are not in the scope of the NFAT:

- The Bipole III transmission line and converter station project;
- The Pointe Du Bois project;
- The commercial arrangements between Hydro and its aboriginal partners for the development of the proposed hydro-electric generating facilities (the impacts of these are included in the cost of the projects that are part of the Plan);
- The environmental reviews of the proposed projects that are part of the Plan, including Environmental Impact Statements (these will be conducted through individual processes by the Manitoba Clean Environment Commission ("CEC"), and where possible the impacts of the matters to be considered by the CEC are included in the costs of the projects that are part of the Plan);
- Aboriginal consultation pursuant to Section 35 of the *Constitution Act* (this is conducted as a separate Crown-Aboriginal consultation process);

- Any past Hydro development proposals or government assessments of past development proposals, including past NFATs;
- Historic environmental costs.

Appendix A

PROVISIONS FOR THE PROTECTION OF COMMERCIALLY SENSITIVE INFORMATION:

Transparency

The Panel is directed to conduct the NFAT in a transparent and public process. However, in conducting the NFAT, the Panel is to ensure adequate protection of any information the disclosure of which may reasonably be expected to cause undue financial loss to Manitoba Hydro ("Hydro") or any of its contractual counterparties or to harm significantly Hydro's or its contractual counterparties' or domestic customers' competitive position, including, but not limited to, any sections of the following documents containing such information (collectively, "Commercially Sensitive Information"):

(a) any and all export contracts and term sheets now or hereafter in existence for the purchase and sale of power and energy entered into between Hydro and its customers in the United States of America, including but not limited to the export contracts and term sheets commonly described as follows: Minnesota Power 250 MW Energy Exchange Agreement; Minnesota Power 250 MW Power Sale Agreement; Wisconsin Public Service 100 MW Power Sale Agreement; Wisconsin Public Service 108 MW Energy Sale Agreement; Wisconsin Public Service Term Sheet, Northern States Power 375/325 MW System Power Sale Agreement; Northern States Power 125 MW System Power Sale Agreement, and Northern States Power 350 MW Seasonal Diversity Agreement (collectively, "Export Contracts");

(b) the internal, non-public load forecast prepared by Hydro on an annual basis (collectively, "Load Forecast"); and

(c) the Hydro document dated September 24, 2010 titled "THE 2010/11 POWER RESOURCE PLAN, Report PPD #10-07" and any further existing or future power resource plans hereinafter developed by Hydro (collectively, "Power Resource Plan")

Document Filings and Evidence

In conducting the NFAT, the Panel shall be able to require the production, from Hydro, of any documents and other such evidence as the Panel determines to be relevant to the conduct of the NFAT within the scope of the Terms of Reference from the Province of Manitoba. The procedures for filings and evidence shall be as set out below:

(a) Public Filings

Any documents that do not contain Commercially Sensitive Information are to be filed on the public record. As part of its NFAT submission Hydro shall file on the public record copies of its Export Contracts, Load Forecast and Power Resource Plan, with details considered by Hydro to be Commercially Sensitive Information redacted.

To the extent that information necessary for the conduct of the NFAT cannot be made public due to the presence of Commercially Sensitive Information, Hydro shall file on the

public record high level summaries and reports that incorporate the relevant information, at a level of summary and aggregation which will not disclose Commercially Sensitive Information.

Any evidence before the Panel shall be public, other than evidence with respect to Commercially Sensitive Information, which testimony shall be received in camera as further described in (b) below. To the extent that it deems practical, the Panel shall limit the scope of *in camera* proceedings so that the major issues in the NFAT review can be canvassed and discussed in public.

(b) Confidential Filings

Any documents that the Panel determines to be relevant but that contain Commercially Sensitive Information are to be filed with the Panel in confidence in unredacted form, including unredacted copies of the Export Contracts, Load Forecast and Power Resource Plan.

On an *in camera* basis, the Panel may:

i) review the complete, unredacted versions of Hydro documents that contain Commercially Sensitive Information; and

ii) permit evidence with respect to Commercially Sensitive Information.

Access to* In Camera *Evidence

Based on the *in camera* review, the Panel may choose to publish findings and conclusions about export revenues, forecast market prices and the like, to inform the public discussion and serve as inputs to further analysis and review by participants at the public hearing, or it may choose to reserve comment until the conclusion of the hearing.

The documents filed and evidence adduced *in camera* shall not be made public, other than through the high-level summaries as described above, and shall only be disclosed to or shared with the following persons, on the terms and conditions as noted below:

1. Members of the Panel, the Board's Executive Director and Board staff may review Commercially Sensitive Information and participate in the *in camera* process for the purpose of carrying out their specific duties with respect to the NFAT without having to sign an undertaking or a non-disclosure agreement.

2. Legal counsel of record of the Board and counsel for registered interveners may review Commercially Sensitive Information and participate in the *in camera* process upon execution of an undertaking to the Panel in a form agreeable to the Panel and Hydro.

3. Any independent consultant(s) appointed by the Panel and any non-staff Panel advisors with a need to know, as determined by the Chair, may review Commercially Sensitive Information and participate in the *in camera* process upon execution of a non-disclosure agreement in a form agreeable to the Panel and Hydro.

Subject to the following dispute resolution provision, the Panel will not publish Commercially Sensitive Information in Orders or other public documents or include information that would enable a third party to reverse engineer Commercially Sensitive Information. The Panel will establish procedures to protect the documents and evidence from inadvertent disclosure and will instruct each individual who receives access to do the same. If the Panel so chooses, it may solicit Hydro's comments on particular documents that are in the process of being prepared in the interests of avoiding inadvertent disclosures.

Dispute Resolution Regarding Commercially Sensitive Information

If, during the in camera review, the Panel identifies any Commercially Sensitive Information, other than third party proprietary price forecasts, which the Panel considers would be beneficial to place on the public record at the NFAT, the Panel may refer those matters in dispute to a neutral third party to be agreed upon between the Panel and Hydro. The third party will receive written submissions and make a decision thereon, on an expedited basis, which decision will be given effect to in the proceedings before the Panel. In arriving at any such decision, the neutral third party shall specifically take into account the general undesirability of making disclosure of any Commercially Sensitive Information that may have been furnished to Hydro by third parties, in reliance upon contractual commitments by Hydro to maintain confidentiality, and the importance of maintaining such confidences.

Tab 70



(HTTPS://MBTRADES.CA/WP-CONTENT/UPLOADS/2019/10/AHC-NEW-LOGO-PNG.PNG)

ALLIED HYDRO COUNCIL

The Allied Hydro Council of Manitoba (AHC) is a Council of 17 construction and trades unions that build hydro projects across Manitoba under the guidelines and standards set out in the Burntwood Nelson Agreement (BNA) (https://www.hydro.mb.ca/projects/bna_agreement.pdf). The AHC and Manitoba Building Trades share 12 member unions that are founding partners of both Councils.

Since the late 1960s, the BNA has been the governing collective agreement for the AHC and the Hydro Projects Management Association and is the longest continuous agreement of its kind in Canada.

Under the BNA, tens of thousands of union members in Manitoba have partnered to construct major Hydro installations, mostly in remote northern regions. These projects have placed Manitoba as the leading producer of clean, renewable energy and include:

- Kettle Rapids Generating Station
- Jenpeg Generating Station
- Long Spruce Generating Station
- Limestone Generating Station
- Henday Convertor Station
- Wusqwatim Generating Station
- Keeyask Generating Station (http://keeyask.com/)
- Keewatinohk Convertor Station

AHC and its member unions are proud of their track record of excellence. Working in remote northern locations on a year-round basis is never easy, but it is rewarding – the legacy of these projects will benefit Manitoba for generations to come.

Presently, the AHC is actively engaged in the latest iconic and historic Manitoba Hydro projects at Keeyask (http://keeyask.com/) and Keewatinohk, both on First Nations lands. The AHC believes that a skilled northern Aboriginal workforce must be an enduring legacy of these projects. To that end, they are an active partner in training residents of First Nations communities and generating sustained employment for Aboriginal workers in the north.

For more information about ongoing Keeyask and Keewatinohk projects, please contact the AHC at info@mbtrades.ca (mailto:info@mbtrades.ca) or call 204.956.7425.

TO VIEW THE BURNTWOOD NELSON AGREEMENT, CLICK HERE (HTTPS://WWW.HYDRO.MB.CA/PROJECTS/BNA_AGREEMENT.PDF).

Sign up for updates from Manitoba Building Trades

email address

SUBSCRIBE

(https://www.facebook.com/ManitobaBuildingTrades) (https://twitter.com/MBTrades)

(https://www.linkedin.com/company/manitoba-building-trades/)

Tab 71

The Burntwood/Nelson River Agreement

In October 2005, Manitoba Hydro and the Allied Hydro Council, a joint council of unions representing project construction workers, agreed to renew the Burntwood Nelson Agreement (BNA) – a no strike/no lockout bargaining agreement covering any major northern hydroelectric projects commencing in the next 10 years.

The BNA, which is an extension of a collective bargaining agreement first negotiated in the late 1960s, sets out hiring preferences – including priority for northern Indigenous residents – as well as procedures for adjusting wages and certain benefits during the life of the agreement. The agreement also contains provisions relating to the recruitment, referral, placement, training and retention of northern Indigenous people and facilitates the hiring of northern Indigenous people by northern Indigenous businesses.

View the BNA (PDF, 2.5 MB)

View detailed descriptions of jobs covered by the BNA (PDF, 510 KB)

HYDRO PROJECTS MANAGEMENT ASSOCIATION

Burntwood Nelson Agreement

Version 2020.07

10/21/2020

BURNTWOOD/NELSON AGREEMENT SIGNATORIES 5
ARTICLES.....9
ARTICLE 1 - TERM OF AGREEMENT 9
ARTICLE 2 - SCOPE AND RECOGNITION..... 10
ARTICLE 3 - THE COUNCIL AND ASSOCIATION 15
ARTICLE 4 -WORK ASSIGNMENTS AND JURISDICTIONS 16
ARTICLE 5 - MANAGEMENT'S RIGHTS..... 18
ARTICLE 6 - ASSOCIATION, COUNCIL AND UNION REPRESENTATIVES..... 19
ARTICLE 7 - STRIKES AND LOCKOUTS 21
ARTICLE 8 – GRIEVANCE PROCEDURE..... 22
ARTICLE 9 - ROOM AND BOARD..... 27
ARTICLE 10 - HOUSING ALLOWANCE..... 29
ARTICLE 11 - MEDICAL EXAMINATIONS 30
ARTICLE 12 - THE HIRING PROCEDURE AND REFERRAL SYSTEM: UNION SECURITY & CHECK OFF: TRANSFER; LAY-OFF AND RECALL PROVISIONS 31
ARTICLE 13 - NORTHERN RESIDENTS AND NORTHERN ABORIGINALS 43
ARTICLE 14 - PAYMENT OF WAGES..... 45
ARTICLE 15 - HOURS OF WORK AND COFFEE BREAKS..... 46
ARTICLE 16 - REPORTING TIME 47
ARTICLE 17 - STATUTORY AND GENERAL HOLIDAYS..... 48
ARTICLE 18 - SAFETY 49
ARTICLE 19 - TRANSPORTATION AND TRAVEL TIME, ISOLATION LEAVE, LEAVES OF ABSENCE AND CHRISTMAS LEAVE PROVISIONS 51
ARTICLE 20 - GOVERNMENT LEGISLATION..... 64
ARTICLE 21 - TOOLS 65
ARTICLE 22 - WORK SITE SHELTER AND SANITARY CONDITIONS..... 66
ARTICLE 23 - INJURIES ON THE JOB 67
ARTICLE 24 - BULLETIN BOARDS..... 68
ARTICLE 25 - STANDARD OF WORK AND LIMITATIONS..... 69
ARTICLE 26 - TERMINATION OF EMPLOYMENT..... 70
ARTICLE 27 - APPENDICES..... 72
ARTICLE 28 - ADDITIONAL CLASSIFICATIONS..... 73
ARTICLE 29 - AGREEMENTS BEING USED FOR REFERENCE PURPOSES 74
ARTICLE 30 - ADJUSTMENT OF APPENDICES..... 75
ARTICLE 31 - MEDIATION..... 77
ARTICLE 32 - INTERPRETATION OF THE AGREEMENT..... 78
ARTICLE 33 - CAMP AND RECREATION FACILITIES..... 79
ARTICLE 34 - WAGE INDEMNIFICATION 80
ARTICLE 35 - COUNTERPARTS..... 82
ARTICLE 36 - SUCCESSORS 83
APPENDICES 90

APPENDIX NO. 1 - LABOURERS 90
APPENDIX NO. 1A – SECURITY GUARDS 98
APPENDIX NO. 2 – CRANE OPERATORS 105
APPENDIX NO. 2A – EQUIPMENT OPERATORS 116
APPENDIX NO. 3 – TEAMSTERS, CHAUFFEURS, WAREHOUSEMEN AND HELPERS 131
APPENDIX NO. 4 - CARPENTERS 142
APPENDIX NO. 4A - MILLWRIGHTS 152
APPENDIX NO. 5 – PAINTERS DIVISION 161
APPENDIX NO. 5A – GLASSWORKERS DIVISION 168
APPENDIX NO. 5B – FLOOR COVERING DIVISION 175
APPENDIX NO. 6 – INSULATOR WORKERS 180
APPENDIX NO. 7 - LATHERS 188
APPENDIX NO. 8 - PLASTERERS 195
APPENDIX NO. 8A – CEMENT MASONS 201
APPENDIX NO. 9 - BRICKLAYERS AND ALLIED CRAFTSMEN 208
APPENDIX NO. 10 – SHEET METAL 219
APPENDIX NO. 10A - ROOFERS 229
APPENDIX NO. 10B – SHEETERS, DECKERS AND CLADDERS 237
APPENDIX NO. 11 – BOILERMAKERS 247
APPENDIX NO. 12 – IRON WORKERS 256
APPENDIX NO. 12A - RODMEN 265
APPENDIX NO. 13 – ELECTRICAL WORKERS 273
APPENDIX NO. 13A - IBEW 285
APPENDIX NO. 14 – PLUMBERS AND PIPEFITTERS 298
APPENDIX NO. 14A – REFRIGERATION SECTION OF P & P 308
APPENDIX NO. 14B – SPRINKLER SYSTEM INSTALLERS 316
APPENDIX NO. 15 – OFFICE AND PROFESSIONAL EMPLOYEES 324
APPENDIX NO. 16 - CATERERS 334
APPENDIX NO. 17 – ELEVATOR CONSTRUCTORS 342
SCHEDULES 350
SCHEDULE “A” – ALLIED HYDRO COUNCIL MEMBER UNIONS 350
SCHEDULE “B” – CHECK-OFF AUTHORIZATION FORM (AHC) 351
SCHEDULE “C” – UNION ASSESSMENTS, INITIATION AND DUES STRUCTURE 353
SCHEDULE “D” – EMPLOYMENT PREFERENCE AREA 360
SCHEDULE “E"' – LETTERS OF AGREEMENT 361
Letter of Agreement No. 1- Special Employment Measures for Specific Projects 365
Letter of Agreement No. 2 - Transfer of Day Off From Sunday to Saturday 367
Letter of Agreement No. 3 - Security Guards Union Affiliation 369
Letter of Agreement No. 5 - Adjustment of Isolation Leave Frequency 371
Letter of Agreement No. 6 - Radiography Work 373
Letter of Agreement No. 8 - Scaffolding Specialist Contractors 374
Letter of Agreement No. 9 - Schedule A - add Cement Masons 375
Letter of Agreement No. 10 - Teamsters - Introduction of Pension Plan 376
Letter of Agreement No. 11 - Louis Riel Day 379

Letter of Agreement No. 23 – Keeyask specifics 380
Letter of Agreement No. 25 - Introduction of Sprinkler System Installers 385
Letter of Agreement No. 26 - Adjustment of Isolation Leave 386
Letter of Agreement No. 27 - Isolation Leave Frequency 388
Letter of Agreement No. 28 - Emergency Medical Classifications 390
Letter of Agreement No. 29 – Addition of Journeyperson Lineman 391
Letter of Agreement No. 30 - Blasters and Drillers compensation 393
Letter of Agreement No. 31 - COPE - Health and Welfare Trust Fund 394
Letter of Agreement No. 32 – Security guard compensation 397
Letter of Agreement No. 33 – Telebelt operator classification 400
Letter of Agreement No. 34 – Commissioning work 401
Letter of Agreement No. 35 – Completion bonus 402
Letter of Agreement No. 36 – Isolation leave frequency 404
Letter of Agreement No. 37 - Ability to Regularly Schedule Sundays 406
Letter of Agreement No. 38 - Supplementary Workers 407
Letter of Agreement No. 39 - Project Labour Management Services Agreement 409
Letter of Agreement No. 40 - Amendment to Hiring Procedure 412
Letter of Agreement No. 41 – Work teams 413
Letter of Agreement No. 42 – Tower crane trade improvement trust fund 418
Letter of Agreement No. 43 – Power engineer classification 420
Letter of Agreement No. 44 – Special measures for hiring apprentices and trainees 421
Letter of Agreement No. 45 – Concrete finisher and red seal cement finisher classification 422
Letter of Agreement No. 46 – Personal Risk Assessments 423
Letter of Agreement No. 47 – COPE relocation of employees 426
Letter of Agreement No. 48 – Layoff subject to recall 427
Letter of Agreement No. 49 – Labourers training trust fund 428
Letter of Agreement No. 50 – Scaffolder classification 431
Letter of Agreement No. 51 – Carpenter foreman coordinator 432
Letter of Agreement No. 52 – Labourer foreman coordinator 434
Letter of Agreement No. 53 – Duration of Isolation leave 435
Letter of Agreement No. 54 – Work team / Composite crew 437
Letter of Agreement No. 55 – Breaks 438
Letter of Agreement No. 56 – Trade Flexibility 440
Letter of Agreement No. 57 – Cancel LOA No 39 446
Letter of Agreement No. 58 – Project Labour Management Services Agreement 447
Letter of Agreement No. 59 – Appendix 8A – Cement Masons Apprenticeship changes 450
Letter of Agreement No. 60 – Workers United – Pension deduction changes 452
Letter of Agreement No. 61 – Burntwood Nelson Agreement – Blasters wage enhancement 453
Letter of Agreement No. 62 – Heavy Duty Gas and Diesel Mechanics Wage Enhancement 454
Letter of Agreement No. 63- Article 8A – Cement Masons – Adjust Reference Classifications for Escalations 456
Letter of Agreement No. 64- COVID 19 Special Measures 457
Letter of Agreement No. 65- COVID 19 Return to Operational Continuance – Enhanced

Normal Protocol 459
Letter of Agreement No. 66- Introduction of Classification to Appendix 13 – Winders & Brazers 463

BURNTWOOD/NELSON AGREEMENT SIGNATORIES

BETWEEN:

HYDRO PROJECTS MANAGEMENT ASSOCIATION

(hereinafter called the "Association")

OF THE FIRST PART

And

THE ALLIED HYDRO COUNCIL OF MANITOBA

(hereinafter called the "Council")

OF THE SECOND PART

CONSTRUCTION & SPECIALIZED WORKERS' UNION OF NORTH AMERICA, and Local Union 1258 of this International Union.

INTERNATIONAL UNION OF OPERATING ENGINEERS, and Local 987 of this International Union.

INTERNATIONAL BROTHERHOOD OF TEAMSTERS, CHAUFFEURS, WAREHOUSEMEN AND HELPERS OF AMERICA, and Local Union 979 of this International Union.
B
UNITED BROTHERHOOD OF CARPENTERS AND JOINERS OF AMERICA, and Local Union 343 (Carpenters) of this International Union and,

Local Union 1443 (Millwrights, Machine Erectors, Industrial Mechanics Maintenance) of this International Union.

INTERNATIONAL UNION OF PAINTERS & ALLIED TRADES, GLASS-WORKERS DIVISION, SIGNWORKERS & CARPET & FLOOR TILE LAYERS DIVISION, and Local Union 739 of this International Union.

INTERNATIONAL ASSOCIATION OF HEAT AND FROST INSULATORS AND ASBESTOS WORKERS, and Local Union 99 of this International Union.

INTERNATIONAL UNION OF BRICKLAYERS AND ALLIED CRAFTWORKERS, and Local Union No. 1 of this International Union.

SHEET METAL WORKERS INTERNATIONAL ASSOCIATION, and Local Union 511 of this International Union.

INTERNATIONAL BROTHERHOOD OF BOILERMAKERS, IRON SHIPBUILDERS & HELPERS OF AMERICA, and Local Union 555 of this International Union.

INTERNATIONAL ASSOCIATION OF BRIDGE, STRUCTURAL, ORNAMENTAL & REINFORCING IRONWORKERS, and Local 728 of this International Union.

INTERNATIONAL BROTHERHOOD OF ELECTRICAL WORKERS, and Local Union 2085 of this International Union.

UNITED ASSOCIATION OF JOURNEYMEN AND APPRENTICES OF THE PLUMBING AND PIPEFITTING INDUSTRY OF THE UNITED STATES AND CANADA, and Local Union 254 of this International Union.

OPERATIVE PLASTERERS & CEMENT MASONS INTERNATIONAL ASSOCIATION, Local Union 222. See Letter of Agreement No. 9.

CANADIAN OFFICE AND PROFESSIONAL EMPLOYEES UNION, Local Union 342.

UNITE HERE, Local Union 206 .

INTERNATIONAL UNION OF ELEVATOR CONSTRUCTORS, and Local 102 of this International Union.

Each being a Trade Union within the meaning of the "Labour Relations Act."

OF THE THIRD PART

And

_____
(hereinafter called the "Contractor")

OF THE FOURTH PART

A G R E E M E N T

WHEREAS Manitoba Hydro is undertaking certain construction work in Manitoba (hereinafter called "the Project");

AND WHEREAS the Contractor is engaged or is about to be engaged in on-site construction work in connection with the Project and is a member of the Association and has designated the Association as its exclusive agent for negotiating and administering this Collective Bargaining Agreement (hereinafter referred to as this Agreement);

AND WHEREAS the Association has recognized the formation of the Council by the International Unions and has agreed to deal with the Council as the exclusive agent of the Unions for negotiating, executing and administering this Agreement;

AND WHEREAS the Council has recognized the Association and has agreed to deal with the Association as the exclusive agent of the Contractor for negotiating and administering this Agreement;

AND WHEREAS the Unions have designated the Council as their exclusive agent for negotiating, executing and administering this Agreement;

AND WHEREAS the Council and the International Unions have designated the Local Unions as having jurisdiction in their respective trades for the Project;

AND WHEREAS the Association, the Council, the Contractor and the Unions are desirous of carrying out the work associated with the Project in a harmonious and peaceful manner without any slowdowns, work stoppages, strikes or lockouts and ensuring a peaceful resolution of any and all grievances, disputes, and differences that may arise between them;

AND WHEREAS the Council and the Association have exchanged their respective constitutions and by-laws for review each by the other, receipt of which is hereby acknowledged, each by the other;

AND WHEREAS the parties intend to avoid unnecessary expense to the Project or to the general public, by prohibiting slowdowns, the forcing of overtime, the use of standby crews, spread work policies and other objectionable practices;

AND WHEREAS the parties are desirous of maximizing the training and employment opportunities of Northern Aboriginals;

AND WHEREAS the parties have agreed that the foregoing recitals together with the Schedules, Appendices, and Letters of Agreement hereto shall be interpreted as forming part and parcel of this Agreement;

NOW THEREFORE THE PARTIES FURTHER AGREE AS FOLLOWS:

Where the words "International Unions" are used they shall mean the International Unions as listed above as parties hereto and where the words "Local Unions" are used they shall mean the Local Unions as listed above as parties hereto.

Where the word “employee” is used, it shall mean a person employed on the Project by a Contractor or Sub-contractor in one of the classifications set out in the Appendices.

Where the word Manitoba Hydro is used, it shall mean the Manitoba Hydro-Electric Board, or the Manitoba Hydro Electric Board and its equity partners, where applicable.

ARTICLES

ARTICLE 1 - TERM OF AGREEMENT

1.1 This Agreement shall be effective on the date of signing and shall continue in effect until:

a) 2017 12 31;

OR

b) Twelve (12) months following the commissioning of the last generator of a hydro electric generating station included under Article 2.1(a) and/or 2.1(b) of this Agreement;

OR

c) Twelve (12) months following the commissioning of the work set out in Article 2.1(c).

which ever date occurs last.

1.2 This Agreement may be terminated, extended or amended, by mutual agreement of the Parties.

ARTICLE 2 - SCOPE AND RECOGNITION

*** Note – See Letter of Agreement #6, for additional information regarding Article 2.2 e) and i)
*** Note – See Letter of Agreement #34, for additional information regarding Article 2, Section 2.2 (Commissioning exemption)

2.1 The Association recognizes the Council as the exclusive bargaining agent for all employees engaged in contracted on-site construction work and services related to:

a) The construction of any new hydro electric generating station including any new northern converter station, and any switchyards and collector lines associated with either:

i) On the Nelson River;

ii) On the Burntwood River, and;

b) Any extension to the Kelsey Generating Station, and;

c) Any extension of the Henday Converter Station associated with the construction of a new hydro-electric generating station, and;

d) The construction of a new generating station, including switchyard and collector lines, at Notigi; provided the first tender call for contracted on-site construction work (excluding exploration work) for each applicable new generating station or converter station and for the extension to the Kelsey Generating Station, respectively, has been issued by Manitoba Hydro on or before 2015 12 31.

For the purposes of this Article, the construction of switchyards and collector lines shall include the following:

- for a new northern Hydro generating station, an AC Switchyard includes all work performed between the take-off structures terminating the AC transmission lines from the generating station and the take-off structures terminating the AC transmission lines to Manitoba Hydro's AC transmission systems; and

- for a Northern AC/DC converter station, a DC switchyard includes all work performed between the DC wall bushings of the converter building and the take-off structures terminating the DC transmission lines to Manitoba Hydro's DC transmission system and an AC switchyard includes all work performed between the take-off structures terminating the AC transmission lines for Manitoba Hydro's AC transmission system and the AC wall bushings of the converter building; and

- the construction of collector lines is defined as all work performed between the AC wall bushings at the generating station and the take-off structures terminating

the AC transmission lines from the generating station at the switchyard. Construction of collector lines shall be governed by Letter of Agreement No. 7.

e) Exploration work that is tendered in relation to a generating or converter station included under 2.1 a), b), c), or d), provided the exploration work is tendered subsequent to the first tender call for on-site construction work;

f) The construction of an all weather road to the site of the Wuskwatim Generating Station, the Gull Generating Station, or to the Kelsey Generating Station or any upgrading of the railspur to Kelsey if either the road or the railspur upgrading is associated with an extension to Kelsey, provided onsite work in relation to same commences prior to 2015 12 31. Moreover such construction shall not be construed to be the "first tender call" for these respective generating stations pursuant to the provisions of Article 2.1(a) or 2.1(b). The maintenance of the said all-weather roads during the project construction period shall be covered under the terms of this Agreement, unless it is performed by the Manitoba Department of Highways or an agent thereof.

2.2 Notwithstanding any other provision of this Agreement, exclusions from this Article 2, Scope and Recognition shall include, but not be limited to, the following:

a) Construction of transmission lines (except as provided in 2.1) and communication facilities, including the clearing of rights of way;

b) All exploration work not included under 2.1(e);

c) Construction work and services related to any established community;

d) Work performed for and under the administration of a Local Government District, the Province of Manitoba, the Government of Canada, or their agents;

e) Testing and/or inspection services, except radiography work (which is subject to (l) below), performed under direct contract to Manitoba Hydro;
*** See Letter of Agreement #6

f) Services provided by consultants to Manitoba Hydro;

g) The operation and maintenance of commercial, municipal and recreational services in any townsite associated with the hydroelectric generating stations defined in 2.1(a);

h) Repair/maintenance work on camp equipment performed by technical specialists;

i) Non continuous work required on heavy construction equipment covering warranty repairs and technical support for maintenance;
*** See Letter of Agreement #6

j) Specialized work performed by technical specialists from the Equipment Manufacturer on permanent equipment, which was not assembled under the Scope of this Agreement;

k) Work associated with the delivery of supplies, materials, parts, and equipment to the Project Site, on the basis of "one drop per load per Contractor". Where supplies, materials, parts, and/or equipment are delivered "Freight on Board" (F.O.B.) to a rail terminus, siding, or spur line in the vicinity of the site, designated by the Contractor as a delivery point for the project, the spotting of the rail cars shall be considered the first drop. Batching and/or delivery of concrete on site is covered under the terms of this Agreement. Processing and/or delivery of aggregate on site is covered under the terms of this Agreement. The Contractor shall designate his storage areas and designated rail delivery points at the Pre Job Conference (Article 4);

l) Provided prior mutual agreement is reached by the Council and the Association on each occasion, other work including, but not limited to, the following:

i) Radiography work of a short term nature performed under direct contract to Manitoba Hydro;

ii) Work associated with the supply of manufacturer's parts for heavy construction equipment.

m) Employees of the Manitoba Hydro Electric Board;

n) Those excluded by the Labour Relations Act of Manitoba.

2.3 It is recognized that there will be employees for whom the Council is recognized as the exclusive bargaining agent but who are not covered by an appendix to this Agreement and who are not otherwise excluded.

2.4 Any employee or group of employees referred to in Article 2.3 may make application to the Council to be covered by this Agreement. When this occurs, the Council shall notify the Association of its intention to bargain on behalf of the employee(s) concerned.

2.5 If the Association and the Council agree as to which Union the employee(s) should be members of and provided the majority of the employees concerned wish to become members of the Union agreed upon, negotiations between the Association Appendix Review Committee and the Council Appendix Review Committee shall commence to establish such additional conditions of employment as may be necessary. If the Joint Appendix Review Committee is unable to agree on:

a) The Union to which the employee(s) should belong;

b) Whether the majority of employees wish to be members of the union;

c) The conditions of employment for the employee(s) involved.

the dispute shall be resolved in accordance with Article 31 of this Agreement.

2.5.1 A Union of the Council may make application to the Council to approach an employee or group of employees, who are not covered by this Agreement and who are not otherwise excluded, to become Union members. In this event, the Council shall proceed as in 2.4 commencing with the second sentence.

2.6 The Unions and the Council shall not interfere with the right and responsibility of the Security Guards in the performance of their duties. The Unions and the Council recognize and shall not interfere in any way with the confidentiality of reports of Security Guards forwarded to Manitoba Hydro.

2.7 Notwithstanding any other provision of this Agreement, the provisions of Article 12.1 may be waived by the Security Contractor when hiring Security Guards, except the Security Contractor shall advise the Council of the names of the persons hired within three (3) working days.

2.8 In the event any Contractor (other than a Security Contractor) employs security guards on the Project associated with his own operation, the provisions of Article 2.6 and 2.7 shall apply except that any reference to Manitoba Hydro in these Articles shall be replaced by the name of the said Contractor.

2.9 A Northern Aboriginal Contractor shall be defined as a Manitoba business: a) that is at least 50% owned by an aboriginal resident(s) or organization(s) and b) that is based in or whose aboriginal owner has resided within the Northern affairs boundary for a cumulative period of 5 years or more.

The provisions of Article 12.1 may be waived by any Northern Aboriginal Contractor who is engaged by Manitoba Hydro on a non tendered direct contract basis, provided that:

a) The Contractor may only waive the said provisions of Article 12.1 if the person to be hired is a Northern Aboriginal, and;

b) Prior to such a hire, the person to be hired provides Manitoba Advanced Education and Training (M.A.E.T.) with information that confirms that he qualifies as a Northern Aboriginal in accordance with Article 12.1.1.3.2 (see also Article 13 for definition of Northern Aboriginal).

While all such employees hired under this Article 2.9 will be required to pay the current amount of applicable union dues and Council assessment, in the case of initiation fees, payment will be made on the basis of fifty cents (50¢) per hour worked and credited towards the payment of this fee. Union dues, Council assessment and payments relative to initiation fees will be collected as a payroll deduction and remitted in accordance with the provisions of Article 12.2.8, 12.2.9 and 12.2.10.

2.10 In this Agreement and the classifications contained herein, any words importing the masculine gender include female persons and, any words importing the female gender include male persons.

2.11 In the event that a provision in any Article to this Agreement is inconsistent with a provision or provisions in any of the Appendices to this Agreement, the provision in the Article shall prevail over the provision or provisions in the Appendices.

ARTICLE 3 - THE COUNCIL AND ASSOCIATION

3.1 The Unions and Contractors hereby confirm the designation of the Council and the Association as their exclusive agents, respectively, for the purpose of bargaining collectively, negotiating and entering into this Agreement, and administering the same.

3.2 As long as this Agreement remains in effect, neither the Association nor the Council nor any member Union of the Council will endeavor to seek separate bargaining rights or separate Agreements concerning work covered by this Agreement.

3.3 The Council shall be composed of the International Building and Construction Trades Unions and the Locals thereof, together with the other Unions as provided in the Constitution and By Laws of the Council in effect as of the date of this Agreement, all of whom are listed in "Schedule A" of this Agreement.

3.4 The Association shall be composed of representatives of Manitoba Hydro, Contractors engaged by Manitoba Hydro on the Project, and their sub-contractors, as provided in the Constitution of the Association in effect as of the date of this Agreement.

3.5 It shall be the responsibility of the Association and the Council to keep each other informed of the names of their respective Officers. The Council shall notify the Association of the names of the Union Business Representatives and the members of the Council Negotiating Committee. The Association shall notify the Council of the members of the Association Negotiating Committee. Prompt notice shall be given of any changes.

3.6 The Council and the Association shall not be bound to deal with anyone other than their respective Officers or Representatives concerning the administration of this Agreement.

3.7 International or Business Representatives of the Local Unions may be authorized by the Council to deal with a Contractor on matters concerning the Local Union they represent.

ARTICLE 4 -WORK ASSIGNMENTS AND JURISDICTIONS

4.1 Subject to the terms and conditions of this Agreement, the Contractor shall have the right to assign all work.

4.2 Before commencement of any work on any portion of a Project, the Contractor shall hold a pre job conference in Winnipeg, or such other location as may be mutually agreeable, attended by representatives of the Council, the Unions and the Association. The purpose of the pre job conference shall be to establish the work assignments and jurisdictions for each trade, to correspondingly mark work demarcation lines on construction drawings, and to identify and resolve any jurisdictional disputes.

4.3 Notification of the pre job conference shall be given by the Contractor to the Council and the Association at least ten (10) calendar days prior to the date set for this meeting.

4.4 The Contractor, in assigning work, shall comply with any applicable decisions of record or agreements of record and specify the basis of assignment. The decisions of record and agreements of record referred to shall be those contained in the most current edition of the book entitled, "Plan for the Settlement of Jurisdiction Disputes in the Construction Industry", approved by the Building and Construction Trades Department AFL CIO, commonly referred to as the "Green Book".

4.4.1 More specifically, work shall be assigned on the following basis:

4.4.1.1 Where the Unions involved agree that a decision of record or agreement of record referred to in 4.4 applies to the work, the Contractor shall assign the work in accordance with such agreements or decisions of record.

4.4.1.2 Where the Unions involved in the Pre Job Conference cannot agree that a particular Union is entitled to perform certain work under a decision of record or an agreement of record, referred to in 4.4, the Contractor shall:

i) Provide a detailed description of the work in dispute to the Contesting trades;

ii) Request the contesting trades to submit, within five (5) working days, evidence substantiating their claim to the work;

iii) Consult with the Association to ascertain how such work had been previously assigned.

following which, the Contractor shall assign the work and indicate the basis on which the assignment is being made including, where applicable, the reason why a decision or agreement of record referred to by one of the contesting trades is, in the opinion of the contractor, not applicable.

4.4.1.3 Where there is no decision of record or agreement of record the Contractor shall consult with representatives of the Association to ascertain how such work has previously been assigned prior to assigning the work.

4.5 If, after the assignment of the work, a dispute arises as to the proper jurisdiction of the work involved, the work shall continue in accordance with the Contractor's assignment and the procedure set out below shall be followed to resolve same. Under no circumstances shall there be any interference with the progress of the work on the Project.

4.5.1 The Association representative shall consult with the representatives of the contesting trades to consider any arguments or facts relating to the disputed work in an effort to resolve the matter.

4.5.2 Failing settlement by the foregoing the dispute will be settled and adjusted according to the prevailing plan established by the Building and Construction Trades Department or in accordance with any other plan, method or procedure that may be adopted in the future by the aforementioned Department. Any decision rendered in accordance with the foregoing shall be binding.

4.6 In the event a plan, method or procedure referred to in Article 4.5.2 is not available, the Joint Appendix Review Committee shall meet within ten (10) calendar days following notice from either party to establish a successor plan. If an agreement cannot be reached, as to the successor plan or its terms of reference, then the procedure in Article 31 shall be followed. Any decision rendered in accordance with the successor plan shall be binding.

ARTICLE 5 - MANAGEMENT'S RIGHTS

5.1 Subject to the terms and conditions of this Agreement, the Contractor has the undisputed right to operate and manage his business in all respects.

5.2 Without restricting the generality of the foregoing, it is agreed that it is the sole and exclusive function of the Contractor:

5.2.1 To determine the methods, procedures, materials, apparatus, and equipment to be utilized in the undertaking of the work; to schedule and assign the work; to direct the workforces; to determine the number of personnel required and when overtime will be worked, and by whom;

5.2.2 To hire, promote, demote, transfer, suspend, layoff, discipline, or discharge for just cause;

5.2.3 To make, enforce and revise from time to time rules and regulations to be observed by employees;

5.2.4 To select and appoint Foremen and General Foremen. Furthermore, subject to the Appendices, to make determinations as to the number of Foremen and General Foremen to be employed.

5.3 The foregoing enumeration of management’s rights shall not be deemed to exclude other functions not specifically set forth. The Contractor, therefore, retains all of its inherent rights, powers, and authority to manage its business except to the extent abridged by a specific provision of this Agreement.

ARTICLE 6 - ASSOCIATION, COUNCIL AND UNION REPRESENTATIVES

6.1 The Association shall appoint a resident Site Representative who will be vested with full authority and power to service members of the Association and administer the application of the terms of this Agreement. The Council agrees to recognize said Representative.

6.2 The Council shall appoint a resident Site Representative who will be vested with full authority and power to service members of the Unions, administer the application of the terms of this Agreement and assist the Association in the implementation of employee oriented programs. The Association agrees to recognize said Representative.

6.3 The Union, where Members of that Union are employed by a Contractor, may appoint a steward(s) from among the Members so employed.

6.3.1 A non working steward will not be permitted.

6.3.2 The union may appoint one (1) steward for each trade (Appendix) per shift for each Contractor (the shift steward), and notification of such appointment shall be provided at the time and under the conditions set out in Article 6.3.3. If work is being performed in more than one (1) separate and distinct work area, the Union may appoint one (1) additional steward (the area steward). If the union appoints more than one (1) steward, the Union shall designate one (1) of the stewards, so appointed, as the Chief Steward and notification of such appointment shall be provided at the time and under the conditions set out in Article 6.3.3.

6.3.3 The Council or the Local Union shall notify the Contractor and the Site Representative of the Association, in writing, within forty eight (48) hours (excluding non working days) of the appointment of any Steward or when an employee ceases to act as Steward.

6.3.4 The Contractor shall recognize that the Steward is acting for those Union Members employed by that Contractor. The Steward shall not be discriminated against for expressing the wishes of such employees however the Steward shall not involve himself or interfere with employees of other Contractors during working hours. The Steward may be called upon by the Contractor to assist in the settlement of grievances pursuant to the provisions of Article 8 of this Agreement.

6.3.5 The Chief Steward provided he is job qualified within the meaning of Article 12, and he is willing to perform the remaining work, shall be one of the last two (2) employees in his Appendix to be laid off. If reclassification is necessary to meet this requirement, the Contractor will determine the Chief Steward's new classification.

6.3.6 A shift steward provided he is job qualified within the meaning of Article 12, and he is willing to perform the remaining work, shall be one of the last four (4) employees in his respective classification on that shift to be laid off. An area steward provided he is job qualified within the meaning of Article 12, and he is willing to perform the remaining work, shall be one of the last four (4) employees in his respective classification in his work area to be laid off.

6.4 In addition to the Site Representative of the Council, other duly authorized Local Union representatives, carrying a properly authorized credential of the Council will be allowed access to the Project Site to conduct Union Business, provided this is done without interfering with the progress of the work and that permission has first been obtained as follows:

6.4.1 With the exception of emergencies, the Local Union Representative will notify the Council at least five (5) working days prior to the date of his intended visit. Upon receipt of this notification the Council will immediately inform the Association.

6.4.2 The Council and Association will notify their respective Site Representatives as to the date the Local Union representative wishes to visit the Site.

6.4.3 If the timing of the planned visit by the Local Union Representative is such that accommodations are not available, the Site Representatives will inform their respective officers and suggest an alternate date for the visit.

6.4.4 Arrangements to visit the Project site should be confirmed by the local union with the Council within twenty four hours of the notice referred to in 6.4.1.

6.4.5 The Site Representatives will inform all parties who may be involved when the Local Union representative is to be at Site.

6.4.6 Where possible, the Site Representatives from the Council and Association shall be present at any discussions between the Local Union representative and the Contractor relating to this Agreement.

ARTICLE 7 - STRIKES AND LOCKOUTS

7.1 Neither the Council, nor any representative of the Council or of the Unions, nor any Union, nor any member of the Unions, nor any employee covered by this Agreement shall in any way, either directly or indirectly, authorize, encourage, condone, support or participate in any strike, walkout, suspension of work, slowdown or work stoppage of any kind on the part of any employee or group of employees during the term of this Agreement.

7.2 The Association, representatives of the Association, the Contractor, representatives of the Contractor not otherwise covered by this Agreement, shall not in any way cause or direct any lockout of employees during the term of this Agreement.

7.3 The Council and the Unions shall not authorize, encourage or condone any picketing on the Project. Employees covered by the Agreement shall not picket Contractors signatory to this Agreement where such Contractors are engaged on work covered by this Agreement.

7.4 If any violation of Article 7.1 occurs, every effort shall be made by the Council and the Unions to achieve immediate full compliance with Article 7.1. Such action by the Council and the Unions shall include instructing such employees to cease the prohibited activities and immediately return to work, if work has ceased, and perform their usual duties and resort to the grievance procedure for the settlement of any complaint. The Council shall immediately advise the Association of the specific steps it has taken in this regard.

7.5 An employee who engages in any of the prohibited activities set out in this Article shall be subject to dismissal or other disciplinary action. Furthermore, if such an employee does not heed the instructions from the Council and Local Union to return to work and perform his usual duties he may as a consequence be dismissed, and in this event, he shall not be eligible for hire or rehire under this Agreement for a period of two (2) years, and his dismissal shall be deemed to be a dismissal for just cause.

7.6 The fact that the Council and/or a Union investigates or deals with an alleged violation of Article 7.1 shall not be deemed to be an acknowledgement by the Council and/or a Union that Article 7.1 has been violated.

7.7 If any violation of Article 7.2 occurs, every effort shall be made by the Association and the Contractor to achieve immediate full compliance with Article 7.2.

7.8 The fact that the Association and/or a Contractor investigates or deals with an alleged violation of Article 7.2 shall not be deemed to be an acknowledgement by the Association and/or a Contractor that Article 7.2 has been violated.

ARTICLE 8 – GRIEVANCE PROCEDURE

8.1 A grievance shall mean any difference or dispute concerning the interpretation, application, administration, or alleged violation of the Agreement. The Council and the Association shall each have the right to initiate a grievance, in relation to the aforementioned matters, at Stage 2.

8.1.1 Notwithstanding the provisions of 8.1, a jurisdictional dispute shall not be processed or settled by the grievance procedures and such disputes shall be solely dealt with pursuant to the provisions of Article 4.

8.1.2 If a Management grievance is filed, the provisions of Article 8.3.1.2 (Stage 2) shall be applied except that the procedures shall be read so that the Association (and/or its members, as stipulated in the grievance document) shall be deemed the initiator of the grievance and the Council (and/or its members, as stipulated in the grievance document) the respondent.

8.2 A grievance shall be initiated within five (5) working days of the date the circumstances giving rise to the grievance were known or ought to have been known. The time limits and procedures set out in this Article shall be complied with provided, however, the Parties may mutually agree, in writing, to extend the time limits. Where no reply is given within the time limit specified in this Article, the Council or the Association, as the case may be, will be entitled to submit the grievance to the next step of the grievance procedure. Any grievance not processed within the applicable time limits shall be deemed to have been abandoned and will be ineligible for arbitration.

8.3 Grievances properly arising under this Agreement shall be processed in the following manner:

8.3.1 Grievance

8.3.1.1 Stage One

Steps

Steps 1 and 2 below shall be completed within four (4) working days of the date Step 1 is commenced.

1. The aggrieved employee(s) will discuss his grievance with his foreman or immediate supervisor with or without his steward, in his discretion, to try and resolve the matter.

2. If the grievance is not resolved at Step 1, it shall be reduced to writing, utilizing the Councils' grievance form, and the written grievance will be submitted to the Site Representative of the Council. The grievance will indicate the relevant grievance particulars, alleged Agreement violations, remedies sought on behalf of the employee, and be signed and dated by the employee or Union Representative.

3. The Site Representative of the Council may submit the written grievance to the appropriate Contractor Representative provided this is done within a further period of three (3) working days. In this event, the Site Representative of the Council shall simultaneously submit a copy of the grievance to the Site Representative of the Association.

8.3.1.2 Stage Two

Steps

1. On receipt of the written grievance, the Contractor will investigate the grievance, meet with the Council Representative, and respond to the grievance in writing. Step 1 must be completed within four (4) working days from the time the grievance is received by the Contractor.

2. If agreement is not reached at Step 1, the Council Site Representative may submit the written grievance to the Association site Representative, provided this occurs within a further period of twenty-four (24) hours measured from the expiry of the four (4) working day period in Step 1 above.

3. On receipt of the written grievance, the Site Representative of the Association and the Council shall meet to further review the grievance details for purposes of settling the grievance. The Site Representatives may involve other persons in this process who have knowledge of the circumstances giving rise to the grievance. The Site Representative of the Association shall reply, in writing, to the Site Representative of the Council. Step 3 shall be completed in four (4) working days of the expiry of the 24 hour period in Step 2 above.

4. If settlement is not reached at Step 3, the President of the Council or his delegate or the Managing Director of the Association or his delegate may submit the grievance to Stage Three, provided this is done in writing, within a further ten (10) working days from the expiry of the four (4) working day period in Step 3 above.

8.3.1.3 Stage Three

Steps

1. Following receipt of the written notification to proceed to Stage Three, the President of the Council or his delegate (hereinafter referred to as the President) and the Managing Director of the Association or his delegate (hereinafter referred to as the Managing Director) shall meet for the purpose of settling the grievance. The President and Managing Director may each, in their sole discretion, opt to have a Union Representative or a Contractor Representative, respectively, in attendance at the meeting, who will act in an advisory capacity. Additionally, other persons may be requested to give evidence of the circumstances giving rise to the grievance. This meeting shall be held within six (6) working days from the date written notification is received to proceed to Stage Three. The Managing Director will reply in writing to the President within three (3) working days from the date of the meeting (in the case of a Management Grievance, the President will reply to the Managing Director).

2. If the grievance is not settled, either Party may process the grievance to Stage Four provided this is done within a further twenty (20) working days from the date of the meeting held under Step 1. In this instance each party will communicate to the other, in writing, whether legal counsel will be utilized.

8.3.2 Grievances Regarding Alleged Wrongful Dismissal

8.3.2.1 Notwithstanding the foregoing, grievances alleging wrongful dismissal of an employee or employees shall be dealt with as follows:

Steps

1. The grievance shall be initiated in writing under Stage Two by the employee or employees concerned or by a duly authorized representative of the Council at the job site within twenty four (24) hours of dismissal. The employee may be assisted by his Union Shop Steward.

2. Following receipt by the Contractor of the written grievance, the Contractor's Representative and the Council Representative shall meet and may involve other persons to give evidence of the incident as required for the purpose of settling the grievance.

3. The Contractor shall reply in writing to the Council's Representative within twenty four (24) hours of receipt of the written grievance.

4. If agreement is not reached at Step 2 above, the Site Representative of the Council may submit the grievance within a further twelve (12) hours following expiration of the twenty four (24) hours to the Site Representative of the Association.

5. Following receipt of this written grievance by the Site Representative of the Association, the Site Representative of the Association and of the Council shall meet and may involve other persons to give evidence of the incident as required for the purpose of settling the grievance. These meetings will normally be held in the office of either Site Representative. The Site Representatives have two (2) working days to resolve the grievance.

6. The Site Representative of the Association shall reply in writing to the Site Representative of the Council within the two (2) working days of Step 5 above.

7. From this point onwards, grievances alleging wrongful dismissal shall be dealt with in the same manner as other grievances under this Article save that, in the event a claim is entered for compensation for loss of wages in a case where reinstatement has resulted, it shall be left with the Council and Association to decide the amount, if any, to be paid and failing agreement the claim shall be referred for settlement by arbitration in accordance with the procedure at Stage Four.

8.3.2.2 If a grievance alleging wrongful dismissal is not submitted within the specified time set out in Step 1 above, the employee's employment shall be deemed to have been terminated when he was dismissed and such dismissal shall not be the subject of a grievance.

8.3.2.3 When an employee has been discharged and a grievance has been filed, the Contractor will continue to provide room and board at no charge to the employee until the completion of step three (3) above and transportation is available in accordance with Article 19.1.4.

8.3.3 Stage Four Applicable for All Grievances

8.3.3.1 For the purpose of Stage Four the President of the Council or his delegate and the Managing Director of the Association or his delegate shall agree upon a list of approved arbitrators, which may be amended from time to time. If agreement cannot be reached on an amended list of arbitrators, the Minister of Labour of the Province of Manitoba shall be asked to appoint an arbitrator(s).

An approved arbitrator shall be assigned to a Stage 4 grievance by the following procedure: the President of the Council or his delegate and the Managing Director of the Association or his delegate shall meet. The names of all approved arbitrators from the agreed list shall be placed into a container, and one name picked, completely at random. The arbitrator shall hear the grievance, deliberate, render his award and serve it upon the parties within thirty (30) working days following the conclusion of the hearing. The arbitrator shall have the authority given to a Board of Arbitration and his decision shall be binding and final upon the Parties hereto. If the arbitrator does not serve the award upon the parties within the said thirty (30) working days, either party may request the Minister of Labour of the Province of Manitoba to consult with both the parties and the arbitrator for the purpose of expediting the settlement of the grievance.

8.3.3.2 Under no circumstances shall the arbitrator have the authority to extend, modify or amend any part of this Agreement in any respect. An arbitrator appointed under this Article shall not be authorized to adjudicate on any matter which comes within the jurisdiction of the Joint Appendix Review Committee and/or the Mediator referred to in Article 31.

8.3.3.3 The expenses of the arbitrator and the arbitration proceedings shall be shared equally by the member Union of the Council, and Contractor, save that each shall pay all expenses incurred in connection with preparation and presentation of their submission.

ARTICLE 9 - ROOM AND BOARD

9.1 An employee of the Contractor shall have the option of receiving room and board in the camp or alternatively of providing his own housing.

9.2 When an employee opts to provide his own housing, the Contractor shall provide the employee with an allowance in the amount and under the conditions set out in Article 10.

9.3 Room and board in the camp shall consist of the provision of lodging and up to three meals per day. There will be no charge to the employee for this room and board under the following conditions:

a) When the employee is working;

b) When the employee is available for work and work is cancelled due to inclement weather;

c) On the employee's scheduled day(s) of rest;

d) On Holidays, as set out in Article 17, providing the employee works the complete shift on his working day immediately preceding and immediately following such a holiday, except where the employee is exempted by virtue of provision (e) below;

e) On days when the employee is sick or when the employee sustains an injury on the job, to a maximum of seven calendar days, provided the employee remains in the locale of the Project and:

i) Advises the appropriate authority of the Contractor at the onset of any absence due to illness or injury, and;

ii) Presents to the Contractor a dated medical certificate from a medical doctor or nurse authorizing the absence from work immediately on return to work.

9.4 When an employee is absent from work for reasons other than that stipulated in 9.3 (b), (c) and (d) or where the requirements of provision 9.3 (e) have not been fulfilled, he will be assessed a payroll deduction of fifteen dollars ($15.00) per day for the period of the absence.

9.5 When an employee leaves the Project site under a leave granted under Article 19, he must obtain a check out slip from the Camp Operator, otherwise he will be assessed a payroll deduction equal to the amount set out in Article 9.4 for the period of his absence.

9.6 To secure room and board in the camp, an employee must

a) Have on his person, for presentation, the identification issued to the employee by the Contractor;

b) Report to the designated office of the Camp Operator for the purpose of registration, room allocation and the issuance of a key. A deposit of five dollars ($5.00) will be required for a room key which will be refunded to the employee upon return of the key at the time of check out;

c) Report to the designated office of the Catering Contractor for the issuance of bedding.

9.7 Employees may purchase a fourth meal at a reasonable cost, to be set by the Camp Operator.

9.8 An employee required to work twelve (l2) hours or more in any one (1) day will be provided with a meal allowance by the Contractor. The value of this meal allowance shall be equivalent to the current cost of a casual meal established from time to time by the Camp Operator.

9.9 Council and Union Representatives who are on official business pertaining to the Project may purchase accommodation and meals from the camp office at a cost to be set by the Camp Operator.

9.10 If an employee residing in the camp is absent from the Project Site for a period longer than a leave granted under Article 19, the Contractor shall remove the employee's personal effects from his room and forward same collect to his last known address.

9.11 All employees shall read and comply with all Camp Rules and Regulations. A copy of the Camp Rules and Regulations will normally be issued to each employee at the time of registration, but in any event a copy will be posted on bulletin boards located within the camp complex.

9.12 In instances where a camp is not to be established and the option of room and board is to be provided in commercial facilities, such as a hotel, the Association shall consult with Manitoba Hydro and advise the Council, in advance of the contract award, of the arrangements for provision of room and board.

ARTICLE 10 - HOUSING ALLOWANCE

10.1 When an employee opts to provide his own housing, the Contractor shall provide the employee with an allowance of fifteen dollars ($15.00) per calendar day.

10.2 The conditions under which this allowance will be paid are the same as those set in Article 9.3 except in the case of provision (e) which will be subject to a further condition in that the allowance will only be paid to a maximum of three (3) calendar days from the date of the onset of any illness or injury.

10.3 An employee supplying his own housing may obtain meals at the camp at a cost to be set by the Camp Operator.

10.4 When an employee providing his own housing elects to move into the camp, this allowance shall be discontinued effective on the date a room is issued by the Camp Operator.

ARTICLE 11 - MEDICAL EXAMINATIONS

11.1 A pre employment medical examination, which shall be at the expense of the Contractor, shall be required for employees of the Caterer who are directly involved in the preparation and handling of food. This examination will normally be given by a physician designated by the Contractor, prior to the employee reporting to the Project Site.

ARTICLE 12 - THE HIRING PROCEDURE AND REFERRAL SYSTEM: UNION SECURITY & CHECK OFF: TRANSFER; LAY-OFF AND RECALL PROVISIONS

*** Note – See Letter of Agreement #40, for additional information regarding Article 12, Section 12.1 (Amendment to Hiring procedure for out of Province union referrals)
*** Note – See Letter of Agreement #44, for additional information regarding Article 12 (Special measures for hiring apprentices and trainees)
*** Note – See Letter of Agreement #48, for additional information regarding Article 12, Section 12.4 (Layoff Subject to Recall)

12.1 The Hiring Procedure and Referral System.

12.1.1 For the purposes of this Article, "job qualified" means that a candidate for employment meets or exceeds the training, accreditation, skill, and experience stipulated in a Contractor's job order. All employees shall be recruited in accordance with the procedures set out below, except as otherwise provided for in Article 12.3, 12.4.2, and Article 2.7, and Article 2.9. Further, it is understood and agreed that Contractors shall have the right to name hire all foremen and general foremen from the referral list prepared by Manitoba Advanced Education and Training (M.A.E.T) or the Unions Out-Of-Work lists, as applicable. The Contractor has the right to reject any candidate referred in accordance with this Article: a) if the candidate is not job qualified, or b) if the candidate was previously employed on the Project and resigned within 30 calendar days of being hired or re-hired or was discharged during the twelve month period preceding the job order, or c) the candidate was previously employed on the Project and received more than two written warnings or a suspension for inappropriate workplace-related conduct or activities, or d) on any other reasonable ground. The Council shall have the right to grieve the decision of a Contractor to reject any candidate referred in accordance with this Article only to the extent of and for the reason of claiming that a rejected referred candidate actually did meet the required qualifications specified in the job order.

12.1.1.1 The Contractor or his agent shall first contact a designated office of M.A.E.T. and advise M.A.E.T. of his specific requirements by placing a job order.

12.1.1.2 M.A.E.T. shall immediately forward a copy of the job order to the Council, as information. The Council shall inform the applicable Local Unions.

12.1.1.3 Except as otherwise provided by Article 12.1.1.3.1., on receipt of the Contractor's job order, M.A.E.T. shall refer, directly to the Contractor, in the sequence set out below, any of the following job qualified candidates who are registered with M.A.E.T.:

a) Northern Aboriginals who reside within the Churchill/Burntwood/ Nelson River area, which area shall be defined as: i) the area of the Churchill River Water Power Reserve from Granville Lake downstream to Hudson Bay; ii) the area of the Burntwood River Water Power Reserve from South Indian Lake downstream to Split Lake; iii) the area of the Nelson River Water Power Reserve from the outlet of Lake Winnipeg downstream to Hudson Bay; and iv) the following communities: the incorporated community of South Indian Lake; the Northern Affairs communities of Granville Lake, Nelson House, Ilford, Wabowden, Thicket Portage, Pikwitonei, Norway House and Cross Lake; the towns of Leaf Rapids, Churchill, and Gillam; the City of Thompson; and Nisichawayasihk Cree Nation, Tataskweyak Cree Nation, York Factory First Nation, Fox Lake First Nation, War Lake First Nation, Norway House Cree Nation and Cross Lake First Nation (See Schedule D for illustration of Burntwood/Nelson/ Churchill River area and communities included).;

b) Secondly, if job vacancies remain, any Northern Residents who are members of the appropriate Local Union of the Council and are not covered by a) above;

c) Thirdly, if job vacancies remain, any other Northern Aboriginals who are not covered by a) or b) above;

d) Fourthly, if job vacancies remain, any other Northern Residents who are not covered by a), b), or c) above.

The definitions of a Northern Aboriginal and Northern Resident are set out in Articles 13.1 and 13.2.

Administrative details concerning Union membership are set out in Article 12.1.4.

12.1.1.3.1 A Northern Aboriginal who:

a) Has been employed on the Project as a trainee or apprentice and such training was interrupted due to a lay-off, and;

b) Has performed on the job in a satisfactory manner and;

c) Is registered with M.A.E.T.

Shall be referred by M.A.E.T. to a Contractor, in advance of any other Northern Residents who have not worked on the Project, to fill training vacancies in that trade as they may arise from time to time.

To facilitate the foregoing, a Contractor will advise M.A.E.T. and the Council, in writing, of the name and social insurance number of any Northern Aboriginal employed as an apprentice or trainee who has been laid off and is eligible for rehire in the trade in which he was training. Such notification shall be provided within ten (10) days of the date of the lay-off.

12.1.1.3.2 To qualify for the employment preference set out in Article 12.1.1.3, candidates must meet the eligibility requirements set out in Article 13, and M.A.E.T. shall be solely responsible for determining whether or not candidates so qualify. However, at the request of M.A.E.T., the Association and the Council will provide joint guidance to M.A.E.T. relative to the application of Article 13.

12.1.1.3.3 Subject to 12.1.2, M.A.E.T. shall have up to forty-eight (48) hours, measured from the time the job order is received, in which to refer Northern Aboriginals and other Northern Residents to the Contractor. The Contractor shall have as much time as he deems appropriate to assess the said referred candidates, and shall advise M.A.E.T., forthwith, if a candidate or candidates so referred are not hired, leaving job vacancies remaining to be filled.

12.1.1.3.4 Candidates so referred, if hired by the Contractor, shall obtain a referral slip issued by M.A.E.T. and report to the Project Site:

a) as soon as possible, but in any event within a period of seventy two (72) hours measured from the time the person is hired, when the Contractor stipulates that his requirements are immediate;

or

b) on the date stipulated by the Contractor when the Contractor stipulates a reporting time in excess of

the maximum provided for in (a) immediately above.

12.1.1.3.5 If a Northern Aboriginal or other Northern Resident does not report to the Project Site as per Article 12.1.1.3.4(a) or 12.1.1.3.4(b), as the case may be, then, if there are no further Northern Aboriginal or Northern Resident candidates on M.A.E.T.'s referral list, the Contractor shall advise M.A.E.T. to proceed to the next step of the hiring procedure (i.e., 12.1.1.4). If there are further Northern Aboriginal or Northern Resident candidates on M.A.E.T's referral list who were not considered by the Contractor then the Contractor shall proceed to consider further candidates in the order of the list provided by M.A.E.T., and a second candidate, if hired by the Contractor, shall obtain a referral slip issued by M.A.E.T. and report to the Project Site as stipulated in Article 12.1.1.3.4. If the said second candidate does not report to the Project Site as per Article 12.1.1.3.4(a) or 12.1.1.3.4(b), as the case may be, then the Contractor shall advise M.A.E.T. to proceed to the next step of the hiring procedure (i.e. 12.1.1.4).

12.1.1.4 If M.A.E.T. is unable to refer a sufficient number of job qualified Northern Aboriginals and other Northern Residents to fulfil the Contractors requirements within said forty-eight (48) hours outlined in 12.1.1.3.3, M.A.E.T. shall, prior to, or at the expiry of the time limit on behalf of the Contractor, advise the Council and the applicable Local Union of the job vacancies remaining to be filled. Moreover, if the Contractor has advised M.A.E.T. under Article 12.1.1.3.3 that referred candidates have not been hired, leaving job vacancies remaining to be filled, M.A.E.T. shall immediately advise the Council and the applicable local union accordingly.

12.1.1.5 The Union, on notification of such job vacancies, may then refer job qualified persons to the Contractor through a designated office of M.A.E.T.

12.1.1.5.1 The Union shall have up to forty-eight (48) hours, measured from the time the Council and Local Union is notified in accordance with 12.1.1.4, in which to refer persons to the Contractor.

12.1.1.5.2 Persons so referred, if hired by the Contractor, shall obtain a referral slip issued by M.A.E.T. and report to the Project Site:

a) As soon as possible, but in any event within a period of seventy two (72) hours measured from the time the person is hired, when the Contractor stipulates that his requirements are immediate;

or

b) On the date stipulated by the Contractor when that date is subsequent to the maximum time period provided for in (a) immediately above.

12.1.1.6 If the Union is unable to refer a sufficient number of job qualified persons to fulfill the Contractor's requirement within the said forty-eight (48) hours, the Union shall prior to, or at the expiry of, the time limit, advise M.A.E.T. of the job order vacancies remaining to be filled. M.A.E.T. shall have an additional forty eight (48) hours, measured from the time M.A.E.T. is notified of the vacancy, in which to refer other job qualified Manitoba Residents to the Contractor.

12.1.1.6.1 Persons hired by the Contractor shall report to the Project Site as provided for in Article 12.1.1.5.2 (a) or (b).

12.1.1.7 The Contractor may recruit persons to fill job order vacancies where:

a) Job order vacancies remain after following the procedures set out in Article 12.1.1.1 to 12.1.1.6;

or

b) Persons referred pursuant to Article 12.1.1.5 and Article 12.1.1.6 do not report to the Project Site within the stipulated time period.

12.1.1.7.1 All persons hired in this manner shall obtain a referral slip issued by M.A.E.T., which referral slip shall be secured prior to commencing work.

12.1.1.8 In the event the Contractor cannot recruit the necessary personnel within a further thirty (30) day period, the Contractor shall reinitiate the job order in accordance with Article 12.1.1 to fill any remaining vacancies.

12.1.2 The time periods referred to in 12.1.1.3.3, 12.1.1.5.1 and 12.1.1.6 are exclusive of Saturday, Sunday, Statutory Holidays and Civic Holidays on which M.A.E.T. offices are closed.

12.1.3 The Contractor shall submit the names of all newly hired employees to the Council within three (3) working days.

12.1.4 In Article 12.1.1.3(b), the appropriate Local Union means the Union named in the Appendix containing the classification corresponding to the Contractor's job order.

For purposes of Article 12.1.1.3(b), each Local Union shall compile and submit to the Council the names and social insurance numbers of all Northern Residents who are members of that Union and who are seeking employment on the Project. The Council shall submit the current listing for the applicable Unions to M.A.E.T. by the tenth (10th) of each month. By mutual agreement between M.A.E.T. and the Council, arrangements differing from the foregoing may be instituted to ensure that the necessary information is available on a timely basis.

12.2 Union Security and Check off

12.2.1 Except as provided in Letter of Agreement No. 3, all employees shall, as a condition of employment and/or continuing employment, be members or obtain membership in the appropriate Union of the Council, and maintain such membership in good standing.

12.2.2 The Contractor shall, at the time of hire, advise all employees who are not members of the appropriate Union that they are required to secure such membership within thirty (30) calendar days of being hired.

12.2.3 To facilitate the obtaining of membership, employees shall sign the "Check off Authorization" form, a copy of which is attached as Schedule B of this Agreement.

12.2.4 The Council shall be responsible for:

a) Obtaining the employee's written authorization for membership in the appropriate Union;

b) Obtaining the employee's signature in respect of the Check off Authorization;

c) Submitting an executed copy of the Check off Authorization to the Contractor, which shall detail the arrangements made with the employee in respect of payment of any initiation fees.

12.2.5 The assignment of Union initiation fees, assessments and dues, and the per capita tax of the Council shall be irrevocable during the term of this Agreement.

12.2.6 Union dues and Council assessments shall be effective from the date of hire.

12.2.7 The Contractor shall make deductions from wages in respect of:

a) Union dues and assessments due to the appropriate Union;

b) Assessments due to the Council which shall be consistent with its Constitution and By Laws;

c) Initiation fees: the arrangements for the deduction of initiation fees shall be that stipulated in the Check off Authorization, but subject to the option referred to in 12.2.13 which is available to certain Trainees and Northern Residents, and the provisions set out in Article 2.9.

12.2.8 During the second week of each month, the Contractor shall transmit the monies deducted from employees up to the end of the preceding pay period. Union dues, assessments and initiation fees shall be forwarded to the officials designated by each Union. Council assessments shall be forwarded to the designated official of the Council.

12.2.9 Monies forwarded to each Union shall be accompanied by documentation, which shall state:

a) The name of the employee on whose behalf the deduction was made;

b) The individual amounts deducted in respect of dues, assessments and/or initiation fees.

12.2.10 Monies forwarded to the Council shall be accompanied by a list of employees, segregated on a trade basis, stating the amount deducted from each employee in respect of Council assessment and the Social Insurance Number.

12.2.11 The aforementioned deductions shall be consistent with Schedule C of this Agreement. The Council shall advise the Contractor and the Association, in writing, of any changes to applicable dues, assessments and initiation fees. This notification shall be provided at least fifteen (15) working days prior to the requested implementation date of any such change, otherwise the changes will be deemed to be effective for the pay period immediately following the date notification is received.

12.2.12 Where a training program is conducted on the Project Site, the following definitions shall apply in respect of this Agreement:

a) A person involved in an "on the job training program" shall be deemed to be an employee on the first day he is on the payroll of the Contractor;

b) A trainee, other than a trainee employed by a Contractor, who is participating in a training program on the Project which is operated and sponsored by the Government of Canada or the Manitoba Government or a department or agency of either, shall be deemed not to be an employee.

12.2.13 A trainee, as referred to in 12.2.l2 (b), who is subsequently hired by a Contractor, or a Northern Resident (other than a Northern Aboriginal who is covered under Article 2.9), shall have the option of paying the required initiation fees on the following basis, provided such employees have not previously been members of a Union covered by this Agreement:

a) In accordance with the arrangements extended to other employees;

or

b) At the employee's request, the Check off Authorization shall reflect the following schedule of deductions:

i) Where the initiation fee is one hundred dollars ($100.00) or less the appropriate amount shall be deducted from the employee's pay on the first full pay period following the acquiring of membership in the Union;

ii) Where the initiation fees are in excess of one hundred dollars ($100.00), an amount of one hundred dollars ($100.00) shall be deducted from the employee's pay on the first full pay period following the acquiring of membership in the Union and the applicable remaining amount in four equal installments on subsequent full pay periods.

12.3 Transfer Provision

12.3.1 A Contractor who is signatory to a construction collective agreement may request that certain persons in the employ of that Contractor be transferred to a Project covered by this Agreement. This provision shall only apply for purposes of securing:

a) Supervisory personnel covered by this Agreement;

b) Personnel with skills of a specialized nature;

c) Personnel with skills necessary for the effective operation of a Contractor's on the job training program;

d) Key personnel required for work on contracts of short duration and in which the craft or skills required to perform the work are generally limited to one or two trades.

12.3.2 A request for a transfer must be submitted to the Council and the Association, in writing, at least five (5) working days in advance of the time the person is required on the Project.

12.3.3 The transfer request shall indicate the following:

a) The name, social insurance number and trade qualifications of the person to be transferred;

b) The Appendix in this Agreement under which the person to be transferred would be working, and the corresponding classification;

c) Related experience relative to 12.3.1 (a), (b) or (c), as the case may be.

12.3.4 The Council shall consult with representatives from the applicable Local Union and within three (3) working days from the date of receipt of the transfer request, the Contractor shall be advised of the respective positions of the Association and the Council; and,

i) if the Council and Association mutually agree that the transfer meets the provisions of this Article, then the Contractor may proceed with the transfer;

or

ii) if the Council and Association mutually agree that the transfer does not meet the provisions of this Article, then the Contractor will be obliged to follow the procedures set out in Article 12.1.1;

or

iii) if either the Council or the Association does not agree that the transfer is in accord with the provisions of this Article, then the Contractor may refer the matter to the President of the Council and the Managing Director of the Association, or their respective delegates, who shall meet and attempt to resolve same. If agreement cannot be reached, the Contractor may request that the matter be resolved in accordance with Article 31.

12.3.5 When a person is transferred, the Association shall notify M.A.E.T. of the name and classification.

12.4 Lay-off and Recall Provisions

12.4.1 Lay-Off

12.4.1.1 Subject to the provisions of Article 12.4.1.2, when a reduction in the Contractor's work force is to be instituted, the Contractor shall lay-off employees, by classification, as follows:

a) Firstly, employees who at the time of hire were not residents of the Province of Manitoba.;

b) Secondly, residents of the Province of Manitoba, other than the Manitoba residents set out in (c), (d), & (e) below;

c) Thirdly, Northern Residents, other than Northern Residents set out in (d) & (e) below;

d) Fourthly, Northern Aboriginals other than those Northern Aboriginals set out in (e) below;

e) Northern Aboriginals referenced in Article 12.1.1.3 a).

12.4.1.1.1 Where classifications in any Appendix have been grouped, either on a capacity basis or because they are subject to a common wage rate, each classification in the group shall be dealt with as a separate classification.

12.4.1.2 The order of lay-off set out in Article 12.4.1.1 shall be followed except:

a) when an employee to whom continuing employment preference is intended is not job qualified to perform the remaining work or whose overall skills, abilities, or work performance, in the judgment of the Contractor, compares less favourably to the overall skills, abilities, or work performance of others similarly employed;

b) When the progress and efficiency of the work would be significantly adversely impacted, the effects of which would not be short term, because of the resultant reallocation of employees to different work locations;

c) when an employee is hired in accordance with the provisions of Article 12.3, or when an employee is covered by the provisions of Article 6.3;

d) when the Contractor elects to retain the services of an employee who has been employed with the Contractor on the Project for more than twelve (12) months during the past eighteen (18) months, provided the retention of such an employee would not result in the lay-off of another employee who also has more than twelve (12) months of employment during the past eighteen (18) months and to whom employment preference is intended in accordance with Article 12.4.1.1.

12.4.2 Lay-Off Subject to Recall

12.4.2.1 The provisions in this Article may be used by the Contractor to facilitate the re employment of an employee whose lay-off has been precipitated by breakdowns, shortages of materials or parts, or changes in the construction schedule, scheduled or unscheduled cessation of work, or other like conditions, and there is a reasonable likelihood the employee will be re employed for purposes of continuing the work to which he was assigned at the time of lay-off.

12.4.2.2 Pursuant to 12.4.2.1 an employee who was a Manitoba Resident at the time of hire may be recalled for employment by the Contractor provided:

a) The employee is advised in writing at the time of lay-off that he is eligible for recall and a copy of this notification is concurrently forwarded to the appropriate Local Union and M.A.E.T. and;

b) The recall is initiated by the Contractor prior to the expiry of 120 calendar days measured from the date of lay-off.

12.4.2.3 When more than one employee in a particular classification (i.e. classifications as set out in the Appendices) is on lay-off subject to recall and,

a) Such employees are involved in a common or collective work assignment, and;

b) Such employees are not recalled on the same date.

Then the order of recall shall be the same as the order of employment preference set out in Article 12.1., except when all such employees are scheduled to be recalled within a period not exceeding twenty-eight (28) calendar days, from the date of the first recall, in which case recalls may occur on a non-preferential basis.

12.4.2.4 To initiate the recall mechanism, the Contractor shall contact M.A.E.T. and provide the name, address and telephone number of the person to be recalled.

12.4.2.5 M.A.E.T. shall contact the person and notify the appropriate Local Union and the Council that this person is to be re employed.

ARTICLE 13 - NORTHERN RESIDENTS AND NORTHERN ABORIGINALS

13.1 When the term Northern Aboriginal is used in this Agreement, it shall mean status Indians, Métis, non-status Indians, and Inuit who qualify as Northern Residents in accordance with the definition set out in Article 13.2.

13.2 For purposes of this Agreement and subject to the provisions set out below, a person shall be deemed to be a Northern Resident if the person has resided in that part of Manitoba north of the Boundary as set out in Schedule D for:

a) A period of five (5) years accumulatively, or more;

and

b) A period of six (6) consecutive months, or more, immediately prior to being referred to employment or re employment without being absent during that six (6) month period from the employment preference zone for more than six (6) weeks accumulatively, except as may be provided for in Article 13.5, 13.6, and 13.7.

13.3 Time spent in employment on the Project shall not be counted towards the acquiring of Northern Residency status pursuant to the provisions of Article 13.2.

13.4 A Northern Resident who is absent from the employment preference zone, referred to in Article 13.2, for a period not exceeding six (6) weeks accumulatively, during the six (6) month period immediately prior to referral for employment shall continue to be considered a Northern Resident.

13.5 A person who is absent from the employment preference zone for a period of more than six (6) weeks accumulatively, during the six (6) month period immediately prior to referral for employment, for purposes of receiving medical treatment or for purposes of attending a recognized educational institution, and except for such absence would otherwise qualify as a Northern Resident, shall continue to be considered a Northern Resident.

13.6 A person who; a) qualified as a Northern Resident, was employed on the Project as an apprentice and was laid off, and b) for the purposes of employment and/or training related to that apprenticeship was absent from the employment preference zone for a period not exceeding 180 (one-hundred & eighty) calendar days measured from the date of lay-off and c) except for b) above would otherwise have qualified as a Northern Resident and d) is a member in good standing of the applicable local union (this will require union confirmation if that person's name does not appear on the monthly union listing), shall continue to be eligible for Northern Residency employment preference for purposes of re-employment as an apprentice in the trade in which that person was formerly employed.

13.7 A person who qualified as a Northern Aboriginal and successfully completed a recognized Pre-Project Training program sponsored by Manitoba, Canada, and/or Manitoba Hydro, and who left the employment preference zone for a period not exceeding ninety (90) calendar days in order to gain relevant work experience, shall continue to be considered a Northern Aboriginal.

13.8 A person who attends a designated office of M.A.E.T. for purposes of registering for possible referral to employment on the Project, and who considers himself to be a Northern Aboriginal or Northern Resident as defined in this Agreement, shall, on request of M.A.E.T., provide reasonable proof of having met the requirements.

ARTICLE 14 - PAYMENT OF WAGES

14.1 Wages shall be paid either weekly or biweekly, by cheque or direct deposit.

14.2 Where the Contractor elects to pay on a weekly basis, wages shall be paid every Thursday, during working hours, and shall include all wages earned up to and including the previous Friday.

14.3 Where the Contractor elects to pay on a biweekly basis, wages shall be paid every second Thursday, during working hours, and shall include all wages earned up to and including the previous Friday.

14.4 Contractors shall advise the Association and the Council, prior to the commencement of work, if paydays will be implemented weekly or biweekly. In either case, the practice adopted by a Contractor shall apply to all his employees.

14.5 An employee shall be provided with a dated statement of earnings, itemized deductions, and hours worked, when wages are paid.

14.6 A new or rehired employee, after working six (6) days on the Project Site, shall be given an advance of one hundred dollars ($100.00) provided the employee has requested this at the time of arrival on Site.

ARTICLE 15 - HOURS OF WORK AND COFFEE BREAKS

*** Note – See Letter of Agreement #2, for additional information regarding Article 15.1
*** Note – See Letter of Agreement #37, for additional information regarding Article 15.1
*** Note – See Letter of Agreement #55, for additional information regarding Article 15.5 (Work Breaks)

15.1 Except as provided in Appendix 1a, due to the nature of the Project, employees will normally be required, if directed, to work up to ten (10) hours per day for six (6) days per week. Unless otherwise provided in the Appendices, Sunday will normally be a day of rest.

15.2 Compensation for hours worked shall be in accordance with the provisions of the Appendices, except as follows: when an employee misses a regular shift or portion thereof during the period Monday to Friday (or the first to the fifth working day, as the case may be) of that work week, and such absence was unauthorized [e.g. not on a leave of absence, Isolation Leave, vacation, or not covered by the provisions of Article 9.3 (e)],then that employee will be paid at the straight time rate on Saturday (or the sixth working day) until he has worked, pursuant to the applicable Appendix, the prescribed hours of work at straight time that were available to be worked in the work week.

15.3 The hours of work per day and the number of days of work per week, as set out in the Appendices are not guaranteed

15.4 Employees shall be at their places of work at regular starting times and shall remain working until regular quitting time, unless otherwise directed by the Contractor.

15.5 An employee shall be provided two (2) coffee breaks per shift, once in the first half of the shift and once in the second half of the shift, each of which shall not exceed ten (10) minutes in duration. The specific timing of coffee breaks shall be determined by the Contractor. Such breaks shall be taken at the employee's work station, except where the Contractor determines that working conditions makes this impractical in which case the Contractor will designate an alternate location.

15.6 An employee will be provided an unpaid lunch break during the shift, which shall not be less than forty-five (45) minutes in duration. The timing and duration of the lunch break will be designated by the Contractor.

ARTICLE 16 - REPORTING TIME

16.1 When an employee takes his tools on the job and reports to the Contractor for the first time after being hired and is refused work for reasons other than inclement weather or the result thereof, or any other reason beyond the control of the Contractor, he shall be paid for the hours remaining in the shift, for which he initially reports, up to a maximum of four (4) hours at his straight time rate.

16.2 Every employee shall be advised of his marshalling point on the Project. If an employee's marshalling point is to be changed by the Contractor, he shall be advised before quitting time on the preceding shift.

16.3 When an employee is notified at the marshalling point, designated by the Contractor, that no work is available on that day, the employee shall not be eligible for reporting pay.

16.4 In the event work is cancelled by the Contractor after an employee has gone beyond the marshalling point, he/she shall receive a minimum of three (3) hours pay at his/her straight time rate.

ARTICLE 17 - STATUTORY AND GENERAL HOLIDAYS

*** Note – See Letter of Agreement #11, for additional information regarding Article 17.1 and 17.3 (Louis Riel Day)

17.1 The following shall be observed as Holidays each year:

New Year's Day	Canada Day	Thanksgiving Day
Good Friday	Labour Day	Christmas Day
Victoria Day	Remembrance Day	Boxing Day

17.2 No work shall be done on Labour Day except in an emergency as necessary for the protection of life and property.

17.3 Any other day, which is proclaimed by the Federal or Provincial Government as a Holiday, shall also be observed.

ARTICLE 18 - SAFETY

18.1 All Regulations of the Workplace Safety and Health Act and all safety regulations established by the Contractor shall be complied with at all times.

18.2 Each Contractor shall establish a safety committee to consist of representatives of the Contractor and an employee designated from each trade in his employ.

18.3 To promote, co ordinate and facilitate the implementation of safety initiatives on a Project basis, a Project Safety Committee shall be established. This Committee shall consist of not less than four (4) or more than twelve (12) persons, of whom half shall include the Site Representative of the Council and employees of the Contractors.

18.3.1 The Site Representative of the Council shall co ordinate and assist in the selection of employee representatives.

18.3.2 The Management members shall consist of representatives of prime Contractors (those Contractors with direct contractual arrangements with Manitoba Hydro), a representative from Manitoba Hydro, and the Site Representative of the Association. The Council shall appoint its Chairperson from the employee representatives serving on the Committee, and the Management members shall appoint their Chairperson. The respective Chairpersons shall chair alternate meetings.

18.3.3 The Committee shall meet at least every two (2) months, however, if conditions warrant, a meeting may be convened at any time, at the request of either Chairperson, or the Site Representative of either the Council or the Association. Minutes of each meeting shall be prepared which shall record in appropriate detail:

a) The issues discussed;

b) Any recommendations of the Committee;

c) Whether or not the issues have been resolved to the satisfaction of the Committee.

18.3.4 Unless otherwise agreed to by the Chairpersons, minutes of meetings shall be prepared, on an alternate basis, by the Site Representative of the Council and Association, respectively. Copies of the minutes shall be posted and appropriately distributed.

18.4 To benefit the overall program of accident control any unsafe conditions, unsafe acts and violations of safety regulations, shall be reported as follows for immediate corrective action:

a) In the case of employees, directly to the Contractor's Foreman;

b) In the case of Job Stewards functioning for each Union, directly to the Contractor's Foreman and/or Safety Officer.

18.5 An employee shall accept responsibility for the safety equipment issued to him by the Contractor. An employee shall report the loss or damage of this equipment to his superior. An employee may be charged for the loss or damage to this equipment if he has been negligent.

18.6 Every employee shall, as a condition of employment, be required to wear a safety helmet of a type approved by the Construction Safety Association.

18.7 Every employee shall own and wear suitable protective footwear and other personal equipment required in the normal course of duties. Special protective clothing may be required for abnormal conditions, for which provisions are made in the applicable Appendices.

ARTICLE 19 - TRANSPORTATION AND TRAVEL TIME, ISOLATION LEAVE, LEAVES OF ABSENCE AND CHRISTMAS LEAVE PROVISIONS

*** Note – See Letters of Agreement #5, #26, #27, #36, and #53, for additional information regarding Article 19.2 (Isolation Leave)

Transportation Departure Point and Project Transportation Point

For purposes of this Article, a Transportation Departure Point (T.D.P.) and the Project Transportation Point (P.T.P.) shall be determined and/or defined as follows:

Location of a Person's Normal Place of Residence	**T.D.P. or Method of Determining T.D.P.**
a) Where a person's normal place of residence at time of hire or rehire is located in that part of Manitoba south of the 52nd parallel on the west side of Lake Winnipeg, or south of the 53rd parallel on the east side of Lake Winnipeg, but including the Community of Poplar River.	Winnipeg
b) Where a person's normal place or residence at time of hire or rehire is located, in Manitoba, in an area, other than the area described in (a) above.	The community or location closest to a person's normal place of residence at time of hire or rehire which is serviced by at least one (1) mode of public transportation, (i.e. regularly scheduled rail, bus or air) which itself, or in combination with other modes of public transportation, provides access to the Project Transportation Point (P.T.P.) (See definition of P.T.P. set out below).
c) Where a person's normal place of residence at time of hire or rehire is located outside of Manitoba.	Winnipeg, except if that person's normal place of residence is located in an adjacent province or territory, and is also located closer to a T.D.P. located within the area described in (b) above, in which case the closest T.D.P. will be utilized.

The Project Transportation Point (P.T.P.) will be that community or location in Manitoba which is:

i) Closest to the Project Site and;

ii) Served by regularly scheduled air transportation from Winnipeg and;

iii) Accessible by air or road or rail to the Project Camp Site.

19.1 Transportation and Travel Time

19.1.1 Transportation and travel time shall apply as provided in this Article, except as otherwise provided in Article 19.2.4.

19.1.2 Transportation on Hire or Rehire

19.1.2.1 Employee's or Prospective Employee's Responsibility Relative to Transportation

Each person will be responsible for arranging and providing transportation from that person's place of residence to that person's T.D.P., and return.

19.1.2.2 Contractor's Responsibility Relative to Transportation

The Contractor shall provide transportation for a person and his required tools as follows, subject to 19.1.2.3.

a) When Winnipeg is the Transportation Departure Point

The Contractor shall arrange and pay for air transportation, including all taxes and fees, if any, associated therewith, from Winnipeg to the P.T.P. in which case the provisions of Article 19.1.2.4 shall apply;

b) When the Transportation Departure Point Is Other Than Winnipeg

The Contractor shall pay for transportation, including all taxes and fees, if any, associated therewith, by bus, rail or air, or a combination thereof if required, from the applicable T.D.P.:

i) To the P.T.P., in which case the provisions of Article 19.1.2.4 shall apply;

or

ii) To the Project Camp Site.

If more than one type of transportation mode is available, the type of transportation to be utilized shall be decided by the Contractor.

c) When a Prospective Employee Requests to Provide His Own Transportation to the Project Camp Site

Provided the Contractor agrees, a person may elect to provide his own transportation (including transportation of the person's tools) to the Project Camp Site for which he will be reimbursed, on his first regular pay, an amount calculated in accordance with the following:

As of February 3, 2019, thirty-seven cents ($0.37) multiplied by the road distance in kilometers, by the most direct route, between:

i) A person's normal place of residence and the Project Camp Site;

or

ii) That person's T.D.P. and the Project Camp Site.

whichever is the shorter distance, to a maximum of one thousand (1000) kilometers.

Effective January 1, of each year, the rate referred to above shall be adjusted in accordance with the following formula:

Regular Bus Fare - Wpg. to Thompson - Jan. 1 - Current Year x .28¢ / $86.40 (April 30 2003 Greyhound rate)

= new rate (rounded to nearest one cent)

The new rate shall be effective on February 1st of the current year. At least ten (10) calendar days in advance of this date, the Association will advise the Council, in writing, of the new rate.

19.1.2.3 Maximum Transportation Costs Payable

The Contractor's cost of providing one way transportation pursuant to the provisions of Article 19.1.2.2(b) shall not exceed the cost of one way economy air-fare on a regularly scheduled flight from Winnipeg to the P.T.P., in effect on the day the person travels.

19.1.2.4 Transportation From the Project Transportation Point (P.T.P.)

Except in the case of 19.1.2.2(b)(ii) and 19.1.2.2(c), the Contractor shall provide transportation from the P.T.P. to the Project Camp Site including the transportation of any required tools. If such transportation is not readily available and it is necessary for the person to purchase meals and/or overnight accommodation at the P.T.P., he will be reimbursed by the Contractor, on the presentation of receipts, for reasonable out of pocket expenses for meals and accommodation, provided he has notified the Contractor on his arrival at the P.T.P. Such expenses shall be paid to an employee on his first regular pay.

19.1.2.5 Travel Time

Subject to 19.1.2.6, a person directed by the Contractor to travel to the Project Site shall be paid for his travel time at the employee's straight time rate.

19.1.2.5.1 Except as otherwise provided in 19.1.2.5.2 and 19.1.2.5.3 below, the amount of travel time to be paid shall be the lesser of:

i) Actual travel time from the person's T.D.P. to the Project Camp Site;

or

ii) The normal equivalent of scheduled air transportation travel time, plus an extra one-half (1/2) hour for clearing security and boarding, from Winnipeg to the P.T.P., and the normal equivalent of travel time from the P.T.P. to the Project Camp Site.

19.1.2.5.2 In the case of a person whose T.D.P. and P.T.P. are the same, travel time shall be:

i) Actual travel time from the P.T.P. to the Project Camp Site when the Contractor provides the transportation;

or

ii) The normal equivalent of travel time from the P.T.P. to the Project Camp Site when a person provides his own transportation, as the case may be.

19.1.2.5.3 When the Contractor provides transportation from the P.T.P. to the Project Camp Site as set out in Article 19.1.2.4., travel time shall apply for any delay in the provision of this transportation, however, if this occurs, the total amount of travel time to be paid from the T.D.P. to the Project camp site shall not exceed eight (8) hours.

19.1.2.6 Payment of Travel Time

Except in the case of a lay-off, travel time will only be paid provided the employee remains in employment for a minimum of twenty (20) calendar days measured from the date of arrival at the Project Camp Site. Travel time shall be paid and included with the employee's first pay which occurs subsequent to the twenty (20) calendar day period, except in the case of a lay-off occurring prior thereto, in which case the travel time shall be paid and included with the employee's final pay.

19.1.2.7 Deduction of Transportation Costs and Expenses

An employee must be employed at the site for a minimum of thirty (30) calendar days, unless laid off by the Contractor, otherwise the transportation costs incurred by the Contractor pursuant to the provisions of Article 19.1.2.2(a) or (b) or (c), as the case may be, and Article 19.1.2.4 will be deducted from the employee's final pay.

19.1.3 Lay-off

19.1.3.1 When an employee is laid off, the Contractor shall provide transportation for the employee and the employee's required tools, as follows:

a) An employee with a Winnipeg T.D.P.:

Such an employee shall have the option of being treated in accordance with the provisions of Article 19.1.2.2(a) in respect of transportation (except the transportation to be provided shall be from the Project Camp Site to Winnipeg) and Article 19.1.2.5.1 in respect of travel time, or the employee may elect to provide his own transportation from the Project Camp Site in which case he will be reimbursed an amount calculated in accordance with the provisions of Article 19.1.2.2(c) and paid travel time in accordance with the provisions of Article 19.1.2.5.1.

b) An employee with other than a Winnipeg T.D.P.:

Such an employee shall have the option of being treated in accordance with the provisions of Article 19.1.2.2(b) in respect of transportation (except the transportation to be provided shall be from the Project Camp Site to the employee's T.D.P.) and Article 19.1.2.5.1 or 19.1.2.5.2, as applicable, in respect of travel time, or the employee may elect to provide his own transportation from the Project Camp Site in which case he will be reimbursed an amount calculated in accordance with the provisions of Article 19.1.2.2(c) and paid travel time in accordance with the provisions of Article 19.1.2.5.1 or 19.1.2.5.2, as applicable.

The reimbursement amounts and travel time in (a) and (b) above shall be included on the employee's final pay.

19.1.3.2 When laying off employees, the Contractor shall not make any distinction between employees, in similar classifications, who have taken Isolation Leave and those who have not taken Isolation Leave provided the duration of their employment on the Project Site is equal.

19.1.4 Resignation and Discharge

19.1.4.1 An employee who terminates his employment of his own volition or who is discharged by the Contractor shall be provided with transportation as follows:

a) To the departure point of the public transportation, if public transportation (rail, bus or air) is available at the Project Camp Site;

or

b) To the P.T.P., if public transportation is not available at the Project Camp Site.

For the provision of transportation to the P.T.P., the Contractor may deduct from the employee's final pay, an amount equal to the road distance in kilometers between the Project Camp Site and the P.T.P. multiplied by the prevailing per kilometer rate in effect pursuant to Article 19.1.2.2(c).

19.1.4.2 When an employee who is eligible for Isolation Leave resigns, the provisions of Article 19.2 in respect of transportation shall apply for one way transportation.

19.1.4.3 When an employee is discharged and provided sufficient funds are owing to the employee, the Contractor, on request, shall provide an advance equal to the cost of transportation to the employee's T.D.P. to a maximum of the cost of one way air fare on a regularly scheduled flight between the P.T.P. and Winnipeg.

19.2 Isolation Leave (Return Transportation Time Periods)

***See Letters of Agreement #5, #26, #27, #36, and #53

19.2.1 Frequency of Isolation Leaves

19.2.1.1 Frequency When Isolation Leave Frequency Is Not Stipulated In An Appendix

An employee working on the Project who is covered by an Appendix which does not stipulate Isolation Leave frequency shall have the option of taking an Isolation Leave after forty (40) calendar days.

19.2.1.2 Frequency When Isolation Leave Provisions Are Set Out In An Appendix

Subject to Article 19.2.1.3, the frequency of Isolation Leaves for an employee working on the Project and covered by an Appendix which contains Isolation Leave provisions shall be that stipulated in the Appendix.

19.2.1.3 Limitation Relative to Frequency of Isolation Leaves

Notwithstanding any other provisions set out in this Agreement, the time period between Isolation Leaves may be greater than but shall not be less than thirty-five (35) calendar days.

19.2.1.4 Make up of Calendar Day Periods

The calendar day periods as set out above or in the Appendices shall be computed on the following basis:

a) A period shall commence from and include the day the employee arrives on the Project Site following hire, rehire, recall, an Isolation Leave or a Leave granted under the provisions of Article 19.3.2;

b) A period shall not include any calendar days on which the employee does not report to work excepting and limited to the conditions set out in Article 9.3(b), (c) and (d), and Article 9.3(e) to a maximum of three (3) calendar days.

19.2.1.5 Duration of Isolation Leave

When an employee is eligible for and opts to take an Isolation Leave, the employee shall be granted a minimum of six (6) working days as leave without pay. However, at the option of the employee, the leave of absence without pay may be for less than six (6) working days but not less than three (3) working days, except when the Contractor and the employee mutually agree that the leave will be less than three (3) days.

Additionally, provided an employee requests same in writing at least fourteen (14) calendar days prior to the commencement of his Isolation Leave, the Contractor shall grant an additional four (4) calendar days leave without pay in the following circumstances:

a) When the employee is eligible for his second consecutive Isolation Leave, and every second (2nd) consecutive Isolation Leave thereafter.

b) When the employee is eligible for an Isolation Leave but elects to continue working and to defer commencement of the Leave for a period equal to the period the employee would have otherwise been required to work to be eligible for consecutive Isolation Leave.

c) On other occasions the employee is eligible for an Isolation Leave, provided the Contractor and employee mutually agree.

19.2.1.6 Requirement to Notify Contractor

To allow the Contractor sufficient time to plan for accommodating Isolation Leaves and for meeting the requirements of Article 19.2.3, an employee shall obtain and submit a completed Isolation Leave Form at least five (5) working days in advance of the completion of a tour of duty, or in the case of an employee electing to delay the commencement of his Isolation Leave, at least five (5) working days prior to the date the employee intends to commence his Isolation Leave.

If such notification is not provided, the Contractor may request an employee to provide the required notification and to schedule the commencement of his Isolation Leave to conform with such notification.

Isolation Leave Forms will be provided by the Contractor. The purpose of these forms will be to confirm whether or not an employee will be taking an Isolation Leave. In the case of an employee taking an Isolation Leave, the form will confirm:

a) The date the employee is eligible for an Isolation Leave;
b) The date the employee intends to leave the Project Site;
c) The date the employee will be returning to the Project Site;
d) Transportation particulars pursuant to (b) and (c) above and Article 19.2.3.1.

Failure to submit a completed Isolation Leave Form will be deemed to be notification that the employee is opting to delay the commencement of his Isolation Leave.

19.2.1.7 Provision for Advancing or Retarding the Commencement of an Isolation Leave

To enhance the planning and execution of the work, and provided the employee is notified at least fourteen (14) calendar days prior to the completion of a tour of duty, the Contractor may request that an employee advance or retard the commencement of his Isolation Leave, by up to three (3) working days or longer than three (3) working days if such additional time is mutually agreed to by the Contractor and the employee. If this occurs any deficit or surplus

of calendar days will be taken into account during the employee's next calendar day accumulation period.

19.2.2 Failure To Return on Time From An Isolation Leave

An employee who does not return to work on the specified date following an approved Isolation Leave shall be deemed to have resigned, except where the employee at the earliest opportunity advises the Contractor of being detained en route due to a lack of transportation and, if requested by the Contractor, provides proof of same.

19.2.3 Transportation Relative to Isolation Leaves

19.2.3.1 An employee, other than an employee in receipt of the housing allowance set out in Article 10, who is eligible for an Isolation Leave and who elects to take his Isolation Leave shall be provided with the following:

a) Employees Whose Transportation Departure Point is Winnipeg

The Contractor shall provide transportation for the employee from the Project Camp Site to the P.T.P. and return, and air transportation from the P.T.P. to Winnipeg and return. However, an employee may elect to provide his own transportation from the Project Camp Site to the employee's T.D.P., and return, in which case the employee will be paid, at the time of departure, an allowance calculated in accordance with the provisions of Article 19.1.2.2(c) and the same amount on the employee's return from Isolation Leave which shall be included with his first (1st) regular pay;

b) Employees Whose Transportation Departure Point is Other Than Winnipeg

Subject to Article 19.1.2.3, the Contractor shall provide transportation for such an employee from the Project Camp Site to the employee's T.D.P., and return, as set out in Article 19.1.2.2(b). However, an employee may elect to provide his own transportation from the Project Camp Site in which case the Contractor will pay such an employee, at the time of his departure on Isolation Leave, an allowance calculated in accordance with the provisions of Article 19.1.2.2(c) and the same amount on the employee's return from Isolation Leave which shall be included with his first regular pay.

19.2.3.2 Transportation Relative to Employees in Receipt of Housing Allowance

An employee who is in receipt of the Housing Allowance set out in Article 10 during any part of a tour of duty shall receive the transportation benefits set out in 19.2.3.1(a) or (b), as applicable when the employee has completed two (2) consecutive tours of duty (as defined in Article 19.2.1.1 to 19.2.1.4 inclusive) and who elects to take his Isolation Leave; and on completion of every second consecutive tour of duty thereafter.

19.2.3.3 Deduction of Isolation Leave Transportation Costs

On return from an Isolation Leave, an employee must be employed at the site for a minimum of thirty (30) calendar days, unless laid off by the Contractor, otherwise the applicable amount, determined in accordance with the schedule set out below, will be deducted from the employee's final pay:

No. Of Calendar Days of Employment Measured from the Employees return from Isolation Leave	**Amount to be Deducted**
a) Less than twenty-one (21) calendar days	a) One-half (1/2) of the transportation costs incurred by the Contractor pursuant to Article 19.2.3.1(a) or (b), as the case may be.
b) Twenty-one (21) to thirty (30) calendar days inclusive	b) The amount set out in (a) above reduced by ten per cent (10%) of this amount for each calendar day of employment beyond twenty (20) calendar days.

19.2.3.4 Lay-off Prior to Isolation Leave

If an employee is laid off subsequent to earning an Isolation Leave but before such leave is actually taken, the employee will be eligible to receive the benefits of Article 19.1.3 and will not be eligible to receive the benefits of Article 19.2.3.

19.2.4 Travel Time Associated With Isolation Leaves

An employee will only be eligible for travel time associated with the taking of an Isolation Leave if the Appendix covering that employee specifically provides for the payment of Isolation Leave travel time.

19.2.5 Employees Not Taking Isolation Leave

Any employee who elects not to take Isolation Leave shall not be entitled to any of the transportation expenses set out in Article 19.2.

19.3 Leaves of Absence (Other than Isolation Leaves)

19.3.1 When an employee requests a leave of absence because of a Workers Compensation Claim, union business, or a death or illness in the family and the request is approved by the Contractor, the employee shall continue to accumulate time towards his next Isolation Leave on his return to work.

19.3.2 When an employee requests a Leave of Absence other than Isolation Leave or other than identified in 19.3.1 and the request is approved by the Contractor, the employee shall forfeit any time accrued towards his next Isolation Leave.

19.3.3 When an employee takes a leave of absence because of a Workers Compensation claim or a death or illness in the family, upon request the Contractor shall provide transportation to the P.T.P.

19.3.4 When an employee takes leave under 19.3.1 or 19.3.2 he shall provide his own transportation to and from the Project Site except as provided for in 19.3.3.

19.4 Christmas Leave

19.4.1 Christmas Leave shall normally be granted. The Christmas Leave period shall commence not later than December 22nd and extend to at least January 3rd. The Contractor shall provide the Association and the Council with his proposed schedule of shutdown as well as those functions that will be required to continue during this period. The schedule and list of continuing functions shall be forwarded to the Site Representative of the Council and of the Association not later than December 1st.

19.4.2 An employee who is eligible for an Isolation Leave at the time of Christmas Leave shall be provided transportation in accordance with the provisions of Article 19.2.3 and that employee shall be deemed to have taken an Isolation Leave and shall commence accruing time towards his next Isolation Leave on his return following Christmas Leave. The provisions of Article 19.2.3.3 shall apply to such an employee.

19.4.3 An employee who:

a) Is not eligible for an Isolation Leave at the time of Christmas Leave, or;

b) Is in receipt of Housing Allowance but who is not eligible, at the time of Christmas Leave, to receive the transportation benefits pursuant to the provisions of Article 19.2.3.2.

Shall be required to provide his own transportation, or the employee may request the Contractor to arrange transportation in which case the cost of providing such transportation shall be collected from the employee by a payroll deduction.

Such an employee shall continue accruing time towards his next Isolation Leave on his return from Christmas Leave.

19.5 Project Transportation Points (P.T.P.)

19.5.1 When the Contractor is required to provide transportation to and/or from the P.T.P. as set out in Article 19, it shall be provided to the location in the P.T.P. from which the employee will be arriving or departing.

ARTICLE 20 - GOVERNMENT LEGISLATION

20.1 In the event that any of the provisions of this Agreement are found to be in conflict with any applicable Federal or Provincial law now existing, or hereinafter enacted, it is agreed that such law shall supersede the conflicting provision without in any way affecting the remainder of this Agreement.

20.2 A determination that any provision of this Agreement is found null and void or in any way conflicts with any applicable Federal, Provincial or common law in no way affects the validity of all other provisions of this Agreement.

ARTICLE 21 - TOOLS

21.1 Journeymen and Apprentices shall be required to supply the tools listed in the Appendices and/or in accordance with accepted practices.

21.2 An employee's tools shall be kept in good condition at all times.

21.3 An employee shall accept responsibility for the tools furnished to him by the Contractor. The Contractor shall inform all employees of the system to be used for the issue, control and return of tools. The Contractor shall give an employee sufficient time to put tools in their designated place. An employee shall immediately report the breakage or loss of any of these tools to his superior.

21.4 The Contractor shall provide guidance to the employees, where necessary, to promote proper use and care of the Contractor's tools.

21.5 An employee shall be held responsible for damage caused by proven misuse or abuse of the Contractor's tools. The Contractor's tools mean hand instruments and portable power tools commonly used as part of his trade and furnished by the Contractor.

21.6 An employee shall not be held responsible for normal wear and tear of tools supplied by the Contractor, provided broken or worn tools are returned.

21.7 The Contractor shall provide a securely locked facility in which employees may store their tools. The employee shall secure his tools in accordance with trade practice when stored in this facility.

21.8 Unless otherwise provided in the applicable Appendix, the Contractor shall be responsible for providing compensation, to replacement value, for tools referred to in Article 21.1 above, which have been destroyed by fire or lost by breaking and entering, while stored in the facility referred to in Article 21.7 above. Any claim for lost or destroyed tools must be submitted in writing, to the Contractor, within ten (10) calendar days of loss unless good reason can be shown for not having done so. The claim must be accompanied by a list itemizing the tools lost or destroyed, their respective value and evidence of loss.

ARTICLE 22 - WORK SITE SHELTER AND SANITARY CONDITIONS

22.1 The Contractor shall provide a clean, heated place of shelter on the work site in which employees may eat their lunch and a heated, secure area in which employees may store their clothes.

22.2 The Contractor shall be responsible for the provision, maintenance and cleanliness of sanitary facilities on the work site. Employees shall exercise care in the use of these facilities to assist in maintaining cleanliness. Sanitary facilities will be heated to a comfortable temperature during the winter months. If running water is not available, chemical hand cleaner shall be provided by the Contractor.

22.3 Sanitary conditions on the work site shall be the legitimate concern of the Project Safety Committee. Any concern over the adequacy of sanitary conditions which cannot be mutually resolved on the work site shall be referred to the Project Safety Committee for resolution. If the matter is not resolved to the satisfaction of this Committee, the Co Chairpersons shall advise the Senior Site Representative of Manitoba Hydro and the applicable Contractor(s) of the concern.

ARTICLE 23 - INJURIES ON THE JOB

23.1 An employee, who is injured during the performance of his work shall suffer no loss of pay for the time he was required to be absent on that shift to receive medical or first aid treatment.

23.2 An employee, who as a result of an injury incurred in the performance of his work requires medical attention off the work site, and due to the injury, is unable to return to work on that day, shall be paid to the end of the full shift on which he was injured. The Contractor may require that a medical certificate be furnished confirming that the employee was unable to return to work on that day.

23.3 The Contractor shall direct the employee's foreman or steward to gather the injured employee's tools and place them in his tool box and store same in a securely locked facility.

23.4 The employee must report to the Contractor, at the first opportunity, any accident or injury.

23.5 If transportation is required to take an injured employee from the work site to the closest first aid or medical facility, and return following receipt of treatment therefrom, it shall be provided by the Contractor.

ARTICLE 24 - BULLETIN BOARDS

24.1 The Council may post notices about union activities on the bulletin boards designated for their use. Notices shall be signed by the appropriate official of the Council.

ARTICLE 25 - STANDARD OF WORK AND LIMITATIONS

25.1 There shall be no limit on production of employees nor restriction on the full use of proper tools or equipment and there shall not be any task work or piecework.

ARTICLE 26 - TERMINATION OF EMPLOYMENT

26.1 Resignation

26.1.1 An employee who intends to resign shall provide the Contractor with at least one (1) hour's notice.

26.1.2 If the employee provides the Contractor with at least eight (8) calendar days notice, the Contractor shall pay the employee and issue his Separation Slip on the employee's last scheduled day of work. Pay shall include all wages and Vacation and Statutory Holiday Pay owing to the employee.

26.1.3 Article 26.5.1.1 shall apply in instances where the employee does not provide eight (8) calendar days notice.

26.2 Discharge and Lay-Off

26.2.1 The Contractor shall give an employee one (1) hour's paid notice of lay-off.

26.2.2 An employee who is discharged by the Contractor shall receive one (1) hour's pay in lieu of notice.

26.2.3 For the one (1) hour's pay relative to discharge and lay-off, the employee shall pack his tools and:

a) Follow the Contractors clearance procedures in accordance with 26.3 and;

b) In the case of camp residents, obtain a camp clearance slip in accordance with 26.4.

26.3 Contractor's Clearance

26.3.1 The Contractor shall advise all employees of the system to be followed for the return of the Contractor's equipment, tools or other issued items at the time of termination of employment.

26.4 Camp Clearance

26.4.1 An employee residing in the camp shall return the following items to the designated office of the Camp Operator following termination of employment:

a) Bedding/equipment issued to the employee for which a receipt will be issued;

b) The employee's room key for which the key deposit shall be refunded.

26.4.2 Concurrently, the Camp Operator shall issue a Camp Clearance Slip to the employee which must be presented to the Contractor.

26.5 Issuance of Pay and Record of Employment

26.5.1 Provided an employee has complied with the Contractor's clearance system, and in the case of a camp resident has obtained a Camp Clearance slip, the Contractor shall:

26.5.1.1 In the case of resignation and discharge:

a) Issue the employee's Record of Employment and;

b) Pay the employee all monies owing or alternately mail the employee's pay cheque within four (4) working days from the date of termination. In the latter case, the employee's pay shall be forwarded by registered mail, addressed as directed by the employee.

26.5.1.2 In the case of Lay-Off:

a) Issue the employee's Record of Employment and;

b) Pay the employee all monies owing.

26.6 If for any reason an employee's Record of Employment cannot be issued by the Contractor at the time of termination, the Contractor shall forward the Record of Employment:

a) With the employee's paycheck where same has not been issued at Site;

b) Within four (4) working days where the employee was paid at the time of termination. The Record of Employment shall be forwarded by registered mail, addressed as directed by the employee.

26.7 If transportation is not available from the Project Site at the time of termination of employment, the former employee may continue to receive room and board in the camp until transportation is available.

26.7.1 If the employee has been laid off, there will be no charge for this room and board.

26.7.2 In the event of discharge or resignation, the former employee will be charged for this room and board at a cost to be set by the Camp Operator.

ARTICLE 27 - APPENDICES

27.1 The wage rates and conditions set out in the Appendices shall apply to work under this Agreement.

27.2 Wage rates and those special conditions which are defined in the clause "Escalation and Reference" in each Appendix will be adjusted in accordance with Article 30.

27.3 Notwithstanding the "Escalation and Reference" provisions set out in each Appendix, conditions of employment which would otherwise qualify as an escalatory item shall not be introduced or escalated in this Agreement, if the application of such conditions of employment would effectively only apply to work under this Agreement.

27.4 The provisions and intent of Articles 9 and 10 of this Agreement shall not be altered as a result of the "Escalation and Reference" provisions set out in each Appendix.

ARTICLE 28 - ADDITIONAL CLASSIFICATIONS

28.1 Either a Contractor or a Local Union may request the establishment of a new classification in an Appendix. Such a request shall be in writing, to the President of the Council and the Managing Director of the Association, and particulars shall be provided as to the necessity of establishing a new classification.

28.2 The President and Managing Director will arrange for a meeting of the Joint Appendix Review Committee (J.A.R.C.)(see Article 30) and this meeting shall be held within ten (10) working days from the date of receipt of the written request, or as otherwise mutually agreed to. The J.A.R.C. will consider whether or not a new classification should be established and if so, the wage rate for such a classification and its effective date, however such effective date shall not be earlier than the date the request was received by the J.A.R.C.

28.3 If the J.A.R.C. is unable to agree on the issues referred to in Article 28.2, the provisions of Article 31 shall be followed.

ARTICLE 29 - AGREEMENTS BEING USED FOR REFERENCE PURPOSES

29.1 Where a collective agreement(s) is referred to in the Escalation and Reference Section of an Appendix, and by virtue of the provisions of that Section, certain terms and conditions of employment in that agreement(s) are used to adjust corresponding terms and conditions in the Appendix, such an agreement(s) shall be known as an 'agreement(s) being used for reference purposes'.

29.2 If during the term of this Agreement, an agreement(s) being used for reference purposes ceases to exist, the Joint Appendix Review Committee shall meet within thirty (30) calendar days from the date of notification from either Party for purposes of establishing new or revised reference provisions for that Appendix. If agreement cannot be reached, the procedure set out in Article 31 shall be followed.

ARTICLE 30 - ADJUSTMENT OF APPENDICES

30.1 Adjustments to Appendices shall be made in accordance with the Section "Escalation and Reference" in each Appendix of this Agreement.

30.2 A Joint Appendix Review Committee shall be established and comprised of an Association Appendix Review Committee and a Council Appendix Review Committee each consisting of up to three (3) members of the Association and Council, respectively. Each committee shall appoint its own chairperson. The Association Appendix Review Committee and the Council Appendix Review Committee may each appoint an “Industry Advisor” and a “Council Advisor”, respectively, who may attend any meetings convened to consider any matters in respect of the adjustment of an Appendix.

30.3 The Association Appendix Review Committee and the Council Appendix Review Committee are authorized, as agents, to execute on behalf of the Association and the Unions, respectively, any adjustment authorized by virtue of this Article, including any adjustment that embodies the award of a Mediator appointed under the provisions of Article 31.

30.4 The following procedure shall be followed when adjustments are to be considered pursuant to the clause "Escalation and Reference" in each Appendix of this Agreement.

30.4.1 Upon the signing of a new agreement(s) being used for reference purposes, the Council shall forthwith notify the Association Appendix Review Committee in writing of any conditions of employment eligible for adjustment in the applicable Appendix, and at the same time the Council shall provide the Association with a copy of the said agreement(s). If necessary, at the request of either Committee, the Joint Appendix Review Committee shall meet, within ten (10) days following receipt of the request to meet, for purposes of resolving any matter in dispute relative to the adjustment of an Appendix.

30.4.2 To avoid undue delays in implementing changes to conditions of employment that the Parties have agreed to, an Appendix may be adjusted (and then executed and distributed) to include only such agreed changes on condition the Appendix would be subject to further adjustments, if required, to accommodate the award of a mediator. (see Article 31).

30.4.3 Notwithstanding any other provision in this Agreement, in the event of a strike or lockout by the Parties signatory to the agreement(s) being used for reference purposes, the effective date of any term or condition of employment eligible for adjustment will be the date of signing of the agreement being used for reference purposes or a memorandum of agreement related thereto, whichever is the earlier, when retroactivity, relative to these dates, is provided in the agreement being used for reference purposes.

30.5 Should the Joint Appendix Review Committee be unable to agree on adjustments regarding wage rates or other conditions of employment eligible for adjustment, the procedure in Article 31 shall be followed.

30.6 The processes set out in this Article shall not be considered to be notice by the Parties pursuant to the provisions of Section 61(3) of the Labour Relations Act of Manitoba.

ARTICLE 31 - MEDIATION

31.1 The procedure set out below shall only be followed when the Association or the Council (including their respective Appendix Review Committees) are unable to reach agreement on the issues or conditions specifically referred to in the Articles of this Agreement as being eligible for mediation under this Article 31.

31.2 Either the Association or the Council shall, within ten (10) days following their last meeting, notify the other in writing of its intention to refer a matter to mediation.

31.3 Within five (5) working days following receipt of the notice, the parties shall meet:

a) To appoint a Mediator;

b) To attempt to commit to writing:

i) The points that have been agreed upon;

ii) The points that have not been agreed upon.

If the parties are unable to agree upon a single Mediator, then the Minister of Labour for the Province of Manitoba shall be requested to appoint the Mediator.

31.4 The Mediator shall call a meeting within fourteen (14) days following his appointment. The parties shall present evidence and argument to the Mediator, without representation by counsel. The Mediator shall render his award and serve it upon the Parties within thirty (30) working days following this meeting.

31.5 The award of the Mediator shall be final and binding upon the Parties, and implemented within ten (10) working days after the day on which it was served upon the Parties.

31.6 The Mediator shall not be authorized to extend, modify or amend this Agreement, other than the issues or conditions referred to in 31.1, or any part of an Appendix, other than the items referred to in the clause "Escalation and Reference" in each Appendix.

31.7 The expenses of the Mediator and the mediation meeting facilities shall be shared equally by the Council and Association, and each party shall pay its own costs of participating in the mediation.

ARTICLE 32 - INTERPRETATION OF THE AGREEMENT

32.1 This Agreement shall be restricted to interpretation by the Association, the Council, an arbitrator appointed under the provisions of Article 8, and a mediator appointed under the provisions of Article 31.

ARTICLE 33 - CAMP AND RECREATION FACILITIES

33.1 Any camp standards negotiated between Manitoba Hydro and the Council prior to commencement of each Project shall apply on that Project Site. If no camp standards are negotiated prior to commencement of a Project, meetings will be held between Manitoba Hydro and the Council to review the camp and recreation facilities that will be provided at the Project Site.

ARTICLE 34 - WAGE INDEMNIFICATION

34.1 This Article shall only be relied on to satisfy an employee's claim to wages, when wages are not paid as a result of the inability of a Contractor to pay wage debts as they fall due in accordance with the terms and conditions of this Agreement.

34.2 The Association will indemnify the following:

a) Wages and benefits owing to an employee in accordance with the terms and conditions of this Agreement;

b) Any monies owing and intended for remittance to a Union or Trust Fund, as the case may be, as provided for in this Agreement.

34.3 If valid claims are made under this Article, the Association will indemnify such claims to a maximum of five hundred thousand dollars ($500 000.00) per Contractor.

34.4 If a claim is to be initiated, the following mandatory procedures shall be followed:

a) The Council will notify the Association, in writing, that a wage default has occurred and such notification shall be provided within twenty (20) calendar days the date wages were due and payable under the terms of this Agreement;

b) Officers of the Association and Council shall meet, as soon as possible, but in any event within ten (10) calendar days from the date of notification of default. The purpose of this meeting shall be to confirm that the provisions of this Article apply and if so, to jointly document all information necessary for:

i) The processing of claims under this Article;

ii) The initiating of claims for the recovery of unpaid wages under one or more of the following Provincial Legislative Enactment's:

- The Builders' Liens Act
- The Construction Industry Wages Act
- The Payment of Wages Act
- Other Acts that may be applicable at the time

Additionally, within this ten (10) calendar day period, the Association and the Council will decide as to the Act or Acts under which claims will be filed for the recovery of unpaid wages. If a dispute arises on this matter, claims shall be filed under all Acts.

The Association will provide and pay for the services of legal counsel, when such services are required.

c) Pursuant to (b) above, claims for unpaid wages shall be filed in accordance with the Act or Acts and the following:

i) In the case where the Act allows the Council to act in the capacity of an agent, the Council will file the claims;

ii) In the case where the Act prescribes that the employee to whom wages are owed must file the claim, the Council will be responsible for advising the employee of this requirement and the employee will provide the Council with a copy of the completed claim, so filed, within five (5) working days from the date of filing.

34.5 Subject to Article 34.6, the time limits set out in Article 34.4 may be extended by mutual consent of the Parties.

34.6 A claim for a wage debt made under this Article by, or on behalf of, an individual employee shall be deemed invalid in the event a corresponding claim is not made under and in accordance with the Act or Acts, as set out in Article 34.4.

34.7 Subject to Article 34.6, and provided that specific information as to the amount owed to an employee has been agreed upon by the Council and the Association, a joint account shall be established by the Parties in which the Association will deposit the aggregate of all verified claims to a maximum of five hundred thousand dollars ($500 000.00). Payment to the joint account shall be effected no later than sixty (60) calendar days from the date of filing of claims under the Act(s).

34.8 Subject to the limitations set out in this Article, funds in the joint account shall only be used to reimburse the difference between the amounts set out in Article 34.2, and the amounts recovered under the Acts referred to in Article 34.4(b)(ii).

34.9 Any funds remaining in the joint account after all claims have been processed shall revert to the Association.

ARTICLE 35 - COUNTERPARTS

35.1 This Agreement may be executed by the Parties in separate counterparts each of which when so executed and delivered shall be an original but all such counterparts shall together constitute one and the same instrument.

ARTICLE 36 - SUCCESSORS

36.1 This Agreement shall inure to the benefit of and be binding upon the Parties, and each of their assigns and successors.

IN WITNESS WHEREOF the parties hereto have executed this Agreement to take effect as of and from the 7th day of October, 2005.

HYDRO PROJECTS MANAGEMENT ASSOCIATION

Per: "Tom Moffat"
Director (Executive Committee)

Per: "D. E. Rogalsky
Managing Director

THE ALLIED HYDRO COUNCIL OF MANITOBA

Per: "G. Bentley":
President

Per: "D. Martin"
Secretary-Treasurer

On its own behalf and on behalf of and as Agent for the following Unions:

CONSTRUCTION & SPECIALIZED WORKERS' UNION OF NORTH AMERICA, and Local Union 1258 of this International Union.

INTERNATIONAL UNION OF OPERATING ENGINEERS, and Local 987 of this International Union.

INTERNATIONAL BROTHERHOOD OF TEAMSTERS, CHAUFFEURS, WAREHOUSEMEN AND HELPERS OF AMERICA, and Local Union 979 of this International Union.

UNITED BROTHERHOOD OF CARPENTERS AND JOINERS OF AMERICA, and Local Union 343 (Carpenters) of this International Union and,

Local Union 1443 (Millwrights, Machine Erectors, Industrial Mechanics Maintenance) of this International Union.

INTERNATIONAL UNION OF PAINTERS & ALLIED TRADES, GLASS-WORKERS DIVISION, SIGNWORKERS & CARPET & FLOOR TILE LAYERS DIVISION, and Local Union 739 of this International Union.

INTERNATIONAL ASSOCIATION OF HEAT AND FROST INSULATORS AND ASBESTOS WORKERS, and Local Union 99 of this International Union.

INTERNATIONAL UNION OF BRICKLAYERS AND ALLIED CRAFTWORKERS, and Local Union No. 1 of this International Union.

SHEET METAL WORKERS INTERNATIONAL ASSOCIATION, and Local Union 511 of this International Union.

INTERNATIONAL BROTHERHOOD OF BOILERMAKERS, IRON SHIPBUILDERS & HELPERS OF AMERICA, and Local Union 555 of this International Union.

INTERNATIONAL ASSOCIATION OF BRIDGE, STRUCTURAL, ORNAMENTAL & REINFORCING IRONWORKERS, and Local 728 of this International Union.

INTERNATIONAL BROTHERHOOD OF ELECTRICAL WORKERS, and Local Union 2085 of this International Union.

UNITED ASSOCIATION OF JOURNEYMEN AND APPRENTICES OF THE PLUMBING AND PIPEFITTING INDUSTRY OF THE UNITED STATES AND CANADA, and Local Union 254 of this International Union.

OPERATIVE PLASTERERS & CEMENT MASONS INTERNATIONAL ASSOCIATION, Local Union 222. See Letter of Agreement No. 9.

CANADIAN OFFICE AND PROFESSIONAL EMPLOYEES UNION, Local Union 342.

UNITE HERE, Local Union 206 .

INTERNATIONAL UNION OF ELEVATOR CONSTRUCTORS, and Local 102 of this International Union.

CONTRACTOR

On behalf of _____
(name of Contractor)

executed this _____ day of _____, 2005.

Per: _____ Per: _____
President Secretary

APPROVED BY:

CONSTRUCTION & SPECIALIZED WORKERS' UNION OF NORTH AMERICA, and Local Union 1258 of this International Union.

Per: _____
International Representative

_____
President or Business Manager

INTERNATIONAL UNION OF OPERATING ENGINEERS, and Local 987 of this International Union.

Per: _____
International Representative

_____
President or Business Manager

INTERNATIONAL BROTHERHOOD OF TEAMSTERS, CHAUFFEURS, WAREHOUSEMEN AND HELPERS OF AMERICA, and Local Union 979 of this International Union.

Per: _____
International Representative

_____
President or Business Manager

UNITED BROTHERHOOD OF CARPENTERS AND JOINERS OF AMERICA, and Local Union 343 (Carpenters) of this International Union and,

Local Union 1443 (Millwrights, Machine Erectors, Industrial Mechanics Maintenance) of this International Union.

Per: _____
International Representative

_____
President or Business Manager

INTERNATIONAL UNION OF PAINTERS & ALLIED TRADES, GLASS-WORKERS DIVISION, SIGNWORKERS & CARPET & FLOOR TILE LAYERS DIVISION, and Local Union 739 of this International Union.

Per: _____
International Representative

_____
President or Business Manager

INTERNATIONAL ASSOCIATION OF HEAT AND FROST INSULATORS AND ASBESTOS WORKERS, and Local Union 99 of this International Union.

Per: _____
International Representative

_____
President or Business Manager

INTERNATIONAL UNION OF BRICKLAYERS AND ALLIED CRAFTWORKERS, and Local Union No. 1 of this International Union.

Per: _____
International Representative

_____
President or Business Manager

SHEET METAL WORKERS INTERNATIONAL ASSOCIATION, and Local Union 511 of this International Union.

Per: _____
International Representative

_____
President or Business Manager

INTERNATIONAL BROTHERHOOD OF BOILERMAKERS, IRON SHIPBUILDERS & HELPERS OF AMERICA, and Local Union 555 of this International Union.

Per: _____
International Representative

_____
President or Business Manager

INTERNATIONAL ASSOCIATION OF BRIDGE, STRUCTURAL, ORNAMENTAL & REINFORCING IRONWORKERS, and Local 728 of this International Union.

Per: _____
International Representative

_____
President or Business Manager

INTERNATIONAL BROTHERHOOD OF ELECTRICAL WORKERS, and Local Union 2085 of this International Union.

Per: _____
International Representative

_____
President or Business Manager

UNITED ASSOCIATION OF JOURNEYMEN AND APPRENTICES OF THE PLUMBING AND PIPEFITTING INDUSTRY OF THE UNITED STATES AND CANADA, and Local Union 254 of this International Union.

Per: _____
International Representative

_____
President or Business Manager

OPERATIVE PLASTERERS & CEMENT MASONS INTERNATIONAL ASSOCIATION, Local Union 222. See Letter of Agreement No. 9.

Per: _____
International Representative

_____
President or Business Manager

CANADIAN OFFICE AND PROFESSIONAL EMPLOYEES UNION, Local Union 342.

Per: _____
International Representative

_____
President or Business Manager

UNITE HERE, Local Union 206 .

Per: _____
International Representative

_____
President or Business Manager

INTERNATIONAL UNION OF ELEVATOR CONSTRUCTORS, and Local 102 of this International Union.

Per: _____
International Representative

_____
President or Business Manager

APPENDICES

APPENDIX NO. 1 - Labourers

BURNTWOOD/NELSON AGREEMENT

MANITOBA HYDRO PROJECT CONSTRUCTION AND SPECIALIZED WORKERS (LABOURERS)

Local Union 1258

*** Note – See Letter of Agreement #30, for additional information regarding Appendix 1, Section 4 (wages)
*** Note – See Letter of Agreement #45, for additional information regarding Appendix 1 (Concrete Finisher and Red Seal Cement finisher classifications)
*** Note – See Letter of Agreement #49, for additional information regarding Appendix 1 (Training Trust Fund)
*** Note – See Letter of Agreement #52, for additional information regarding Appendix 1 (Foreman Coordinator)
*** Note – See Letter of Agreement #61, for additional information regarding Appendix 1 (Blaster wage enhancement)

1. Hours of Work and Overtime

a) Hours Monday through Friday

Nine (9) hours shall constitute a day's work for four (4) days Monday through Thursday, and eight (8) hours shall constitute a day's work for Friday.

The regular first shift shall normally be scheduled within the period from 7:00 a.m. to 6:00 p.m.

b) Overtime - Monday through Friday

If more than the recognized daily hours are worked in any day or shift on:

i) Monday through Thursday, such time shall be paid at the rate of time and one-half for the first three (3) hours, and double time for hours worked thereafter in any one day;

ii) Friday, such time shall be paid at the rate of time and one-half for the first four (4) hours, and double time for hours worked thereafter in any one day.

c) Overtime - Saturdays, Sundays and Holidays

On Saturdays, except as provided in Article 15.2, time and one-half shall be paid for all hours worked.

On Sundays, and Holidays as specified in Article 17, double time shall be paid for all hours worked.

2. Shift Conditions

On any job that a second shift is worked, an employee shall be paid a shift premium of 0.067 of his standard hourly rate of pay for each hour worked at straight time provided, the shift extends beyond 6:00 p.m. and ends before 12:00 midnight.

On any job that a shift is worked completely within the period 6:00 p.m. to 7:00 a.m., or where a shift continues past 12:00 midnight or where a shift starts before 6:00 a.m., an employee shall be paid a shift premium of 0.105 of the standard hourly rate of pay for each hour worked at straight time.

Shift Premiums will only apply on hours worked at straight time.

The starting and quitting time of all shift work will be decided by the Contractor.

Overtime payment for shift work will be in accordance with the provisions as set out above.

3. Travelling Time

Any time spent travelling by an employee in excess of fifteen (15) minutes going to work and fifteen (15) minutes returning from work will be paid at straight time rates. Travelling time shall be measured from the employee's assigned marshalling point on the Project to the work site.

4. Wages

The following wage rates will become effective on the date shown:

4.1 Non-Trainees (i.e., employees not covered by 4.2 below)

	Effective				
	May 1, 2016	**May 1, 2017**	**May 1, 2018**	**April 21, 2019**	**May 1, 2019**
Blaster (with Provincial Blaster Certificate)	31.63	32.45	33.31	41.30	42.39
Powderman	31.26	32.07	32.92		33.79
Driller – Diamond, Wagon & Air Track Etc.	31.26	32.07	32.92		33.79
Rock Scaler (Vertical Faces)	25.75	26.42	27.12		27.84
Jackhammer & Air Tool Operator	25.75	26.42	27.12		27.84
Concrete Worker: a) Vibrator Operator b) Screedman, Floatman	 26.69 25.77	 27.39 26.44	 28.11 27.14		 28.85 27.86
Concrete Finisher (per LOA 45)	29.43	30.21	31.01		31.83
Red Seal Cement Finisher (per LOA 45)	33.28	34.17	35.08		36.01
Small Mixer Operator (including operators of grout mixers and gunnite tools) and Mortarman	24.98	25.63	26.31		27.01
Pipelayer, Caulker on Tile and Concrete Pipe	24.98	25.63	26.31		27.01
Portable Compressor & Small Pump Operator (2" discharge and under)	24.82	25.46	26.13		26.82
Driller's Helper	24.75	25.39	26.06		26.75
General Construction Labourer* with 6 months or more accumulative experience on building construction in the industrial, commercial or institutional sectors	25.44	26.10	26.79		27.50
General Construction Labourer* with less than six 6 months experience	22.67	23.26	23.87		24.50
Certified General Labourer	28.01	28.50	29.15		29.83
Heavy Construction Labourers **	21.69	22.25	22.84		23.45

Flagman, Spotter	18.55	19.03	19.53		20.05

*General Construction Labourer includes, but is not limited to, wreckers, barmen, form strippers, labourers assisting carpenters and labourers involved in applying grout prior to a concrete pour and in curing and green cutting of concrete.

** Heavy Construction Labourer includes, but is not limited to, labourer's work on all clearing, excavation, grading, backfilling associated with heavy construction, dewatering and foundation preparation work including cleaning of rock surfaces in preparation for the 1st concrete pour; labourer's work associated with washing, screening and crushing plants.

In respect of the General Construction Labourer Classifications, the number of persons employed in the (b) classification compared to the (a) classification shall not exceed the ratio of unskilled to skilled labourers prescribed in the Construction Industry Wages Act. When a contractor appoints a Labour Foreman, he shall be paid fifteen percent (15%) over the highest classification base wage rate working under his direct supervision.

When a contractor appoints a Lead Hand, he shall be paid seven percent (7%) over the individual's base wage rate**.**

4.2 Trainees

a) A trainee means any person who is hired to participate in a contractor's formally structured on-the-job training program in any classifications set out in the Appendix, the nature of which are not designated trades (ie designated as being appropriate for apprenticeship or certification or both pursuant to the Apprenticeship and Trades Qualifications Act of the Province of Manitoba);

b) Trainees shall be paid a percentage of the rate in effect for the classification for which the employee is being trained in accordance with the following:

0 – 1200 hours	60%
1201 – 2400 hours	77%
2401 – 3600 hours	96%

If the duration of the training program is less than 200 hours (or 400 hours or 600 hours, as the case maybe), the employee's rate shall be increased to 100% of the rate in effect for that classification, effective on the first working day following the employee's successful completion of the training program.

c) Prior to implementing any formal on-the-job training programs for any classifications set out in the Appendix, the Contractor shall provide the Association and the Council with the following information:

i) The classification for which on-the-job training will be instituted and the scheduled commencement date of the training;
ii) The duration of the training.

d) The Contractor may employ one (1) trainee for every three (3) Labourers of total "Labourers" on each work site.

e) An employee who is hired in a non-training classification may be re-assigned to a formal on-the-job training program under the following conditions:

i) An employee requests, in writing, to participate in the Contractor's formal on-the-job training program and the Contractor approves the request;

ii) The Contractor requests that an employee be re-assigned to a formal on-the-job training program and the employee and the Council are in agreement with the re-assignment.

f) An employee who is re-assigned in accordance with (e) above shall be deemed to be a trainee and paid in accordance with the provisions of (b) above;

g) The Contractor shall provide each employee who successfully completes the Contractor's formal on-the-job training program with a letter confirming the type of training received and the corresponding number of hours the employee spent in such training.

5. Annual Vacation and Vacation Pay

Annual vacation will be arranged as provided in The Employment Standards Code of Manitoba.

Vacation Pay allowance will be accumulated for the credit of each employee at the rate of six percent (6%) of the employee's standard hourly rate for each hour worked.

Vacation pay allowance will be paid to an employee on his regular pay day.

6. Pay in Lieu of Statutory Holidays

Whether or not an employee works on any of the Statutory Holidays under Article 17, he shall receive in lieu of paid holidays, four and a half percent (4.5%) of his standard hourly rate for each hour worked. The employee shall be paid this amount every payday.

7. Trust Funds

Pension Plan

The Contractor, on behalf of each employee, and each employee covered by the Appendix, shall contribute the amounts set out below to the Specialized Workers' Pension Trust Fund. Contributions shall apply to all hours worked and shall be collected at the source as a payroll deduction.

The Contractor's contribution shall be:

Effective	May 1, 2016	$2.39 per hour
Effective	May 1, 2017	$2.49 per hour
Effective	May 1, 2018	$2.64 per hour
Effective	May 1, 2019	$2.74 per hour

The Employee's contribution shall be:

Effective	May 1, 2013	$0.60 per hour

Health & Welfare

The Contractor, on behalf of each employee, and each employee covered by the Appendix, shall contribute the amounts set out below to the Specialized Workers' Health and Welfare Trust Fund. Contributions shall apply to all hours worked and shall be collected at the source as a payroll deduction.

The Contractor's contribution shall be:

Effective	May 1, 2016	$0.50 per hour
Effective	May 1, 2017	$0.55 per hour
Effective	May 1, 2018	$0.55 per hour
Effective	May 1, 2019	$0.60 per hour

The Employee's contribution shall be:

Effective	May 1, 2013	$0.70 per hour

Submission of Trust Funds

The Contractor shall forward the above Trust Fund contributions to the designated Administrators of each plan on or before the fifteenth day (15th) of each month following the month in which contributions were made.

A form shall be supplied by the Union for the Contractor to identify the application of all contributions, and such form shall indicate the Administrator and the address to which contributions shall be forwarded.

8. Trusteed Training Fund Provision

Provided:

a) The Local Union to which employees covered by this Appendix belong establishes a Training Trust Fund in which employees covered by this Appendix are eligible to participate;

b) Written verification is forwarded to the Association and the Council by the Board of Trustees of each plan confirming:

i) Proviso (a), above;

ii) That Trust Agreements have been executed and registered.

As the above conditions have been met, a trusteed training fund will be introduced into this Appendix on the following basis:

The contractor, on behalf of each employee, shall respectively contribute the amounts set out below to the Construction and Specialized Workers Union Local 1258, Training Trust Fund. Contributions shall apply to all hours worked (regular and overtime).

The contractor's contribution shall be:

Effective October 17, 2016 $0.25 per hour

Contractor contributions to the fund will be discontinued immediately if one or more of the following occurs:

i) The fund ceases to be governed by a trust;

ii) The provisions of the trust are not fulfilled;

iii) Employers are no longer represented on the Board of Trustees.

- In the event either the Association or the Council has reason to believe that one or more of the conditions described in (i), (ii), or (iii) above have occurred, the matter shall be referred to the Joint Appendix Review Committee. Until the matter is resolved, Contractors shall hold all Contractor contributions in trust.

Submission of Trust Funds

The contractor shall forward the above Trust Fund contributions to the designated Administrator of the Plan on or before the fifteenth (15th) day of each month following the month in which contributions were made.
A form shall be supplied by the Union for the Contractor to identify the application of all contributions, and such form shall indicate the Administrator and the address to which contributions shall be forwarded.

9. Escalation and Reference

9.1 Wages Rates

The wage rate for all classifications in this Appendix shall be adjusted by a percentage, equivalent to and effective on the dates of any adjustment in wage rates, calculated on a percentage basis, which are negotiated from time to time for the classification of "General Labourer" by the Construction and Specialized Workers' Union, Local Union 1258, and the Construction Labour Relations Association of Manitoba.
In applying the percentage adjustment, the resultant wage rate shall be rounded to the nearest cent.

9.2 Vacation and Statutory Holiday Pay

Vacation and Statutory Holiday Pay shall be adjusted to be consistent with that negotiated between the Construction and Specialized Workers' Union, Local Union 1258, and the Construction Labour Relations Association of Manitoba.

9.3 Pension Plan and Health and Welfare

The Pension Plan and Health and Welfare Plan contributions will be adjusted to be consistent with the contributions negotiated from time to time by the Construction and Specialized Workers' Union, Local Union 1258, and the Construction Labour Relations Association of Manitoba, subject to the restrictions set out in Section 9.3.2.

9.3.2 The Contractor's contributions to the Pension and Health and Welfare Plans may be applied on a per hour worked basis, however, the Contractor's contribution rate for any overtime hours shall not be greater than the contribution rate in effect for straight time hours.

9.4 Notwithstanding anything contained in this Agreement or in this Appendix, the regular hours of work are not subject to adjustment during the life of this Agreement, and such regular hours of work shall be paid at regular rates of wages.

9.5 The provisions of 9.1 to 9.3 inclusive shall be dealt with by following the procedure set out in Article 30 of this Agreement.

APPENDIX NO. 1a – Security Guards

CONSTRUCTION AND SPECIALIZED WORKERS
(SECURITY GUARDS)

Local Union 1258

BURNTWOOD/NELSON AGREEMENT

*** Note – See Letter of Agreement #3, for additional information regarding Appendix 1A (Labourers being union affiliate for Security Guards)
*** Note – See Letter of Agreement #32, for additional information regarding Appendix 1A, Section 7 (Wages)

1. Hours of Work and Overtime

Due to the nature of the work employees covered by this Appendix may be required, if requested by the Contractor, to work up to twelve (12) hours per day or shift for six (6) consecutive days.

Nine (9) hours shall constitute a day's work for four (4) consecutive days, eight (8) hours shall constitute a day's work for the following consecutive day, and four (4) hours shall constitute a day's work for the following consecutive day. If more than the recognized daily hours are worked on any day or shift on these first six (6) days, such time shall be paid for at the rate of time and one-half.

On the seventh day, and on Holidays (Article 17), time and one-half shall be paid for all hours worked. Such overtime on the seventh day and on Holidays shall be applied to all hours worked on shifts that commence on or subsequent to 00:00 hours and prior to 24:00 hours of the calendar day on which the seventh day or Holiday falls.

Work schedules setting out the shift to be worked and the starting time of such shifts shall be posted in a place accessible to all employees.

An employee will be assigned a minimum of one (1) day of rest per work week.

2. Meal Breaks

In the event the Contractor requests an employee to remain on duty during a meal break, he shall be paid during the meal break at the applicable rate of pay.

3. Shift Conditions

An employee directed to work a night shift shall be paid a premium of twenty five cents (25¢) for each hour worked at the straight time rate provided, the majority of the shift is worked between the hours of 6:00 p.m. and 7:00 a.m.

Shift premium will only apply on hours worked at straight time.

4. Call Out

When an employee completes his regular shift, leaves the job and is subsequently called out for unscheduled work by the Contractor, he shall be paid a minimum of two (2) hours at the rate of time and one-half.

5. Rest Time

When an employee has not been provided with a break of at least eight consecutive hours between shifts, excluding any call out time of two (2) hours or less, he shall be paid time and one-half for all hours worked on the succeeding shift.

6. Travelling Time

Any time spent travelling by an employee in excess of fifteen (15) minutes both going to and returning from work will be paid at straight time rates. Travelling time shall be measured from the employee's assigned marshalling point on the Project to the work site.

7. Wages

Wage rates shall be as follows:

a) Security Guards (other than Trainees)

Effective	(1) Starting Rate	(2) Rate After 90 Days
May 1, 2016	$17.17	$17.84
May 1, 2017	$17.60	$18.28
May 1, 2018	$18.05	$18.74
May 1, 2019	$18.51	$19.22

On hire, Security Guards shall be paid the applicable "starting rate" set out in column (1). On the ninety first (91st) day of continuous employment on a project site, the employee's wage rate shall be increased correspondingly to that set out in column (2).

When an employee is rehired by a Contractor to work on the project site on which he had previously qualified for the rate set out in column 2, the employee shall be paid the rate set out in column 2.

When the Contractor appoints a Lead Hand, the employee so appointed shall receive a minimum of one dollar ($1.00) per hour above the highest hourly rate in effect in respect of Security Guards under his supervision.

b) Trainees

A person who is hired for participation in a formal on the job training program shall be paid an hourly rate equal to ninety percent (90%) of the 'Starting Rate' for security guards in effect at the time of hire, rounded to the nearest one cent (1¢).

The trainee shall be paid this rate until he has completed ninety (90) calendar days of continuous employment on the Project. However, if a trainee is laid off before having completed the said ninety (90) calendar days, and is subsequently rehired, the trainee shall be credited with the time previously worked. For any employment subsequent to the completion of the ninety (90) calendar day training period, the employee shall be advanced in pay scale to the applicable 'Starting Rate' for security guards.

A trainee shall generally be under the supervision and direction of qualified security guards during the training period and shall not be required to assume the duties and responsibilities of qualified security guards excepting:

i) When such assignments are for training purposes and the time required to perform same does not exceed three (3) hours;

ii) When such assignments are necessitated as a direct result of the unexpected absence of qualified security guards, provided the work assignment is consistent with the trainee's level of development and the assignment does not exceed one shift.

8. Vacation and Vacation Pay

Annual vacation will be arranged as provided in the Employment Standards Code for the Province of Manitoba.

Vacation Pay will be accumulated for the credit of each employee at the rate of six percent (6%) of the employee's standard hourly rate for each hour worked.
Vacation pay allowance will be paid to an employee on his regular pay day.

9. Pay in Lieu of Holidays

Whether or not an employee works on any of the Holidays set out in Article 17, he shall receive in lieu of paid Holidays, four and a half percent (4.5%) of his total gross wages, exclusive of overtime earned in the calendar year. The employee shall be paid this amount not later than the 31st day of December of the calendar year or upon termination of his employment whichever day is the earlier.

10. Other Conditions of Employment

a) Union Membership

Provided a Security Guard Employee covered by this Agreement is willing to become a Member of the Union in accordance with Article 12.2.1, Union Membership shall not be denied.

b) Supply of Uniforms

i) The Contractor shall supply uniforms (as may be required by the Contractor) for which the employee will not be charged, except as noted below;

Uniforms shall not include footwear, underwear, gloves and/or mitts.

ii) Furnished uniforms, excluding shirts, shall be cleaned and maintained at the Contractor's expense;

iii) Uniforms and equipment issued by the Contractor shall be returned by the employee, on termination of employment, to the senior authority of the Contractor on the Project Site. An employee shall be held responsible for proven negligent misuse or damage to uniforms and equipment.

c) Bonding

When requested by the Contractor, it shall be a condition of employment that Security Guards must qualify for and become bonded. In this case, the potential employee shall upon request fill in the necessary application, and the costs of such bonding shall be paid by the Contractor.

d) Personal Contracts

Any individual contract or agreement between a Contractor and an employee which sets out terms and conditions of employment in variance with the terms and conditions of employment contained in this Agreement shall be null and void in respect of employees covered by this Appendix while they are employed under this Agreement.

11. Pension and Health and Welfare Trust Funds

Pension Plan

The contractor on behalf of each employee, and each employee covered by this Appendix, shall respectively contribute the amounts set out below to the Labourers union (or directly to the Pension provider as necessary), local 1258, Pension Trust Fund. Contributions shall apply to all hours worked (regular and overtime). Employee contributions shall be collected at the source as a payroll deduction

The Contractor's contribution shall be:

Effective	November 15, 2015	$0.50 per hour

The Employee's contribution shall be:

Effective	November 15, 2015	$0.50 per hour

Health & Welfare

The contractor on behalf of each employee, and each employee covered by this Appendix, shall respectively contribute the amounts set out below to the Labourers union (or directly to the H&W provider as necessary), local 1258, Health and Welfare Trust Fund. Contributions shall apply to all hours worked (regular and overtime). Employee contributions shall be collected at the source as a payroll deduction

The Contractor's contribution shall be:

Effective	November 15, 2015	$0.60 per hour

The Employee's contribution shall be:

Effective	November 15, 2015	$0.60 per hour

Submission of Trust Funds

The Contractor shall forward the above Trust Fund contributions to the designated Administrators of each plan on or before the fifteenth day (15th) of each month following the month in which contributions were made.

A form shall be supplied by the Union for the Contractor to identify the application of all contributions, and such form shall indicate the Administrator and the address to which contributions shall be forwarded

12. Escalation and Reference

12.1 Wage Rates

As provided in Section 12.2, the wage rates for all classifications in this Appendix shall be adjusted by a percentage, equivalent to the percentage adjustment in wage rates and in the employers' contribution rate to pension and health and welfare plans negotiated from time to time for the classification of "General Labourer" (hereinafter referred to as the Reference Classification) by the Construction and Specialized Workers' Union, Local Union 1258, and the Construction Labour Relations Association of Manitoba.

12.2 Method of Calculating Percentage Adjustment of Classifications

The percentage adjustment of the Reference Classification shall be determined in accordance with the following formula:

$$\frac{\text{(Change in W) + (Change in P) + (Change in H\&W)}}{\text{(Expired W) + (Expired P) + (Expired H\&W)}} \times 100$$

Where:

- Change means the increase or decrease in that benefit.
- W means wage rate.
- P and H&W means the required employers' contribution rate to the pension and/or the health and welfare plan.
- Expired means the rate in effect when the last percentage adjustment was calculated.

12.2.1 In calculating the percentage adjustment of the Reference Classification, the result shall be rounded to the nearest hundredth of a per cent.

12.2.2 Effective Date of Adjustments

When changes to W or W and P and/or H&W in the agreement being used for reference purposes occur on the same date, the percentage adjustment of all such changes shall be calculated to determine the percentage adjustment by which wage rates in the Appendix are to be adjusted and the foregoing shall be the effective date of the resultant wage rates.

When changes to P and/or H&W are not effective on the effective date of any changes to W in the agreement being used for reference purposes, such changes shall be deemed to be effective on the date of a change to W next occurring, and the procedures set out above shall be followed.

When: a) there are no changes to W but there are changes to P and/or H&W, or b) there are changes to P and/or H&W but no subsequent changes to W during the term of the agreement being used for reference purposes, the calculated percentage adjustment shall be effective on the effective date of such changes in the agreement being used for reference purposes.

12.2.3 In applying the percentage adjustments, the resultant wage rates shall be rounded to the nearest cent.

12.3 Vacation and Holiday Pay

The percentage figure set out in Sections 8 and 9 of this Appendix, shall be adjusted to be the same as that in effect in Appendix No. 1 of this Agreement.

12.4 Notwithstanding anything contained in this Agreement or in this Appendix, the regular hours of work are not subject to adjustment during the life of this Agreement, and such regular hours of work shall be paid at regular rates of wages.

12.5 The provisions of 12.1 to 12.3 inclusive shall be adjusted by following the procedure set out in Article 30 of this Agreement.

APPENDIX NO. 2 – Crane Operators

INTERNATIONAL UNION OF OPERATING ENGINEERS

Local Union 987
Conditions Applicable to Crane Operators

BURNTWOOD/NELSON AGREEMENT

*** Note – See Letter of Agreement #33, for additional information regarding Appendix 2 (Telebelt Classification addition)
*** Note – See Letter of Agreement #42, for additional information regarding Appendix 2 (Tower Crane trade improvement trust fund)

1. Hours of Work and Overtime

Eight (8) hours shall constitute a day's work for five (5) days, Monday to Friday inclusive. Said hours shall normally be within the period from 7:00 a.m. until 6:00 p.m.

If more than the recognized daily hours are worked in any day or shift, Monday to Friday inclusive, such time shall be paid at the rate of time and one-half for the first two (2) hours and double the regular straight time hourly rate for all hours worked thereafter.

On Saturdays, except as provided in Article 15.2**,** Sundays, and Holidays as specified in Article 17, double time shall be paid for all hours worked.

2. Shift Conditions

If the conditions are such that work on that particular job cannot be done within the said normal hours (7:00 a.m. to 6:00 p.m.), then eight (8) hours may be worked during any hours and may constitute a regular shift on that job.

A premium of .067 of the regular straight time rate will be paid for each shift hour worked on a shift that cannot be done within the said normal hours except that on those shift hours which are worked between 12:00 midnight and 6:00 a.m. a premium of .142 of the regular straight time rate will be paid. Shift premium will not be paid on any overtime hours worked.

Overtime payment for shift work shall be in accordance with the provisions as set out above.

The starting and quitting time of all shift work will be decided by the Contractor.

3. Travel Time

Any time spent travelling by an employee in excess of fifteen (15) minutes going to work and fifteen (15) minutes returning from work will be paid at straight time rates. Travelling time shall be measured from the employee's assigned marshalling point on the Project to the work site.

4. Wages

Wage Rates shall be as follows:

4.1 Journeyman Status (i.e., Non-Trainees)

	Effective May 1, 2016	Effective May 1, 2017	Effective May 1, 2018	Effective May 1, 2019
Whirley, Tower, Climbing and Powerhouse Overhead Bridge Crane Classifications				
Operators of all Powerhouse Overhead Bridge Cranes and Operators of Climbing and Tower Cranes	$43.31	$44.46	$45.65	$46.87
Tower &Climbing Crane Apprentices				
1st year 0-750 hours - 55% of Tower Crane Operator Rate of Pay	$23.82	$24.46	$25.11	$25.78
1st year 751-1500 hours - 60% of Tower Crane Operator Rate of Pay	$25.98	$26.68	$27.39	$28.12
2nd year 1501-2250 hours – 70% of Tower Crane Operator Rate of Pay	$30.32	$31 .12	$31.96	$32.81
2nd year 1701-3400 hours – 75% of Tower Crane Operator Rate of Pay	$32.48	$33.35	$34.24	$35.15
New Journeyman 0-900 hours – 85% of Tower Crane Operator Rate of Pay	$36.81	$37.79	$38.80	$39.84
New Journeyman 901-1800 hours – 95% of Tower Crane Operator Rate of Pay	$41.14	$42.24	$43.37	$44.53
Mobile Crane Operators				
Class 1- Up to 50 ton and boom truck over 25 ton	$38.42	$39.44	$40.50	$41.58
Class 2 – 51 ton to 99 ton	$40.51	$41.59	$42.70	$43.84
Class 3 – 100 ton to 199 ton	$41.91	$43.03	$44.18	$45.36
Class 4 - 200 ton to 300 ton Crane Operators shall receive a premium of two and a half (2.5¢) cents per ton over the Class 4 rate while operating cranes over 300 ton capacity.	$43.31	$44.46	$45.65	$46.87
Mobile Crane Apprentices				
1st year 0-1700 hours - 60% of Class 1	$23.05	$23.67	$24.30	$24.95
2nd year 1701-3400 hours – 70% of Class 2	$28.36	$29.11	$29.89	$30.69
3rd year 3401-5100 hours – 80% of Class 3	$33.53	$34.43	$35.34	$36.29

Boom Truck Hoist Classifications				
Operators of Boom Truck Hoists up to 25 tons	30.74	31.56	32.40	33.27
Operators of Boom Truck Hoists > 25 tons	$38.42	$39.44	$40.50	$41.58

Note: The above classifications include operators of cranes converted for the placing of concrete (creter, telebelt or similar) and cranes adapted for pile driving and foundation boring. *** For these positions a hoisting ticket and/or red seal are not required for their operation.

When two (2) powerhouse overhead bridge cranes are being operated and the Contractor, pursuant to the provisions of Article 4, has assigned the operation of the first crane to the Operating Engineers, Local 987 and the second crane to the I.B.E.W., Local 2085, if the wage rate of the first crane operator is less than the wage rate of the second, the wage rate of the first crane operator shall be adjusted to be equal with the second, during the period both cranes are being operated as aforementioned.

All mobile and crawler crane operators must:

i. Be able to operate efficiently with maximum boom and jib.

ii. Be fully knowledgeable of all applicable safety requirements and regulations.

iii. Be able to perform routine maintenance on the equipment operated.

iv. Be able to set up and move the crane with due consideration for footing conditions, machine level and the positioning of outriggers, etc.

v. Be able to lift maximum loads safely at all positions of radius.

vi. Be able to control swing load out.

vii. Be able to assemble and dismantle jibs and booms.

viii. Be able to adjust both clutches and brakes (conventional) and inspect cables.

4.2 Mobile Crane Premiums

In respect of the classifications set out in Section 4.1 (b) above, a crane operator assigned to operate a mobile and crawler crane with a lattice boom (conventional crane) shall be paid the following premium while operating such equipment:

While operating a crane in Class 1 and 2, operators shall receive a $2.50 per hour premium if the crane has a lattice boom, or tower attachment, over the Class 1 or 2 rate.

While operating a crane in Class 3 or 4, operators shall receive a $3.50 per hour premium if the crane has a lattice boom, or tower attachment, over the Class 3 or 4 rate.

While operating a crane with a "super lift" attachment and/or a "luffing jib", operators shall receive a $2.00 per hour premium over the base rate.

4.3 Crane Foreman

When the Contractor appoints a Crane Foreman, the person so appointed shall receive a minimum of fifteen per cent (15%) per hour above the employee's existing rate.

4.4 Crane Operator Apprentices

The Contractor may employ one (1) Apprentice for every one (1) Journeyman employed by the Contractor as Crane Operators. Crane Operator Apprentices (except Boom Truck Hoist Operator Apprentices and Tower Crane Operator Apprentices) shall be paid the following, or the minimum wage rates prescribed in the Trade of Crane and Hoisting Equipment Operator Regulations, whichever is more favourable to the Apprentice:

0 to 1700 hour	- 60% of ***Class 1*** Journeyman
1701 - 3400 hours	- 70% of ***Class 2*** Journeyman
3401 - 5100 hours	- 80% of ***Class 3*** Journeyman

In order for an Apprentice to qualify for the next step on the Apprentice Scale, the Apprentice must successfully complete 1700 hours of practical and technical training.

Boom Truck Hoist Operator Apprentices shall be paid the following percentages of the applicable rate for a certified boom truck hoist operator as set out in Section 4.1 (c) above, or the minimum wage rates prescribed in the Trade of Crane and Hoisting Equipment Operator Regulations, whichever is more favourable to the Apprentice:

1st year - 60%
2nd year - 80%

Tower Crane Operator Apprentices shall be paid the following percentages of the applicable rate for a tower crane operator as set out in Section 4.1 (a) above, or the minimum wage rates prescribed in the Trade of Crane and Hoisting Equipment Operator Regulations, whichever is more favourable to the Apprentice:

1st year - 60%
2nd year - 80%

5. Rest Period

If an employee is not provided with at least an eight (8) hour rest period between shifts, the employee shall be paid at the applicable overtime rate until such time as an eight (8) hour break occurs.

If an employee is required to work through his lunch period he shall be paid at the applicable overtime rate for that period of time.

6. Callouts

An employee called out for work after he has competed his regular shift and has departed from the job site shall be paid a minimum of four (4) hours at the applicable overtime rate.

7. Vacation and Statutory Holiday Pay

Each employee shall be paid an amount equal to ten and a half percent (10.5%) of his gross wages (i.e., straight time and overtime wages) of which four and a half percent (4.5%) shall be in lieu of pay for the Statutory and General Holidays set out in Article 17.

Vacation pay and pay in lieu of Statutory Holidays shall be paid to each employee on his regular pay day. Such payments shall be considered as advance payments and in the case of vacation pay, full payment of all vacation with pay owing to the employee pursuant to the Employment Standards Code for the Province of Manitoba.

8. Pension and Health and Welfare Trust Funds

(a) Pension Trust Fund

The Contractor and each employee covered by this Appendix shall respectively contribute the amounts set out below to the Operating Engineers (987) Pension Trust Fund. Contributions shall apply to all hours worked. Contributions for all Apprentices shall be pro-rated at the applicable Apprentice percent to Journeyman rate, i.e. as a first year Apprentice will be paid at 55% of the Journeyman rate of pay, the Contractor will also therefore contribute a pension contribution for the Apprentice at 55% of the amount that a Journeyman is to receive (the same rationale is applicable for each step on the Apprentice Wage Scale). Employee contributions shall be collected at the source as a payroll deduction.

The Contractor's contribution shall be:

Effective May 1, 2016	$5.60 per hour
Effective May 1, 2017	$5.95 per hour
Effective May 1, 2018	$6.31 per hour
Effective May 1, 2019	$6.69 per hour

The employee's contribution shall be:

- Nil

(b) Health and Welfare Trust Fund

The Contractor shall contribute to the Operating Engineers (987) Health and Welfare Trust Fund the amount set out below for each hour worked by all employees covered by this Appendix:

Effective May 1, 2016, $1.65 per hour
Effective May 1, 2017 $1.70 per hour
Effective May 1, 2018 $1.75 per hour
Effective May 1, 2019 $1.80 per hour

(c) Trade Improvement Trust Fund

(1) Subject to (2) below, the Contractor and each employee covered by this Appendix shall respectively contribute the amounts set out below to the Operating Engineers (987) Trade Improvement Trust Fund. Contributions shall apply to all hours worked and employee contributions shall be collected at the source as a payroll deduction.

The Contractor's contribution shall be:

- Effective May 1, 2016 - 65¢ per hour
- Effective May 1, 2017 - 65¢ per hour
- Effective May 1, 2018 - 65¢ per hour
- Effective May 1, 2019 - 65¢ per hour

The Employee's contribution shall be:

- Nil

(2) Contractor and Employee contributions to the Fund will be discontinued immediately if one or more of the following occurs:

(i) the Fund ceases to be governed by a Trust,

(ii) the provisions of the Trust are not fulfilled,

(iii) Employers are no longer represented on the Board of Trustees,

(iv) The Trade Improvement Fund is not included in any of the following Collective Agreements:

- Heavy Equipment Rental Agreement
- The General Contractors Heavy Equipment Trade Division Agreement
- Heavy Equipment Industrial/Mechanical Agreement

(3) In the event either the Association or the Council has reason to believe that one or more of the conditions described in (i), (ii),(iii), or (iv) above has occurred, the matter shall be referred to the Joint Appendix Review Committee. Until the matter is resolved, Contractors shall hold all Contractor and Employee contributions in trust.

(d) Submission of Trust Funds

The Contractor shall forward the above Trust Fund Contributions to the Operating Engineers (Local 987) Pension Trust Fund, Health and Welfare Trust Fund, and Operating Engineers Trade Improvement Trust Fund to:

Coughlin and Associates Ltd.
100-175 Hargrave Street
Winnipeg, MB R3C 3R8

The said amounts will be submitted by the fifteenth (15th) day of the month following the month in which the hours were worked.

9. Log Book

Provided the Union supplies Crane Operators with appropriate log books, and the log book is submitted to the Contractor by the employee, the Contractor will record therein, in the space allocated for such purposes, the type and capacity of the Crane being operated by that employee, and the period of time the employee was operating such equipment.

10. Isolation Leave (Return Transportation Time Periods)

The return transportation time period referred to in Article 19.2.1 for this Appendix shall be:

- after twenty-eight (28) calendar days.

Travel time shall only apply on the return portion of an Isolation Leave trip (i.e. from the employee's T.D.P. to the Project Camp Site).

The amount of travel time to be paid shall be in accordance with the provisions of Article 19.1.2.5.1 or 19.1.2.5.2, as the case may be, and if applicable, the provisions of Article 19.1.2.5.3. Travel time shall be paid at the employee's straight time rate and an employee shall receive such payment pursuant to the provisions of Article 19.1.2.6.

11. Escalation and Reference

11.1 Wage Rates

(a) Whirley and Tower and Climbing and Powerhouse Overhead Bridge Crane Classifications

The wage rates for the classifications in Section 4.1 (a)(i), in this Appendix shall be adjusted by an amount equal to and effective on the dates of any adjustments in wages rates for the Class No. 6, 151 to 200 ton capacity (or the equivalent thereof) Crane Operator negotiated from time to time by the International Union of Operating Engineers, Local 987 and the Construction Labour Relations Association of Manitoba (C.L.R.A.) and set out in the Heavy Equipment Industrial/Mechanical (I/M) Collective Agreement, and the wage rates for the classifications in Section 4.1 (a)(ii), in this Appendix shall be adjusted by an amount equal to and effective on the dates of any adjustments in wages rates for the Class No. 4, 200 – 300 ton capacity (or the equivalent thereof) Crane Operator negotiated from time to time by the International Union of Operating Engineers, Local 987 and the Construction Labour Relations Association of Manitoba (C.L.R.A.) and set out in the Heavy Equipment Industrial/Mechanical (I/M) Collective Agreement.

(b) Mobile and Crawler Crane Classifications

The wage rates for each weight capacity grouping of Mobile and Crawler Crane classifications**,** and tonnage premiums for cranes over 200 tons as set out in Section 4.1(b) shall be adjusted by an amount equal to and effective on the dates of any adjustments in wage rates for the weight capacity grouping of Mobile and Crawler Crane classifications and tonnage premiums for cranes over 200 tons corresponding thereto negotiated from time to time by Local 987 and the C.L.R.A. and set out in the Heavy Equipment Industrial/Mechanical Agreement (I/M Agreement).

(c) Boom Truck Hoist Classifications

The wage rates for each weight capacity grouping of Boom Truck Hoist classifications as set out in Section 4.1(c) shall be adjusted by a percentage equal to and effective on the dates of any increases or decreases to wage rates for the Class 2, 25 ton or greater capacity (or equivalent thereof) Crane Operator negotiated from time to time by Local 987 and the C.L.R.A. and set out in the Heavy Equipment Industrial/Mechanical Agreement (I/M Agreement).

(d) Apprentices

The wage rates for Apprentices (except Boom Truck Hoist Operator Apprentices and Tower Crane Operator Apprentices) shall be adjusted to be consistent with the said Heavy Equipment Industrial/Mechanical Agreement (I/M Agreement).

(e) Lattice (Conventional) Boom Premium

The lattice boom premium set out in Section 4.2 shall be adjusted by an amount equal to and effective on the dates of any adjustments in the lattice boom premium negotiated from time to time by the aforementioned Parties and set out in the I/M Agreement, provided such premium continues to be considered, by the Parties to the I/M Agreement, an intrinsic component of wage rates, otherwise, payment of the premium shall be discontinued and pursuant to Article 30, the premium shall be deleted from this Appendix.

11.2 Overtime

Overtime payments, subject to the restrictions set out in Section 11.5, will be adjusted to be consistent with overtime conditions in the I/M Heavy Equipment Collective Agreement save and except that overtime at a rate greater than time and one-half will not be introduced in this Appendix in respect of the first two (2) hours of overtime, Monday to Friday inclusive.

11.3 Vacation and Holiday Pay

The percentage figure set out in the Vacation and Holiday Pay Section of this Appendix shall be adjusted to be the same as that negotiated from time to time by the Heavy Equipment I/M Trade Division of the Construction Labour Relations Association of Manitoba and the Operating Engineers, Local 987.

11.4 Other Conditions of Employment

Except as otherwise noted, the following conditions of employment will be adjusted to be consistent with corresponding conditions of employment negotiated by Local 987 and the C.L.R.A. and set out in the I/M Agreement:

(a) the registered and trusteed pension and health and welfare plans (subject to the restrictions set out in Section 11.4.1).

(b) the trusteed trade improvement plan (subject to the provisions of Section 8(c)(2) and the restrictions set out in Section 11.4.1).

(c) the time period between Isolation Leaves (subject to the restrictions of Article 19.2.1.3).

(d) Travel time associated with the taking of an Isolation Leave, and the hourly rate at which travel time will be paid (subject to the restrictions set out in Section 11.4.2).

11.4.1 The Contractor's contribution to any of the plans referred to in Section 11.4(a) and (b) may be applied on a per hour worked basis; however, the Contractor's contribution rate in respect of overtime hours shall not be greater than the required contribution rate for contractors in respect of straight time hours.

11.4.2 Travel time may only apply to the return portion of an Isolation Leave trip (i.e. from the employee's T.D.P. to the Project Camp Site). The amount of travel time to be paid shall not be greater than the travel time set out in Articles 19.1.2.5.1, 19.1.2.5.2 and 19.1.2.5.3, as may be applicable. The hourly rate at which travel time may be paid shall not be greater than the employee's straight time rate. Payment of travel time shall be in accordance with the provisions of Article 19.1.2.6.

11.5 Notwithstanding anything contained in this Agreement or in this Appendix, the regular hours of work are not subject to adjustment during the life of this Agreement, and such regular hours of work shall be paid at regular rates of wages.

11.6 The provisions of 11.1 to 11.4 inclusive shall be dealt with by following the procedure set out in Article 30 of this Agreement.

11.7 Notwithstanding anything contained in this Agreement or in this Appendix, in the event that the wage rate for Class 4, 200 – 300 ton capacity, (or equivalent thereof) Crane Operators in the I/M Agreement differs from the wage rate for Class 1 Tower and Climbing Crane Operators in the Collective Agreement between the Construction Labour Relations Association of Manitoba (C.L.R.A.), General Contractors Heavy Equipment Trade Division, and the International Union of Operating Engineers, Local 987, and/or the wage rate for Class 6, 151 to 200 ton capacity, (or equivalent thereof) Crane Operators in the I/M Agreement differs from the wage rate for Class 2 Tower and Climbing Crane Operators in the Collective Agreement between the Construction Labour Relations Association of Manitoba (C.L.R.A.), General Contractors Heavy Equipment Trade Division, and the International Union of Operating Engineers, Local 987, the Joint Appendix Review Committee shall meet within 30 days to determine if the I/M Agreement is still an appropriate Agreement to be used for reference purposes. If the Joint Appendix Review Committee cannot reach agreement, the matter shall be resolved under the provisions of Article 31 (Mediation).

APPENDIX NO. 2a – Equipment Operators

INTERNATIONAL UNION OF OPERATING ENGINEERS

Local Union 987
Equipment Operators and Allied and Support Services

BURNTWOOD/NELSON AGREEMENT

*** Note – See Letter of Agreement #42, for additional information regarding Appendix 2A, (Tower Crane trade improvement trust fund)
*** Note – See Letter of Agreement #43, for additional information regarding Appendix 2A, Section 4 (Power Engineer classification and wage adjustment)
*** Note – See Letter of Agreement #62, for additional information regarding Appendix 2A, (Heavy Duty Diesel Mechanics wage enhancement)

1. Hours of Work and Overtime

(a) Hours Monday through Friday

Nine (9) hours shall constitute a day's work for four (4) days Monday through Thursday, and eight (8) hours shall constitute a day's work for Friday.

The regular first shift shall normally be scheduled within the period from 7:00 a.m. to 6:00 p.m.

(b) Overtime - Monday through Friday

If more than the recognized daily hours are worked in any day or shift on:

(i) Monday through Thursday, such time shall be paid at the rate of time and one-half for the first three (3) hours, and double time for hours worked thereafter in any one day.

(ii) Friday, such time shall be paid at the rate of time and one-half for the first four (4) hours, and double time for any hours worked thereafter.

(c) Overtime Saturdays, Sundays and Holidays

On Saturdays, except as provided in Article 15.2, time and one-half shall be paid for the first ten (10) hours worked and double time for any hours worked thereafter.

On Sundays, and Holidays as specified in Article 17, double time shall be paid for all hours worked.

(d) Day-off, Other Than Sunday

When an employee is required to work shifts to accommodate the continuous operation of compressors, pumps, boilers or other such equipment, an employee can be assigned a day of rest, other than Sunday.

In this case, for purposes of applying provisions 1 (a), (b) and (c) above, the assigned day of rest shall be recognized as a Sunday and the subsequent six (6) consecutive days as Monday through Saturday.

2. Shift Conditions

On any job that a second shift is worked, an employee shall be paid a shift premium of 0.067 of his standard hourly rate of pay for each hour worked at straight time provided the shift extends beyond 6:00 p.m. and ends before midnight.

On any job that a shift is worked completely within the period 6:00 p.m. to 7:00 a.m., or where a shift continues past midnight, or where a shift starts before 6:00 a.m., an employee shall be paid a shift premium of 0.105 of the standard hourly rate of pay for each hour worked at straight time.

Shift premiums will only apply on hours worked at straight time.

The starting and quitting time of all shift work will be decided by the Contractor.

Overtime payment for shift work shall be in accordance with the provisions as set out above.

3. Travelling Time

Any time spent travelling by an employee in excess of fifteen (15) minutes going to work and fifteen (15) minutes returning from work will be paid at straight time rates. Travelling time shall be measured from the employee's assigned marshalling point on the Project to the work site.

4. Wages

Wage rates shall be as follows:

4.1 Non-Trainees (i.e., employees not covered by 4.2 and 4.3 below)

CLASSIFICATION	Effective June 28, 2019
GROUP 1	
Operators of shovels, clamshells and draglines:	
a) 10 cu.yd. and up to and including 15 cu.yd.	$ 34.49
b) 5 cu.yd. and up to but not including 10 cu.yd.	$ 33.77
c) under 5 cu.yds.	$ 32.91
GROUP 2	
Operator of backhoes and gradalls:	
a) 10 cu.yd. and up to and including 15 cu.yd	$ 33.90
b) 5 cu.yd. and up to but not including 10 cu.yd.	$ 32.91
c) 2½ cu.yd. and up to but not including 5 cu.yd.	$ 30.82
d) under 2½ cu.yd.	$ 28.95
GROUP 3	
Operators of crawlers and wheel type loaders including loaders converted for forklifting:	
a) 10 cu.yd. and up to and including 15 cu.yd. capacity	$ 30.28
b) 5 cu.yd. and up to but not including 10 cu.yd. capacity	$ 28.67
c) under 5 cu.yd. capacity	$ 27.90
GROUP 4	
Operators of crawler and wheel type tractors with attachments such as ripper and/or dozer and/or scraper etc.:	
a) D-10, D-9 in tandem, (or equivalent)	$ 29.20
b) D-9 or under, (or equivalent)	$ 28.58

GROUP 5	
Operators of self-propelled wheeled type scrapers (all types):	
a) 30 cu.yd. and up to and including 45 cu.yd.	$ 28.45
b) under 30 cu.yd. capacity	$ 27.54
GROUP 6	
Operators of Batch Plants:	
a) over 200 cu.yd. per hour rated capacity	$ 32.77
b) over 100 cu.yd. per hour including 200 cu.yd. per hour rated capacity	$ 30.58
c) over 50 cu.yd. and up to and including 100 cu.yd. per hour rated capacity	$ 28.33
d) 50 cu.yd. rated capacity and under	$ 27.31
GROUP 7	
Operators of crusher, screening and washing plants with rated capacity:	
a) 100 cu.yd. per hour and up	$ 28.45
b) Under 100 cu.yd. per hour	$ 27.54
GROUP 8	
Operators of conveyor belts and conveyor type loader (Barber Greene, Kohlman or similar types):	$ 27.31
GROUP 9	
Operators of inboard or outboard boats with motors rated:	
a) over 225 HP	$ 27.77
b) 225 HP and under	$ 25.99
GROUP 10	
Operators of motor graders:	
a) Finishing	$ 29.18
b) Other	$ 27.77
GROUP 11	

Operators of truck-mounted foundation boring machines:	
a) over 100 HP	$ 28.54
b) 100 HP and under	$ 27.54
GROUP 12	
Operators of Forklifts and Dinky locomotives:	
a) Forklifts	$ 27.31
b) Dinky locomotives	$ 28.45
GROUP 13	
Operators of:	
a) Tuggers, powerhoists, and Bullmooses	$ 29.89
b) Electrical hoisting equipment,fixed or travelling, with remote or suspended controls, up to and including 30 ton capacity	$ 29.18
c) Boom Truck Hoists, including Hiabs, hydra lifts, or similar of less than 7300 kilogram capacity*	$ 29.18
GROUP 14	
Operators of grout plants, concrete pumps, air drills and diamond drills:	$ 27.20
GROUP 15	
Operators of self-propelled vibratory compactors and tractor hauled compactor units:	
a) over 100 HP	$ 26.89
b) 100 HP and under	$ 26.30
GROUP 16	
Air compressor attendants:	
a) 1000 CFM and over	$ 26.89
b) under 1000 CFM	$ 26.30
GROUP 17	
Pump attendants:	
a) 6" discharge and over	$ 26.89
b) 2" to under 6" discharge	$ 26.30
GROUP 18	
Heavy Duty Gas and Diesel Mechanics:	

a) with a certificate of qualification	$ 35.33
b) without a certificate of qualification	$ 32.86
GROUP 19	
Serviceman	$ 28.45
GROUP 20	
Drill Doctor (Drill Mechanic):	
a) Hydraulic Drills	$ 32.21
b) Airtrac Drills	$ 32.09
c) Bit Sharpener	$ 28.95
GROUP 21	
Welders:	
a) CWB certified	$ 33.88
b) Non-certified	$ 33.21
GROUP 22	
Mechanic's helpers, welder's helpers, serviceman's helpers and oiler's	$ 24.76
GROUP 23	
Power Engineer:	
a) Third Class	$ 29.09
b) Fourth Class	$ 28.33
GROUP 24 *	
Power Engineer:	
a) Fourth Class*	$ 40.65

* Per LOA 43, the classification of Power Engineer, level 4, has been re-established. This pay group 24, will be in effect only by employer BBE, who is completing the general civil work at the Keeyask Generating Station. On completion of the BBE contract, pay group 24 will become null and void, and will be deleted.

When the Contractor appoints a Mechanic or Equipment Foreman, the person so appointed shall receive a minimum of ten per cent (10%) per hour above the highest paid rate of those employees being supervised.

*For boom truck hoists in excess of 7,299 kgs., see Appendix 2.

If dredging work is undertaken, at the request of either the Association or Council, the

Joint Appendix Review Committee will establish Operating Engineer Classifications associated with dredging, and rates of pay for such classifications.

4.2 Heavy Duty Mechanic Apprentices and Boom Truck Hoist Operator Apprentices

Heavy Duty Mechanic Apprentices shall be paid the following percentages of the rate for a certified heavy duty mechanic, as set out in (A) above.

1st year - 60%
2nd year - 70%
3rd year - 75%
4th year - 85%

Unless otherwise agreed to by the Council and the Association, the number of apprentices who may be employed by a Contractor shall not exceed one (1) apprentice for every three (3) qualified heavy duty mechanics employed.

Boom Truck Hoist Operator Apprentices shall be paid the following percentages of the rate for a certified boom truck hoist operator as set out in Group 13, d),above, or the minimum wage rates prescribed in the Trade of Crane and Hoisting Equipment Operator Regulations, whichever is more favourable to the Apprentice:

1st year - 60%
2nd year - 80%

The number of apprentices who may be employed by a Contractor shall not exceed one (1) apprentice for every one (1) certified Boom Truck Hoist Operator employed.

4.3 Trainees

(a) A trainee means any person who is hired to participate in a contractor's formally structured on-the-job training program in any classifications set out in the Appendix, the nature of which are not designated trades (ie designated as being appropriate for apprenticeship or certification or both pursuant to the Apprenticeship and Trades Qualifications Act of the Province of Manitoba).

(b) Trainees shall be paid a percentage of the rate in effect for the classification for which the employee is being trained in accordance with the following:

1 - 200 hours	60 %
201 - 400 hours	70 %
401 - 600 hours	80 %
601 or more hours	90 %

If the duration of the training program is less than 200 hours (or 400 hours or 600 hours, as the case maybe), the employee's rate shall be increased to 100% of the rate in effect for that classification, effective on the first working day following the employee's successful completion of the training program.

(c) Prior to implementing any formal on-the-job training programs for any classifications set out in the Appendix, the Contractor shall provide the Association and the Council with the following information:

i. the classification for which on-the-job training will be instituted and the scheduled commencement date of the training

ii. the duration of the training.

(d) The number of trainees shall not exceed twenty-five percent (25%) of the total number of employees employed by a Contractor and covered by this Appendix except as may otherwise be agreed to by the Association and the Council.

(e) An employee who is hired in a non-training classification may be re-assigned to a formal on-the-job training program under the following conditions:

(i) an employee requests, in writing, to participate in the Contractor's formal on-the-job training program and the Contractor approves the request;

(ii) the Contractor requests that an employee be re-assigned to a formal on-the-job training program and the employee and the Council are in agreement with the re-assignment.

(f) An employee who is re-assigned in accordance with (e) above shall be deemed to be a trainee and paid in accordance with the provisions of (b) above.

(g) The Contractor shall provide each employee who successfully completes the Contractor's formal on-the-job training program with a letter confirming the type of training received and the corresponding number of hours the employee spent in such training.

5. Vacations and Vacation Pay

Annual vacation will be arranged as provided in The Employment Standards Code for the Province of Manitoba.

Vacation Pay allowance will be accumulated for the credit of each employee at the rate of six percent (6%) of the employee's standard hourly rate for each hour worked.

Vacation pay allowance will be paid to an employee on his regular pay day.

6. Pay in Lieu of Holidays

Whether or not an employee works on any of the Holidays under Article 17, he shall receive in lieu of paid holidays, four and a half percent (4.5%) of his standard hourly rate for each hour worked. The employee shall be paid this amount on his regular payday.

7. Pension and Health and Welfare Trust Funds

(a) Pension Trust Fund

The Contractor and each employee covered by this Appendix shall respectively contribute the amounts set out below to the Operating Engineers (987) Pension Trust Fund. Employer contributions for all Apprentices and Trainees shall be pro-rated at the applicable Apprentice to Journeyman or Trainee to Non-trainee wage rate. Contributions shall apply to all hours worked. Employee contributions shall be collected at the source as a payroll deduction.

The Contractor's contribution shall be:

Effective July 3, 2016	$4.30 per hour
Effective May 1, 2017	$4.50 per hour
Effective May 1, 2018	$4.65 per hour

The employee's contribution shall be:

- nil.

(b) Health and Welfare Trust Fund

The Contractor shall contribute to the Operating Engineers (987) Health and Welfare Trust Fund the amount set out below for all hours worked by all employees covered by this Appendix:

Effective May 1, 2018	$1.70 per hour
Effective June 29, 2019	$1.80 per hour

(c) Submission of Trust Funds

The Contractor shall forward the above Trust Fund Contributions to the Operating Engineers (Local 987) Pension Trust Fund and Health and Welfare Trust Fund. The said amounts will be submitted by the fifteenth day of the month following the month in which the hours were worked.

8. Trade Improvement Trust Fund

(a) Subject to (b) below, the Contractor and each employee covered by this Appendix shall respectively contribute the amounts set out below to the Operating Engineers (987) Trade Improvement Trust Fund. Contributions shall apply to all hours worked and employee contributions shall be collected at the source as a payroll deduction.

The Contractor's contribution shall be:

- Thirty cents per hour.

The Employee's contribution shall be:

- nil**.**

The Contractor shall forward the above contributions to the Operating Engineers (987) Trade Improvement Trust Fund by the fifteenth (15th) day of the month following the month in which the hours were worked.

(b) Contractor and Employee contributions to the Fund will be discontinued immediately if one or more of the following occurs:

(i) the Fund ceases to be governed by a Trust,

(ii) the provisions of the Trust are not fulfilled,

(iii) Employers are no longer represented on the Board of Trustees,

(iv) the Trade Improvement Trust Fund is not included in any of the following

collective agreements:

- Heavy Equipment Rental Agreement
- The General Contractors Heavy Equipment Trade Division Agreement
- Heavy Equipment Industrial/Mechanical Agreement

(c) In the event that either the Association or the Council has reason to believe that one or more of the conditions described in (b) above has occurred, the matter shall be referred to the Joint Appendix Review Committee. Until the matter is resolved, Contractors shall hold all Contractor and employee contributions in trust.

9. Escalation and Reference

9.1 Wage Rates

9.1.1 General Approach

Subject to and in accordance with the conditions set out below, and subject to any adjustments arising from the application of Section 9.3, the sum of the wage rates and Contractors' contributions to pension and health and welfare plans set out in Section 4 and Section 7 (Group 1 to 23 inclusive) of this Appendix will be adjusted by a percentage equivalent to the weighted percentage adjustment in wage rates and in the employers' contribution rate to pension and health and welfare plans negotiated from time to time for each of the Reference Classifications set out in 9.1.2.

9.1.2 Reference Classifications and Weighting

The Reference Classifications and the weighting of these classifications shall be as follows:

Reference Classification	Weighting Factor
The Crane Operator classification incorporating those Crane Operators operating cranes of sixty (60) ton capacity - as set out in the Industrial/Mechanical Agreement negotiated and executed by the Construction Labour Relations Association (CLRA) of Manitoba and the Operating Engineers, Local 987.	25%
Journeyman Sheet Metal Worker - as set out in the Agreement negotiated and executed by the CLRA of Manitoba and Sheet Metal Workers, Local Union 511.	25%
Journeyman Carpenter - as set out in the Agreement negotiated and executed by the CLRA of Manitoba and the Carpenters,	25%

Local Union 343.	
General Labourer - as set out in the Agreement negotiated and executed by the CLRA of Manitoba and the Construction and Specialized Workers' Union, Local Union 1258.	25%

9.1.3 Method of Calculating Weighted Percentage Adjustment of Reference Classifications

The weighted percentage adjustment of each Reference Classification shall be determined in accordance with the following formula:

$$\frac{\text{(Change in W) + (Change in P) + (Change in H\&W)}}{\text{(Expired W) + (Expired P) + (Expired H\&W)}} \times 100 \times \text{Weighting Factor}$$

Where:

- Change means the increase or decrease in that benefit.
- W means wage rate
- P and H&W means the required employers' contribution rate to the pension and/or the health and welfare plan.
- Expired means the rate in effect when the last weighted percentage adjustment was calculated.
- Weighting factor means the factor assigned to a particular Reference Classification as set out in 9.1.1.

9.1.3.1 In calculating the weighted percentage adjustment of a Reference Classification, the arithmetic result shall be rounded to the nearest hundredth of a percent.

9.1.4 Effective Date of Wage Rate Adjustments and Adjustments to Pension and Health and Welfare Plans and Application of the Formula

9.1.4.1 Effective Date of Wage Rate Adjustments

When the wage rate adjustment of a Reference Classification(s) is effective on the first of any month, then the wage rate adjustment of the hourly rates in this Appendix shall be effective on that date.

When the wage rate adjustment of a Reference Classification(s) is not effective on the first of any month, it shall be deemed to be effective on the first of the month following, and the wage rate adjustment of hourly rates in this Appendix shall be effective on that date.

9.1.4.2 Effective Date of Adjustments to the Employers' Contribution Rate to Pension and/or Health and Welfare Plans

When the adjustment to the employers' contribution to the pension and/or health and welfare plans of a Reference Classification(s) is effective on the effective date, or pursuant to 9.1.4.1 the deemed effective date, of any wage rate adjustment of any Reference Classification, then such adjustment shall be calculated and taken into account on that date. If this is not the case, then such adjustment shall be calculated and taken into account on the closest following effective date of a wage rate adjustment.

9.1.4.3 In applying the weighted percentage adjustment, the resultant wage rate shall be rounded to the nearest cent, following which, any adjustment required by virtue of Section 9.3 shall be introduced to yield the new wage rate schedule that will apply in this Appendix.

9.2 Vacation and Statutory Holiday Pay

Vacation and Statutory Holiday Pay shall be adjusted to be consistent with that negotiated between the Labourers' International Union of North America, Local 1258**,** and the Construction Labour Relations Association of Manitoba. However, such Vacation and Statutory Holiday Pay shall not be less than six percent (6%) and four percent (4%), respectively, of the employee's straight time hourly rate.

9.3 Pension and Health and Welfare

9.3.1 Subject to the conditions set out below, Pension and Health and Welfare Contributions shall be adjusted to be consistent with contributions in effect in the Heavy Equipment Industrial/Mechanical Agreement negotiated by the CLRA of Manitoba and the Operating Engineers, Local 987. Notwithstanding the above, with respect to the pension plan, the Council may elect to adjust by an amount less than the increases stipulated from time to time in the said Heavy Equipment I/M Agreement.

9.3.2 The Contractor's contribution to the Pension and Health and Welfare Plans

may be applied on a per hour worked basis; however, the Contractor's contributions rate in respect of overtime hours shall not be greater than the required contribution rate for Contractors in respect of straight time hours.

9.3.3 Pursuant to 9.3.1, when the negotiated effective date of any adjustment to the Contractor's contribution rate to either the Pension or Health and Welfare Plans does not occur on the effective date of an adjustment to wage rates in this Appendix, at the option of the Operating Engineers, Local 987, the implementation of such an adjustment may be delayed so that it coincides with the effective date of the next subsequent adjustment to wage rates. Notification, in writing, specifying that the Operating Engineers are electing to exercise this option shall be provided by the Council Appendix Review Committee to the Association Appendix Review Committee at the time and under the conditions set out in Article 30.5.1.

9.3.4 Any adjustment to the Contractor's contribution rate to the Pension and/or Health and Welfare Plans will be dealt with as follows:

9.3.4.1 When the effective date of the adjustment to either Plan coincides with an adjustment date for wage rates in this Appendix, the resultant hourly rates (i.e., the hourly rates resulting from the application of the weighted percentage adjustment factor) will be reduced by the amount of the increase (or increased by the amount of any decrease) in the Contractor's contribution rate to the Plans.

9.3.4.2 When the effective date of the adjustment to either Plan does not coincide with an adjustment date for wage rates in this Appendix, the hourly wage rates in this Appendix will be reduced by the amount of the increase (or increased by the amount of any decrease) in the Contractor's contribution rate to the Plans.

9.3.4.3 In the event the Local 987 Union requests a reduction in the Contractors' contribution to the pension plan, with the decrease being accounted for by increasing the hourly rates, the request shall be only permitted to the extent the Contractors' contribution is greater than the employers' required contribution to the pension plan set out in the Heavy Equipment I/M Agreement described in section 9.3.1.

9.4 Notwithstanding anything contained in this Agreement or in this Appendix, the regular hours of work are not subject to adjustment during the life of this Agreement, and such regular hours of work shall be paid at regular rates of wages.

9.5 Wage rates, Vacation and Holiday Pay, and Pension and Health and Welfare

contributions shall be adjusted by following the procedure set out in Article 30.

APPENDIX NO. 3 – Teamsters, Chauffeurs, Warehousemen and Helpers

INTERNATIONAL BROTHERHOOD OF TEAMSTERS, CHAUFFEURS, WAREHOUSEMEN AND HELPERS OF AMERICA

Local Union 979

BURNTWOOD/NELSON AGREEMENT

*** Note – See Letter of Agreement #10, for additional information regarding Appendix4, section 7

1. Hours of Work and Overtime

(a) Hours Monday through Friday

Nine (9) hours shall constitute a day's work for four (4) days Monday through Thursday, and eight (8) hours shall constitute a day's work for Friday.

The regular first shift shall normally be scheduled within the period from 7:00 a.m. to 6:00 p.m.

(b) Overtime - Monday through Friday

If more than the recognized daily hours are worked in any day or shift on:

i) Monday through Thursday, such time shall be paid at the rate of time and one-half for the first three (3) hours, and double time for hours worked thereafter in any one day.

ii) Friday, such time shall be paid at the rate of time and one-half for the first four (4) hours, and double time for hours worked thereafter.

(c) Overtime - Saturdays, Sundays and Holidays

On Saturdays, except as provided in Article 15.2, time and one-half shall be paid for the first ten (10) hours worked and then double time for any hours worked thereafter.

On Sundays, and Holidays as specified in Article 17, double time shall be paid for all hours worked.

2. Shift Conditions

On any job that a second shift is worked, an employee shall be paid a shift premium of 0.067 of his standard hourly rate of pay for each hour worked at straight time provided, the shift extends beyond 6:00 p.m. and ends before midnight.

On any job that a shift is worked completely within the period 6:00 p.m. to 7:00 a.m., or where a shift continues past midnight or where a shift starts before 6:00 a.m., an employee shall be paid a shift premium of 0.105 of the standard hourly rate of pay for each hour worked at straight time.

Shift Premiums will only apply on hours worked at straight time.

The starting and quitting time of all shift work will be decided by the Contractor.

Overtime payment for shift work shall be in accordance with the provisions as set out above.

3. Travelling Time

Any time spent travelling by an employee in excess of fifteen (15) minutes going to work and fifteen (15) minutes returning from work will be paid at straight time rates. Travelling time shall be measured from the employee's assigned marshalling point on the Project to the work site.

4. Wages

Wage rates will be paid as follows:

4.1 Non-Trainees (i.e., employees not covered by 4.2 below)

CLASSIFICATION	Effective May 1, 2017	Effective May 1, 2018	Effective May 1, 2019	Effective May 1, 2020
GROUP 1 Belly dump trucks End-dumps (Rock Wagon) Euclid or similar Low Beds Wheeler tractor Hauling units	**$28.95**	**$29.68**	**$30.32**	**$30.07**
GROUP 2 Semi-trailers Fuel Trucks A-Frame; Boom Truck	**$28.36**	**$29.07**	**$29.70**	**$29.45**

Hoists, including Hiabs, Hydra lifts, or similar of less than 7300 kilogram capacity; Transit Mix Trucks Truck Mechanic Partsman				

CLASSIFICATION	Effective May 1, 2017	Effective May 1, 2018	Effective May 1, 2019	Effective May 1, 2020
GROUP 3 Tandem Trucks Buses Forklifts Water Trucks Winch Trucks Truck Serviceman Warehouse person - after 6 months	**$27.85**	**$28.55**	**$29.17**	**$28.92**
GROUP 4 Trucks under 5-ton rating Manhaul Trucks Passenger Vans Warehouse person - Starting Rate Swamp Buggy Mechanic's and Serviceman's helper	**$27.30**	**$27.99**	**$28.59**	**$28.34**
GROUP 5 a) Boom Truck Hoists, including Hiabs, Hydro lifts, or similar of 13,600 kilogram capacity or greater (Operator must be certified or Apprentice)	**$31.29**	**$32.08**	**$32.77**	**$32.52**
b) Boom Truck Hoists, including Hiabs, Hydra lifts, or similar of 7,300 kilogram to 13,599 kilogram capacity (Operator must be certified or Apprentice)	**$29.82**	**$30.58**	**$31.23**	**$30.98**

Utility Driver *	**$31.29**	**$32.08**	**$32.77**	**$32.52**

* Utility Driver - A person hired as a Utility Driver shall be qualified to operate any of the equipment listed in Groups 1 to 5, inclusive.

When a contractor appoints a Truck Foreman or Warehouse Foreman, the employee so appointed shall receive a minimum of one dollar ($1.00) per hour above the highest rate of those employees being supervised.

In the event additional mechanic classifications are required in this Appendix, the scale of wage rates for such classifications shall be established by the Joint Appendix Review Committee on request from either the Council or the Association.

Fire retardant coveralls will be supplied to fuel truck drivers and their helpers.

4.2 Trainees

(a) A trainee means any employee who is hired to participate in a contractor's formally structured on-the-job training program in any classifications set out in the Appendix, the nature of which are not designated trades (ie designated as being appropriate for apprenticeship or certification or both pursuant to the Apprenticeship and Trades Qualifications Act of the Province of Manitoba).

(b) Trainees shall be paid a percentage of the rate in effect for the classification for which the employee is being trained in accordance with the following:

1 - 200 hours	60 %
201 - 400 hours	70 %
401 - 600 hours	80 %
601 or more hours	90 %

If the duration of the training program is less than 200 hours (or 400 hours or 600 hours, as the case maybe), the employee's rate shall be increased to 100% of the rate in effect for that classification, effective on the first working day following the employee's successful completion of the training program.

(c) Prior to implementing any formal on-the-job training programs for any classifications set out in the Appendix, the Contractor shall provide the Association and the Council with the following information:

i) the classification for which on-the-job training will be instituted and the scheduled commencement date of the training

ii) the duration of the training

(d) The number of trainees shall not exceed twenty-five percent (25%) of the total number of employees employed by a Contractor and covered by this Appendix except as may otherwise be agreed to by the Association and the Council.

(e) An employee who is hired in a non-training classification may be re-assigned to a formal on-the- job training program under the following conditions:

(i) an employee requests, in writing, to participate in the Contractor's formal on-the-job training program and the Contractor approves the request;

(ii) the Contractor requests that an employee be re-assigned to a formal on-the-job training program and the employee and the Council are in agreement with the re-assignment.

(f) An employee who is re-assigned in accordance with (e) above shall be deemed to be a trainee and paid in accordance with the provisions of (b) above.

(g) The Contractor shall provide each employee who successfully completes the Contractor's formal on-the- job training program with a letter confirming the type of training received and the corresponding number of hours the employee spent in such training.

4.3 Boom Truck Hoist Operator Apprentices

Boom Truck Hoist Operator Apprentices shall be paid the following percentages of the rate for a certified boom truck hoist operator as set out in Group 5 (b)above or the minimum wage rates prescribed in the Trade of Crane and Hoisting Equipment Operator Regulations, whichever is more favourable to the Apprentice:

1st year - 60%
2nd year - 80%

The number of apprentices who may be employed by a Contractor shall not exceed one (1) apprentice for every one (1) certified Boom Truck Hoist Operator employed.

5. Vacation and Vacation Pay

(a) Annual vacation will be arranged as provided in The Employment Standards Code for the Province of Manitoba.

(b) Vacation Pay allowance will be accumulated for the credit of each employee at the rate of six percent (6%) of the employee's standard hourly rate for each hour worked.

(c) Vacation Pay Allowance will be paid to an employee on his regular pay day.

6. Pay in Lieu of Holidays

Whether or not an employee works on any of the Holidays under Article 17, he shall receive in lieu of paid Holidays, four and one half percent (4.5%) of his standard hourly rate for each hour worked. The employee shall be paid this amount on his regular payday.

7. Health and Welfare and Pension Trust Funds

*** Note – See Letter of Agreement #10

(a) Health and Welfare

The Contractor on behalf of each employee, and each employee covered by this Appendix shall respectively contribute the amounts set out below to the Teamsters, Local 362 Health and Welfare Plan. Contributions shall apply to all hours worked. Employee contributions shall be collected at the source as a payroll deduction.

The Contractor's contribution shall be:

Effective	May 1, 2019	$2.70 per hour
Effective	May 1, 2020	$2.95 per hour

The employee's contribution shall be: nil.

Submission of Trust Funds

The Contractor shall forward the above Trust Fund contributions to the designated Administrator of the Plan on or before the fifteenth day (15th) of each month following the month in which contributions were made.

A form shall be supplied by the Union for the Contractor to identify the application of all contributions, and such form shall indicate the Administrator and the address to which contributions shall be forwarded.

(b) Pension Plan Provision

The Contractor on behalf of each employee, and each employee covered by this Appendix shall respectively contribute the amounts set out below to the Teamsters, Local 362 Pension Plan. Contributions shall apply to all hours worked. Employee contributions shall be collected at the source as a payroll deduction.

The Contractor's contribution shall be:

Effective	May 1, 2019	$3.00 per hour

The employee's contribution shall be: nil.

Submission of Trust Funds

The Contractor shall forward the above Trust Fund contributions to the designated Administrator of the Plan on or before the fifteenth day (15th) of each month following the month in which contributions were made.

A form shall be supplied by the Union for the Contractor to identify the application of all contributions, and such form shall indicate the Administrator and the address to which contributions shall be forwarded.

8. Trusteed Training Fund Provision

Provided:

(a) the Local Union to which Teamsters belong establishes a trusteed training fund, and

(b) written verification is forwarded to the Association and the Council by the Board of Trustees of the fund confirming;

(i) proviso (a), above

(ii) that Trust Agreements have been executed and registered,

a trusteed training fund will be introduced into this Appendix on the basis that it will be solely funded by employee contributions.

9. Escalation and Reference

9.1 Wage Rates

9.1.1 General Approach

Subject to and in accordance with the conditions set out below, and subject to any adjustment arising from the application of Section 9.3, the sum of the wage rates and Contractors' contributions to pension and health and welfare plans set out in Section 4 and Section 7 of this Appendix will be adjusted by a percentage equivalent to the weighted percentage adjustment in wage rates and in the employers' contribution rate to pension and health and welfare plans negotiated from time to time for each of the Reference Classifications set out in 9.1.2.

9.1.2 Reference Classifications and Weighting

The Reference Classifications and the weighting of these classifications shall be as follows:

Reference Classification	**Weighting Factor**
The Crane Operator classification incorporating those Crane Operators operating cranes of sixty (60) ton capacity - as set out in the Industrial/Mechanical Agreement negotiated and executed by the Construction Labour Relations Association (CLRA) of Manitoba and the Operating Engineers, Local 987	25%
Journeyman Sheet Metal Worker - as set out in the Agreement negotiated and executed by the CLRA of Manitoba and Sheet Metal Workers, Local Union 511.	25%
Journeyman Carpenter - as set out in the Agreement negotiated and executed by the CLRA of Manitoba and the Carpenters, Local Union 343.	25%
General Labourer - as set out in the Agreement negotiated and executed by the CLRA of Manitoba and the Construction and Specialized Workers' (Labourers), Local Union 1258.	25%

9.1.3 Method of Calculating Weighted Percentage Adjustment of Reference Classifications

The weighted percentage adjustment of each Reference Classification shall be determined in accordance with the following formula:

$$\frac{\text{(Change in W) + (Change in P) + (Change in H\&W)}}{\text{(Expired H\&W)}} \times 100 \times \text{Weighting Factor}$$

Where:

- Change means the increase or decrease in that benefit.
- W means wage rate
- P and H&W means the required employers' contribution rate to the pension and/or the health and welfare plan.
- Expired means the rate in effect when the last weighted percentage adjustment was calculated.
- Weighting factor means the factor assigned to a particular Reference Classification as set out in 9.1.2.

9.1.3.1 In calculating the weighted percentage adjustment of a Reference Classification, the arithmetic result shall be rounded to the nearest hundredth of a percent.

9.1.4 Effective Date of Wage Rate Adjustments and Adjustments to Pension and Health and Welfare Plans and Application of the Formula

9.1.4.1 Effective Date of Wage Rate Adjustments

When the wage rate adjustment of a Reference Classification(s) is effective on the first of any month, then the wage rate adjustment of the hourly rates in this Appendix shall be effective on that date.

When the wage rate adjustment of a Reference Classification(s) is not effective on the first of any month, it shall be deemed to be effective on the first of the month following, and the wage rate adjustment of hourly rates in this Appendix shall be effective on that date.

9.1.4.2 Effective Date of Adjustments to the Employers' Contribution Rate to Pension and/or Health and Welfare Plans

When the adjustment to the employers' contribution to the pension and/or health and welfare plans of a Reference Classification(s) is effective on the effective date, or pursuant

to 9.1.4.1 the deemed effective date, of any wage rate adjustment of any Reference Classification, then such adjustment shall be calculated and taken into account on that date. If this is not the case, then such adjustment shall be calculated and taken into account on the closest following effective date of a wage rate adjustment.

9.1.4.3 In applying the weighted percentage adjustment, the resultant wage rate shall be rounded to the nearest cent, following which, any adjustment required by virtue of Section 9.3 shall be introduced to yield the new wage rate schedule that will apply in this Appendix.

9.2 Vacation and Statutory Holiday Pay

Vacation and Statutory Holiday Pay shall be adjusted to be consistent with that negotiated between the Labourers' International Union of North America, Local 1258, and the Construction Labour Relations Association of Manitoba. However, such Vacation and Statutory Holiday Pay shall not be less than six percent (6%) and four percent (4%), respectively, of the employee's straight time hourly rate.

9.3 Health and Welfare and Pension

9.3.1 Subject to the conditions set out below, Health and Welfare and Pension contributions shall be adjusted to be consistent with contributions required in respect of Members of Local 979 covered by this Appendix and participating in the Teamsters Local 362 Health and Welfare Plan and Pension Plan.

9.3.2 The Contractor's contribution to the Health and Welfare and Pension Plans may be applied on a per hour worked basis; however, the contractor's contributions rate in respect of overtime hours shall not be greater than the required contribution rate for contractors in respect of straight time hours.

9.3.3 Pursuant to 9.3.1, when the negotiated effective date of any adjustment to the Contractor's contribution rate to the Health and Welfare and/or Pension Plans does not occur on the effective date of an adjustment to wage rates in this Appendix, at the option of the Teamsters Local 979, the implementation of such an adjustment may be delayed so that it coincides with the effective date of the next subsequent adjustment to wage rates. Notification, in writing, specifying that the Teamsters are electing to exercise this option shall be provided by the Council Appendix Review Committee to the Association Appendix Review Committee in accordance with the provisions of Section 9.3.5.

9.3.4 Any adjustment to the Contractor's contribution rate to the Health and Welfare and/or Pension Plans will be dealt with as follows:

9.3.4.1 When the effective date of the adjustment to the Plan coincides with an adjustment date for wage rates in this Appendix, the resultant hourly rates (i.e., the hourly rates resulting from the application of the weighted percentage adjustment factor) will be reduced by the amount of the increase (or increased by the amount of any decrease) in the Contractor's contribution rate to the Plan.

9.3.4.2 When the effective date of the adjustment to the Plan does not coincide with an adjustment date for wage rates in this Appendix, the hourly wage rates in this Appendix will be reduced by the amount of the increase (or increased by the amount of any decrease) in the Contractor's contribution rate to the Plan.

9.3.5 Notification, in writing, of any adjustment to the Health and Welfare and/or Pension Plans shall be provided by the Council Appendix Review Committee to the Association Appendix Review Committee at least twenty (20) calendar days in advance of the proposed implementation date of such adjustment. If such notification is not provided, the effective date of the adjustment shall be deemed to be twenty (20) calendar days from the date of receipt of the notification.

9.4 Notwithstanding anything contained in this Agreement or in this Appendix, the regular hours of work are not subject to adjustment during the life of this Agreement, and such regular hours of work shall be paid at regular rates of wages.

9.5 Wage rates, Vacation and Holiday Pay, and Health and Welfare contributions shall be adjusted by following the procedure set out in Article 30.

APPENDIX NO. 4 - Carpenters

UNITED BROTHERHOOD OF CARPENTERS AND JOINERS OF AMERICA

Local Union No. 343 (Carpenters)

BURNTWOOD/NELSON AGREEMENT

*** Note – See Letter of Agreement #8, for additional information regarding Appendix 4, section 4
*** Note – See Letter of Agreement #50, for additional information regarding Appendix 4 (Scaffolder Classification)
*** Note – See Letter of Agreement #51, for additional information regarding Appendix 4 (Foreman Coordinator)

1. Hours of Work and Overtime

Nine (9) hours shall constitute a day's work for four (4) days Monday to Thursday inclusive, and eight (8) hours shall constitute a day's work for Friday. Said hours shall normally be within the period from 7:00 a.m. until 6:00 p.m.

If more than the recognized daily hours are worked in any one shift, then such additional hours shall be paid for at the rate of time and one-half the regular straight time hourly rate to a maximum of ten (10) hours, all hours worked after ten (10) shall be paid at double-time the straight time hourly rate for all subsequent overtime hours on that shift..

On Saturdays, except as provided in Article 15.2, time and one-half of the regular straight time hourly rate shall be paid for the first eight (8) hours, and double of the regular straight time hourly rate shall be paid beyond eight (8) hours.

On Sundays and Holidays, as specified in Article 17, double the regular straight time hourly rate shall be paid.

For purposes of computing overtime premium applicable for Saturday, Sunday and holiday work the following rules shall apply:

Saturday overtime premium is due from 6:00 a.m. Saturday until 6:00 a.m. Sunday.
Sunday overtime premium is due from 6:00 a.m. Sunday until 6:00 a.m. Monday.
Holiday overtime premium is due from 6:00 a.m. on the holiday until 6:00 a.m. the following day.

2. Shift Conditions

If the conditions are such that work on a particular job cannot be done within the said normal hours (7:00 a.m. to 6:00 p.m.) then nine (9) hours, or eight (8) hours, as the case may be, may be worked during any hours and may constitute a regular shift on that job.

Any shift, the hours of which fall completely within the period from 7:00 a.m. to 12:00 midnight, shall be free of shift premium.

A shift premium of .142 of the straight time hourly rate shall be paid for 50% of all hours worked at the straight time rate on any shift commencing prior to twelve midnight and terminating subsequent thereto and in which four (4) hours or less are worked between 12:00 midnight and 6:00 a.m.

A shift premium of .142 of the straight time hourly rate shall be paid for all straight time hours worked on any shift commencing prior to 12:00 midnight and terminating subsequent thereto and in which more than four (4) hours are worked between 12:00 midnight and 6:00 a.m.

A shift premium of .142 of the regular straight time hourly rate shall be paid for any straight time hours worked on any shift which commences at or after 12:00 midnight and prior to 4:00 a.m.

A shift premium of .142 of the regular straight time rate shall be paid for all straight time hours worked up to 6:00 a.m. on any regular shift which commences at or after 4:00 a.m. Shift premium shall not be paid on any overtime hours worked.

Overtime payment for shift work shall be in accordance with the provisions as set out above.
The starting and quitting time for shift work will be decided by the Contractor.

3. Rest Period

If an employee is not provided with at least an eight (8) hour of rest period between shifts, the employee shall be paid double time rates until such time as an eight (8) hour break occurs.

4. Wages

Wages rates shall be as follows:

	May 1, 2016	May 1, 2017	May 1, 2018	May 1, 2019
Certified Carpenter Base Wage Rate (Enhanced Journeyman Carpenter)	$35.48	$36.43	$37.48	$38.58
Other (non-certified) Carpenter	$31.12	$31.97	$32.92	$33.91
Industrial Scaffolder	$37.26	$38.12	$38.69 (effective March 17, 2019)	$39.27

Definition of a Journeyman Carpenter:

It is agreed that the definition of a Journeyman Carpenter under this Agreement is a Carpenter who:

a) Has a Certificate of Qualification under the Apprenticeship Act of Manitoba;

b) Has a Certificate of Proficiency under the Apprenticeship and Trades

Qualifications Act of Manitoba. *(Issued by the Province of Manitoba);

c) Has a Certificate of Exemption issued by the Carpentry Trade Improvement Committee. ** (The Committee formed by the Construction Labour Relations Association of Manitoba and the Union, whose terms of reference include promoting and encouraging qualification under the Apprenticeship and Trades Qualifications Act.).

* Certificates from other Provinces or Countries which are equivalent to the above noted Manitoba Certificates in the opinion of the Carpentry Trade Improvement Committee, will be accepted after approval by the Committee, whose decision will be final.

** The Committee may issue a Certificate of Exemption to any Member of the Union who is considered a satisfactory carpenter.

Carpenter Apprentices:

"Apprentice" means an employee indentured in the Trade of Carpentry as specified by the Apprenticeship and Trades Qualifications Act of the Province of Manitoba.

Apprentices shall work with the tools of the trade and shall be under the supervision of a Journeyman. The ratio of apprentices to Journeymen shall be one to one or as laid down from time to time by the Apprenticeship and Trades Qualifications Act of the Province of Manitoba.

Should a shortage of Journeymen exist and the Union is unable to supply the Contractor's needs for qualified workers, then a joint application will be made to waive the ratio requirements of the Act.

Carpentry apprentices shall be paid the percentage of the Journeyman Carpenter's rate per hour as laid down from time to time by the Apprenticeship Board of Manitoba.

Currently these rates are as listed below:

Classification	May 1, 2016	May 1, 2017	May 1, 2018	May 1, 2019
Journeyman Base Rate	$34.58	$35.53	$36.58	$37.68
4th Yr Apprent (90%)	$31.12	$31.98	$32.92	$33.91
3rd Yr Apprent (75%)	$25.94	$26.65	$27.44	$28.26
2nd Yr Apprent (65%)	$22.48	$23.09	$23.78	$24.49
1st Yr Apprent (55%)	$19.02	$19.54	$20.12	$20.72

Foremen:

When the Contractor appoints a working carpentry foreman, he shall be paid the percentage set out below above the Journeyman rate rounded to the nearest five cents (5¢). Midpoint results shall be adjusted upward to the next five cents (5 ¢)

Eighteen percent (18%)

	May 1, 2016	May 1, 2017	May 1, 2018	May 1, 2019
Foreman Rate	$41.70	$42.83	$44.06	$45.35

A “Lead Hand” Journeyman Carpenter shall receive $2.00 per hour in addition to the base Journeyman rate. The Contractor will have the sole discretion to appoint Lead Hands as well as the assignment of their job-site responsibilities but will ensure that a lead hand is not responsible for more than fifteen (15) Carpenters.

	May 1, 2016	May 1, 2017	May 1, 2018	May 1, 2019
Lead Hand Rate	$37.48	$38.43	$39.48	$40.58

Scaffolder Apprentices:

"Apprentice" means an employee indentured in the Trade of Scaffolding as specified by the Apprenticeship and Trades Qualifications Act of the Province of Manitoba.

Pre-apprentice *	1 – 450 hours	50% of journeyman rate
1st year	451 – 1350 hours	60% of journeyman rate
2nd year	1351 – 2700 hours	70% of journeyman rate
3rd year	2701 – 4050 hours	80% of journeyman rate
4th year	4051 – 5400 hours	90% of journeyman rate

5. Vacation and Vacation Pay

The annual vacation will be arranged as provided in the Manitoba Employment Standards Code.

Payment for the annual vacation will be as provided in the above noted Code or on the basis of six percent (6%) of the employee's standard hourly rate for each hour worked, whichever is more favorable to the employee.

Advance payment in lieu of pay at time of vacation in the amount set forth above shall be added to each employee's wages each pay period.

6. Payment in Lieu of Holidays

Whether or not an employee works on any of the Holidays set out in Article 17, he shall receive in lieu of paid holidays, four percent and a half (4.5%) of his standard hourly rate for each hour worked. The employee shall be paid this amount on his regular pay day.

When Christmas Day, Boxing Day, New Year's Day or Canada Day falls on a Saturday or Sunday that is a non-working day, the closest following working day(s) will be observed. However, this provision shall not apply to any employee who is on Christmas Leave, Isolation Leave or any other type of Leave of Absence when such Holidays occur.

7. Trust Funds

The Contractor, on behalf of each employee, and each employee covered by this Appendix, shall contribute the amounts set out below to the Carpentry Trade Pension Trust Fund (Manitoba) and the Local Union 343 Welfare Trust Fund (Manitoba). Contributions shall apply to all hours worked. Employee contributions shall be collected at the source as a payroll deduction. Employer hourly pension contributions for Apprentice classifications will be based on the Certified Journeyman contribution amount multiplied by the applicable in-year percentages identified in Section 4 under “Carpenter Apprentices”.

A) Carpentry Trade Pension Trust Fund (Manitoba):

	Contractor's Contribution	Employee's Contribution
Effective May 1, 2016	$3.69 per hour	$1.16 per hour
Effective May 1, 2017	$3.69 per hour	$1.16 per hour
Effective May 1, 2018	$ 3.69 per hour	$1.21 per hour
Effective May 1, 2019	$ 3.69 per hour	$1.31 per hour

B) Local Union Welfare Trust Fund (Manitoba):

	Contractor's contribution	Employee's Contribution
Effective May 1, 2016	$0.83 per hour	$0.33 per hour
Effective May 1, 2017	$0.83 per hour	$0.33 per hour
Effective May 1, 2018	$0.83 per hour	$0.33 per hour
Effective May 1, 2019	$0.83 per hour	$0.33 per hour

Contributions shall be submitted by the Contractor to the Administrator of the Fund on or before the 15th day of the month following the month for which such contributions are payable. The Administrator shall supply reporting forms to the Contractor.

8. Carpentry Trade Improvement Plan

The Contractor and each employee covered by this Appendix shall contribute the amounts set out below to the Carpentry Trade Improvement Plan. Contributions shall apply to all hours worked. Employee contributions shall be collected at the source as a payroll deduction.

	May 1, 2016	**May 1, 2017**	**May 1, 2018**	**May 1, 2019**
Employer Contribution per hour worked	$0.45	$0.45	$0.45	$0.45
Employee Contribution per hour worked	$0.05	$0.05	$0.05	$0.05

The total sum so collected shall be remitted to "The Carpentry Trade Improvement Committee" once each month, not later than the 15th day of the month following.

The money will be used by the Carpentry Trade Improvement Committee to promote apprenticeship and improve the qualifications of the Carpenters working within the area covered by this Agreement.

9. UBCJA Per Capita Contribution

All Employers shall deduct the sum of Five Cents ($.05) per hour from all employees who are a member of the local and shall remit that sum to the Union by the fifteenth (15) day of the month following the month in which the work was performed. This employee deduction shall be in addition to the working dues that an employee pays and should be included in the working dues deduction reporting that the Union receives each month

10. Isolation Leave (Return Transportation Time Periods)

The return transportation time period referred to in Article 19.2.1 shall be:

- After thirty-five (35) calendar days.

Travel time shall only apply on the return portion of an Isolation Leave trip (i.e. from the employee's T.D.P. to the Project Camp Site).

The amount of travel time to be paid shall be in accordance with the provisions of Article 19.1.2.5.1 or 19.1.2.5.2, as the case may be, and if applicable, the provisions of Article 19.1.2.5.3.

Travel time shall be paid at one-half of the employee's straight time hourly rate and an employee shall receive such payment pursuant to the provisions of Article 19.1.2.6.

11. Tools

Employees shall supply the ordinary hand tools of the trade. Power tools, including bits and/or attachments, mitre boxes, special augers and bits and any devices such as powder actuated tools shall be supplied by the Contractor.

If any power wood working machines or power wood working tools are used, they shall be supplied by the Contractor. Only employees who are qualified to use powder actuated devices, as required by the Workplace Safety & Health Act shall be permitted to use such devices.

12. Escalation and Reference

12.1 Wage Rate Provisions

The wage rate for the classifications set out in this Appendix will be adjusted by an amount equal to and effective on the dates of any adjustments in wage rates for corresponding classifications which may be negotiated from time to time by the United Brotherhood of Carpenters and Joiners of America, Local Union 343 and the Construction Labour Relations Association of Manitoba.

Classifications eligible for adjustment may include general foreman, foreman, leadhand, chargehand, pusher, journeyman, apprentices, helpers and trainees.

12.1.1 Except as otherwise noted, the following provisions will be incorporated or adjusted to be consistent with corresponding provisions negotiated from time to time by the aforementioned Parties:

a) Definitions and qualificational requirements for applicable classifications;
b) Ratios indicating the number of apprentices, helpers, or other types of trainees who may be employed;
c) Height pay including that associated with swing stage work.

12.2 Other Conditions of Employment

Except as otherwise noted, the following conditions employment will be incorporated or adjusted to be consistent with corresponding conditions of employment negotiated from time to time by the aforementioned Parties:

a) Overtime payments (subject to the restrictions set out in Section 12.3);

b) Shift premium but excluding any shift premium applicable to overtime hours;

c) Vacation and Vacation pay - such provisions may include any provisions relative to the timing of payment of vacation pay but shall not include any provisions stipulating when vacation time must be granted; and in lieu of such a provision the following shall be substituted: “the scheduling of time off for vacation shall be arranged by mutual agreement between the Contractor and the employee”;

d) Pay in lieu of Holidays and any provisions requiring the transferring and observing of the Holiday on a day, other than the day on which the Holiday falls (subject to the restrictions set out in Section 12.2.1).;

e) Registered and trusteed pension and health and welfare plans (subject to the restrictions set out in Section 12.2.2);

f) Callout provisions;

g) Rest provisions between shifts;

h) Personal effects insurance provisions;
i) Provisions governing welding and other special trade related tests;

j) Safety clothing;

k) Tool lists and provisions governing loss of such tools on the Project;

l) The following trusteed plans, each of which shall be subject to the restrictions set out in Section 12.2.3:
i) Building fund;
ii) Trade improvement plans including educational and apprenticeship funds;
iii) Industrial promotion funds.

m) The time period between Isolation Leaves (subject to the restrictions of Article 19.2.1.3);

n) Travel time associated with the taking of an Isolation Leave, and the hourly rate at which travel time will be paid (subject to the restrictions set out in Section 12.2.4).

12.2.1 A Holiday set out in Article 17 may be observed on a day, other than the day on which it falls, provided the Holiday falls on a Saturday or Sunday which is a non-working day, in which case the Holiday may be observed on the closest following working day. The transferring of a Holiday shall not apply to any employee who is on Christmas Leave, Isolation Leave or any other type of Leave of Absence when the Holiday occurs.

12.2.2 The Contractor's contribution to any pension and health and welfare plan may be applied on a per hour worked basis; however, the Contractor's contribution rate in respect of overtime hours shall not be greater than the required contribution rate for Contractors in respect of straight time hours.

12.2.3 The Contractor's contribution to any of the plans referred to in Section 12.2 (l) may be applied on a per hour worked basis; however, the Contractor's contribution rate in respect of overtime hours shall not be greater than the required contribution rate for Contractors in respect of straight time hours.

12.2.4 Travel time may only apply to the return portion of an Isolation Leave trip (i.e. from the employee's T.D.P. to the Project Camp Site). The amount of travel time to be paid shall not be greater than the travel time set out in Articles 19.1.2.5.1, 19.1.2.5.2 and 19.1.2.5.3, as may be applicable. The hourly rate at which travel time may be paid shall not be greater than the employee's straight time rate. Payment of travel time shall be in accordance with the provisions of Article 19.1.2.6.

12.3 Notwithstanding anything contained in this Agreement or in this Appendix, the regular hours of work are not subject to adjustment during the life of this Agreement, and such regular hours of work shall be paid at regular rates of wages.

Further, overtime payments at a rate greater than time and one-half will not be introduced in this Appendix in respect of the first two (2) hours of overtime, Monday to Friday inclusive.

12.4 The provisions of 11.1 and 11.2 above shall be dealt with by following the procedure set out in Article 30 of this Agreement.

APPENDIX NO. 4a - Millwrights

UNITED BROTHERHOOD OF CARPENTERS AND JOINERS OF AMERICA

Local Union No. 1443

Millwrights, Machine Erectors, Industrial Mechanics, Maintenance

BURNTWOOD/NELSON AGREEMENT

1. Hours of Work and Overtime

Eight (8) hours shall constitute a day's work for five (5) days Monday to Friday inclusive. Said hours shall normally be within the period from 6:00 a.m. until 6:00 p.m.

If more than the recognized daily hours are worked in any day or shift, Monday to Friday inclusive, such time shall be paid at the rate of time and one-half for the first two (2) hours and double time for any hours worked thereafter in that day or shift.

On Saturdays, except as provided in Article 15.2, Sundays and on Holidays as specified in Article 17, double time shall be paid.

2. Shift Conditions

If conditions are such that work on that particular job cannot be done within the said normal hours (6:00 a.m. to 6:00 p.m.) then eight (8) hours may be worked during any hours and may constitute a regular shift on that job.

Shift work shall be defined as work assignments lasting two (2) or more days all or part of the working time being outside the normal working hours, Monday to Friday inclusive. All shift work shall be paid at the rate of time plus ten percent (10%). Shift work premium will not be paid on any overtime hours worked.

Overtime payment for shift work shall be in accordance with the provisions set forth above.

The starting and quitting time for shift work will be decided by the Contractor.

3. Rest Period

If an employee is not provided with at least an eight (8) hour rest period between shifts, the employee shall be paid at the appropriate overtime rate until such time as an eight (8) hour break occurs.

4. Wages

Wage rates shall be as follows:

a) Journeyman Millwrights:

May 1, 2016	May 1, 2017	May 1, 2018	May 1, 2019
$ 37.50	$ 38.86	$ 40.26	$ 41.71

b) Foremen:

When a working Millwright Foreman is appointed by the Contractor, a Millwright with a Certificate of Qualification from the Province of Manitoba or an inter-provincial Certificate will be given preference.

The first Foreman will be responsible for up to fifteen Millwright employees, and subsequent Foremen will be responsible for up to a maximum of fifteen Millwright employees. Millwright Foremen shall be paid between one hundred and five percent (105%) and one hundred and twenty percent (120%) of the Journeyman rate, in the discretion of the Contractor

c) General Foreman

When the Contractor appoints a General Foreman, he shall be paid between one hundred and twenty percent (120%) and one hundred and thirty-five percent (135%) of the Journeyman rate, in the discretion of the Contractor. A General Foreman shall be appointed at a minimum crew size of forty-five Millwright employees.

d) Apprentices

The scale of wages for Apprentices indentured on or after November 22, 1995 shall be:

1st year 50% of the Journeyman's prevailing wage rate.
2nd year 60% of the Journeyman's prevailing wage rate.
3rd year 70% of the Journeyman's prevailing wage rate.
4th year 80% of the Journeyman's prevailing wage rate.

A year shall consist of a minimum of 1600 hours actually worked.

Apprentices shall take the prescribed courses established by the Apprenticeship Branch of the Manitoba Department of Advanced Education and Training. If an Apprentice fails to successfully complete each course, he shall not qualify for advancement and shall remain at the same rate of pay until he has successfully completed that course.
The Contractor may employ one (1) apprentice for every three (3) journeymen employed.

5. Trade Qualification

A journeyman Millwright means a person in possession of a Certificate of Qualification issued by the Province of Manitoba, or an inter-provincial Certificate issued by any Department of Labour in Canada.

A Millwright who is hired to perform welding work shall hold a valid welding certification required by the employer.

An employee whose C.W.B. certification expires while in the employ of the Contractor shall take the test to re-certify on the Contractor's time. If the employee resigns within 45 days the time taken for testing shall be deducted from his last pay cheque. The cost of the test shall be paid for by the Millwright Trade Improvement Trust Fund.

6. Vacations and Vacation Pay

The annual vacation will be arranged as provided in the Manitoba Employment Standards Code.

Payment for the annual vacation will be as provided in the above noted Code or on the basis of six percent (6%) of the employee's gross earnings for all hours worked.

Vacation Pay shall be paid every pay period or upon termination of employment, whichever is sooner.

7. Pay in Lieu of Holidays

Whether or not an employee works on any of the Holidays set out in Article 17, an employee shall receive in lieu of paid holidays, four and a half percent (4.5%) of the employee's gross earnings for all hours worked.

Except Remembrance Day, if one (1) of the above referenced Holidays falls on a Saturday, where Saturday is a non-working day, or Sunday, the closest following working day(s) will be observed. However, this provision shall not apply to any employee who is on Christmas Leave, Isolation Leave or any other type of Leave of Absence when the Holiday(s) occurs.

The employee shall be paid this amount on his regular pay day.

8. Millwright Industry Trust Funds

The Contractor and each employee shall respectively contribute the following amounts to each Trust Fund listed below.

Contributions shall apply on all hours earned (e.g., when double time is in effect, contributions shall be doubled).

Employee contributions shall be collected at the source as a payroll deduction.

a) Health and Welfare Fund

The Employer and the employee shall contribute the amounts (per hour earned) detailed below for each Journeyman as follows:

	May 1, 2016	**May 1, 2017**	**May 1, 2018**	**May 1, 2019**
Employer	$ 1.77	$ 1.77	$ 1.77	$1.77
Employee	$ 0.18	$ 0.21	$ 0.25	$ 0.29

b) Pension Fund

The Employer and the employee shall contribute the amounts (per hour earned) detailed below for each Journeyman as follows:

	May 1, 2016	**May 1, 2017**	**May 1, 2018**	**May 1, 2019**
Employer	$ 6.14	$ 6.14	$ 6.14	$ 6.14
Employee	$ 0.25	$ 0.50	$ 0.75	$ 1.00

Pension contributions for Apprentices shall be based on the following formula:

1st Year	50% of Journeyman Contribution
2nd Year	60% of Journeyman Contribution
3rd Year	70% of Journeyman Contribution
4th Year	80% of Journeyman Contribution

c) Regional Council Training Trust Fund

Contributions to the Regional Council Training Trust Fund will be as follows (per hour worked):

	May 1, 2016	**May 1, 2017**	**May 1, 2018**	**May 1, 2019**
Employer	$ 0.39	$ 0.39	$ 0.39	$ 0.39
Employee	$ 0.27	$ 0.29	$ 0.31	$ 0.33

d) UBCJA Per Capita Contribution

Contributions to the UBCJA Per Capita Contribution is an Employee Deduction of five cents (.05) per hour worked of all members of Local 1443. The Employee deduction shall be in the addition to the working dues that the Employee pays and should be included in the working dues deduction reporting that the Union receives each month.

Contributions shall be submitted to the Administrator of each Fund on or before the 21st day of the month following the month in which contributions are payable. Reporting forms will be supplied by the Administrator for purposes of listing employees and corresponding contributions. The Contractor will complete the form and remit same with the contribution cheque for each fund.

9. Safety Clothing

Personal work clothes are to be supplied by the employee.

The Contractor will supply welders with welding gloves, welding goggles, arc welding helmet, replaceable glass shields for helmets, welding sleeves, and, if required by Manitoba Hydro, fireproof coveralls.

The employee must accept responsibility for safety equipment issued by the Contractor and must report the loss or damage of same to the Contractor.

One (1) pair of coveralls will be supplied to an employee who is requested to work in an area which is mutually agreed to be extremely dirty. This pair of coveralls will be returned to the Contractor upon the completion of the work to be performed in the dirty area.

10. Isolation Leave (Return Transportation Time Periods)

The return transportation time period referred to in Article 19.2.1 for this Appendix shall be:

- After twenty eight (28) calendar days.

Travel time shall only apply on the return portion of an Isolation Leave trip (i.e. from the employee's T.D.P. to the Project Camp Site).

The amount of travel time to be paid shall be in accordance with the provisions of Article 19.1.2.5.1 or 19.1.2.5.2, as the case may be, and if applicable, the provisions of Article 19.1.2.5.3.

Travel time shall be paid at the employee's straight time rate, and an employee shall receive such payment pursuant to the provisions of Article 19.1.2.6.

11. Tools

The following basic tools must be provided by the Millwright and the Apprentice, as described by his level:

	Description	
*1	1" Outside Micrometer	4th Year
*1	6" Precision Scale	3rd Year
*1	50' Steel Tape	4th Year
*1	6" Vernier Calliper or dial caliper .001 scale	2nd Year
1	Set Feeler Gauge 3 ½ to 4” long	2nd Year
2	Plumb Bobs	3rd Year
1	Set Caliper up to 6"	3rd Year
1	10' Steel Tape	1st Year
1	Set Divider to 12"	3rd Year
1	Scriber	2nd Year
2	Ball Peen Hammers, 12 oz. and 32 oz.	1st and 2nd Year
1	1 lb. deal blow	3rd Year
1	Hack Saw	3rd Year
1	Set of Punch and Chisels	2nd Year
1	Pair Tin Snips (aircraft type)	2nd Year
1	Pair of Pliers – slipjoint, long nose, diagonal sidecutters	1st Year
1	Set Allen Head Wrenches to 3/8"	2nd Year
1	Set 1/2" Drive Sockets to 1 1/8"	1st Year
1	Set assorted Screw Drivers	1st Year
2	Pair Vice Grip Pliers	1st Year, 3rd Year
2	Tommy Bar	2nd Year, 3rd Year
1	Set Combination Wrenches to 1 1/8"	1st Year
1	Set Adjustable Wrenches to 12" (8”, 10”, 12”)	2ndYear, 3rd Year, 4th Year
2	Tool boxes	1st Year, 3rd Year
2	Locks	1st Year, 3rd Year

11.1 Loss of Tools

The Contractor will reimburse an employee fifty percent (50%) of the cost of replacing those tools identified above with an asterisk when they are broken on the job, providing the employee supplies proof of such breakage to the Contractor.

The Contractor will be responsible for compensation for tools destroyed by fire or loss by breaking and entering when stored in a location provided by the Contractor.

Claims for lost or destroyed tools must be submitted in writing with list of such tools and value thereof, and substantial evidence of loss, satisfactory to the insurance company. Such list must be submitted within ten (10) days of loss unless reason satisfactory to the insurance company can be shown for not having done so.

12. Escalation and Reference

12.1 Wage Rate Provisions

The wage rate for the classifications set out in this Appendix will be adjusted by an amount equal to and effective on the dates of any adjustments in wage rates for corresponding classifications which may be negotiated from time to time by the United Brotherhood of Carpenters and Joiners of America, Local Union 1443 (Millwrights, Machine Erectors, Industrial Mechanics) and the Construction Labour Relations Association of Manitoba.

Classifications eligible for adjustment may include general foreman, foreman, leadhand, chargehand, pusher, journeyman, apprentices, helpers and trainees.

12.1.1 Except as otherwise noted, the following provisions will be incorporated or adjusted to be consistent with corresponding provisions negotiated from time to time by the aforementioned Parties:

a) Definitions and qualificational requirements for applicable classifications;

b) Ratios indicating the number of apprentices, helpers, or other types of trainees who may be employed;

c) Height pay including that associated with swing stage work.

12.2 Other Conditions of Employment

Except as otherwise noted, the following conditions of employment will be incorporated or adjusted to be consistent with corresponding conditions of employment negotiated from time to time by the aforementioned Parties:

a) Overtime payments (subject to the restrictions set out in Section 12.3);

b) Shift premium but excluding any shift premium applicable to overtime hours;

c) Vacation and Vacation Pay - such provisions may include any provisions relative to the timing of payment of vacation pay but shall not include any provisions stipulating when vacation time must be granted, and in lieu of

such a provision the following shall be substituted: "the scheduling of time off for vacation shall be arranged by mutual agreement between the Contractor and the employee";

d) Pay in lieu of Holidays and any provisions requiring the transferring and observing of the Holiday on a day, other than the day on which the Holiday falls (subject to the restrictions set out in Section 12.2.1);

e) Registered and trusteed pension and health and welfare plans (subject to the restrictions set out in Section 12.2.2);

f) Callout provisions;

g) Rest provisions between shifts;

h) Personal effects insurance provisions;

i) Provisions governing welding and other special trade related tests;

j) Safety clothing;

k) Tool lists and provisions governing loss of such tools on the Project;

l) The following trusteed plans, each of which shall be subject to the restrictions set out in Section 12.2.3:

   i) Building fund

   ii) Trade improvement plans including educational and apprenticeship funds

   iii) Industrial promotion funds.

m) The time period between Isolation Leaves (subject to the restrictions of Article 19.2.1.3);

n) Travel time associated with the taking of an Isolation Leave, and the hourly rate at which travel time will be paid (subject to the restrictions set out in Section 12.2.4).

12.2.1 A Holiday set out in Article 17 may be observed on a day, other than the day on which it falls, provided the Holiday falls on a Saturday or Sunday which is a non-working day, in which case the Holiday may be observed on the closest following working day. The transferring of a Holiday shall not apply to any employee who is on Christmas Leave, Isolation Leave or any other type of Leave of Absence when the Holiday occurs.

12.2.2 The Contractor's contribution to any pension and health and welfare plan may be applied on a per hour worked basis; however, the Contractor's contribution rate in respect of overtime hours shall not be greater than the required contribution rate for Contractors in respect of straight time hours.

The aforementioned limitation shall not apply to a pension or health and welfare plan in effect in this Appendix on January 1, 1989 and in which higher employer contribution levels were required in respect of overtime hours compared to straight time hours. This exemption shall remain in effect provided required employer contributions to such plans do not change to a single contribution rate relative to straight time and overtime hours.

12.2.3 The Contractor's contribution to any of the plans referred to in Section 12.2 (l) may be applied on a per hour worked basis; however, the Contractor's contribution rate in respect of overtime hours shall not be greater than the required contribution rate for contractors in respect of straight time hours.

12.2.4 Travel time may only apply to the return portion of an Isolation Leave trip (i.e. from the employee's T.D.P. to the Project Camp Site). The amount of travel time to be paid shall not be greater than the travel time set out in Articles 19.1.2.5.1, 19.1.2.5.2 and 19.1.2.5.3, as may be applicable. The hourly rate at which travel time may be paid shall not be greater than the employee's straight time rate. Payment of travel time shall be in accordance with the provisions of Article 19.1.2.6.

12.3 Notwithstanding anything contained in this Agreement or in this Appendix, the regular hours of work are not subject to adjustment during the life of this Agreement, and such regular hours of work shall be paid at regular rates of wages. Further, overtime payments at a rate greater than time and one-half will not be introduced in this Appendix in respect of the first two (2) hours of overtime, Monday to Friday inclusive.

12.4 The provisions of 12.1 and 12.2 above shall be dealt with by following the procedure set out in Article 30 of this Agreement.

APPENDIX NO. 5 – Painters Division

INTERNATIONAL BROTHERHOOD OF PAINTERS AND ALLIED TRADES

Local Union 739, Painters Division

BURNTWOOD/NELSON AGREEMENT

1. Hours of Work and Overtime

Nine (9) hours shall constitute a day's work for four (4) days Monday to Thursday inclusive, and eight (8) hours shall constitute a day's work for Friday. Said hours shall normally be within the period from 7:00 a.m. until 6:00 p.m.

If more than the recognized daily hours are worked in any day or shift, Monday to Friday, such time shall be paid at the rate of time and one-half of the straight time hourly rate.

On Saturdays, except as provided in Article 15.2, time and one-half shall be paid.

On Sundays and on Holidays as specified in Article 17, double time shall be paid.

2. Shift Conditions

If the conditions are such that work on that particular job cannot be done within the said normal hours (7:00 a.m. to 6:00 p.m.) then nine (9) hours or eight (8) hours, as the case may be, may be worked during any hours and may constitute a regular shift on that job.

When an employee is required to work such shift hours on a shift that cannot be done within the said normal hours, the employee shall be paid a shift premium of .066 of the regular straight time hourly rate for each hour worked at the straight time rate.

Overtime payment for shift work shall be in accordance with the provisions as set out above.

The starting and quitting time for all shift work will be decided by the Contractor.

3. Wages

Wage rates shall be as follows:

Effective Date:	May 1, 2019 to April 30, 2020	May 1, 2020 to April 30, 2021	May 1, 2021 to April 30, 2022
Certified Industrial Journeyman Painter (Sandblasting/Spraying)			
General Foreman	33.73	34.32	34.91
Journeyman	30.66	31.20	31.71
3rd Year (85%)	26.06	26.52	26.98
2nd Year (75%)	23.00	23.40	23.91
1st Year (55%)	16.86	17.16	17.46
Certified Industrial Journeyman Painter (Brush and Rollers)			
General Foreman	32.23	32.80	33.37
Journeyman	29.30	29.82	30.34
3rd Year (85%)	24.91	25.35	25.79
2nd Year (75%)	21.98	22.36	22.76
1st Year (55%)	16.12	16.40	16.69

Unqualified painters with proof of five (5) years in the trade shall receive sixty-five percent (65%) of the applicable journeyman rate

c) Foremen

When the Contractor appoints a working foreman, the foreman shall be paid:

- Commercial – five (5%) increase for crew size of 4 or more – ten (10%) increase for crew size over 8
- Industrial – five (5%) increase for crew size 3-4 including foreman – ten (10%) increase for crew size of 5 or more
- Crew size does not include dedicated safety watch personnel

d) Apprentices

0 to 1800 hours - 55% of the journeyman rate
1801 to 3600 hours - 75% of the journeyman rate
3601 to 5400 hours - 85% of the journeyman rate

The Contractor may employ one (1) apprentice for the first Journeyman employed and one additional apprentice for every two (2) Journeymen employed thereafter.

4. Premiums

The following premiums shall apply:

- Exterior (not including bridges) 85 feet and over - fifty cents (50¢) per hour

- Under slung bridge work - one dollar ($1.00) per hour.

5. Vacation and Vacation Pay

Annual vacation will be arranged as provided in The Employment Standards Code for the Province of Manitoba.

Vacation Pay allowance will be accumulated for the credit of each employee at the rate of six percent (6%) of the employee's standard hourly rate for each hour worked, except first and second year Apprentices who shall receive four percent (4%) of the standard hourly rate for each hour worked.

Advance payment in lieu of pay at time of vacation in the amount set forth above shall be added to each employee's wages on each pay period.

6. Payment in Lieu of Holidays

Whether or not an employee works on any of the Holidays under Article 17, he shall receive in lieu of paid Holidays four and a half percent (4.5%) of his standard hourly rate for each hour worked.

7. Trust Funds

a) Health and Welfare

The Contractor shall contribute the amount set out below to the International Brotherhood of Painters and Allied Trades, Sign Workers and Painters Division, Local 739, Health and Welfare Trust Fund for all hours worked by all employees covered by this Appendix.

Effective May 1, 2019 $1.50 per hour

Health and Welfare contributions commence after 390 hours. Trust Fund contributions shall be remitted by the 15th of the month following the month in which contributions were collected to the following address:

Local 739 Health and Welfare Trust Fund
c/o Coughlin and Associates Ltd.
PO Box 764 Winnipeg, MB R3C 2L4
Phone No.(204) 942-4438

b) Pension

Except as provided below, the Contractor shall contribute the amount set out below for all hours worked by all employees covered by this Appendix to the International Brotherhood of Painters and Allied Trades Union and Industry

Effective	May 1, 2019	$4.00 per hour

It is agreed that all new apprentices (first and second year) shall not be participants in the Pension until they have attained 2,400 hours while working for the Contractor or a contractor signatory to the Agreement being used for reference purposes.

A Unified remittance form shall be supplied by the Union to the Contractor and such form shall make provision for the listing of each employee's name, social insurance and number of hours worked. The completed remittance form, and the pension trust fund contributions and the Apprenticeship and Employee Development Fund (see Section 7 (c) below) contributions shall be forwarded to the 'I.B.P.A.T. Local 739 Benefit Trust Funds' at the following address:

Local 739 Health and Welfare Trust Fund
c/o Coughlin and Associates Ltd.
PO Box 764 Winnipeg, MB R3C 2L4
Phone No.(204) 942-4438

Contributions shall be remitted by the 15th of the month following the month in which contributions were collected.

c) Apprenticeship and Employee Development Fund

a) Subject to (b) below, the Contractor and each employee covered by this Appendix shall respectively contribute the amounts set out below to the Provincial Apprenticeship and Employee Development Fund.

Contributions shall apply to all hours worked and employee contributions shall be collected at the source as a payroll deduction.

The Contractor's contribution shall be:	15 cents per hour
The Employee's contribution shall be:	5 cents per hour

b) Contractor and Employee contributions to the Fund will be discontinued immediately if one or more of the following occurs:

i) The Fund ceases to be governed by a Trust;

ii) The provisions of the Trust are not fulfilled;

iii) Employers are no longer represented on the Board of Trustees.

c) In the event that either the Association or the Council has reason to believe that one or more of the conditions described in (b) above has occurred, the matter shall be referred to the Joint Appendix Review Committee. Until the matter is resolved, Contractors shall hold all Contractor and employee contributions in trust.

8. Tools

The following tools and equipment shall be provided by all employees:

	Description
	White Overalls
	Broad Knife (1 3" and 1 5" to 6")
1	Putty Knife
1	Scraper
1	Hammer
1	Nail Set
1	Phillips Screw Driver
4	Robertson Screw Drivers (#1, 2, 3 & 4)
2	Flat Screw Drivers (large and small)
1	Hard Hat (approved under the Workplace Safety and Health Act)
1	Hand Sander
1	Pliers
1	Paint Brush spinner
2	Pot Hooks
1	Suitable Footwear (approved under the Workplace Safety and Health Act)

In addition to the foregoing, Spray Mechanics shall supply 1 - 10" and 8" crescent wrench and a Respirator (respirator of a type approved by the Contractor, the Union and the Workplace Safety and Health Division).

In addition to the above tool lists, Sandblasting Mechanics shall supply 1 - 8" pipe wrench.

If such an employee reports to work and is not in possession of the above noted tools and overalls, the Contractor shall supply same, for which the employee will be charged at cost.

A lock box is to be supplied by the Employer for the use of the Employees on the job site.

The Employer will be responsible for compensation for tools and equipment destroyed by fire or lost by breaking and entering from a storage place provided by the Employer.

Responsibility for normal wear and tear of tools and equipment supplied by the Employer is accepted by the Employer on return of broken or worn tools and equipment.

Claim for lost or destroyed tools and equipment must be submitted in writing with list of such tools and equipment and value thereof, and substantial evidence of loss. Such list must be submitted within five (5) working days of loss unless good reason can be shown for not having done so.

9. Escalation and Reference

9.1 Wage Rate Provisions

The wage rate for the classifications set out in this Appendix will be adjusted by an amount equal to and effective on the dates of any adjustments in wage rates for corresponding classifications which may be negotiated from time to time by the International Brotherhood of Painters and Allied Trades, Local 739, Painters Division and the Member Firms of the Manitoba Painters Negotiating Council, except that the Non-certified painter rate shall remain at 90% of the Certified Journeyman Painter rate throughout the term of this Agreement.

Classifications eligible for adjustment may include general foreman, foreman, leadhand, chargehand, pusher, journeyman, and apprentices.

9.1.1 Except as otherwise noted, the following provisions will be incorporated or adjusted to be consistent with corresponding provisions negotiated from time to time by the aforementioned Parties:

a) Definitions and qualificational requirements for applicable classifications;

b) Ratios indicating the number of apprentices, or other types of trainees who may be employed;

c) Height pay including that associated with swing stage work.

9.2 Other Conditions of Employment

Except as otherwise noted, the following conditions of employment will be incorporated or adjusted to be consistent with corresponding conditions of employment negotiated from time to time by the aforementioned Parties.

a) Shift premium but excluding any shift premium applicable to overtime

hours;

b) Pay in lieu of Holidays;

c) Vacation and Vacation Pay - such provisions may include any provisions relative to the timing of payment of vacation pay but shall not include any provisions stipulating when vacation time must be granted, and in lieu of such a provision the following shall be substituted: "the scheduling of time off for vacation shall be arranged by mutual agreement between the Contractor and the employee";

d) Registered and trusteed pension and health and welfare plans (subject to the restrictions set out in Section 9.2.1);

e) Rest provisions between shifts;

f) Provisions governing special trade related tests;

g) Safety clothing;

h) Tool lists and provisions governing loss of such tools on the Project.

9.2.1 The Contractor's contribution to any pension and health and welfare plan may be applied on a per hour worked basis; however, the Contractor's contribution rate in respect of overtime hours shall not be greater than the required contribution rate for Contractors in respect of straight time hours.

9.3 Notwithstanding anything contained in this Agreement or in this Appendix, the regular hours of work are not subject to adjustment during the life of this Agreement, and such regular hours of work shall be paid at regular rates of wages.

9.4 The provisions of 9.1 and 9.2 above shall be dealt with by following the procedure set out in Article 30 of this Agreement.

APPENDIX NO. 5a – Glassworkers Division

INTERNATIONAL BROTHERHOOD OF PAINTERS AND ALLIED TRADES

Local Union 739, Glass Workers Division

1. Hours of Work and Overtime

Nine (9) hours shall constitute a day's work for four (4) days Monday to Thursday inclusive, and eight (8) hours shall constitute a day's work for Friday. Said hours shall normally be within the period from 7:00 a.m. until 6:00 p.m.

If more than the recognized daily hours are worked in any day or shift, Monday to Friday, such time shall be paid at the rate of time and one-half of the straight time hourly rate, up to a combined total of 12 hours, after which the rate of pay shall be two times the straight time hourly rate.

On Saturdays, except as provided in Article 15.2, time and one-half shall be paid for the first 8 hours, after which the rate of pay shall be two times the straight time hourly rate.

On Sundays and on Holidays as specified in Article 17, double time shall be paid.

2. Shift Conditions

If the conditions are such that work on a particular job cannot be done during the regular daily hours, (7:00 a.m. to 6:00 p.m.) then nine (9) hours or eight (8) hours, as the case may be, may be worked during any hours and may constitute a regular shift on that job. Overtime payment for shift work shall be in accordance with the provisions as set out above.

The starting and quitting time for all shift work will be decided by the Contractor.

3. Callout

When emergency calls are made after completing the regular shift, the employee shall be paid at the applicable overtime rate, however, the employee shall not be paid less than the equivalent of four hours at the employee's straight time rate for any one (1) callout.

4. Wages

Wage rates shall be as follows:

(a) Journeyman Glass and Metal Mechanics

	May 1, 2016	May 1, 2017	May 1, 2018
Journeyman	$31.38	$31.87	$32.36

(b) Apprentices

			May 1, 2016	May 1, 2017	May 1, 2018
1st Period	0-900 hours	50% of Jnmn	$15.69	$15.94	$16.18
1st Period	901-1800 hours	55% of Jnmn	$17.26	$17.53	$17.80
2nd Period	1801-2700 hours	60% of Jnmn	$18.83	$19.13	$19.42
2nd Period	2701-3600 hours	65% of Jnmn	$20.40	$20.72	$21.04
3rd Period	3601-4500 hours	70% of Jnmn	$21.97	$22.31	$22.66
3rd Period	4501-5400 hours	75% of Jnmn	$23.54	$23.91	$24.27
4th Period	5401-6300 hours	80% of Jnmn	$25.11	$25.50	$25.89
4th Period	6301-7200 hours	85% of Jnmn	$26.68	$27.09	$27.51

The ratio of apprentices to journeymen shall not exceed three (3) apprentices for each journeyman employed.

Any employee who does not have a journeyman certificate and who is not an apprentice will be evaluated by the Contractor on the basis of experience, range of experience and proficiency and slotted into the apprenticeship program.

(c) Leadhands

When a working leadhand is appointed by the Contractor he shall be paid a premium of one dollar and twenty-five cents ($1.25) per hour in addition to his normal rate.

5. Height Premium

A premium rate of one dollar ($1.00) per hour, in addition to the normal rate, shall be paid for all work performed from a swing stage.

6. Vacation and Vacation Pay

The annual vacation will be provided in accordance with the Employment Standards Code for the Province of Manitoba.

Vacation pay allowance will be accumulated for the credit of each employee at the rate of six percent (6%) of the employee's standard hourly rate for each regular hour worked. This vacation pay allowance will be paid to an employee on his regular paydays, and shall be considered as advance payment for any vacation taken by the employee pursuant to the Employment Standards Code for the Province of Manitoba.

7. Pay in Lieu of Holidays

Whether or not an employee works on any of the Holidays set out in Article 17, an employee shall receive in lieu of paid Holidays, four and a half percent (4.5%) of the employee's standard hourly rate for each hour worked to a maximum of forty (40) hours per week. An employee shall be paid such amounts on each regular pay.

8. Trust Funds

(a) Health and Welfare

The Contractor and each employee shall respectively contribute the amounts set out below to the Local Union 739 Health and Welfare Trust Fund. Contributions shall be based on hours worked**.** Employee contributions shall be collected at the source as a payroll deduction.

The Contractor's contribution shall be:

Effective May 1, 2016	$1.18 per hour
Effective May 1, 2017	$1.23 per hour
Effective May 1, 2018	$1.28 per hour

The employee's contribution shall be:

- 22 cents per hour

(b) Pension

The Contractor shall contribute the amount set out below to the International Brotherhood of Painters and Allied Trades Union and Industry Pension Fund (Canada). Contributions shall apply to all hours worked by all employees covered by this Appendix.

The Contractor's contribution shall be:

Effective May 1, 2016	$2.00 per hour
Effective May 1, 2017	$2.15 per hour
Effective May 1, 2018	$2.30 per hour

Contributions are to commence only when the employee achieves the status of 3rd period (70%) apprentice.

Contributions shall be remitted to the Administrator of each Fund by the 15th of the month following the month for which contributions are payable. Contributions shall be accompanied by a reporting form listing the employee's name and the respective amount remitted.

9. Safety Clothing

When the Contractor determines that protective clothing or equipment is necessary, he will provide the clothing and equipment to the employee without cost. However, if the clothing or equipment is lost or, in the judgement of the Contractor damaged beyond use through negligence or carelessness of the employee, the Contractor may replace the damaged or lost clothing or equipment at the expense of the employee.

10. Tools

A journeyman shall supply the following hand tools, which shall be of professional grade:

Quantity	Description
1 set	Allen Keys Metric
1 set	Allen Keys Standard
1 only	Chalk String
1 only	Chisel - Wood
1 only	Chisel - Cold
1 only	Rat Tail File
1 only	Flat File
1 only	Small Round File
1 pair	Glass Pliers
1 only	Hacksaw
1 only	Hammer - Claw
1 only	Level - 2 Foot
1 only	Level - 4 Foot
1 only	Measuring Tape
1 only	Nail Set
1 pair	Pliers
1 pair	Glass Pliers
1 only	Plumb Bob
1 only	Pry Bar
1 only	Razor Knife
1 only	Screwdriver - Rob. - Green
1 only	Screwdriver - Rob. - Yellow
1 only	Screwdriver - Rob. - Red
1 only	Screwdriver - Rob. - Black
1 only	Screwdriver - Phil. - CP - 1
1 only	Screwdriver - Phil. - CP - 4
4 only	Screwdriver – Flat
1 only	Square - Combination
2 only	Tap Handles - 1/4"
1 only	Vice Grip
1 only	Crescent Wrench
1 only	Side cutters or Tin snips
1 only	Set of Stubby Screwdrivers
1 only	Caulking Gun
1 only	Pop Rivet Gun

If an employee is not in possession of the required tools above-noted, the Contractor shall supply them and charge them, at cost, to the employee.

The Contractor shall replace Employees' tools, if turned in, that are broken or worn due to normal use.

An apprentice shall be required to purchase the above tools during the first three (3) months of his apprenticeship.

The Contractor shall provide all power tools. The employee shall cooperate to keep said power tools in good condition.

11. Escalation and Reference

11.1 Wage Rate Provisions

The wage rate for the classifications set out in this Appendix will be adjusted by an amount equal to and effective on the dates of any adjustments in wage rates for corresponding classifications which may be negotiated from time to time by the International Union of Painters and Allied Trades, Local Union 739, Glassworkers Division and the Management signatory, Quality Glass Installations.

Classifications eligible for adjustment may include general foreman, foreman, leadhand, chargehand, pusher, journeyman, apprentices, helpers and trainees.

11.1.1 Except as otherwise noted, the following provisions will be incorporated or adjusted to be consistent with corresponding provisions negotiated from time to time by the aforementioned Parties:

(a) definitions and qualificational requirements for applicable classifications.

(b) ratios indicating the number of apprentices, helpers, or other types of trainees who may be employed.

(c) height pay including that associated with swing stage work.

11.2 Other Conditions of Employment

Except as otherwise noted, the following conditions of employment will be incorporated or adjusted to be consistent with corresponding conditions of employment negotiated from time to time by the aforementioned Parties:

(a) shift premium but excluding any shift premium applicable to overtime hours.

(b) pay in lieu of Holidays.

(c) Vacation and Vacation Pay - such provisions may include any provisions relative to the timing of payment of vacation pay but shall not include any provisions stipulating when vacation time must be granted, and in lieu of such a provision the following shall be substituted: 'the scheduling of time off for vacation shall be arranged by mutual agreement between the Contractor and the employee'.

(d) registered and trusteed pension and health and welfare plans (subject to the restrictions set out in Section 11.2.1).

(e) rest provisions between shifts

(f) provisions governing special trade related tests

(g) safety clothing

(h) tool lists and provisions governing loss of such tools on the Project.

11.2.1 The Contractor's contribution to any pension and health and welfare plan may be applied on a per hour worked basis; however, the Contractor's contribution rate in respect of overtime hours shall not be greater than the required contribution rate for Contractors in respect of straight time hours.

11.3 Notwithstanding anything contained in this Agreement or in this Appendix, the regular hours of work are not subject to adjustment during the life of this Agreement, and such regular hours of work shall be paid at regular rates of wages.

11.4 The provisions of 11.1 and 11.2 above shall be dealt with by following the procedure set out in Article 30 of this Agreement.

APPENDIX NO. 5b – Floor Covering Division

INTERNATIONAL BROTHERHOOD OF PAINTERS AND ALLIED TRADES

Local Union No. 739, Floor Covering Division

BURNTWOOD/NELSON AGREEMENT

1. Hours of Work and Overtime

Nine (9) hours shall constitute a day's work for five (5) days, Monday until Friday inclusive.

Except as provided in Article 15.2, overtime at the rate of time and one-half of the standard hourly rate shall be paid for all hours worked in excess of forty five (45) hours per week and for all hours worked on Saturdays.

On Sundays and Holidays as specified in Article 17, double time shall be paid.

2. Wages

Wage rates shall be as follows:

a) Journeyman Floor Covering Installers

Effective	May 1, 2016	$30.08 ***
Effective	May 1, 2017	$30.84 ***
Effective	May 1, 2018	$31.60

*** Note, no 2016 increase will be applied. Increases noted with an effective date of May 1, 2017, will only be effective January 1, 2018 (ie/ retro only to Jan 1, 2018)

b) Apprentices:

First Level	55% of the Journeyman Rate
Second Level	70% of the Journeyman Rate
Third Level	87.5 % of the Journeyman Rate
(until achievement of Journeyman status)	

A Journeyman means a person who holds a certificate of qualification or proficiency from a Provincial Apprenticeship system or from a source recognized by the Contractor or has acquired the skills of the trade by working in the trade for a period of not less than six years, and is proficient in performing all of the following tasks:

- Self-levelling and latex floor patching;
- Installation of carpet with a minimum six inch repeat pattern;

- Liquid welding;
- Installation of composite vinyl flooring with epoxy cement;
- Installation with automatic and hand welding of composition flooring;
- Mono-bound installation.

3. Vacation and Vacation Pay

Annual vacation will be arranged as provided in the Manitoba Employment Standards Code.

Vacation pay allowance will be accumulated for the credit of each employee at the rate of six percent (6%) of the employee's standard hourly rate for each hour worked, except first and second year apprentices and Improvers who shall receive four percent (4%) of the standard hourly rate for each hour worked.

Advance payment in lieu of pay at time of vacation in the amount set forth above shall be added to each employee's wages each pay period.

4. Pay in Lieu of Holidays

Whether or not an employee works on any of the Holidays under Article 17, he shall receive in lieu of paid Holidays, four percent and a half (4.5%) of his standard hourly rate for each hour worked. The employee shall be paid this amount not later than the 31st day of December of the calendar year or upon termination of his employment whichever day is the earlier.

5. Health and Welfare

The employee shall contribute the amounts set out below to the Local Union 739 Health & Welfare Trust Fund. Contributions shall be based on hours worked. Employee contributions shall be collected at the source as a payroll deduction.

The employee contributions shall be:

Effective May 1, 2017 $1.45 per hour (*** Note – retro dates on these premiums shall only apply back to Jan 1, 2018)
Effective May 1, 2018 $1.50 per hour

Health and Welfare Trust Fund contributions shall be remitted by the 10th of the Month following the month in which contributions were collected to the following address:

Local 739 Health and Welfare Trust Fund
PO Box 764
Winnipeg, MB R3C 3R8

6. Pension Provision

Provided:

a) The Local Union to which Carpet and Resilient Floor Tile Layers belong establishes a health and welfare plan and/or a pension plan in which employees covered by this Appendix are eligible to participate;

b) Written verification is forwarded to the Association and the Council by the Board of Trustees of each plan confirming:

i) Proviso (a), above;

ii) That Trust Agreements have been executed and registered.

A pension plan will be introduced into this Appendix on the following basis:

At the time of introduction of the health and welfare plan and/or the pension plan,the hourly rates for all classifications in this Appendix shall be reduced by the amount of the contractor's contribution to the said plan or plans. At the option of the Council, contributions to the plan or plans shall be made up by employee contributions or a combination of contractor and employee contributions. The Council shall advise the Association of the required contractor and/or employee contributions at the time the plan or plans are established.

Pension and/or health and welfare contributions shall be subject to adjustments, however all contributions shall continue to be made as outlined above and the effective date of such adjustments shall correspond to an effective date of changes to wages (See Section 7.1).

7. Escalation and Reference

7.1 Wage Rates

As provided in Section 7.2, the wage rates for all classifications in this Appendix shall be adjusted by a percentage, equivalent to the percentage adjustment in wage rates and in the employers' contribution rate to pension and health and welfare plans negotiated from time to time for the classification of journeyman painter (brush and rollers)(hereinafter referred to as the Reference Classification) by the International Brotherhood of Painters and Allied Trades, Local 739, Painters Division, and the Member Firms of the Manitoba Painters Negotiating Council.

7.2 Method of Calculating Percentage Adjustment of Classifications

The percentage adjustment of the Reference Classification shall be determined in accordance with the following formula:

$$\frac{\text{(Change in W) + (Change in P) + (Change in H\&W)}}{\text{(Expired W) + (Expired P) + (Expired H\&W)}} \times 100$$

Where:

- Change means the increase or decrease in that benefit.
- W means wage rate.
- P and H&W means the required employers' contribution rate to the pension and/or the health and welfare plan.
- Expired means the rate in effect when the last percentage adjustment was calculated.

7.2.1 In calculating the percentage adjustment of the Reference Classification, the result shall be rounded to the nearest hundredth of a per cent.

7.2.2 Effective Date of Adjustments

When changes to P and/or H&W in the agreement being used for reference purposes occur on the same date, the percentage adjustment of all such changes shall be calculated to determine the percentage adjustment by which wage rates in the Appendix are to be adjusted and the foregoing shall be the effective date of the resultant wage rates.

When changes to P and/or H&W are not effective on the effective date of any changes to W in the agreement being used for reference purposes, such changes shall be deemed to be effective on the date of a change to W next occurring, and the procedures set out above shall be followed.

When: a) there are no changes to W but there are changes to P and/or H&W, or b) there are changes to P and/or H&W but no subsequent changes to W during the term of the agreement being used for reference purposes, the calculated percentage adjustment shall be effective on the effective date of such changes in the agreement being used for reference purposes.

7.2.3 In applying the percentage adjustments, the resultant wage rates shall be rounded to the nearest cent.

7.3 Vacation and Holiday Pay

The percentage figure set out in Sections 3 and 4 of this Appendix, shall be adjusted to be the same as that in effect in Appendix No. 5 of this Agreement.

7.4 The provisions of 7.1 and 7.2 above shall be adjusted by following the procedure set out in Article 30 of this Agreement.

7.5 Notwithstanding anything contained in this Agreement or in this Appendix, the regular hours of work are not subject to adjustment during the life of this Agreement, and such regular hours of work shall be paid at regular rates of wages.

APPENDIX NO. 6 – Insulator Workers

INTERNATIONAL ASSOCIATION OF HEAT AND
FROST INSULATORS AND ALLIED WORKERS

Local Union No. 99

BURNTWOOD/NELSON AGREEMENT

Revised August 10, 2018

1. Hours of Work and Overtime

Nine (9) hours shall constitute a day's work for four (4) days Monday to Thursday inclusive, and eight (8) hours shall constitute a day's work for Friday. Said hours shall normally be within the period from 7:00 a.m. until 6:00 p.m.

If more than the recognized daily hours are worked in any day or shift, Monday to Friday inclusive, such time shall be paid at the rate of time and one-half of the straight time hourly rate for the first two hours worked and double the straight time hourly rate for all hours worked thereafter.

On Saturdays and Sundays, except as provided in Article 15.2, all hours worked shall be paid at the rate of one and one-half (1½) times the regular straight time hourly rate.

On Holidays as specified in Article 17, double time shall be paid.

2. Shift Conditions

If the conditions are such that work on that particular job cannot be done within the said normal hours (7:00 a.m. to 6:00 p.m.) then nine (9) hours, or eight (8) hours, as the case may be, may be worked during any hours and may constitute a regular shift on that job.

An employee who works the majority of his hours between 4:00 p.m. and 12:00 a.m. will receive shift premium at the amount of two dollars ($2.00) per hour above the standard hourly rate for all consecutive hours worked. In the case of an employee working the majority of his hours between 12:00 a.m. and 8:00 a.m. he will receive shift premium at the amount of two dollars ($2.00) per hour above the base hourly rate for all consecutive hours worked.

Overtime payment for shift work shall be in accordance with the provisions as set out above.

Shift premium shall not be paid on any overtime hours worked.

The starting and quitting time of all shift work will be decided by the contractor.

3. Wages

Wage rates shall be as follows:

a) Journeyman Insulator - Industrial

	May 1, 2019***	May 1, 2020	May 1, 2021
Journeyman 'A'	$31.89	TBA	TBA
Journeyman 'B' (only to be used for calculation of Apprentice rates)	$30.00	TBA	TBA
1st Year Apprentice (58%)	$17.40	TBA	TBA
2nd Year Apprentice (69%)	$20.70	TBA	TBA
3rd Year Apprentice (81%)	$24.30	TBA	TBA
4th Year Apprentice (92%)	$27.60	TBA	TBA

*** As a wage reduction from prior years, although the effective date is May 1, 2019 no recovery of wages will be completed.

TBA – will be announced through Wage Re-Opener 1 and Wage Re-Opener 2 in the applicable years.

b) Foreman Premium
When the Contractor appoints a journeyman as a working foreman he shall be paid, in addition to the journeyman's rate, the applicable amount set out below:

In charge of:

Four (4) to fifteen (15) employees, 105% to 120% of the journeyman rate, in the discretion of the Contractor.

c) General Foreman Premium
A General Foreman will receive between 120% to 135% of the base Journeyman rate (as determined by the employer). A General Foreman can be appointed at the discretion of the employer, or will be appointed at a minimum crew size of forty-five (45) members.

d) Apprentices

1st year - 58% of Journeyman's rate
2nd year - 69% of Journeyman's rate
3rd year - 81% of Journeyman's rate
4th year - 92% of Journeyman's rate

A fourth year Apprentice must work at the trade for four (4) years and pass any trade examinations before he can become a Journeyman Insulator.

The ratio of Apprentices to Journeymen employed by a Contractor may equal one journeyman to one Apprentice.

When the Union is unable to supply competent and qualified Journeymen, contractors may use fourth year Apprentices to expedite the job.

No Apprentice shall be made up to Journeyman status by the Union or advanced in pay scale by the contractor until he has completed his full allotment of time at the trade as set forth above. For purposes of computing apprentice pay scales 1800 hrs. shall equal one (1) year's credit. The Union will issue each Apprentice with a log book. The contractor will, once a year or on termination of employment, whichever comes first, fill in the number of hours worked at each aspect of the trade in the employee's log book together with a report on the employee's aptitude for the trade, his progress in learning the trade and his attitude.

4. Height Premiums

Employees working on swing stages or bosun chairs shall not receive a premium.

5. Vacation and Vacation Pay

Annual vacation will be arranged as provided in The Employment Standards Code for the Province of Manitoba.

Vacation pay allowance will be accumulated for the credit of each employee at the rate of six percent (6%) of the employee's standard hourly rate for each hour worked.

Advance payment in lieu of pay at time of vacation in the amount set forth above shall be added to each employee's wages on each pay period.

6. Payment in Lieu of Holidays

Whether or not an employee works on any of the Holidays set out in Article 17, he shall receive in lieu of paid Holidays four and a half percent (4.5%) of his gross hourly rate for each hour worked (gross hourly rate shall be deemed to mean his base hourly rate plus the 6% for vacation pay). The employee shall receive this allowance at the time and under the conditions set forth in the Employment Standards Code for the Province of Manitoba. [Gross hourly rate shall be deemed to mean his standard hourly rate plus six percent (6%) of same].

7. Trust Funds

Health and Welfare

The Contractor and each employee shall contribute the amounts set out below to the Manitoba Multiple Trade Health and Welfare Trust Fund. Contributions shall apply to all hours worked and shall be collected at the source as a payroll deduction.

Effective May 1, 2015:

The Contractor's contribution shall be:	$0.55
The Employee's contribution shall be:	$0.55

Pension Fund

The Contractor and each employee covered by this Appendix shall respectively contribute the amounts set out below to the Manitoba Multiple Trade Pension Trust Fund for all hours worked by all employees covered by this Appendix. The employee's contributions shall be collected at the source as a payroll deduction.

The Contractor's contribution shall be:

Effective May 19, 2013 $2.30 per hour

The Employee's contribution shall be:

Effective May 1, 2019 $2.75 per hour

Note: The Contractor's contributions to the Manitoba Multiple Trade Pension Trust Fund will be prorated for Apprentice Insulators in accordance with the following percentages:

Apprentices

1st year	-	58% of Journeyman's rate
2nd year	-	69% of Journeyman's rate
3rd year	-	81% of Journeyman's rate
4th year	-	92% of Journeyman's rate

Contributions to the above Pension Fund and Health and Welfare Fund shall be submitted each month by the 15th of the month following the month for which contributions are collected.

8. Insulators Health Hazards Fund

The Contractor shall deduct at the source the amount set out below for each hour worked by each employee covered by this Appendix, and remit same in a single lump sum payment to the Insulators Health Hazards Fund c/o the Local Union by the 15th of the month following the month in which contributions are collected. The Union shall supply satisfactory deduction forms suitable to the Contractor.

The Employee's contribution shall be: 2¢ per hour

9. Safety Equipment and Tools

The Contractor shall furnish and maintain without charge to the employee:

- All necessary power tools
- All necessary protective devices
- Hand cleaner and protective face cream
- Special brushes and staple gun
- All metal cutting tools that are worn out or damaged due to work on - stainless steel metal

The employee shall be responsible for the return in good condition of all protective devices, power tools, tools and protective clothing issued by the Contractor. The Contractor accepts the responsibility for normal wear and tear. The employee may be charged depreciated replacement cost for lost or abused items.

The Contractor will provide work gloves (leather palm) upon the request of the employee. The employee will return worn-out work gloves to the Contractor prior to receiving a new pair. The Contractor will provide coveralls to employees who are working with foam glass, mastics and bulk adhesive products. The employee will return worn-out coveralls to the Contractor prior to receiving a replacement pair at no charge and will return the coveralls when the work in question is completed.

An approved respirator shall be furnished by the Contractor on request. Replacement respirators will be provided at no cost, only when the used respirator is turned in to the Contractor's representative, and is obviously unfit for further use. If the used respirator is not turned in the cost of the new respirator will be deducted from the employee's pay. A supply of respirator filters shall be available at no cost to the employee.

Tools

The Contractor will be responsible for compensation for tools destroyed by fire or lost by breaking and entering from a storage place provided by the Contractor. Claims for lost or destroyed tools must be submitted in writing with a list of such tools and the value thereof, along with substantial evidence of loss. This list must be submitted within five working days of loss unless good reason can be shown for not having done so.

The following basic tools must be provided by the employee:

Description			
	3rd & 4th Year	2nd Year	1st Year
1 tool pouch or carryall	X	X	X
1 16 ft tape	X	X	X
1 pair 7" or 8" nippers	X	X	X
1 knife	X	X	X
1 banana knife or utility knife	X	X	X
1 scissors	X	X	X
2 Metal Masters (M1 & M2)	X	X	X
1 pointer trowel, 5" or 6"	X	X	X
1 pruning saw	X	X	
1 keyhole saw	X	X	
1 scratch awl	X		
1 hammer	X		
1 set of dividers	X		
1 screwdriver set	X		
1 12" tin snips	X		
1 flat trowel, 4 1/2" x 11"	X		

10. Escalation and Reference

10.1 Wage Rate Provisions

The wage rate for the classifications set out in this Appendix will be adjusted by an amount equal to and effective on the dates of any adjustments in wage rates for corresponding classifications which may be negotiated from time to time by the International Association of Heat and Frost Insulators and Allied Workers, Local Union No. 99 and the Insulating Contractors Trade Division of the Construction Labour Relations Association of Manitoba.

Classifications eligible for adjustment may include general foreman, foreman, leadhand, chargehand, pusher, journeyman, apprentices, helpers and trainees.

10.1.1 Except as otherwise noted, the following provisions will be incorporated or adjusted to be consistent with corresponding provisions negotiated from time to time by the aforementioned Parties:

a) Definitions and qualificational requirements for applicable classifications;

b) Ratios indicating the number of apprentices, helpers, or other types of trainees who may be employed;

c) Height pay including that associated with swing stage work.

10.2 Other Conditions of Employment

Except as otherwise noted, the following conditions of employment will be incorporated or adjusted to be consistent with corresponding conditions of employment negotiated from time to time by aforementioned Parties:

a) Overtime payments (subject to the restrictions set out in Section 10.3);

b) Shift premium but excluding any shift premium applicable to overtime;

c) Vacation and Vacation Pay - such provisions may include any provisions relative to the timing of payment of vacation pay but shall not include any provisions stipulating when vacation time must be granted, and in lieu of such a provision the following shall be substituted: "the scheduling of time off for vacation shall be arranged by mutual agreement between the Contractor and the employee";

d) Pay in lieu of Holidays and any provisions requiring the transferring and observing of the Holiday on a day, other than the day on which the Holiday falls (subject to the restrictions set out in Section 10.2.1);

e) Registered and trusteed pension and health and welfare plans (subject to the restrictions set out in Section 10.2.2);

f) Rest provisions between shifts;

g) Provisions governing special trade related tests;

h) Safety clothing;

i) Tool lists and provisions governing loss of such tools on the Project;

j) The following trusteed Plan, which shall be subject to the restrictions set out in Section 10.2.3: Insulators Health Hazards Fund.

10.2.1 A Holiday set out in Article 17 may be observed on a day, other than the day on which it falls, provided the Holiday falls on a Saturday or Sunday which is a non-working day, in which case the Holiday may be observed on the closest following working day. The transferring of a Holiday shall not apply to any employee who is on Christmas Leave, Isolation Leave or any other type of Leave of Absence when the Holiday occurs.

10.2.2 The Contractor's contribution to any pension and health and welfare plan may be applied on a per hour worked basis; however, the Contractor's contribution rate in respect of overtime hours shall not be greater than the required contribution rate for Contractors in respect of straight time hours.

10.2.3 The Contractor's contribution to the plan referred to in Section 10.2 (j) may be applied on a per hour worked basis; however, the Contractor's contribution rate in respect of overtime hours shall not be greater than the required contribution rate for contractors in respect of straight time hours.

10.3 Notwithstanding anything contained in this Agreement or in this Appendix, the regular hours of work are not subject to adjustment during the life of this Agreement, and such regular hours of work shall be paid at regular rates of wages. Further, overtime payments at a rate greater than time and one-half will not be introduced in this Appendix in respect of the first two (2) hours of overtime, Monday to Friday inclusive.

10.4 The provisions of 10.1 and 10.2 above shall be dealt with by following the procedure set out in Article 30 of this Agreement.

APPENDIX NO. 7 - Lathers

Manitoba Regional Council of Carpenters, Lathers,
Millwrights and Allied Workers

Local Union 343 (Lathing and Drywall)

BURNTWOOD/NELSON AGREEMENT

1. Hours of Work and Overtime

Nine (9) hours shall constitute a day's work for four (4) days Monday to Thursday inclusive, and eight (8) hours shall constitute a day's work for Friday. Said hours shall normally be within the period from 7:00 a.m. until 6:00 p.m.

If more than the recognized daily hours are worked in any one (1) day or shift, Monday to Friday inclusive, such time shall be paid at the rate of time and one-half.

On Saturdays, except as provided in Article 15.2, time and one-half shall be paid.

On Sundays, and on Holidays, as set out in Article 17, double time shall be paid.

2. Shift Conditions

If conditions are such that work on that particular job cannot be done within the said normal hours (7:00 a.m. to 6:00 p.m.) then nine (9) hours, or eight (8) hours, as the case may be, may be worked during any hours and may constitute a regular shift on that job.

Overtime payment for shift work shall be in accordance with the provisions as set out above.

The starting and quitting time of all shift work will be decided by the contractor.

3. Wages

Wage rates shall be as follows:

3.1 Interior Systems Mechanics: (formerly Lathers and Drywall Applicators)

(a) Journeyman Interior Systems Mechanic**:**

Effective	
January 1, 2017	$30.45 per hour

(b) Working Foremen

When a working Foreman is appointed by the Contractor, the person so appointed must be a qualified Journeyman Interior Systems Mechanic and will be paid fifteen (15%) percent above the Journeyman's wage rate.

(c) Height Premiums

All employees working on swing stages or bosom chairs shall receive four (4) percent of the certified Journeyperson rate, in addition to his/her regular rate of pay.

(d) Apprentices

First six months	50% of Journeyman’s rate
Second six months	60% of Journeyman’s rate
Second year	65% of Journeyman’s rate
Third year	70% of Journeyman’s rate
Fourth year	80% of Journeyman’s rate

The ratio of Apprentice to Journeyman shall be a minimum 1:1 ratio of journeymen to apprentices.

The Union will issue each Apprentice with a log book. The Contractor will, once each year or on termination of employment, whichever comes first, fill in the number of hours worked at each aspect of the trade in the employee's log book together with a report on the employee's aptitude for the trade, his progress in learning the trade and his attitude.

4. Rest Period

When an employee has not been provided with a full eight (8) hours rest period between shifts, the employee will be paid at double the straight time hourly rate for all hours worked until such time as an eight hour break occurs.

5. Vacations and Vacation Pay

Annual Vacation will be arranged as provided for in the Employment Standards Code for the Province of Manitoba.

Vacation pay allowance will be accumulated for the credit of each employee at the rate of six percent (6%) of the employee's standard hourly rate for each hour worked, except as set out below.

A person hired who is not a journeyman and who was not a Member of the Union as of May 1, 1990 will receive Vacation Pay at the rate of four percent (4%) of the employee's standard hourly rate for each hour worked.

Advance payment in lieu of pay at time of vacation in the applicable amount set forth above shall be added to each employee's wages on each pay period.

6. Payment in Lieu of Holidays

Whether or not an employee works on any of the Holidays set out in Article 17, he shall receive in lieu of paid Holidays four and a half percent (4.5%) of his standard hourly rate for each hour worked. The employee shall receive this allowance at the time and under the conditions set forth in the Employment Standards Code.

7. Trust Funds

The Contractor and each employee covered by this Appendix shall contribute the amounts set out below to the Manitoba Multiple Trade Health and Welfare and Pension Trust Funds. Contributions shall apply to all hours worked. The employee's contributions shall be collected at the source as a payroll deduction.

(a) Health and Welfare

Contractor's contribution	83 cents per hour worked
Employee's contribution	25 cents per hour worked

(b) Pension Fund

Contractor's contribution	$1.50 per hour worked

Contributions to the above pension fund and health and welfare fund shall be submitted each month by the 15th of the month following the month for which contributions are collected.

(c) Training Trust Fund

(a) Subject to (b) below, the Contractor and each employee covered by this Appendix shall respectively contribute the amounts set out below to the Training Trust Fund. Contributions shall apply to all hours worked and employee contributions shall be collected at the source as a payroll deduction.

The Contractor's contribution shall be:

Thirty cents per hour.

The Employee's contribution shall be:

Five cents per hour.

The Contractor shall forward the above contributions to the Training Trust Fund by the fifteenth (15th) day of the month following the month in which the hours were worked.

(b) Contractor and Employee contributions to the Fund will be discontinued immediately if one or more of the following occurs:

(i) the Fund ceases to be governed by a Trust,

(ii) the provisions of the Trust are not fulfilled,

(iii) Employers are no longer represented on the Board of Trustees.

(c) In the event that either the Association or the Council has reason to believe that one or more of the conditions described in (b) above has occurred, the matter shall be referred to the Joint Appendix Review Committee. Until the matter is resolved, Contractors shall hold all Contractor and employee contributions in trust.

8. Tools

(a) Tools and equipment to be supplied by Journeyman Interior Systems Mechanics**:**

1 Tool box 10" x 10" x 20" preferred
1 Pair of Nippers (Todds #4)
1 Pair of Aircraft Snips (Wiss)
1 Lathers Hatchet
1 5/8" Cold Chisel
1 Plumb Bob minimum weight 2 lb.
1 Hack Saw Frame and #32 blades

1 Gypsum Knife and pouch
1 24" x 18" Steel Square
1 100 foot nylon line
1 Screw Driver (or combination preferred)
1 Drywall Saw (Keyhole)
1 25 foot or 50 foot Tape
1 Level 2 feet long
1 16 foot Steel Tape (3/4")
1 Pair of Snips (#8 Wiss)
1 3/4" Cold Chisel
1 Taper Punch
1 Stub Nail Magnet
1 Lathers nail bag and belt
1 45 - Sliding Square
1 Chalk Line Dispenser and Chalk
Marking pencils or the equivalent
1 2 lb. Ball Peen Hammer
1 Hard Hat
1 Pair Safety Goggles
1 Pair Safety Shoes
1 Screw Gun (Safety approved)
1 100' Extension Cord (Safety approved)

All other power tools shall be supplied by the Contractor.

(b) Interior Systems Mechanics Apprentices' Tools

When hiring an Apprentice the Contractor agrees to supply a basic set of tools at cost to the Apprentice. Payment for these tools by the Apprentice shall be made during the first month of employment. A full set of tools must be acquired by the Apprentice within his first year of apprenticeship.

The basic set of tools required consists of the following:

1 Lath Hatchet
1 5/8" Cold Chisel
1 16' Measuring Tape (3/4")
1 #8 Todd Pattern Nippers
1 Wallboard Knife and Blades
1 Pair Safety Goggles
1 Screw Gun (Safety approved)
1 Crescent Type Hack Saw Frame
1 Nail Bag
1 #8 Wiss Brand Cutting Snips
1 Pair of Aircraft Snips (Wiss)
1 Hard Hat
1 Pair Safety Shoes
100' Extension Cord (Safety approved)

(c) Interior Systems Mechanics Journeymen assigned Drywall Applications and Apprentices' Tools

1 Tool Box 10" x 10" x 20" and Lock
1 Wallboard Knife and Blades
1 Board Lifter
1 Plumb Bob
1 Cold Chisel
1 16" x 24" Steel Square
1 Tool Pouch
1 Sharpening Stone (Approved Notches)
1 Hammer Type Stapler
1 Pair of Aircraft Snips (Wiss)
1 T Square
1 16' Measuring Tape (3/4")
1 Pair Safety Goggles
1 Hard Hat1 Screw Gun (Safety approved)
1 100' Extension Cord (Safety approved)
1 Wallboard Saw
1 Approved Wallboard Hatchet
1 2' Level
1 Chalk Line and Dispenser
1 Hack Saw
1 Combination Screw Driver
1 Keyhole Saw
1 Notched Adhesive Spreader
1 Taper Punch
1 Pair of Nippers
1 Set of Kwik Cutters
1 Pair Safety Shoes

All other power tools shall be supplied by the Contractor.

When hiring an Apprentice the Contractor agrees to supply a basic set of tools at cost to the employee. Payment for these tools by the employee shall be made during the first month of employment. A full set of tools must be acquired by the employee within his first year of employment.

9. Escalation & Reference

9.1 Wage Rate Provisions

The wage rate for the classifications set out in this Appendix will be adjusted by an amount equal to and effective on the dates of any adjustments in wage rates for corresponding classifications which may be negotiated from time to time by the Manitoba Regional Council of Carpenters, Lathers, Millwrights and Allied Workers, Local Union 343, and the Drywall and Lathing Trade Divisions of the Construction Labour Relations Association of Manitoba.

Classifications eligible for adjustment may include general foreman, foreman, leadhand, chargehand, pusher, journeyman, apprentices, helpers and trainees.

9.1.1 Except as otherwise noted, the following provisions will be incorporated or adjusted to be consistent with corresponding provisions negotiated from time to time by the aforementioned Parties:

(a) definitions and qualificational requirements for applicable classifications.

(b) ratios indicating the number of apprentices, helpers, or other types of trainees who may be employed.

9.2 Other Conditions of Employment

Except as otherwise noted, the following conditions of employment will be incorporated or adjusted to be consistent with corresponding conditions of employment negotiated from time to time by the aforementioned Parties:

(a) shift premium but excluding any shift premium applicable to overtime hours.

(b) Vacation and Vacation Pay - such provisions may include any provisions relative to the timing of payment of vacation pay but shall not include any provisions stipulating when vacation time must be granted, and in lieu of such a provision the following shall be substituted: 'the scheduling of time off for vacation shall be arranged by mutual agreement between the Contractor and the employee'.

(c) pay in lieu of Holidays.

(d) registered and trusteed pension and health and welfare plans (subject to the restrictions set out in Section 9.2.1).

(e) rest provisions between shifts

(f) provisions governing special trade related tests

(g) safety clothing

(h) tool lists and provisions governing loss of such tools on the Project.

9.2.1 The Contractor's contribution to any pension and health and welfare plan may be applied on a per hour worked basis; however, the Contractor's contribution rate in respect of overtime hours shall not be greater than the required contribution rate for Contractors in respect of straight time hours.

9.3 Notwithstanding anything contained in this Agreement or in this Appendix, the regular hours of work are not subject to adjustment during the life of this Agreement, and such regular hours of work shall be paid at regular rates of wages.

9.4 The provisions of 9.1 and 9.2 above shall be dealt with by following the procedure set out in Article 30 of this Agreement.

NOTE: THIS REPRESENTS AN INTERIM ESCALATION OF THIS APPENDIX NO. 8, UNTIL SUCH TIME AS IT IS SUPERSEDED BY A PERMANENT ESCALATION ONCE THE APPROPRIATE REFERENCE AGREEMENT IS IN HAND.

APPENDIX NO. 8 - Plasterers

THE OPERATIVE PLASTERERS AND CEMENT
MASONS INTERNATIONAL ASSOCIATION

Local Union No. 222 (Plasterers)

BURNTWOOD/NELSON AGREEMENT

1. Hours of Work and Overtime

Nine (9) hours shall constitute a day's work for four (4) days Monday to Thursday inclusive, and eight (8) hours shall constitute a day's work for Friday. Said hours shall normally be within the period from 7:00 a.m. until 6:00 p.m.

If more than the recognized daily hours are worked in any one (1) day or shift, Monday to Friday inclusive, such time shall be paid at the rate of time and one-half.

On Saturdays, except as provided in Article 15.2, time and one-half shall be paid.

On Sundays, and on holidays, as set out in Article 17, double time shall be paid.

2. Shift Conditions

If the conditions are such that work on that particular job cannot be done within the said normal hours (7:00 a.m. to 6:00 p.m.) then nine (9) hours, or eight (8) hours, as the case may be, may be worked during any hours and may constitute a regular shift on that job.

Overtime payment for shift work shall be in accordance with the provisions as set out above.

The starting and quitting time of all shift work will be decided by the contractor.

3. Wages

Wage rates shall be as follows:

(a) Journeyman Plasterers

Effective June 1, 2009, $23.70 per hour

Effective January 1, 2010, $24.65 per hour

(b) Working Foreman

When the Contractor appoints a working Plasterer Foreman, he shall receive a minimum of seventy cents (70 cents) per hour above the Journeyman's wage rate.

(c) Plastering Trade Trainees

The rate for a Trainee Plasterer's shall be:

Trainee 1 (1st 1200 hours):

effective June 1, 2009 - $14.25 per hour

effective January 1, 2010 - $14.75 per hour

Trainee 2 (between 1200 and 2400 hours):

effective June 1, 2009 - $19.00 per hour

effective January 1, 2010 - $19.70 per hour

The Contractor may employ one (1) Plastering Trainee for each Journeyman Plasterer employed.

When a person is hired as an experienced Plasterer's Helper the employee will be required to carry the following tools, all of which must be maintained in good condition.

Hammer	Pliers
Pointing Trowel	Wash Brush
Shingle	Small Saw
Scraping Trowel	

4. Rest Period

When an employee has not been provided with a full eight (8) hours rest period between shifts, the employee will be paid at double the straight time hourly rate for all applicable hours worked until such time as an eight hour break occurs.

5. Vacation and Vacation Pay

Annual vacation will be arranged as provided in The Employment Standards Code for the Province of Manitoba.

Vacation pay allowance will be accumulated for the credit of each employee at the rate of six percent (6%) of the employee's standard hourly rate for each hour worked, except as set out below.

A person who is not a Journeyman and who was not a Member of the Union as of May 1, 1990, will receive Vacation Pay at the rate of four percent (4%) of the employee's standard hourly rate for each hour worked.

Advance payment in lieu of pay at time of vacation in the applicable amount set forth above shall be added to each employee's wages on each pay period.

6. Payment in Lieu of Holiday

Whether or not an employee works on any of the holidays under Article 17, he shall receive in lieu of paid holidays four percent (4%) of his standard hourly rate for each hour worked. The employee shall be paid this allowance at the time and under the conditions set forth in the Employment Standards Code.

7. Trust Funds

The Contractor and each employee covered by this Appendix shall contribute the amounts set out below to the Manitoba Multiple Trade Health and Welfare and Pension Trust Funds. Contributions shall apply to all hours worked. The employee's contributions shall be collected at the source as a payroll deduction.

a) Health and Welfare

Contractor's contribution	10 cents per hour
Employee's contribution	70 cents per hour

b) Pension Fund

Contractor's contribution	50 cents per hour
Employee's contribution	80 cents per hour

Contributions to the above pension fund and health and welfare fund shall be submitted each month by the 15th of the month following the month for which contributions are collected.

c) Training Trust Fund

a) Subject to (b) below, the Contractor and each employee covered by this Appendix shall respectively contribute the amounts set out below to the Training Trust Fund. Contributions shall apply to all hours worked and employee contributions shall be collected at the source as a payroll deduction.

The Contractor's contribution shall be:	two cents per hour
The Employee's contribution shall be:	two cents per hour

The Contractor shall forward the above contributions to the Training Trust Fund by the fifteenth (15th) day of the month following the month in which the hours were worked.

b) Contractor and Employee contributions to the Fund will be discontinued immediately if one or more of the following occurs:

i) The Fund ceases to be governed by a Trust;

ii) The provisions of the Trust are not fulfilled;

iii) Employers are no longer represented on the Board of Trustees.

c) In the event that either the Association or the Council has reason to believe that one or more of the conditions described in (b) above has occurred, the matter shall be referred to the Joint Appendix Review Committee. Until the matter is resolved, Contractors shall hold all Contractor and employee contributions in trust.

8. Tools & Equipment

All journeymen and apprentices shall provide the following tools:

	Description
	hawk
2	plastering trowels and point trowels
1	soft bristle brush for finishing work (minimum width 6")
1	small tool brush
	metal angle float
	wood float
1	carpet or sponge rubber float
	chalkline
	spirit level
	tinsnips
	square rule
	hatchet
	hammer
	saw
	browning brush
	mitre rod
	scratcher
	foundation marker
	white coveralls

9. Escalation and Reference

9.1 Wage Rate Provisions

The wage rate for the classifications set out in this Appendix will be adjusted by an amount equal to and effective on the dates of any adjustments in wage rates for corresponding classifications which may be negotiated from time to time by the Operative Plasterers and Cement Masons International Association Local 334, (Plasterers) and the Plastering Contractors Trade Division of the Construction Labour Relations Association of Manitoba.

Classifications eligible for adjustment may include general foreman, foreman, leadhand, chargehand, pusher, journeyman, apprentices, helpers and trainees.

9.1.1 Except as otherwise noted, the following provisions will be incorporated or adjusted to be consistent with corresponding provisions negotiated from time to time by the aforementioned Parties:

a) Definitions and qualificational requirements for applicable classifications;

b) Ratios indicating the number of apprentices, helpers, or other types of trainees who may be employed.

9.2 Other Conditions of Employment

Except as otherwise noted, the following conditions of employment will be incorporated or adjusted to be consistent with corresponding conditions of employment negotiated from time to time by the aforementioned Parties:

a) Shift premium but excluding any shift premium applicable to overtime hours;

b) Vacation and Vacation Pay - such provisions may include any provisions relative to the timing of payment of vacation pay but shall not include any provisions stipulating when vacation time must be granted, and in lieu of such a provision the following shall be substituted: "the scheduling of time off for vacation shall be arranged by mutual agreement between the Contractor and the employee";

c) Pay in lieu of Holidays;

d) Registered and trusteed pension and health and welfare plans (subject to the restrictions set out in Section 9.2.1);

e) Rest provisions between shifts;

f) Provisions governing special trade related tests;

g) Safety clothing;

h) Tool lists and provisions governing loss of such tools on the Project.

9.2.1 The Contractor's contribution to any pension and health and welfare plan may be applied on a per hour worked basis; however, the Contractor's contribution rate in respect of overtime hours shall not be greater than the required contribution rate for Contractors in respect of straight time hours.

9.3 Notwithstanding anything contained in this Agreement or in this Appendix, the regular hours of work are not subject to adjustment during the life of this Agreement, and such regular hours of work shall be paid at regular rates of wages.

9.4 The provisions of 9.1 and 9.2 above shall be dealt with by following the procedure set out in Article 30 of this Agreement.

APPENDIX NO. 8a – Cement Masons

THE OPERATIVE PLASTERERS AND CEMENT MASONS INTERNATIONAL ASSOCIATION

Local Union No.222 (Cement Masons)

BURNTWOOD/NELSON AGREEMENT

*** Note – See Letter of Agreement #9, for additional information regarding Appendix 8A

1. Hours of Work and Overtime

Nine (9) hours shall constitute a day's work for four (4) days Monday through Thursday, and eight (8) hours shall constitute a day's work for Friday. Said hours shall normally be within the period from 7:00 a.m. until 6:00 p.m.

If more than the recognized daily hours are worked in any one (1) day or shift, Monday to Thursday, such time shall be paid at the rate of time and one-half for the first three (3) hours and double time for hours worked thereafter in any one (1) day.

If more than the recognized daily hours are worked on Friday, such time shall be paid at the rate of time and one-half for the first four (4) hours and double time for hours worked thereafter.

On Saturdays, except as provided in Article 15.2, time and one-half shall be paid.

On Sundays and holidays as specified in Article 17, double time shall be paid.

2. Shift Conditions

If conditions are such that work on that particular job cannot be done within the said normal hours (7:00 a.m. to 6:00 p.m.) then nine (9) hours or eight (8) hours, as the case may be, may be worked during any hours and may constitute a regular shift. When a shift ends between 6:00 p.m. and 7:00 a.m. an employee shall receive 1.09 times his normal rate for all hours worked at straight time. Shift work premium will not be paid on any overtime hours worked.

Overtime payment for shift work shall be in accordance with the provisions as set out above.

The starting and quitting time of all shift work will be decided by the Contractor.

3. Wages

(a) Journeyman Cement Masons:

Effective May 1, 2019 $34.81

(b) Foreman:

When the Contractor appoints a working foreman, he shall receive a minimum of $1.25 (one dollar and twenty-five cents) per hour above the Journeyman's wage rate. In the discretion of the Contractor, the amount may be higher.

(c) Pre-apprentice:

i) The contractor may employ one (1) pre-apprentice for each Journeyperson employed.

ii) Pre-apprentices may be employed for a maximum of 500 hours. The employer shall maintain a log book for all hours worked as a pre-apprentice. The contractor shall forward a copy of the employee's log book to the union upon their request.

iii) The wage scale of pre-apprentices shall be;

First 500 hours (55% of the Journeyperson rate.)

(d) Apprentices:

i) The Contractor may employ one (1) apprentice for every Journeyman employed.

ii) The term of apprenticeship in the trade is two levels, with each level consisting of a period of at least 12 months during which the apprentice must complete 1,800 hours of technical training and practical experience.

iii) The scale of wages for apprentices shall be:

Level 1 (0 - 1800 hours) - 65% of the Journeyman's rate
Level 2 (1801 – 3600 hours) - 80% of the Journeyman's rate

iv) The Contractor will maintain a log book on each apprentice and hours to be credited towards that employee's apprenticeship will be entered on a weekly basis. The Contractor will provide the log book to the apprentice upon termination of employment and will forward to the Union a copy of the log book entries indicating the number of hours credited to that apprentice.

v) Apprentices shall provide the hand tools set out in the Tool Section of this Appendix.

4. Vacation and Vacation Pay

Annual vacation will be arranged as provided in The Employment Standards Code for the Province of Manitoba.

Vacation pay allowance will be accumulated for the credit of each employee at the rate of six percent (6%) of the employee's standard hourly rate for each hour worked, except as set out below.

Advance payment in lieu of pay at time of vacation in the applicable amount set forth above shall be added to each employee's wages on each pay period.

5. Pay in Lieu of Holidays

Whether or not an employee works on any of the Holidays under Article 17, he shall receive in lieu of paid Holidays, four percent (4%) of his standard hourly rate for each hour worked. The employee shall be paid this allowance at the time and under the conditions set forth in the Employment Standards Code.

6. Trust Funds

The Contractor and each employee covered by this Appendix shall contribute the amounts set out below to the Manitoba Multiple Trade Health and Welfare and Pension Trust Funds. Contributions shall apply to all hours worked. The employee's contributions shall be collected at the source as a payroll deduction.

(a) Health and Welfare

Contractor's contribution	55 cents per hour
Employee's contribution	70 cents per hour

(b) Pension Fund

Contactor's contribution	$1.99 (one dollar and ninety-nine cents per hour)
Employee's contribution	80 cents per hour

(c) Employee contributions for pre-apprentice workers shall be optional.

Contributions to the above Pension Fund and Health and Welfare Fund shall be submitted each month by the 15th of the month following the month for which contributions are collected.

7. Tools

Cement Masons shall provide the following hand tools:

2 hand trowels (one 14" and one 16")
1 pointing trowel
1 hand float
1 chipping hammer
1 brush (5" or 6")
1 chalk line
1 spirit level
1 tape (minimum 12' or 4 m)
1 edger
1 jointer

8. Escalation and Reference

8.1.1 General Approach

Subject to and in accordance with the conditions set out below, and subject to any adjustments arising from the application of Section 8.2, the wage rates set out in this Appendix will be adjusted by a percentage equivalent to the weighted percentage adjustment in wage rates and in the employers' contribution rate to pension and health and welfare plans negotiated from time to time for each of the Reference Classifications set out in 8.1.2.

8.1.2 Reference Classifications and Weighting

The Reference Classifications and the weighting of these classifications shall be as follows:

Reference Classification	Weighting Factor
The Journeyman Carpenter Classification as set out in the Agreement negotiated and executed by the CLRA of Manitoba and the United Brotherhood of Carpenters and Joiners of America, Local Union 343.	100%

8.1.3 Method of Calculating Weighted Percentage Adjustment of Reference

Classifications

The weighted percentage adjustment of each Reference Classification shall be determined in accordance with the following formula:

$$\frac{\text{(Change in W) + (Change in P) + (Change in H\&W)}}{\text{(Expired W) + (Expired P) + (Expired H\&W)}} \times 100 \times \text{Weighting Factor}$$

Where:

- Change means the increase or decrease in that benefit.
- W means wage rate.
- P and H&W means the required employers' contribution rate to the pension and/or the health and welfare plan.
- Expired means the rate in effect when the last weighted percentage adjustment was calculated.
- Weighting factor means the factor assigned to a particular Reference Classification as set out in 8.1.2.

8.1.3.1 In calculating the weighted percentage adjustment of a Reference Classification, the arithmetic result shall be rounded to the nearest hundredth of a percent.

8.1.4 Effective Date of Wage Rate Adjustments and Adjustments to Pension and Health and Welfare Plans and Application of the Formula

8.1.4.1 Effective Date of Wage Rate Adjustments

When the wage rate adjustment of a Reference Classification(s) is effective on the first of any month, then the wage rate adjustment of the hourly rates in this Appendix shall be effective on that date.

When the wage rate adjustment of a Reference Classification(s) is not effective on the first of any month, it shall be deemed to be effective on the first of the month following, and the wage rate adjustment of hourly rates in

this Appendix shall be effective on that date.

8.1.4.2 Effective Date of Adjustments to the Employers' Contribution Rate to Pension and/or Health and Welfare Plans

When the adjustment to the employers' contribution to the pension and/or health and welfare plans of a Reference Classification(s) is effective on the effective date, or pursuant to 8.1.4.1 the deemed effective date, of any wage rate adjustment of any Reference Classification, then such adjustment shall be calculated and taken into account on that date. If this is not the case, then such adjustment shall be calculated and taken into account on the closest following effective date of a wage rate adjustment.

8.1.4.3 In applying the weighted percentage adjustment, the resultant wage rate shall be rounded to the nearest cent, following which, any adjustment required by virtue of Section 8.2 shall be introduced to yield the new wage rate schedule that will apply in this Appendix.

8.2 Pension and Health and Welfare

8.2.1 The Contractor's responsibility for contributions to the Pension and Health and Welfare Trust Funds referenced in Section 6 of this Appendix shall be no greater than one dollar and 99 cents ($1.99) per hour worked, and 55 cents per hour worked, respectively. In the event that the Operative Plasterers and Cement Masons International Association Local Union No. 222 requires increased contributions to its Pension and/or Health and Welfare Trust Funds, the total amount of said increase will be deducted from the employees' wages or become an employee contribution.

8.2.2 The Contractor's contribution to the Pension and Health and Welfare Plans may be applied on a per hour worked basis; however, the Contractor's contributions rate in respect of overtime hours shall not be greater than the required contribution rate for Contractors in respect of straight time hours.

8.3 Notwithstanding anything contained in this Agreement or in this Appendix, the regular hours of work are not subject to adjustment during the life of this Agreement, and such regular hours of work shall be paid at regular rates of wages.

8.4 The provisions of Sections 8.1 and 8.2 shall be dealt with by following the

procedure set out in Article 30 of this Agreement.

APPENDIX NO. 9 - Bricklayers and Allied Craftsmen

INTERNATIONAL UNION OF BRICKLAYERS AND ALLIED CRAFTSMEN

Local Union No. 1 of Manitoba

BURNTWOOD/NELSON AGREEMENT

1. Hours of Work and Overtime

Nine (9) hours shall constitute a day's work for four (4) days Monday to Thursday inclusive, and eight (8) hours shall constitute a day's work for Friday. Said hours shall normally be within the period from 7:00 a.m. until 6:00 p.m.

Overtime for Bricklayers and Masons

If more than the recognized daily hours are worked in any day or shift, such time shall be paid at the rate of time and one half for the first two (2) hours and double the regular straight time hourly rate for all hours worked thereafter in that shift.

On Saturdays, except as provided in Article 15.2, and on Sundays and Holidays as set out in Article 17, double time shall be paid.

Overtime for Tilesetters, Terrazzo Layers and Stone Setters

If more than the recognized daily hours are worked in any day or shift, such time shall be paid at the rate of time and one half.

On Saturdays (except as provided in Article 15.2) and Sundays, time and one half shall be paid. On Holidays as set out in Article 17, double time shall be paid excepting Good Friday, Thanksgiving Day, Civic Holiday, and Victoria Day for which time and one-half shall be paid.

2. Shift Conditions

If the conditions are such that work on that particular job cannot be done within the said normal hours (7:00 a.m. to 6:00 p.m.) then nine (9) hours, or eight (8) hours as the case may be, may be worked during any hours and will be deemed to constitute a regular shift on that job.

For Bricklayers and Masons, a premium of fifteen (15%) of the regular straight time rate will be paid for each shift hour worked on a shift that cannot be done within the said normal working hours. Shift premium will not be paid on any overtime hours worked.

Overtime payment for shift work shall be in accordance with the provisions as set out above.

The starting and quitting time of all shift work will be decided by the Contractor.

3. Wages

Wage rates shall be as follows:

3.1 Bricklayers and Masons

(a) Journeyman Bricklayers and Masons

Effective:	May 1, 2019	October 1, 2019	May 1, 2020	October 1, 2020	May 1, 2021	October 1, 2021
Journeyman	$38.27	$38.52	$38.77	$39.02	$39.27	$39.52
Apprentice						
3rd Year 90%	$34.44	$34.67	$34.89	$35.12	$35.34	$35.57
2nd Year 75%	$28.70	$28.89	$29.08	$29.27	$29.45	$29.64
1st Year 60%	$22.96	$23.11	$23.26	$23.41	$23.56	$23.71

(b) Bricklayer and Masonry Foreman

When the Contractor appoints a working foreman, that Foreman shall be paid an hourly rate fifteen (15%) above the Journeyman's rate, rounded to the nearest five (5) cents. Mid point results shall be rounded upwards to the next five cents (55).

(c) Bricklayer and Masonry Apprentices

Bricklayer Apprentices registered with the Department of Labour shall be paid the rate as laid down from time to time by the Apprenticeship Board of Manitoba as follows:

1st year	60% of Journeyman's rate (1,600 Hrs)
2nd year	75% of Journeyman's rate (1,600 Hrs)
3rd year	90% of Journeyman's rate (1,600 Hrs)

A registered Bricklayer or Masonry Apprentice shall be deemed not to have completed his apprenticeship until he has passed the final examination for his Manitoba Certificate of Qualification. Failing this, the said Apprentice will remain in the third year category of his apprenticeship in status and pay rate, until such time as he obtains his certificate.

No second or third year Apprentice shall be advanced to the next years pay rate unless he has passed his regular school courses for that year and has served the necessary qualifying time.

When an apprentice passes the examination and has the required hours the apprentice shall immediately thereafter receive wages at the next level of apprenticeship.

The ratio of apprentices to journeymen shall not exceed one apprentice for every two journeyman bricklayers employed.

3.2 Tilesetters, Terrazzo Layers and Stone Setters

(a) Journeyman Tilesetters, Terrazzo Layers, and Stone Setters

NOTE: The wages set out for 3.2 (a) represents an interim escalation based on the ICI Construction and Wage Schedule till such time as an appropriate agreement is in hand

Effective January 1, 2014
$23.60/hr

(b) Foremen - Stone, Tile and Terrazzo Trades

When the Contractor appoints a working foreman that foreman shall be paid at least fifteen cents (15¢) per hour above the Journeyman's rate.

(c) Apprentices - Stone, Tile and Terrazzo Trades

Apprentices training in the Marble Tile and Terrazzo trades shall be paid the rate as laid down from time to time by the Apprenticeship Board of Manitoba as follows:

1st year	50% of Journeyman's rate
2nd year	55% of Journeyman's rate
3rd year	65% of Journeyman's rate
4th year	75% of Journeyman's rate

No Apprentice shall be made up to Journeyman status by the Union or advanced in pay scale by the Contractor until he has completed his full allotment of time at the trade. For purposes of computing Apprentice pay scales, 1800 hours shall equal one (1) year's credit. The Union will issue each Apprentice with a log book. The Contractor will, once each year or on termination of employment, whichever comes first, fill in the number of hours worked together with a report on the employee's aptitude for the trade, his progress in learning the trade and his attitude.

(d) Qualified Grouter

effective May 1, 2006
$12.30/hr

A qualified Grouter is an Apprentice who, after the normal second year of apprenticeship, the Contractor, the Union and the Apprentice have mutually agreed that apprenticeship training should be discontinued and the person placed in the Grouter category.

The duties of the Grouter may include:

1. For all products that fall within the jurisdiction of the union:

- Grouting
- e.g., quarry tile; slate; brick; marble; granite; etc.
- Mixing of all materials
  - e.g., cement bed; plaster; terrazzo; epoxy systems; etc.
- Preparation work
  - e.g., cleaning of floor slabs prior to installation of products.
- Cutting to size
  - e.g., marble tile and slab; quarry tile; etc.
- Grinding of terrazzo.
- Drilling of anchor holes and edging, finishing, and bullnosing work in relation to marble and granite slabs.
- All typical helper functions that are required for the trade.

(e) Tile and Terrazzo Trainees

To encourage and promote the development of future tradesmen in the tile and terrazzo industry, certain personnel may be employed at the discretion of the Employer in this category. Persons with some experience in the trade wishing to enter into the apprenticeship training program, may do so at any time once he has completed the minimum of one (1) year within this Trainee category. The Employer has the right to determine where a new apprentice will fall on the current Apprentice wage scale. The union agrees that all Trainees do not have to join the Union as a condition of employment, and further that the Employer is not obligated to deduct Union dues for Trainee employees during the one (1) year training period. Once the one (1) year training period has been completed, the Employer shall commence deducting the applicable Union dues. The Employer shall notify the Union when new trainees are hired.

The Trainee hourly rate of pay shall be: $10.38

4. Height Premiums

Bricklaying and masonry employees working on swing stages or bosun chairs shall receive the following premiums:

Over 45 feet	=	50¢ per hour
Over 150 feet	=	75¢ per hour

5. Vacation and Vacation Pay

Annual vacation will be arranged as provided in the Employment Standards Code for the Province of Manitoba.

Vacation pay allowance will be accumulated for the credit of each employee at the rate of six percent (6%) of the employee's standard hourly rate for each hour worked.

Advance payment, in lieu of pay at the time of vacation, in the amount set forth above, shall be added to each employee's wages on each pay period.

6. Payment in Lieu of Holidays

Whether or not an employee works on any of the Holidays set out in Article 17, he shall receive in lieu of paid Holidays, four and one half percent (4.5%) of his standard hourly rate for each hour worked. The employee shall be paid this amount at each pay period and under the conditions set forth in the Employment Standards Act.

7. Health and Welfare and Pension Trust Funds

The Contractor and each employee covered by this Appendix shall contribute the amounts set out below to the Manitoba Multiple Trade Health and Welfare Trust Fund and the Manitoba Multiple Trade Pension Trust Fund. Contributions shall apply to all hours worked and employee contributions shall be collected at the source as a payroll deduction.

(a) Contributions for Bricklayers and Masons

(i) Health & Welfare Contributions

Contractor's Contribution for Journeyman and Apprentice

Effective July 2, 2013 - $1.25 per hour

Employee's Contribution

nil.

(ii) Pension Contributions

Effective: May 1, 2019		
	Employer Contribution	Employee Contribution
Journeyman	$6.30	$1.25
Apprentice		
3rd Year 90%	$5.67	$1.13
2nd Year 75%	$4.73	$0.94
1st Year 60%	$3.78	$0.75

(b) Contributions for Stone, Tile and Terrazzo Trades

i) Health & Welfare Contributions

	Contractor's Contribution	Employee's Contribution
Effective May 1, 2006	$1.05 per hour	80 cents per hour
Effective October 1, 2006	$1.09 per hour	80 cents per hour

ii) Pension Contributions

	Contractor's Contribution	Employee's Contribution
Effective May 1, 2006	$3.02 per hour	$1.00 per hour
Effective October 1, 2006	$3.27 per hour	$1.00 per hour

Contributions to the Masonry Trust Fund and to the Manitoba Multiple Trade Health and Welfare Trust Fund shall be submitted each month by the 15th of the month following the month for which contributions are collected.

8. Rest Period

If an employee is not provided with at least an either (8) hour rest period between shifts, The employee shall be paid at double the regular straight time hourly rate until such time as an eight (8) hour break occurs.

9. Industry Funds

In recognition of the importance of advancing and promoting the interests of the masonry trade and industry in general, all for the mutual benefit of the members of the Masonry Trade Division (the "Division"), the Union and its members, and the Manitoba Masonry Institute (Contractors Section) (M.M.C.A) and its members, the parties hereto agree that certain contributions hereinafter set forth shall be made to the M.M.C.A and to the Union

to promote such objectives.

The Contractor shall contribute: the sum of thirty cents (30¢) per hour for each hour worked by its employees.

The total of both the employee contributions, if any, and employer contributions shall be forwarded to the M.M.C.A. not later than the 15th day of the month following the month in which such deductions or contributions were made, together with the "employer report form" to be supplied by the M.M.C.A.

10. Isolation Leave (Return Transportation Time Periods)

The return transportation time period referred to in Article 19.2.1 for this Appendix No. 9 for Bricklayers and Masons shall be:

- After thirty-five (35) calendar days.

The return transportation time period referred to in Article 19.2.1 for this Appendix No. 9 for Tilesetters, Terrazzo Layers, and Stone Setters shall be:

- after forty (40) calendar days for a first tour of duty, and after thirty-five (35) calendar days for each consecutive tour of duty thereafter.

Travel time shall only apply on the return portion of an Isolation Leave trip (i.e. from the employee's T.D.P. to the Project Camp Site).

The amount of travel time to be paid shall be in accordance with the provisions of Article 19.1.2.5.1 or 19.1.2.5.2, as the case may be, and if applicable, the provisions of Article 19.1.2.5.3.

Travel time shall be paid at one half of the employee's straight time rate, and an employee shall receive such payment pursuant to the provisions of Article 19.1.2.6.

11. Tools

Journeymen and apprentices shall be required to supply the ordinary hand tools of the Trade. The following tools shall be the minimum requirement for each and every bricklayer.

All tools shall be kept in good condition at all times. The bricklayer must replace any tools, which are not in good condition, within a reasonable period of time. Employers may replace employee tools and deduct the cost of the tool from the employee’s paycheque if tools are not replaced in a reasonable period of time.

1	Brick hammer	2	Flat jointers
1	Mash hammer	1	Trowel

2	Chisels 10" and 6"	1	Hand brush
1	Pointing trowel		Tool box or bag
1	Bolster or brick set	1	Four foot level
1	Two foot level	1	100' line
2	Convertible round jointers	1	Raker
1	Combination Imperial/Metric Rule or Tape, Line Pins or Corner Blocks		

Mason lines will be provided by the Contractor.

Tilesetters shall provide the following tools:

Water level – 30’ long min.	Tool box c/w lock
Rubber mallet	Mortar hook
2’ aluminum level	Pliers
Wood saw	Plaster trowel
Hole cutting hammers	Pencil and sharpener
Notched trowels	Light extension cord – 50’ long
2’ square	4’ aluminum level
Manual operated tile cutter & wheel	Claw hammer
Screw drivers	Hack saw
Assortment of chisels	Tile nippers
Chalk line	Pointing trowel
Tin snips	Rubber float
Wonderboard knife	

Terrazzo workers shall provide the following tools:

2’ aluminum level		1	Pointing trowel
Hack saw		1	Pound hammer
Chalk line			Wood saw
Pliers		2	Flat trowels
Tin snips			Claw hammer
Assorted chisels			Light extension cord – 50’ long
Too box c/w lock			Wonderboard knife
Rubber mallet			

Marble setters shall provide the following tools:

4’ aluminum level	Small grind stone
Hack saw	Screw drivers
Assortment of chisels	Chalk line
2’ square	Light extension cord – 50’ long
Plaster bowl	Claw hammer
2’ aluminum level	Pliers
Wood saw	Pencils and sharpener

Pointing trowels	Small clamps
Tin snips	Tool box c/w lock
Pound hammer	Rubber mallet
Wonderboard knife	

12. Escalation and Reference

12.1 Wage Rate Provisions

The wage rate for the classifications set out in this Appendix will be adjusted by an amount equal to and effective on the dates of any adjustments in wage rates for corresponding classifications which may be negotiated from time to time by the International Union of Bricklayers and Allied Craftsmen, Local Union No. 1 of Manitoba and the Manitoba Masonry Institute and the Manitoba Masonry Contractors Association (relative to Brick and Stone Masonry) and the Marble, Tile and Terrazzo Trade Division of the Construction Labour Relations Association of Manitoba.

Classifications eligible for adjustment may include general foreman, foreman, leadhand, chargehand, pusher, journeyman, apprentices, helpers and trainees.

12.1.1 Except as otherwise noted, the following provisions will be incorporated or adjusted to be consistent with corresponding provisions negotiated from time to time by the aforementioned Parties:

(a) definitions and qualificational requirements for applicable classifications.

(b) ratios indicating the number of apprentices, helpers, or other types of trainees who may be employed.

(c) height pay including that associated with swing stage work.

12.2 Other Conditions of Employment

Except as otherwise noted, the following conditions of employment will be incorporated or adjusted to be consistent with corresponding conditions of employment negotiated from time to time by the aforementioned Parties:

(a) overtime payments (subject to the restrictions set out in Section 12.3)

(b) shift premium but excluding any shift premium applicable to overtime hours.

(c) Vacation and Vacation Pay - such provisions may include any provisions

relative to the timing of payment of vacation pay but shall not include any provisions stipulating when vacation time must be granted, and in lieu of such a provision the following shall be substituted: 'the scheduling of time off for vacation shall be arranged by mutual agreement between the Contractor and the employee'.

(d) pay in lieu of Holidays and any provisions requiring the transferring and observing of the Holiday on a day, other than the day on which the Holiday falls (subject to the restrictions set out in Section 12.2.1).

(e) registered and trusteed pension and health and welfare plans (subject to the restrictions set out in Section 12.2.2).

(f) callout provisions.

(g) rest provisions between shifts

(h) personal effects insurance provisions

(i) provisions governing welding and other special trade related tests

(j) safety clothing

(k) tool lists and provisions governing loss of such tools on the Project.

(l) the following trusteed plans, each of which shall be subject to the restrictions set out in Section 12.2.3:
i) building fund
ii) trade improvement plans including educational and apprenticeship funds.

(m) the time period between Isolation Leaves (subject to the restrictions of Article 19.2.1.3).

(n) travel time associated with the taking of an Isolation Leave, and the hourly rate at which travel time will be paid (subject to the restrictions set out in Section 12.2.4).

12.2.1 A Holiday set out in Article 17 may be observed on a day, other than the day on which it falls, provided the Holiday falls on a Saturday or Sunday which is a non working day, in which case the Holiday may be observed on the closest following working day. The transferring of a Holiday shall not apply to any employee who is on Christmas Leave, Isolation Leave or any other type of Leave of Absence when the Holiday occurs.

12.2.2 The Contractor's contribution to any pension and health and welfare plan

may be applied on a per hour worked basis; however, the Contractor's contribution rate in respect of overtime hours shall not be greater than the required contribution rate for Contractors in respect of straight time hours.

12.2.3 The Contractor's contribution to any of the plans referred to in Section 12.2 (l) may be applied on a per hour worked basis; however, the Contractor's contribution rate in respect of overtime hours shall not be greater than the required contribution rate for contractors in respect of straight time hours.

12.2.4 Travel time may only apply to the return portion of an Isolation Leave trip (i.e. from the employee's T.D.P. to the Project Camp Site). The amount of travel time to be paid shall not be greater than the travel time set out in Articles 19.1.2.5.1, 19.1.2.5.2 and 19.1.2.5.3, as may be applicable. The hourly rate at which travel time may be paid shall not be greater than the employee's straight time rate. Payment of travel time shall be in accordance with the provisions of Article 19.1.2.6.

12.3 Notwithstanding anything contained in this Agreement or in this Appendix, the regular hours of work are not subject to adjustment during the life of this Agreement, and such regular hours of work shall be paid at regular rates of wages. Further, overtime payments at a rate greater than time and one half will not be introduced in this Appendix in respect of the first two (2) hours of overtime, Monday to Friday inclusive.

12.4 The provisions of 12.1 and 12.2 above shall be dealt with by following the procedure set out in Article 30 of this Agreement.

APPENDIX NO. 10 – Sheet Metal

THE SHEET METAL WORKERS INTERNATIONAL ASSOCIATION

Local Union 511 (Sheet Metal Workers)

BURNTWOOD/NELSON AGREEMENT

1. Hours of Work and Overtime

Eight (8) hours shall constitute a day's work for five (5) days Monday to Friday inclusive. Said hours shall normally be within the period from 7:00 a.m. until 6:00 p.m.

If more than the recognized daily hours are worked in any day or shift, Monday to Friday, such time shall be paid at the rate of time and one-half for the first two (2) hours, and double time for hours worked thereafter in that shift.

On Saturdays, except as provided in Article 15.2, Sundays and on Holidays, as specified in Article 17, double time shall be paid.

2. Shift Conditions

If conditions are such that work on that particular job cannot be done within the said normal hours (7:00 a.m. to 6:00 p.m.) then eight (8) hours may be worked during any hours and may constitute a regular shift on that job.

A premium of 6.6% of the regular straight time rate will be paid for each shift hour worked on a shift that cannot be done within the said normal hours except that on those shift hours which are worked between 12:00 midnight and 6:00 a.m. a premium of 14.2% of the regular straight time rate will be paid. Shift premium will not be paid on any overtime hours worked.

Overtime payment for shift work shall be in accordance with the provisions as set out above.

The starting and quitting time of all shift work will be decided by the contractor.

3. Wages

Wage rates shall be as follows:

WAGES			
Classification	3 - July-16	1-May-17	1-May-18
Senior Journeyperson (100%)	$39.84	$40.57	$41.38
Journeyperson	$38.34	$39.07	$39.88
Fourth Year	$33.07	$33.67	$34.35
Third Year	$29.08	$29.62	$30.21
Second Year	$25.10	$25.56	$26.07
First Year	$19.92	$20.29	$20.69
Pre-Apprentice Level 2 (1001-1800 Hrs)	$18.95*	Jan 1, 2017 $19.55*	$19.55*
Pre-Apprentice Level 1 (0-1000 Hrs)	$15.94	$16.23	$16.55
Classified Shop Worker	$15.94	$16.23	$16.55
Welder 1	$33.86	$34.48	$35.17
Welder 2	$29.88	$30.43	$31.04
Welder 3	$25.90	$26.37	$26.90
Helpers	$31.87	$32.46	$33.10
*** CWIA General Construction Labourer Trainee 2 Min. Rate**			

d) Chargehand Premium

When the Contractor appoints a working Chargehand, he shall be paid the following premiums:

When in charge of at least 2 other persons and up to 4 persons 3%/hr
When in charge of at least 5 other persons and up to 10 persons 5%/hr
When in charge of at least 11 other persons and up to 20 persons 7%/hr
When in charge of 21 persons and over 10%/hr

above the employee's regular rate of pay.

Pre-Apprentice Level 1 wage for a maximum of one thousand (1000) hours (this classification does not pay employee or receive Employer contributions for Pension Plan or Health & Welfare Plans for the first one thousand (1000) hours). After one thousand (1000) hours, employee and Employer Pension Plan and Health and Welfare Plan contributions commence.

All pre-apprentices shall be registered with the Union and be given first priority when a new apprentice is to be indentured into the industry. The maximum hours a pre-apprentice shall remain in this classification is 1800 hours. Upon completion of 1800 hours, a pre-apprentice shall be indentured as a first year apprentice or reclassified.

All apprentices must successfully complete their in-school training in order to qualify for the applicable rate of pay. Pay increases based solely on hours will only apply to those apprentices who through "no fault of their own" are unable to attend classes. Apprentices refusing to attend school shall have their apprenticeship contract cancelled.

4. Worker Ratios

For the first Journeyman employed the Contractor may employ one (1) Apprentice. Once three (3) Journeymen and three (3) Apprentices are hired, the Employer may hire one Pre-Apprentice.

No ratio is applicable to Welders but the Contractor agrees that, while Welders may do other work incidental to their trade, this category will not be used to subvert the intent of the worker ratio system.

The parties hereto agree that the maximum number of Apprentices em0ployed in the field shall not exceed one Apprentice for each Journeyman employed and the maximum number of Classified shop Workers and/or Apprentices employed in the shop will not exceed four Apprentices or Classified Shop Workers for each shop Journeyperson employed.

5. Vacation and Vacation Pay

The annual vacation will be arranged as provided in the Manitoba Employment Standards Code.

Payment for the annual vacation will be on the basis of six percent (6%) of the employee's gross wages. Gross wages shall be defined as being all regular straight time hourly wages plus all overtime premium wages and all shift work premium wages.

Vacation pay allowance will be paid to employees on their regular pay day. Such payment shall be considered as advance payment for any vacation taken by the employee under the conditions provided in the Employment Standards Code for the Province of Manitoba.

6. Pay in Lieu of Holidays

Whether or not an employee works on any of the Holidays set out in Article 17, he shall receive in lieu of paid Holidays, four and a half percent (4.5%) of his gross wages, as defined above.

If a Holiday falls on a Saturday which is a non-working day or Sunday, then the closest following work day will be observed. However, this provision shall not apply to Remembrance Day nor shall it apply to any employee who is on Christmas Leave, Isolation Leave or any other type of Leave of Absence when the Holiday occurs.

7. Trust Funds

The Contractor and each employee will contribute the amounts set out below to the Sheet Metal Workers Employee Benefits Funds. Contributions shall apply to all hours worked by each employee covered by this Appendix. Employee contributions shall be collected at the source as a payroll deduction.

a) Sheet Metal Workers Pension Fund

PENSION						
	3-July-16		1-May-17		1-May-18	
Classification	**Employer/Hr**	**Employee/Hr**	**Employer/Hr**	**Employee/Hr**	**Employer/Hr**	**Employee/Hr**
Sr. Journeyperson	$ 0.60	$ 4.90	$ 0.60	$ 5.20	$ 0.60	$ 5.50
Journeyperson	$ 0.60	$ 4.90	$ 0.60	$ 5.20	$ 0.60	$ 5.50
4th Yr Apprentice	$ 0.50	$ 4.07	$ 0.50	$ 4.32	$ 0.50	$ 4.57
3rd Yr Apprentice	$ 0.44	$ 3.58	$ 0.44	$ 3.80	$ 0.44	$ 4.02
2nd Yr Apprentice	$ 0.38	$ 3.09	$ 0.38	$ 3.28	$ 0.38	$ 3.47
1st Yr Apprentice	$ 0.30	$ 2.45	$ 0.30	$ 2.60	$ 0.30	$ 2.75
Pre-App level 2	$ 0.24	$ 1.96	$ 0.24	$ 2.08	$ 0.24	$ 2.20
Classified Shop Worker	$ 0.24	$ 1.96	$ 0.24	$ 2.08	$ 0.24	$ 2.20
Welder 1	$ 0.51	$ 4.17	$ 0.51	$ 4.42	$ 0.51	$ 4.68
Welder 2	$ 0.45	$ 3.68	$ 0.45	$ 3.90	$ 0.45	$ 4.13
Welder 3	$ 0.39	$ 3.19	$ 0.39	$ 3.38	$ 0.39	$ 3.58
Helper	$ 0.48	$ 3.92	$ 0.48	$ 4.16	$ 0.48	$ 4.40

b) Health and Welfare Fund*

HEALTH & WELFARE		
	EMPLOYEE	EMPLOYER
July 3, 2016	$ 0.63	$ 0.63
May 1, 2016	$ 0.63	$ 0.63
May 1, 2017	$ 0.63	$ 0.63

c) Education Training Fund

	EE CONTRIBUTION	ER CONTRIBUTION
Education Training Fund	$ 0.10	$ 0.10

*Note - Pre-Apprentice Pension and Health and Welfare contributions and Contractor Pension and Health and Welfare contributions on their behalf do not commence until a Pre-Apprentice has completed 1,000 hours.

The Contractors shall forward the above contributions to the Administrator of the Fund not later than the 10th day of the month following the month in which contributions are payable. Reporting forms shall be supplied to the Contractor by the Union.

8. Benevolent Fund

The contractor shall deduct at the source as a payroll deduction from each employee covered by this Appendix the amounts set out below, and remit same to Local Union 511 Benevolent Fund:

FUND NAME	EE CONTRIBUTION	ER CONTRIBUTION
Benevolent Fund	$ 0.02	$ -

This fund shall be used to provide:

a) Assistance to members in paying Health and Welfare premiums where required;

b) Up grading courses for tradesmen;

c) Other benevolent services for and on behalf of members.

This fund shall not be disbursed for purposes that can work against the better interest of the Contractors.

All benevolent contributions are to be forwarded to the office of the Administrator, 438 Higgins Avenue, Winnipeg, Manitoba, R3A 1S5, prior to the 10th day of the month following the month in which contributions are payable. Reporting Forms shall be provided to the Contractor by the Union.

9. Building Trades Council and Western Conference Funds

The contractor shall deduct at the source as a payroll deduction from each employee covered by this Appendix, an amount of 6¢(*) per hour for each hour or part hour of employment and remit same to the Sheet Metal Workers International Association, Local Union 511, 438 Higgins Avenue, Winnipeg, Manitoba, R3A 1S5.

FUND NAME	EE CONTRIBUTION	ER CONTRIBUTION
Building Trades Council Fund	$ 0.05	$ -
Western Canadian Conference Sheet Metal Workers	$ 0.01	$ -

(*) i.e., 5¢ in respect of the B.T.C. Fund and 1¢ in respect of the W.C. Fund.
These monies will be remitted to the fund by the 10th day of the month following the month in which the contributions are payable. Remittance forms shall be provided by the Union to the Contractor.

10. Personal Effects Insurance

When an employee is required to reside in a construction camp, the cost of insurance against loss of his personal effects by fire, to a maximum of one thousand dollars ($1000.00), will be reimbursed by the Contractor on presentation of a paid premium receipt.

11. Isolation Leave (Return Transportation Time Periods)

The return transportation time period referred to in Article 19.2.1 for this Appendix shall be:

- After thirty-five (35) calendar days.

Travel time shall only apply on the return portion of an Isolation Leave trip (i.e. from the employee's T.D.P. to the Project Camp Site).

The amount of travel time to be paid shall be in accordance with the provisions of Article 19.1.2.5.1 or 19.1.2.5.2, as the case may be, and if applicable, the provisions of Article 19.1.2.5.3.

Travel time shall be paid at the employee's straight time rate, and an employee shall receive such payment pursuant to the provisions of Article 19.1.2.6.

12. Tools

Journeymen, Helpers, and Apprentices shall supply the ordinary hand tools of the trade and to maintain same in first class condition at all times as a condition of employment.

The Union agrees to participate in the enforcement of this provision against any of its members who fail to supply and maintain the above noted tools in first class condition.

The ordinary hand tools of the trade are:

a) Standard List

		Apprentices Year				Journeyman
		1	2	3	4	
1.	1 – 25' tape measure	x	x	x	x	x
2.	1 – Setting hammer (16 oz. square face)	x	x	x	x	x
3.	1 – Aviation snips (left hand)	x	x	x	x	x
4.	1 – Aviation snips (right hand)	x	x	x	x	x
5.	1 – Scratch awl	x	x	x	x	x
6.	2 – Locking pliers (vice grips) Standard and Wide nose	x	x	x	x	x
7.	Flat screwdrivers (2 sizes)	x	x	x	x	x
8.	1 - Square point screwdriver(Robertson #6 and #8)		x	x	x	x
9.	1 – Phillips screwdriver (standard)		x	x	x	x
10.	1 – Slip joint plier 8"		x	x	x	x
11.	1 - Hacksaw frame		x	x	x	x
12.	1 – 10" adjustable wrench (crescent)			x	x	x
13.	1 - 12" spirit level				x	x
14.	1 - Combination square			x	x	x
15.	1 - Chalk line/plumb bob				x	x
16.	1 - Pop riveter				x	x
17.	1 - Set hexagon keys (Allen keys)				x	x
18.	1 - Hand punch (small Whitney)					x
19.	1 - Battery Operated Drill (14.4 volt)		x	x	x	x
20.	1 - Uni-Shear			x	x	x

13. Escalation and Reference

13.1 Wage Rate Provisions

The wage rate for the classifications set out in this Appendix will be adjusted by an amount equal to and effective on the dates of any adjustments in wage rates for corresponding classifications which may be negotiated from time to time by the Sheet Metal Worker's International Association, Local Union 511 and the Sheet Metal Contractor's Trade Division of the Construction Labour Relations Association of Manitoba.

Classifications eligible for adjustment may include general foreman, foreman, leadhand, chargehand, pusher, journeyman, apprentices, helpers and trainees.

13.1.1 Except as otherwise noted, the following provisions will be incorporated or adjusted to be consistent with corresponding provisions negotiated from time to time by the aforementioned Parties:

a) Definitions and qualificational requirements for applicable classifications;

b) Ratios indicating the number of apprentices, helpers, or other types of trainees who may be employed;

c) Height pay including that associated with swing stage work.

13.2 Other Conditions of Employment

Except as otherwise noted, the following conditions of employment will be incorporated or adjusted to be consistent with corresponding conditions of employment negotiated from time to time by the aforementioned Parties:

a) Overtime payments (subject to the restrictions set out in Section 13.3);

b) Shift premium but excluding any shift premium applicable to overtime hours;

c) Vacation and Vacation Pay - such provisions may include any provisions relative to the timing of payment of vacation pay but shall not include any provisions stipulating when vacation time must be granted, and in lieu of such a provision the following shall be substituted: “the scheduling of time off for vacation shall be arranged by mutual agreement between the Contractor and the employee”;

d) Pay in lieu of Holidays and any provisions requiring the transferring and observing of the Holiday on a day, other than the day on which the Holiday falls (subject to the restrictions set out in Section 13.2.1);

e) Registered and trusteed pension and health and welfare plans (subject to the restrictions set out in Section 13.2.2);

f) Callout provisions;

g) Rest provisions between shifts;

h) Personal effects insurance provisions;

i) Provisions governing welding and other special trade related tests;

j) Safety clothing;

k) Tool lists and provisions governing loss of such tools on the Project;

l) The following trusteed plans, each of which shall be subject to the restrictions set out in Section 13.2.3:

   i) Building fund;

   ii) Trade improvement plans including educational and apprenticeship funds;

   iii) Industrial promotion funds.

m) The Plans set out in Section 8 and 9 of this Appendix, subject to the limitation that these Plans will be solely funded by the employee and all required contributions shall be collected at the source as a payroll deduction;

n) The time period between Isolation Leaves (subject to the restrictions of Article 19.2.1.3);

o) Travel time associated with the taking of an Isolation Leave, and the hourly rate at which travel time will be paid (subject to the restrictions set out in Section 13.2.4).

13.2.1 A Holiday set out in Article 17 may be observed on a day, other than the day on which it falls, provided the Holiday falls on a Saturday or Sunday which is a non-working day, in which case the Holiday may be observed on the closest following working day. The transferring of a Holiday shall not apply to any employee who is on Christmas Leave, Isolation Leave or any other type of Leave of Absence when the Holiday occurs.

13.2.2 The Contractor's contribution to any pension and health and welfare plan may be applied on a per hour worked basis; however, the Contractor's contribution rate in respect of overtime hours shall not be greater than the required contribution rate for Contractors in respect of straight time hours.

13.2.3 The Contractor's contribution to any of the plans referred to in Section 13.2 (l) may be applied on a per hour worked basis; however, the Contractor's contribution rate in respect of overtime hours shall not be greater than the required contribution rate for contractors in respect of straight time hours.

13.2.4 Travel time may only apply to the return portion of an Isolation Leave trip (i.e. from the employee's T.D.P. to the Project Camp Site). The amount of travel time to be paid shall not be greater than the travel time set out in Articles 19.1.2.5.1, 19.1.2.5.2 and 19.1.2.5.3, as may be applicable. The hourly rate at which travel time may be paid shall not be greater than the employee's straight time rate. Payment of travel time shall be in accordance with the provisions of Article 19.1.2.6.

13.3 Notwithstanding anything contained in this Agreement or in this Appendix, the regular hours of work are not subject to adjustment during the life of this Agreement, and such regular hours of work shall be paid at regular rates of wages. Further, overtime payments at a rate greater than time and one-half will not be introduced in this Appendix in respect of the first two (2) hours of overtime, Monday to Friday inclusive.

13.4 The provisions of 13.1 and 13.2 above shall be dealt with by following the procedure set out in Article 30 of this Agreement.

APPENDIX NO. 10a - Roofers

INTERNATIONAL ASSOCIATION OF SHEET METAL, AIR, RAIL AND TRANSPORTATION WORKERS (SMART) LOCAL UNION 511 (SHEET METAL WORKERS)

Local Union 511 (Roofing Section)

BURNTWOOD/NELSON AGREEMENT

1. Hours of Work and Overtime

Nine (9) hours shall constitute a day's work for four (4) days Monday to Thursday inclusive, and eight (8) hours shall constitute a day's work for Friday. Said hours shall normally be within the period from 7:00 a.m. until 6:00 p.m.

If more than the recognized daily hours are worked in any day or shift, Monday to Friday inclusive, such time shall be paid at the rate of time and one-half.

On Saturdays and Sundays, except as provided in Article 15.2, time and one-half shall be paid for all hours worked.

On Holidays, double the regular straight time hourly rate shall be paid for all hours worked.

2. Wages

Wage rates shall be as follows:

Classification	Effective May 1, 2016	Effective May 1, 2017	Effective May 1, 2018
Journeyman Roofer	$33.70	$34.80	$35.95
Roofer #1	$30.33	$31.32	$32.36
Roofer Apprentices			
3rd Year	$26.96	$27.84	$28.76
2nd Year	$23.59	$24.36	$25.17
1st Year	$20.22	$20.88	$21.57
Classified Worker			
Classified Worker (Over 2400 hrs)	$23.75	$24.45	$24.45
Step 2 (1201 hrs to 2400 hrs @ 55%)	$18.95	$19.55	$19.55
Step 1 (first 1200 hrs @ 50%)	$16.85	$17.40	$17.98

The classifications covered are defined as follows:

1) Journeyman: As defined by the Manitoba Apprentices and Trades Qualification Act (Roofer Regulation). Recognized by a Certificate of Qualification in the trade of Roofer.

2) Roofer #1: An experienced Roofer with a minimum of 3,600 hours of roofing practice capable of performing 90% of the duties of a Journeyman Roofer (a non-ticket Journeyman).

3) Apprentice: As defined by the Roofer Trade Regulation. Must have a minimum of 2,000 hours of roofing experience prior to registering.

4) Classified Worker: A worker with limited or no roofing experience capable of performing entry level tasks or single job specific skills.

Classified Worker (first 1,200 hours) shall not be eligible for Employer or Employee pension contributions and Health and Welfare contributions.

Foreman Premium:

When the Contractor appoints a working foreman, he shall be paid a premium of:

Effective May 13, 2013: $4.00 per hour.

3. Vacation and Vacation Pay

Annual vacation will be paid to employees on the basis of six percent (6%) of the gross wages excluding overtime earned.

Vacation pay allowance will be paid to employees on their regular pay day. Such payment shall be considered as advance payment for any vacation taken by the employee under the conditions provided in the Employment Standards Code for the Province of Manitoba.

4. Pay in Lieu of Holidays

Whether or not an employee works on any of the Holidays under Article 17, he shall receive in lieu of paid Holidays, four and a half percent (4.5%) of his total gross wages, exclusive of overtime earned in the calendar year. The employee shall be paid this amount on his regular payday.

5. Trust Funds

Health and Welfare Fund

The employee and the Contractor shall contribute the amounts set out below to The Sheet Metal Workers and Roofers Health and Welfare Plan. Contributions shall apply to all hours worked. The employee's contribution shall be deducted from the employee's regular pay cheque.

	Employer Contributions	Employee Contributions
Effective May 1, 2016	$0.88/hr	$0.60/hr
Effective May 1, 2017	$0.88/hr	$0.62/hr
Effective May 1, 2018	$0.88/hr	$0.63/hr

Pension Fund

The employee and the Contractor shall contribute the amounts set out below to the Sheet Metal Workers and Roofers Pension Fund. Contributions shall apply to all hours worked. The employee's contributions shall be deducted from the employee's regular pay cheque.

Effective May 1, 2016

	Employer Contributions	Employee Contributions
Journeyman	$2.05/hr	$1.35/hr
Roofer #1	$1.85/hr	$1.28/hr
3rd Apprentice	$1.64/hr	$1.20/hr
2nd Apprentice	$1.44/hr	$1.13/hr
1st Apprentice	$1.23/hr	$1.05/hr
Classified Worker	$1.13/hr	$1.02/hr
Classified Worker Step 2	$1.13/hr	$1.02/hr

Payments and reporting forms for both of the above funds to be received by the Administrator of the Sheet Metal Workers and Roofers Health and Welfare and Pension Trust Funds not later than the 15th of the month following the month for which contributions are being made.

Training Fund

The Contractor and each employee will contribute the amounts set out below to the trusteed industry training fund:

Contractor's Contribution 10¢ per hour worked
Employee's Contribution 10¢ per hour worked

6. Benevolent Fund

The contractor shall deduct at the source as a payroll deduction the amount set out below for each hour worked by each employee covered by this Appendix and remit same to Local Union 511 Benevolent Fund:

2¢ per hour

This fund shall be used to provide:

a) Assistance to members in paying Health and Welfare premiums where required.

b) Up-grading courses for tradesmen.

c) Other benevolent services for and on behalf of members.

This fund shall not be disbursed for purposes that can work against the better interest of the Contractors.

All benevolent contributions are to be forwarded to the office of the Administrator, 438 Higgins Ave. Winnipeg, Manitoba R3A 1S5, prior to the 10th day of the calendar month following the period for which contributions are being reported.

Combination Reporting Forms shall be provided to the Contractor by the Union.

7. Building Trades Council and Western Conference Funds

The Contractor shall deduct at the source as a payroll deduction an amount of 6¢* per hour worked (or any part thereof) from each employee covered by this Appendix and same shall be remitted by the Contractor to the International Association of Sheet Metal, Air, Rail, and Transportation Workers (SMART), Local Union 511, 438 Higgins Ave. Winnipeg, Manitoba R3A 1S5.

* i.e. 5¢ in respect of the B.T.C. Fund and 1¢ in respect of the W.C. Fund.

These monies will be remitted to the fund by the 10th day of the month following that which contributions cover, in the manner provided by the Unified Remittance Form.

8. Isolation Leave (Return Transportation Time Periods)

The return transportation time period referred to in Article 19.2.1 for this Appendix shall be:

- After twenty eight (28) calendar days.

Travel time shall only apply on the return portion of an Isolation Leave trip (i.e. from the employee's T.D.P. to the Project Camp Site).

The amount of travel time to be paid shall be in accordance with the provisions of Article 19.1.2.5.1 or 19.1.2.5.2, as the case may be, and if applicable, the provisions of Article 19.1.2.5.3.

Travel time shall be paid at the employee's straight time rate, and an employee shall receive such payment pursuant to the provisions of Article 19.1.2.6.

9. Tools

Journeymen, Roofer #1, Apprentices, and Classified Workers Step 1 and Classified Worker Step 2 shall supply the following tools of the trade:

		Description
Classified Workers Step 1	1	Utility Knife
	1	Insulation Knife
	1	Tool Belt (to hold knives)
	1	25’ Tape
		Personal Protective Equipment (safety hard hat, safety boots, and other normal protective equipment)

Additionally, Classified Workers (Step 2), Journeymen, Roofer #1, and Apprentices shall supply:

		Description
Classified Workers Step 2	1	Claw Hammer
	1	Pointed Trowel
	1	8” Crescent Wrench
	1	Screw Driver
	1	Tool Belt (to hold tools)

The Contractor will be responsible for compensation for tools destroyed by fire or lost by breaking and entering from a storage place provided by the Contractor. Claims for such lost or destroyed tools must be submitted in writing with a list thereof, their value, and substantial evidence of loss. Claims must be submitted within ten days of the date of loss unless good reason can be shown for not having done so.

10. Escalation and Reference

10.1 Wage Rate Provisions

The wage rate for the classifications set out in this Appendix will be adjusted by an amount equal to and effective on the dates of any adjustments in wage rates for corresponding classifications which may be negotiated from time to time by the International Association of Sheet Metal, Air, Rail and Transportation Workers (SMART), Local Union 511 (Roofing Section) and the Roofing Contractors Trade Division of the Construction Labour Relations Association of Manitoba.

Classifications eligible for adjustment may include general foreman, foreman, leadhand, chargehand, pusher, journeyman, apprentices, helpers and trainees.

10.1.1 Except as otherwise noted, the following provisions will be incorporated or adjusted to be consistent with corresponding provisions negotiated from time to time by the aforementioned Parties:

a) Definitions and qualificational requirements for applicable classifications;

b) Ratios indicating the number of apprentices, helpers, or other types of trainees who may be employed;

c) Height pay including that associated with swing stage work.

10.2 Other Conditions of Employment

Except as otherwise noted, the following conditions of employment will be incorporated or adjusted to be consistent with corresponding conditions of employment negotiated from time to time by the aforementioned Parties:

a) Overtime payments (subject to the restrictions set out in Section 10.3);

b) Shift premium but excluding any shift premium applicable to overtime hours;

c) Vacation and Vacation Pay - such provisions may include any provisions relative to the timing of payment of vacation pay but shall not include any provisions stipulating when vacation time must be granted, and in lieu of such a provision the following shall be substituted: “the scheduling of time off for vacation shall be arranged by mutual agreement between the Contractor and the employee”;

d) Pay in lieu of Holidays and any provisions requiring the transferring and observing of the Holiday on a day, other than the day on which the Holiday falls (subject to the restrictions set out in Section 10.2.1);

e) Registered and trusteed pension and health and welfare plans (subject to the restrictions set out in Section 10.2.2);

f) Callout provisions;

g) Rest provisions between shifts;

h) Personal effects insurance provisions;

i) Provisions governing welding and other special trade related tests;

j) Safety clothing;

k) Tool lists and provisions governing loss of such tools on the Project

l) The following trusteed plans, each of which shall be subject to the restrictions set out in Section 10.2.3:

   i) Building fund;

   ii) Trade improvement plans including educational and apprenticeship funds;

   iii) Industrial promotion funds.

m) The Plans set out in Section 6 and 7 of this Appendix, subject to the limitation that these Plans will be solely funded by the employee and all required contributions shall be collected at the source as a payroll deduction;

n) The time period between Isolation Leaves (subject to the restrictions of Article 19.2.1.3);

o) Travel time associated with the taking of an Isolation Leave, and the hourly rate at which travel time will be paid (subject to the restrictions set out in Section 10.2.4);

10.2.1 A Holiday set out in Article 17 may be observed on a day, other than the day on which it falls, provided the Holiday falls on a Saturday or Sunday which is a non-working day, in which case the Holiday may be observed on the closest following working day. The transferring of a Holiday shall not apply to any employee who is on Christmas Leave, Isolation Leave or any other type of Leave of Absence when the Holiday occurs.

10.2.2 The Contractor's contribution to any pension and health and welfare plan may be applied on a per hour worked basis; however, the Contractor's contribution rate in respect of overtime hours shall not be greater than the required contribution rate for Contractors in respect of straight time hours.

10.2.3 The Contractor's contribution to any of the plans referred to in Section 10.2 (l) may be applied on a per hour worked basis; however, the Contractor's contribution rate in respect of overtime hours shall not be greater than the required contribution rate for contractors in respect of straight time hours.

10.2.4 Travel time may only apply to the return portion of an Isolation Leave trip (i.e. from the employee's T.D.P. to the Project Camp Site). The amount of travel time to be paid shall not be greater than the travel time set out in Articles 19.1.2.5.1, 19.1.2.5.2 and 19.1.2.5.3, as may be applicable. The hourly rate at which travel time may be paid shall not be greater than the employee's straight time rate. Payment of travel time shall be in accordance with the provisions of Article 19.1.2.6.

10.3 Notwithstanding anything contained in this Agreement or in this Appendix, the regular hours of work are not subject to adjustment during the life of this Agreement, and such regular hours of work shall be paid at regular rates of wages. Further, overtime payments at a rate greater than time and one-half will not be introduced in this Appendix in respect of the first two (2) hours of overtime, Monday to Friday inclusive.

10.4 The provisions of 10.1 and 10.2 above shall be dealt with by following the procedure set out in Article 30 of this Agreement.

APPENDIX NO. 10b – Sheeters, Deckers and Cladders

INTERNATIONAL ASSOCIATION OF SHEET METAL, AIR, RAIL AND TRANSPORTATION WORKERS (SMART) LOCAL UNION 511 (SHEET METAL WORKERS)

Local Union 511 (Sheeters, Deckers and Cladders Section)

BURNTWOOD/NELSON AGREEMENT

1. Hours of Work and Overtime

Eight (8) hours shall constitute a day's work for five (5) days Monday to Friday inclusive, the maximum regular workweek shall be forty (40) hours. Said hours shall normally be within the period from 7:00 a.m. until 6:00 p.m.

If more than the maximum daily hours are worked in any one (1) day or shift, Monday to Friday inclusive, such time shall be paid at the rate of time and one-half (1 1/2x) of the straight time hourly rate.

Time and one-half (1 ½X) shall be paid up to a maximum of ten (10) hours worked in any calendar week, Monday to Friday. Double (2X) time for all hours worked thereafter. Double (2X) time for all work on Saturdays, Sundays, and holidays

On Saturdays, except as provided in Article 15.2, Sundays and holidays, as specified in Article 17, double time shall be paid.

2. Shift Conditions

If conditions are such that work on that particular job cannot be done within the said normal hours (7:00 a.m. to 6:00 p.m.) then eight (8) hours may be worked during any hours and may constitute a regular shift on that job.

A premium of 10% of the regular straight time rate will be paid for each shift hour worked on a shift that cannot be done within the said normal hours. Shift premium will not be paid on any overtime hours worked.

Overtime payment for shift work shall be in accordance with the provisions as set out above.

The starting and quitting time of all shift work will be decided by the Contractor.

3. Wages

Classifications

1) Journeyman: A worker whom has accumulated a minimum of 7,200 hours working at the trade and holds a valid Certificate of Qualification issued by the Province or the Sheeter/Decker Training Committee, hereinafter referenced to as the S.D.T.C;

   i) Journeyman 'A' classification shall encompass all work of 200 squares of metal wall panels, insulated roof panels, and roof deck over 500 squares;

   ii) Journeyman 'B' classification shall encompass all work under 200 squares of metal wall panels, insulated roof panels, and roof deck under 500 squares and all packaged building systems;

2) Sheeter Decker Cladder Skilled Tradesperson 2: A worker will remain in this classification for a maximum of 1200 hours working at the trade, and once completed with be reclassified as a Journeyman A or B.

3) Sheeter Decker Cladder Skilled Tradesperson 1: A worker will remain in this classification for a maximum of 1200 hours working at the trade.

4) SDC General Construction Labourer 2: Once a worker has completed the appropriate period of time as a SDC General Construction Labourer 1, the worker will be classified as a SDC General Construction Labourer 2 and will remain in this classification for a period of 1500 working hours.

5) SDC General Construction Labourer 1: Once a worker has completed the appropriate period of time as a SDC General Construction Labourer Trainee 2, the worker will be classified as a SDC General Construction Labourer 1 and will remain in this classification for a period of 1500 working hours.

6) SDC General Construction Labourer Trainee 2: Once a worker has completed the appropriate period of time as a SDC General Construction Labourer Trainee 1, the worker will be classified as a SDC General Construction Labourer Trainee 2 and will remain in this classification for a period of 1200 working hours.

7) SDC General Construction Labourer Trainee 1: A SDC General Construction Labourer Trainee 1 will remain in this classification for a maximum of 1200 working hours.

Notes: Sheeter Decker Cladder (SDC) General Construction Labourer will occur on a progressive fashion. The issue will be discussed between the Local Union and the Contractor with respect to the employee's further movement up the classification scale.

Percentages

1)	Journeyman (B)	96% of Journeyman A rate
2)	SDC Skilled Tradesperson 2	85% of Journeyman A rate
3)	SDC Skilled Tradesperson 1	80% of Journeyman A rate
4)	SDC General Construction Labourer 2	75% of Journeyman A rate
5)	SDC General Construction Labourer 1	67% of Journeyman A rate
6)	SDC General Construction Labourer Trainee 2	55% of Journeyman A rate
7)	SDC General Construction Labourer Trainee 1	45% of Journeyman A rate

Wage Rates

	Effective 2016 05 01	Effective 2017 05 01	Effective 2018 05 01
Journeyman A	$37.09	$38.33	$39.63
Journeyman B	$35.61	$36.80	$38.04
SDC Skilled Tradesperson 2	$31.53	$32.58	$33.69
SDC Skilled Tradesperson 1	$29.67	$30.66	$31.70
SDC General Construction Labourer 2	$27.82	$28.75	$29.72
SDC General Construction Labourer 1	$24.85	$25.68	$26.55
SDC General Construction Labourer Trainee 2	$20.40	$21.08	$21.80
SDC General Construction Labourer Trainee 1	$16.69	$16.69	$17.83

Ratio

1. A minimum of one (1) Journeyman or Skilled Tradesperson must be employed on each job for every one (1) SDC General Construction Labourer Trainee employed.

2. No ratio applies to Sheeter Decker Cladder Skilled 1 and/or 2

Chargehand Premium:

i) When the Employer places an employee in charge of the production of three (3) or more other employees and delegates to him/her the general supervision of a job or project the employee shall receive a Chargehand Premium of an additional four dollars ($4.00) per hour (effective May 1, 2016).

4. Vacation and Vacation Pay

The annual vacation will be arranged as provided in the Employment Standards Code for the Province of Manitoba.

Payment for the annual vacation will be as provided in the above noted Act or on the basis of six (6%) of the employee's gross earnings. Gross earnings shall be defined as earnings at the standard hourly rate for all straight time hours worked plus earnings at the overtime premium hourly rate for all overtime hours worked.

Vacation pay allowance will be paid to employees on their regular pay day. Such payment shall be considered as advance payment for any vacation taken by the employee under the conditions provided in the Employment Standards Code for the Province of Manitoba.

5. Pay in Lieu of Holidays

Whether or not an employee works on any of the holidays set out in Article 17, he shall receive in lieu of paid holidays, four and a half (4.5**)** percent of the employee's gross earnings, as defined above.

Where Christmas Day, New Year's Day or Canada Day falls on a Saturday or Sunday that is a non-working day, the parties may, by mutual consent agree to an alternate day off. However, this shall not apply to any employee who is on Christmas Leave, an Isolation Leave or any other type of leave of absence when any of these Holidays occurs.

6. Trust Funds

Health and Welfare Fund

The employee and the Contractor shall contribute the amounts set out below to the Administrator of the Sheet Metal Workers and Roofers Health and Welfare Plan. The employee's contribution shall be deducted from the employee's regular pay cheque. Contributions shall apply to all hours worked.

The Contractor's contribution will be:

Effective	May 1, 2016	$0.78 per hour
Effective	May 1, 2017	$0.78 per hour
Effective	May 1, 2018	$0.78 per hour

The Employee's contribution will be:

Effective	May 1, 2016	$0.60 per hour
Effective	May 1, 2017	$0.62 per hour
Effective	May 1, 2018	$0.63 per hour

Pension Fund

The employee and the Contractor shall contribute the amounts set out below to the Administrator of the Sheet Metal Workers and Roofers Pension Fund. The employee's contribution shall be deducted from the employee's regular pay cheque. Contributions shall apply to all hours worked.

The Contractor's contribution shall be:

	May 1, 2016	May 1, 2017	May 1, 2018
Journeyman A	$2.40	$2.40	$2.40
Journeyman B	$2.40	$2.40	$2.40
SDC Skilled Tradesperson 2	$2.04	$2.04	$2.04
SDC Skilled Tradesperson 1	$1.92	$1.92	$1.92
SDC Gen. Const Labourer 2	$1.80	$1.80	$1.80
SDC Gen. Const Labourer 1	$1.61	$1.61	$1.61
SDC Const. Labourer Trainee2	$1.32	$1.32	$1.32
SDC Const. Labourer Trainee	$1.08	$1.08	$1.08

The Employee's contribution shall be:

May 1, 2016	May 1, 2017	May 1, 2018
$1.20	$1.20	$1.20

Payments and reporting forms for both of the above funds to be received by the Administrator (Local 511) not later than the 10th of the month following the month for which contributions are applicable.

Training Fund

The Employee and the Contractor shall contribute the amounts set out below to the Administrator of the Sheet Metal Workers and Roofers Industry Training Fund. The employee's contribution shall be deducted from the employee's regular pay cheque. Contributions shall apply to all hours worked.

The Contractor's contribution shall be: 15¢ per hour

The Employee's contribution shall be: 5¢ per hour

7. Benevolent Fund

The contractor shall deduct 2¢ per hour worked from the employee's wages and remit same to Local Union 511 Benevolent Fund. This fund shall be used to provide:

a) Assistance to members in paying Health and Welfare premiums where required;

b) Up grading courses for tradesmen;

c) Other benevolent services for and on behalf of members.

This fund shall not be disbursed for purposes that can work against the better interest of the Contractors.

All benevolent contributions are to be forwarded to the office of the Administrator, 438 Higgins Avenue, Winnipeg, Manitoba, R3A 1S5**,** prior to the 10th day of the calendar month following the period for which contributions are being reported. Combination Reporting Forms shall be provided to the Contractor by the Union.

8. Building Trades Council, Western Conference and Market Recovery Funds

The Contractor shall deduct thirty-one (31¢)* per hour worked (or any part thereof) from the employees' wages and remit same to the Sheet Metal Workers International Association, Local Union 511**,** 438 Higgins Avenue, Winnipeg, Manitoba, R3A 1S5.

* i.e. five cents (5¢) in respect of the B.T.C. Fund, one cent (1¢) in respect of the W.C. Fund and twenty-five cents (25¢) in respect of the Market Recovery Fund.

These monies will be remitted to the fund by the 10th day of the month following that which contributions cover, in the manner set out in the Unified Remittance Form.

9. Isolation Leave (Return Transportation Time Periods)

The return transportation time period referred to in Article 19.2.1 for this Appendix shall be:

- After twenty eight (28) calendar days.

Travel time shall only apply on the return portion of an Isolation Leave trip (i.e. from the employee's T.D.P. to the Project Camp Site).

The amount of travel time to be paid shall be in accordance with the provisions of Article 19.1.2.5.1 or 19.1.2.5.2, as the case may be, and if applicable, the provisions of Article 19.1.2.5.3.

Travel time shall be paid at the employee's straight time rate, and an employee shall

receive such payment pursuant to the provisions of Article 19.1.2.6.

10. Tools

Journeymen and Apprentices shall supply the ordinary hand tools of the trade. They shall be:

	Description
1	Pair straight snips
1	Pair tinner snips left hand
1	Pair tinner snips right hand
1	Tinners hammer
1	Pair vice grips standard jaw
1	Pair vice grips wide jaw
1	Flat screwdriver
1	25’ tape measure
1	4’ level
1	Crescent wrench 10”

11. Escalation and Reference

11.1 Wage Rate Provisions

The wage rate for the classifications set out in this Appendix will be adjusted by an amount equal to and effective on the dates of any adjustments in wage rates for corresponding classifications which may be negotiated from time to time by the International Association of Sheet Metal, Air, Rail and Transportation Worker (SMART), Local Union 511 (Sheeters, Deckers and Cladders Section) and the Construction Labour Relations Association of Manitoba.

Classifications eligible for adjustment may include general foreman, foreman, leadhand, chargehand, pusher, journeyman, apprentices, helpers and trainees.

11.1.1 Except as otherwise noted, the following provisions will be incorporated or adjusted to be consistent with corresponding provisions negotiated from time to time by the aforementioned Parties:

a) Definitions and qualificational requirements for applicable classifications;

b) Ratios indicating the number of apprentices, helpers, or other types of trainees who may be employed;

c) Height pay including that associated with swing stage work.

11.2 Other Conditions of Employment

Except as otherwise noted, the following conditions of employment will be incorporated or adjusted to be consistent with corresponding conditions of employment negotiated from time to time by the aforementioned Parties:

a) Overtime payments (subject to the restrictions set out in Section 11.3);

b) Shift premium but excluding any shift premium applicable to overtime hours;

c) Vacation and Vacation Pay - such provisions may include any provisions relative to the timing of payment of vacation pay but shall not include any provisions stipulating when vacation time must be granted, and in lieu of such a provision the following shall be substituted: "the scheduling of time off for vacation shall be arranged by mutual agreement between the Contractor and the employee";

d) Pay in lieu of Holidays and any provisions requiring the transferring and observing of the Holiday on a day, other than the day on which the Holiday falls (subject to the restrictions set out in Section 11.2.1);

e) Registered and trusteed pension and health and welfare plans (subject to the restrictions set out in Section 11.2.2);

f) Callout provisions;

g) Rest provisions between shifts;

h) Personal effects insurance provisions;

i) Provisions governing welding and other special trade related tests;

j) Safety clothing;

k) Tool lists and provisions governing loss of such tools on the Project;

l) The following trusteed plans, each of which shall be subject to the restrictions set out in Section 11.2.3:

   i) Building fund;

   ii) Trade improvement plans including educational and apprenticeship funds;

   iii) Industrial promotion funds.

m) The Plans set out in Section 7 and 8 of this Appendix, subject to the limitation that these Plans will be solely funded by the employee and all required contributions shall be collected at the source as a payroll deduction;

n) The time period between Isolation Leaves (subject to the restrictions of Article 19.2.1.3);

o) Travel time associated with the taking of an Isolation Leave, and the hourly rate at which travel time will be paid (subject to the restrictions set out in Section 11. 2.4).

11.2.1 A Holiday set out in Article 17 may be observed on a day, other than the day on which it falls, provided the Holiday falls on a Saturday or Sunday which is a non-working day, in which case the Holiday may be observed on the closest following working day. The transferring of a Holiday shall not apply to any employee who is on Christmas Leave, Isolation Leave or any other type of Leave of Absence when the Holiday occurs.

11.2.2 The Contractor's contribution to any pension and health and welfare plan may be applied on a per hour worked basis; however, the Contractor's contribution rate in respect of overtime hours shall not be greater than the required contribution rate for Contractors in respect of straight time hours.

11.2.3 The Contractor's contribution to any of the plans referred to in Section 11.2 (l) may be applied on a per hour worked basis; however, the Contractor's contribution rate in respect of overtime hours shall not be greater than the required contribution rate for contractors in respect of straight time hours.

11.2.4 Travel time may only apply to the return portion of an Isolation Leave trip (i.e. from the employee's T.D.P. to the Project Camp Site). The amount of travel time to be paid shall not be greater than the travel time set out in Articles 19.1.2.5.1, 19.1.2.5.2 and 19.1.2.5.3, as may be applicable. The hourly rate at which travel time may be paid shall not be greater than the employee's straight time rate. Payment of travel time shall be in accordance with the provisions of Article 19.1.2.6.

11.3 Notwithstanding anything contained in this Agreement or in this Appendix, the regular hours of work are not subject to adjustment during the life of this Agreement, and such regular hours of work shall be paid at regular rates of wages. Further, overtime payments at a rate greater than time and one-half will not be

introduced in this Appendix in respect of the first two (2) hours of overtime, Monday to Friday inclusive.

11.4 The provisions of 11.1 and 11.2 above shall be dealt with by following the procedure set out in Article 30 of this Agreement.

APPENDIX NO. 11 – Boilermakers

INTERNATIONAL BROTHERHOOD OF BOILERMAKERS,
IRON SHIPBUILDERS, BLACKSMITHS, FORGERS AND HELPERS

Local Union 555

BURNTWOOD/NELSON AGREEMENT

1. Hours of Work and Overtime

Eight (8) hours shall constitute a day's work for five (5) days Monday to Friday inclusive. Said hours shall normally be within the period from 7:00 a.m. until 6:00 p.m.

If more than the recognized daily hours are worked in any day or shift, Monday to Friday inclusive, such time shall be paid at the rate of time and one-half of the straight time rate for the first two (2) hours and double time for hours worked thereafter in any one (1) day.

On Saturdays, except as provided in Article 15.2, Sundays and on Holidays, as set out in Article 17, double time shall be paid.

2. Shift Conditions

If conditions are such that work on that particular job cannot be done within the said normal hours (7:00 a.m. to 6:00 p.m.) then eight (8) hours may be worked during any hours and may a regular shift on that job.

For the purpose of defining the shifts, the first shift shall be the day shift. The second shift shall be the afternoon shift and shall follow the first shift. The third shift shall be the night shift and shall follow the second shift.

An employee working on the second or third shift shall be paid the shift premium set out below, and such premium shall apply to all hours worked at the straight time rate on such shifts:

$3.75 per hour

Shift premium shall not apply on overtime hours.

The starting and quitting time of all shift work shall be decided by the Contractor.

Overtime payment for shift work shall be in accordance with the provisions as set out above.

3. Rest Period

If an employee is required to return to work before an eight (8) hour break occurs, the employee will be paid at the applicable overtime rates until such time as an eight (8) hour break occurs.

4. Wages

Wage rates shall be as follows:

Classification	Effective May 5, 2019	Effective June 1, 2019*	Effective May 3, 2020**	Effective May 2, 2021**
General Foreman	46.92	46.83	47.62	47.62
Foreman	43.17	43.08	43.88	43.88
Assistant Foreman	39.42	39.33	40.11	40.11
Journeyman	37.92	37.83	38.61	38.61
3rd Year Apprentice	34.05	33.95	34.75	34.75
2nd Year Apprentice	28.21	28.11	28.94	28.94
1st Year Apprentice	22.39	22.30	23.14	23.14
Helper	N/A***	N/A***	N/A***	N/A***

** The rates 2021 will be subject to a Canadian CPI review in 2021.
*** No rates identified for this classification. If you employ a Boilermakers Helper, please contact your HPMA representative

5. Apprentices

The number of Apprentices that may be employed on the job shall not exceed the ratio of one (1) Apprentice to four (4) Journeymen, however, there may be situations where this ratio is impractical in which case the Association and Council must consult and come to a mutual agreement.

Apprentices shall not progress to Journeyman wage rate until they have successfully completed their Certificate of Qualification (CFQ) or Boilermaker Red Seal where applicable.

Apprentices shall be given the support of Journeymen and Foremen and under the guidance of the Journeyman, Apprentices may perform rigging, fitting, welding, layout work or any other part of the trade of a Journeyman Boilermaker.

Apprentice intakes will consist of up to twenty-five percent (25%) Helmets to Hardhats (H2H) candidates if available.

6. Welding Tests

Any Welder possessing a current Provincial Government welding certificate of qualification, who is required to take a Provincial Government test shall be paid for the time required to take the test including materials and inspector fees. Should a secondary test be required by the Contractor, the employee shall be paid for the time required to take such a test.

Any Welder possessing a current Provincial Government welding certificate of qualification who is instructed to proceed to take tests necessitating his having to travel outside the city limits of the city in which he resides shall be reimbursed in an amount necessary to compensate him for travelling time and transportation expenses.

Welders passing a test will be furnished a copy of the test papers from the Contractor or party requiring a test within thirty (30) days, or upon completion of the job whichever is sooner, provided they are available at that time; otherwise the Contractor will provide a letter confirming the test and results.

When a Welder is required to perform a test of a type other than a standard Provincial test, the Contractor shall, on request, make available suitable material to allow a brief period of practice prior to taking the actual test.

When a Welder is to take an official Provincial test on which the issuance or reissuance of his certificate will depend, he shall not be required to do so under conditions which would unfairly affect his ability to perform the test.

For other tests, the Contractor may prescribe test conditions approximating, but not exceeding, conditions which may be encountered on the job.

Welders required to take any test shall be allowed to complete the test.

7. Vacation and Vacation Pay

Each employee shall receive six percent (6%) of his gross wages as vacation allowance. Gross wages shall include straight time and overtime earnings; shift premium; reporting time as per Article 16; and all travel time applicable under this Agreement. The vacation allowance shall be paid on regular paydays.

8. Payment in Lieu of Holidays

Holiday allowances shall be credited to the employee's account at four percent and one half (4.5%) of his gross wages. Gross wages shall include straight time and overtime earnings; shift premium; reporting time as per Article 16; and all travel time applicable under this Agreement. The Holiday allowance shall be paid on regular paydays.

9. Health and Welfare Fund

The Contractor shall contribute the amounts set out below to the Boilermakers National Health and Welfare Fund of Canada for all hours worked, and hours paid for travel and reporting time, by all employees covered by this Appendix on the following basis:

The Contractor's contribution shall be:

Effective June 1, 2019 $3.35 per hour for hours paid at straight time
*Effective date for payroll adjustments will be November 1, 2019.

Effective May 3, 2020 $3.45 per hour for hours paid at straight time

Contributions payable on overtime hours worked shall be calculated by multiplying the above contribution rate by a factor of 1.5 or 2.0 to correspond to the overtime rate being paid to the employee.

10. Pension

The Contractor shall contribute the amounts set out below to the Boilermakers' National Pension Fund for all hours worked, and hours paid for travel and reporting time, by all employees covered by this Appendix on the following basis.

The Contractor's contribution shall be:

Effective July 15, 2018 $5.25 per hour for hours paid at straight time
*Effective date for payroll adjustments will be October 8, 2018.

Contributions payable on overtime hours worked shall be calculated by multiplying the above contribution rate by a factor of 1.5 or 2.0 to correspond to the overtime rate being paid to the employee.

11. Trade Improvements (Apprenticeship Fund)

The Contractor shall contribute the amounts set out below to the Apprenticeship Fund for all hours earned, and hours paid for travel and reporting time, by all employees covered by this Appendix on the following basis:

Twenty cents per hour

12. Educational Training Fund

The Contractor shall contribute the amounts set out below for all hours earned and hours paid for travelling and reporting time, by all employees covered by this Appendix, to both Educational Training Funds on the following basis:

	Educational Training Fund #1	Educational Training Fund #2
June 1, 2019	$0.45/hour	$0.41/hour
May 3, 2020	$0.45/hour	$0.41/hour

13. National Apprenticeship and Educational Training Fund

The Contractor shall contribute the amounts set out below for all hours earned and hours paid for travelling and reporting time, by all employees covered by this Appendix, to the National Apprenticeship and Educational Training Fund on the following basis:

Effective July 15, 2018 $0.31 per hour for hours paid at straight time
*Effective date for payroll adjustments will be October 8, 2018.

14. Union Promotion Fund

The Contractor shall contribute the amounts set out below to the Union Promotion Fund for all hours earned, including hours paid for travel and reporting time, by all employees covered by this Appendix on the following basis:

Ten cents per hour

Contributions to this Fund shall be remitted to the Winnipeg office of Local Union 555.

Except as outlined below, provisions of the Fund shall not be subject to any further changes except by mutual agreement of the parties.
In the event the Fund is deleted from the Agreement being used for reference purposes, it shall be deleted from the Appendix No. 11 effective on the date of deletion or conversion, as the case may be.

15. Industrial Promotion Fund

Employees shall contribute the amounts set out below to the Industrial Promotion Fund, "Helmets to Hardhats (H2H)" for all hours worked, by all employees covered by this Appendix on the following basis:

One cent per hour

Contributions to this Fund shall be remitted to the Winnipeg office of Local Union 555.

16. Submission of Contributions to Funds

The Local Union will assist the Contractor in obtaining reporting forms for the various Funds set out above. The forms will indicate the information required and, where such information is not otherwise provided, the location to which contributions should be forwarded. Submissions must be made by the 15th of the month following the month in which contributions are payable.

17. Safety Clothing

When required by the work to be performed, the Contractor shall supply to the employee at no cost the following; hard hats, sweat bands, liners, welding and burning goggles, non-prescription safety glasses, appropriate welding gloves, welding helmets, appropriate welding leathers (i.e. jackets, capes and/or sleeves) and leatherfaced gloves (unless special processes dictate otherwise).

In addition to the above, Welders capes shall be kept available for temporary issue to Welders when engaged on work requiring additional protection, such as but not limited to arc-air gouging and overhead welding.

An employee shall not be charged for the above items provided they are returned in reasonable condition, or if lost or damaged for reasons beyond the employee's control, such loss or damage is reported immediately.

18. Personal Effects Insurance

The Contractor shall indemnify an employee to a maximum of four hundred dollars ($400.00) for personal effects, which are damaged or destroyed by fire on the job site.

19. Isolation Leave (Return Transportation Time Periods)

The return transportation time period referred to in Article 20.2.1 for this Appendix shall be:

- after thirty-five (35)calendar days.

20. Escalation and Reference

20.1 Wage Rate Provisions

The wage rate for the classifications set out in this Appendix will be adjusted by an amount equal to and effective on the dates of any adjustments in wage rates for corresponding classifications which may be negotiated from time to time (for application in Manitoba) by the International Brotherhood of Boilermakers, Iron Shipbuilders, Blacksmiths, Forgers and Helpers, and the Boilermakers Contractors' Association.

Classifications eligible for adjustment may include general foreman, foreman, leadhand, chargehand, pusher, journeyman, apprentices, helpers and trainees.

20.1.1 Except as otherwise noted, the following provisions will be incorporated or adjusted to be consistent with corresponding provisions negotiated from time to time by the aforementioned Parties:

(a) definitions and qualificational requirements for applicable classifications.

(b) ratios indicating the number of apprentices, helpers, or other types of trainees who may be employed.

(c) height pay including that associated with swing stage work.

20.2 Other Conditions of Employment

Except as otherwise noted, the following conditions of employment will be incorporated or adjusted to be consistent with corresponding conditions of employment negotiated from time to time by the aforementioned Parties:

(a) overtime payments (subject to the restrictions set out in Section 20.3)

(b) shift premium but excluding any shift premium applicable to overtime hours.

(c) Vacation and Vacation Pay - such provisions may include any provisions relative to the timing of payment of vacation pay but shall not include any provisions stipulating when vacation time must be granted, and in lieu of such a provision the following shall be substituted: 'the scheduling of time off for vacation shall be arranged by mutual agreement between the Contractor and the employee'.

(d) pay in lieu of Holidays and any provisions requiring the transferring and observing of the Holiday on a day, other than the day on which the Holiday falls (subject to the restrictions set out in Section 20.2.1).

(e) registered and trusteed pension and health and welfare plans (subject to the restrictions set out in Section 20.2.2).

(f) callout provisions.

(g) rest provisions between shifts

(h) personal effects insurance provisions

(i) provisions governing welding and other special trade related tests

(j) safety clothing

(k) tool lists and provisions governing loss of such tools on the Project.

(l) the following trusteed plans, each of which shall be subject to the restrictions set out in Section 20.2.3:
  (i) building fund
  (ii) trade improvement plans including educational and apprenticeship funds
  (iii) industrial promotion funds.

(m) the time period between Isolation Leaves (subject to the restrictions of Article 20.2.1.3).

(n) travel time associated with the taking of an Isolation Leave, and the hourly rate at which travel time will be paid (subject to the restrictions set out in Section 20.2.4).

20.2.1 A Holiday set out in Article 17 may be observed on a day, other than the day on which it falls, provided the Holiday falls on a Saturday or Sunday which is a non-working day, in which case the Holiday may be observed on the closest following working day. The transferring of a Holiday shall not apply to any employee who is on Christmas Leave, Isolation Leave or any other type of Leave of Absence when the Holiday occurs.

20.2.2 The Contractor's contribution to any pension and health and welfare plan may be applied on a per hour worked basis; however, the Contractor's contribution rate in respect of overtime hours shall not be greater than the required contribution rate for Contractors in respect of straight time hours.

The aforementioned limitation shall not apply to a pension or health and welfare plan in effect in this Appendix on January 1, 1989 and in which higher employer contribution levels were required in respect of overtime hours compared to straight time hours. This exemption shall remain in effect provided required employer contributions to such plans do not change to a single contribution rate relative to straight time and overtime hours.

20.2.3 The Contractor's contribution to any of the plans referred to in Section 20.2 (l) may be applied on a per hour worked basis; however, the Contractor's contribution rate in respect of overtime hours shall not be greater than the required contribution rate for contractors in respect of straight time hours.

20.2.4 Travel time may only apply to the return portion of an Isolation Leave trip (i.e. from the employee's T.D.P. to the Project Camp Site). The amount of travel time to be paid shall not be greater than the travel time set out in Articles 20.1.2.5.1, 20.1.2.5.2 and 20.1.2.5.3, as may be applicable. The hourly rate at which travel time may be paid shall not be greater than the employee's straight time rate. Payment of travel time shall be in accordance with the provisions of Article 20.1.2.6.

20.3 Notwithstanding anything contained in this Agreement or in this Appendix, the regular hours of work are not subject to adjustment during the life of this Agreement, and such regular hours of work shall be paid at regular rates of wages. Further, overtime payments at a rate greater than time and one-half will not be introduced in this Appendix in respect of the first two (2) hours of overtime, Monday to Friday inclusive.

20.4 The provisions of 20.1 and 20.2 above shall be dealt with by following the procedure set out in Article 30 of this Agreement.

APPENDIX NO. 12 – Iron Workers

THE INTERNATIONAL ASSOCIATION OF BRIDGE
STRUCTURAL AND ORNAMENTAL IRON WORKERS
Local Union 728

BURNTWOOD/NELSON AGREEMENT

1. Hours of Work and Overtime

Eight (8) hours shall constitute a day's work for five (5) days, Monday to Friday inclusive. Said hours shall normally be within the period from 7:00 a.m. until 6:00 p.m.

If more than the recognized daily hours are worked in any day or shift on Monday to Friday inclusive, such time shall be paid at the rate of time and one-half for the first two (2) hours and double time for any hours worked thereafter on that day.

On Saturdays, except as provided in Article 15.2, Sundays and Holidays, as specified in Article 17, double time shall be paid.

2. Shift Conditions

If conditions are such that work on a particular job cannot be done within the said normal hours (7:00 a.m. to 6:00 p.m.) then eight (8) hours may be worked during any hours and may constitute a regular shift on that job.

A shift premium of $3.30/hr. will be paid for each straight time hour of a regular single shift that is worked between 10:00 PM and 6:00 AM.

An employee assigned to any second or third shift shall be paid a shift premium for each hour worked at the straight time rate on such shifts as follows:

Effective May 1, 2019 - $3.00

Shift premium shall not apply to any overtime hours worked.

The foregoing premiums shall not apply to shifts worked on Saturdays, Sundays and Holidays in which overtime rates are in effect.

Overtime payment for shift work shall be in accordance with the provisions as set out above.

The starting and quitting time of all shift work will be decided by the Contractor.

3. Callouts

An employee called out for work after he has completed his regular shift and has gone home shall be given not less than four (4) hours work, or if the work is not available, shall be paid for four (4) hours at the applicable overtime rate.

4. Rest Period

When an employee has completed his shift and is recalled to a job without having had a break of at least eight (8) hours, he shall be paid at a rate of double time until such time as a break of eight (8) hours occurs.

5. Wages

Wage rates shall be as follows:

(a) Journeymen, Structural Ironworkers and Ironworker Welders

May 1, 2019	May 1, 2020	May 1, 2021
$39.90	$39.90	$39.90

(b) Foremen

When the Contractor appoints a Foreman, he shall be paid not less than, effective May 1, 2010, $5.00 per hour, above the rate for a Journeyman Structural Iron Worker for up to a 3-man crew, and $7.50 per hour for a 4-man crew or more. The Contractor shall have discretion to appoint Foremen to suit the particular circumstances of the job. However, when ten (10) employees covered by this Appendix are employed and a Foreman has not been appointed, the Contractor shall appoint a Foreman.

(c) General Foreman

At the Employers discretion, should they choose to employ a General Foreman, they will be paid not less than the base wage rate for Journeyman Ironworker plus double the extra rate for Foremen

(d) Apprentices

At intervals of 1800 hours, including hours worked and in-school training hours, each Apprentice's rate will be reviewed by the Erection Foreman/Superintendent and the Apprentice will be given increases, if his ability warrants, on the following basis:

APPRENTICES		May 1, 2019	May 1, 2020	May 1, 2021
5400 or more hours	100%	$39.90	$39.90	$39.90
Level 3 Apprentice (3600-5399 hours)	85%	$33.92	$33.92	$33.92
Level 2 Apprentice (1800-3599 hours)	70%	$27.93	$27.93	$27.93
Level 1 Apprentice (0-1799 hours)	60%	$23.94	$23.94	$23.94

Apprentice Ironworkers will receive a pro-rated amount of the Journeyman Employer Pension contribution for each year of this agreement based on his percentage to Journeyman rate.

The Contractor will employ a minimum of one (1) Apprentice for every four (4) Journeymen where practical and available. The ratio of Apprentices to Journeymen may be adjusted higher by mutual agreement between the Contractor and the Union.

6. Trade Qualifications

a) Journeyman

A journeyman structural ironworker must be experienced in structural steel erection of all kinds including buildings, bridges, tanks, towers etc., have a thorough working knowledge of all erection tools and equipment used in the trade and be able to perform the necessary work operations in a safe and workmanlike manner, including:

i) Assemble and reeve erecting cranes, travelers, guy and stiff leg derricks and move travelers, all under the general direction of his supervisor;

ii) Hook on, climb, connect and signal the hoisting engineer;

iii) Erect scaffolds, fit and bolt joints in proper fashion preparatory to riveting and perform riveting operations;

iv) Carry out all the miscellaneous tasks which arise on erection jobs, such as tying knots, burning, drilling and reaming, etc.

A journeyman ironworker welder must be able to qualify under Class 'O' of the current Canadian Standards Association Code. He must be able to adjust his welding machine, have a thorough working knowledge of all tools and equipment used in the trade, and be able to perform, in a safe and workmanlike manner, operations such as:

i) Climbing;

ii) Erection of scaffolding for welding;

iii) Fit-up work for welding;

iv) Understanding welding symbols and procedures;

v) Burning and chipping.

7. Vacation Pay and Pay in Lieu of Holidays

Each employee shall receive an amount equal to ten and a half percent (10.5%) of his gross earnings of which four and a half percent (4.5%) shall be in lieu of paid Statutory Holidays. Each employee shall be entitled to four (4) weeks annual vacation to be taken at a time mutually agreed upon by the Contractor and the employee.

Vacation pay allowances shall be paid to employees on their regular pay day. Such payments shall be considered as advance payment for any vacation taken by the employee under the conditions provided in the Employment Standards Code for the Province of Manitoba.

8. Trust Funds

a) Health and Welfare

The Contractor shall contribute to the Iron Workers Central Welfare Trust Fund (Manitoba) the amounts set out below for each hour worked by each employee covered by this Appendix:

Effective	May 1, 2019	$1.86
Effective	May 1, 2020	$1.96

b) Pension Plan

The Contractor shall contribute to the Iron Workers Central Pension Fund (Manitoba) the amounts set out below for each hour worked by each employee covered by this Appendix:

	May 1, 2019	May 1, 2020	May 1, 2021
JOURNEYMAN	$7.05	$7.05	$7.05
Level 3 Apprentice	$5.29*	$5.29	$5.29
Level 2 Apprentice	$4.23*	$4.23	$4.23
Level 1 Apprentice	$3.53*	$3.53	$3.53

*As this reduction in contributions is effective May 1, 2019, we will not recover any overpayments to that date. The reduction will take place on a go forward date only.

Note: The Contractor's contributions to the Iron Workers Central Pension Fund (Manitoba) will be prorated for Apprentice Ironworkers in accordance with the percentage to Journeyman wage rate as outlined in Section 5(c) of this Appendix. Contributions to the Iron Workers Central Welfare Fund (Manitoba) and the Iron Workers Central Pension Fund (Manitoba) shall each be forwarded by the Contractor by the 15th day of the month following the month in which the hours were worked.

9. Trade Improvement and Apprenticeship Fund

The Contractor shall contribute the amount set out below to the Iron Workers Trade Improvement Fund (Manitoba). Contributions shall apply to all hours worked by all employees covered by this Appendix:

Effective	May 1, 2019	40 cents per hour
Effective	May 1, 2020	30 cents per hour

The Contractor shall forward such contributions by the 15th day of the month following the month in which the hours were worked.

10. Travel Time

Where the distance between the marshalling point and the work site exceeds twenty (20) kilometers, any time spent travelling beyond this twenty (20) kilometers radius at the start end of the shift shall be paid at the employee's straight time rate.

11. Safety Clothing

The Contractor will supply rod pouches, welding helmets, safety glasses, welders gloves or mitts, whichever is appropriate, and all safety equipment as directed by the Manitoba Occupational Safety Act, when ironworkers are required to perform welding and burning work.

The cost of any equipment listed above which is not returned on termination of employment will be collected from the employee by a payroll deduction.

12. Clothing Insurance and Protective Clothing

a) The Contractor will reimburse the employee for all reasonable losses associated with fire or theft (in the job trailer and/or the gang box) of the employee's working clothes and working equipment (i.e. rigging belts, crescent wrenches, tapes, bullpins, 1 ¼ inch spud wrenches) at the work site, provided appropriate receipts are provided.

The Contractor will reimburse the employee for all reasonable losses associated with fire of the employee's belongings and working equipment at the camp site, provided appropriate receipts are provided, to a one time employee maximum of $500.00. To qualify for the $500.00 coverage, the employee must submit a list of his personal effects, prior to becoming a resident of the camp, to the Contractor;

b) On abnormally dirty maintenance, revamp and repair work, in which the employee's clothes may be abnormally or permanently damaged, the Contractor shall supply and maintain the necessary protective clothing at no cost to the employee.

c) Where and when necessary the Employer shall supply rain gear, rubber footwear or any other safety footwear that is required other than the regular CSA approved (Green Triangle) Safety Boots which the employee is required to supply. All supplied items will be returned to the Employer at the conclusion of the job in question and any non-returned items will be deducted from the employees final pay cheque

13. Isolation Leave (Return Transportation Time Periods)

The return transportation time period referred to in Article 19.2.1 for this Appendix shall be:

- After thirty-five (35) calendar days.

Travel time shall only apply on the return portion of an Isolation Leave trip (i.e. from the employee's T.D.P. to the Project Camp Site).

The amount of travel time to be paid shall be in accordance with the provisions of Article 19.1.2.5.1 or 19.1.2.5.2, as the case may be, and if applicable, the provisions of Article 19.1.2.5.3.

Travel time shall be paid at the employee's straight time rate, and an employee shall receive such payment pursuant to the provisions of Article 19.1.2.6.

14. Escalation and Reference

14.1 Wage Rate Provisions

The wage rate for the classifications set out in this Appendix will be adjusted by an amount equal to and effective on the dates of any adjustments in wage rates for corresponding classifications which may be negotiated from time to time by the International Association of Bridge, Structural and Ornamental Iron Workers, Local 728 and the Construction Labour Relations Association of Manitoba.

Classifications eligible for adjustment may include general foreman, foreman, leadhand, chargehand, pusher, journeyman, apprentices, helpers and trainees.

14.1.1 Except as otherwise noted, the following provisions will be incorporated or adjusted to be consistent with corresponding provisions negotiated from time to time by the aforementioned Parties:

a) Definitions and qualification requirements for applicable classifications;

b) Ratios indicating the number of apprentices, helpers, or other types of trainees who may be employed;

c) Ratios stipulating when a foreman, lead-hand, chargehand, or pusher is to be appointed; however, if such a ratio is less than ten (10) to one (1) (i.e., the number of persons being supervised relative to the supervisor) when incorporating this provision in this Appendix, the ratio shall be ten (10) to one (1).

14.1.2 The appointment of General Foreman shall be at the sole discretion of the Contractor.

14.2 Other Conditions of Employment

Except as otherwise noted, the following conditions of employment will be incorporated or adjusted to be consistent with corresponding conditions of employment negotiated from time to time by the Local and the aforementioned Parties:

a) Overtime payments (subject to the restrictions set out in Section 14.3);

b) Shift premium but excluding any shift premium applicable to overtime hours;

c) Vacation and Vacation Pay - such provisions may include any provisions relative to the timing of payment of vacation pay but shall not include any provisions stipulating when vacation time must be granted, and in lieu of such a provision the following shall be substituted: “the scheduling of time off for vacation shall be arranged by mutual agreement between the Contractor and the employee”;

d) Pay in lieu of Holidays and any provisions requiring the transferring and observing of the Holiday on a day, other than the day on which the Holiday falls (subject to the restrictions set out in Section 14.2.1);

e) Registered and trusteed pension and health and welfare plans (subject to

the restrictions set out in Section 14.2.2);

f) Callout provisions;

g) Rest provisions between shift;

h) Personal effects insurance provisions;

i) Provisions governing welding and other special trade related tests;

j) Safety clothing;

k) Tool lists and provisions governing loss of such tools on the Project;

l) The following trusteed plans, each of which shall be subject to the restrictions set out in Section 14.2.3:

i) Building fund;

ii) Trade improvement plans including educational and apprenticeship funds;

iii) Industrial promotion funds.

m) The time period between Isolation Leaves (subject to the restrictions of Article 19.2.1.3);

n) Travel time associated with the taking of an Isolation Leave, and the hourly rate at which travel time will be paid (subject to the restrictions set out in Section 14.2.4).

14.2.1 A Holiday set out in Article 17 may be observed on a day, other than the day on which it falls, provided the Holiday falls on a Saturday or Sunday which is a non-working day, in which case the Holiday may be observed on the closest following working day. The transferring of a Holiday shall not apply to any employee who is on Christmas Leave, Isolation Leave or any other type of Leave of Absence when the Holiday occurs.

14.2.2 The Contractor's contribution to any pension and health and welfare plan may be applied on a per hour worked basis; however, the Contractor's contribution rate in respect of overtime hours shall not be greater than the required contribution rate for Contractors in respect of straight time hours. The aforementioned limitation shall not apply to a pension or health and welfare plan in effect in this Appendix on January 1, 1989 and in which higher employer contribution levels were required in respect of overtime hours compared to straight time hours. This exemption shall remain in effect provided required employer contributions to such plans do not

change to a single contribution rate relative to straight time and overtime hours.

14.2.3 The Contractor's contribution to any of the plans referred to in Section 14.2 (l) may be applied on a per hour worked basis; however, the Contractor's contribution rate in respect of overtime hours shall not be greater than the required contribution rate for contractors in respect of straight time hours.

14.2.4 Travel time may only apply to the return portion of an Isolation Leave trip (i.e. from the employee's T.D.P. to the Project Camp Site). The amount of travel time to be paid shall not be greater than the travel time set out in Articles 19.1.2.5.1, 19.1.2.5.2 and 19.1.2.5.3, as may be applicable. The hourly rate at which travel time may be paid shall not be greater than the employee's straight time rate. Payment of travel time shall be in accordance with the provisions of Article 19.1.2.6.

14.3 Notwithstanding anything contained in this Agreement or in this Appendix, the regular hours of work are not subject to adjustment during the life of this Agreement, and such regular hours of work shall be paid at regular rates of wages. Further, overtime payments at a rate greater than time and one-half will not be introduced in this Appendix in respect of the first two (2) hours of overtime, Monday to Friday inclusive.

14.4 The provisions of 14.1 and 14.2 above shall be dealt with by following the procedure set out in Article 30 of this Agreement.

APPENDIX NO. 12a - Rodmen

THE INTERNATIONAL ASSOCIATION OF BRIDGE, STRUCTURAL AND ORNAMENTAL IRONWORKERS

Local 728 (Rodmen)

BURNTWOOD/NELSON AGREEMENT

1. Hours of Work and Overtime

Eight (8) hours shall constitute a day's work for five (5) days Monday to Friday inclusive. Said hours shall normally be within the period from 7:00 a.m. until 6:00 p.m.

If more than the recognized daily hours are worked in any day or shift, such time shall be paid at the rate of time and one-half for the first two (2) hours and double time for hours worked thereafter in any one (1) day.

On Saturdays, except as provided in Article 15.2, Sundays and on Holidays, as set out in Article 17, double time shall be paid.

2. Shift Conditions

If conditions are such that work on a particular job cannot be done within the said normal hours (7:00 a.m. to 6:00 p.m.) then eight (8) hours may be worked during any hours and may constitute a regular shift on that job.

A shift premium of $3.30/hr. will be paid for each straight time hour of a regular single shift that is worked between 10:00 PM and 6:00 AM.

An employee assigned to any second or third shift shall be paid a shift premium for each hour worked at the straight time rate on such shifts as follows:

Effective May 1, 2019 - $3.00

Shift premium shall not apply to any overtime hours worked.

The foregoing premiums shall not apply to shifts worked on Saturdays, Sundays and Holidays in which overtime rates are in effect.

Overtime payment for shift work shall be in accordance with the provisions as set out above.

The starting and quitting time of all shift work will be decided by the Contractor.

3. Callouts

An employee called out for work after he has completed his regular shift and has gone home shall be given not less than four (4) hours work, or if the work is not available shall be paid for four (4) hours at the applicable overtime rate.

However, the Contractor may call out employees to unload or to do such work as may be necessary to protect property during inclement weather. If this occurs, the employee shall be paid not less than two (2) hours at the applicable rate of pay for each time the employee is called out.

4. Rest Period

When an employee completes his regular shift and is recalled to a job without having had at least eight (8) hours rest time, he shall be paid at the rate of double time until such time as an eight (8) hour rest time occurs.

5. Wages

Wage rates shall be as follows:

a) Journeymen Reinforcing Rodmen

	May 1, 2019	May 1, 2020	May 1, 2021
Journeyman	$36.21	$36.21	$36.21

b) Foremen

When the Contractor appoints a Journeyman as a Foreman, he will be paid not less than $5.00 per hour more than the rate for Journeymen for up to a 3 man crew, and not less than $7.50 per hour more than the rate for Journeymen for a 4 man crew or more.

c) General Foreman

At the Employers discretion, should they chose to employ a General Foreman, they will be paid not less than the base wage rate for Journeyman Ironworker plus double the extra rate for Foremen

d) Apprentices

At intervals of 1800 hours which will include hours worked and in school training hours, each Apprentice's rate will be reviewed the Contractor and the Union, and the Apprentice will be given increases, if his ability warrants, on the following basis:

Apprentices		May 1, 2019	May 1, 2020	May 1, 2021
5400 or more hours	100%	$36.21	$36.21	$36.21
Level 3 Apprentice (3500 – 5399 hours)	85%	$30.78	$30.78	$30.78
Level 2 Apprentice (1800 – 3599 hours)	75%	$27.16	$27.16	$27.16
Level 1 Apprentice (0 – 1799 hours)	65%	$23.54	$23.54	$23.54

The Contractor will employ a minimum of one (1) Apprentice for every four (4) Journeymen where practical and available. The ratio of Apprentices to Journeymen may be adjusted higher by mutual agreement between the Contractor and the Union.

The Union will provide apprentices with log books. Following hiring, an apprentice will submit his log book to the Contractor and the Contractor will record therein, in the space allocated for such purposes, the type and extent of trade related training the apprentice has received while in the employ of the Contractor.

6. Trade Qualifications

Journeyman Rodman:

A Journeyman Rodman must be experienced in the fabricating, placing and tying of reinforcing steel including the placing of reinforcing steel in all types of reinforced concrete structures. He must have a thorough working knowledge of tools and equipment used in the trade as laid down in the CRSI Recommended Practice for Placing Reinforcing Bars, l959. Journeymen must be able to perform the following operations in a safe and workmanlike manner:

a) Sling, climb and signal the hoist operator;

b) Erect scaffolding or tie the necessary knots and sling scaffolds when necessary;

c) Place reinforcing steel in accordance with recognized ACI Standards under the direction of his supervisor;

d) Read and interpret bar lists, placing drawings, cutting sheets;

e) Operate bending and cutting machines under direction of his supervisor;

f) Work with a hickey;

g) Measure off work under direction of his supervisor.

All Employees:

All employees are required to furnish the following tools: Pliers, Wire Reel, Wire cutters, Tape measure/ruler, and appropriate rigging belt to carry tools. Such tools, when broken on the job, not through employee negligence, shall be replaced by the Contractor provided the broken tool is immediately provided to the Contractor at that time.

An employee may have deducted from his outstanding wages the cost of tools and equipment for which he signed yet failed to return to the Contractor.

7. Vacation Pay and Pay in Lieu of Holidays

Each employee shall receive an amount equal to ten and a half percent (10.5%) of his gross earnings of which four and a half percent (4.5%) shall be in lieu of paid Statutory Holidays. Each employee shall be entitled to four (4) weeks annual vacation to be taken at a time mutually agreed upon by the Contractor and the employee.

Vacation pay allowances shall be paid to employees on their regular pay day. Such payments shall be considered as advance payment for any vacation taken by the employee under the conditions provided in the Employment Standards Code for the Province of Manitoba.

8. Trust Funds

a) Health and Welfare

The Contractor shall contribute to the Ironworkers Central Welfare Trust Fund (Manitoba) the amounts set out below for each hour worked by each employee covered by this Appendix:

Effective	May 1, 2019	$1.86
Effective	May 1, 2020	$1.96

b) Pension

The Contractor shall contribute to the Ironworkers Central Pension Fund (Manitoba) the amounts set out below for each hour worked by each employee covered by this Appendix:

		May 1, 2019	May1, 2020	May 1, 2021
Journeyman		$6.00	$6.00	$6.00
Apprentice Level 3		$4.59	$4.59	$4.59
Apprentice Level 2		$4.05	$4.05	$4.05
Apprentice Level 1		$3.51	$3.51	$3.51

*As this reduction in contributions is effective May 1, 2019, we will not recover any overpayments to that date. The reduction will take place on a go forward date only.

Contributions to each of the above named funds shall be submitted by the Contractor by the 15th of the month following the month in which the hours were worked.

9. Trade Improvement and Apprenticeship Fund

The Contractor shall contribute the amount set out below to the Ironworkers Trade Improvement Fund (Manitoba). Contributions shall apply to all hours worked by all employees covered by this Appendix:

Effective	May 1, 2019	40 cents per hour
Effective	May 1, 2020	30 cents per hour

The Contractor shall forward such contributions by the 15th day of the month following the month in which the hours were worked.

10. Personal Effects Insurance

The Contractor will reimburse the employee for all reasonable losses associated with fire or theft (in the job trailer and/or the gang box) of the employee's working clothes and working equipment (i.e. belts, spool reels, tape measure, wire cutters, and cutting pliers) at the work site, provided appropriate receipts are provided.

The Contractor will reimburse the employee for all reasonable losses associated with fire of the employee's belongings and working equipment at the camp site, provided appropriate receipts are provided, to a one time employee maximum of $500.00. To qualify for the $500.00 coverage, the employee must submit a list of his personal effects, prior to becoming a resident of the camp, to the Contractor.

11. Travel Time

Where the distance between the marshalling point and the work site exceeds twenty (20) kilometres, any time spent travelling beyond the twenty (20) kilometre radius at the start and end of a shift shall be paid at the employee's straight time rate.

12. Isolation Leave (Return Transportation Time Periods)

The return transportation time period referred to in Article 19.2.1 for this Appendix shall be:

- After twenty-nine (29) calendar days.

Travel time shall only apply on the return portion of an Isolation Leave trip (i.e. from the employee's T.D.P. to the Project Camp Site).

The amount of travel time to be paid shall be in accordance with the provisions of Article 19.1.2.5.1 or 19.1.2.5.2, as the case may be, and if applicable, the provisions of Article 19.1.2.5.3.

Travel time shall be paid at the employee's straight time rate, and an employee shall receive such payment pursuant to the provisions of Article 19.1.2.6.

13. Escalation and Reference

13.1 Wage Rate Provisions

The wage rate for the classifications set out in this Appendix will be adjusted by an amount equal to and effective on the dates of any adjustments in wage rates for corresponding classifications which may be negotiated from time to time by the International Association of Bridge, Structural and Ornamental Ironworkers, Local Union No. 728 and the Ironworkers - Reinforcing Contractors Trade Division of the Construction Labour Relations Association of Manitoba.

Classifications eligible for adjustment may include general foreman, foreman, lead-hand, charge-hand, pusher, journeyman, apprentices, helpers and trainees.

13.1.1 Except as otherwise noted, the following provisions will be incorporated or adjusted to be consistent with corresponding provisions negotiated from time to time by the aforementioned Parties:

a) Definitions and qualificational requirements for applicable classifications;

b) Ratios indicating the number of apprentices, helpers, or other types of trainees who may be employed.

13.2 Other Conditions of Employment

Except as otherwise noted, the following conditions of employment will be incorporated or adjusted to be consistent with corresponding conditions of

employment negotiated from time to time by the aforementioned Parties:

a) Overtime payments (subject to the restrictions set out in Section 13.3;

b) Shift premium but excluding any shift premium applicable to overtime hours;

c) Vacation and Vacation Pay - such provisions may include any provisions relative to the timing of payment of vacation pay but shall not include any provisions stipulating when vacation time must be granted, and in lieu of such a provision the following shall be substituted: "the scheduling of time off for vacation shall be arranged by mutual agreement between the Contractor and the employee";

d) Pay in lieu of Holidays;

e) Registered and trusteed pension and health and welfare plans (subject to the restrictions set out in Section 13.2.1);

f) Callout provisions;

g) Rest provisions between shifts;

h) Personal effects insurance provisions;

i) Provisions governing welding and other special trade related tests;

j) Safety clothing;

k) Tool lists and provisions governing loss of such tools on the Project;

l) The jointly trusteed Trade Improvement and Apprenticeship Fund set out in Section 9 of this Appendix (subject to the restrictions set out in Section 13.2.2);

m) The time period between Isolation Leaves (subject to the restrictions of Article 19.2.1.3);

n) Travel time associated with the taking of an Isolation Leave, and the hourly rate at which travel time will be paid (subject to the restrictions set out in Section 13.2.3).

13.2.1 The Contractor's contribution to any pension and health and welfare plan may be applied on a per hour worked basis; however, the Contractor's contribution rate in respect of overtime hours shall not be greater than the

required contribution rate for Contractors in respect of straight time hours.

13.2.2 The Contractor's contribution to the plan referred to in Section 13.2 (l) may be applied on a per hour worked basis; however, the Contractor's contribution rate in respect of overtime hours shall not be greater than the required contribution rate for contractors in respect of straight time hours.

13.2.3 Travel time may only apply to the return portion of an Isolation Leave trip (i.e. from the employee's T.D.P. to the Project Camp Site). The amount of travel time to be paid shall not be greater than the travel time set out in Articles 19.1.2.5.1, 19.1.2.5.2 and 19.1.2.5.3, as may be applicable. The hourly rate at which travel time may be paid shall not be greater than the employee's straight time rate. Payment of travel time shall be in accordance with the provisions of Article 19.1.2.6.

13.3 Notwithstanding anything contained in this Agreement or in this Appendix, the regular hours of work are not subject to adjustment during the life of this Agreement, and such regular hours of work shall be paid at regular rates of wages. Further, overtime payments at a rate greater than time and one-half will not be introduced in this Appendix in respect of the first two (2) hours of overtime, Monday to Friday inclusive.

13.4 The provisions of 12.1 and 12.2 above shall be dealt with by following the procedure set out in Article 30 of this Agreement.

APPENDIX NO. 13 – Electrical Workers

THE INTERNATIONAL BROTHERHOOD OF ELECTRICAL WORKERS

Local Union 2085

BURNTWOOD/NELSON AGREEMENT

Wage Rates and Conditions for Electrician's Work

1. Hours of Work and Overtime

Eight (8) hours shall constitute a day's work for five (5) days Monday to Friday inclusive. Said hours shall normally be within the period from 7:00 a.m. until 6:00 p.m.

If more than the recognized daily hours are worked in any day or shift, Monday to Friday inclusive, such time shall be paid at the rate of time and one-half for the first two (2) hours and double time for all hours worked thereafter.

On Saturdays, except as provided in Article 15.2, Sundays and Holidays, as specified in Article 17, double time shall be paid.

2. Shift Conditions

If conditions are such that work on that particular job cannot be done within the said normal hours (7:00 a.m. to 6:00 p.m.) then eight (8) hours may be worked during any hours and may constitute a regular shift on that job.

Shift work shall be defined as scheduled work assignments lasting two (2) or more days, and in which the working hours of the shift are, in whole or in part, outside of the period from 7:00 a.m. to 6:00 p.m., Monday to Friday inclusive.

An employee shall receive 1.10 times his standard hourly rate for all hours worked at straight time. The shift differential shall not apply on overtime hours.

The starting and quitting time of all shift work shall be decided by the Contractor.

Overtime payment for shift work shall be in accordance with the provisions as set out above.

3. Wages, Definitions and Qualificational Requirements

3.1 Wages

Wage rates shall be as follows:

	May 1, 2016	May 1, 2017	May 1, 2018	May 1, 2019
Journeyperson	$40.90	$42.33	$43.81	$45.34
Apprentices				
1st Year	$16.36	$16.93	$17.52	$18.14
2nd Year	$20.45	$21.17	$21.91	$22.67
3rd Year	$26.59	$27.51	$28.48	$29.47
4th Year	$32.72	$33.86	$35.05	$36.27

3.2 Definitions and Qualificational Requirements

** See Letter of Agreement No. 66

Journeyman Electrician: An electrical worker who has four (4) or more years experience in the trade and has a current class H Journeyman Electrician's licence under the Province of Manitoba.

Registered Apprentices: Apprentices shall be registered in the Province of Manitoba and work and be paid in accordance with the Manitoba Apprenticeship and Tradesmen's Qualifications Act and this Agreement.

The number of apprentices who may be employed by a Contractor in this trade shall not exceed the following:

(i) A Contractor who is engaged in or carries on a business of electrical construction and who employs one (1) working Journeyman or is himself a working Journeyman, may employ one (1) Apprentice, and one (1) additional Apprentice for every two (2) additional working Journeymen employed. Notwithstanding the above, a 1:1 Journeyman to Apprentice ratio may be utilized if mutually agreed to between the Contractor and Local 2085. Requests for a 1:1 ratio shall not be unreasonably denied.

Foreman: When the Contractor appoints a foreman, he shall be a Journeyman Electrician and a Member of Local 2085. The Contractor shall have discretion to appoint Foremen to suit the particular circumstances of the job. However, for every ten (10) employees so employed, the Contractor shall appoint a Foreman. A Foreman shall receive between 105% to 120% of the Journeyman rate, in the discretion of the Contractor.

General Foreman: When the Contractor appoints a General Foreman, he shall be Journeyman Electrician and a member of Local 2085. The Contractor shall appoint a General Forman at a minimum crew size of 45, and shall receive between 120% and 135% of the Journeyman rate, in the discretion of the Contractor.

Cable Splicer: A Journeyman Electrician who has been qualified by training and admitted to the status of Journeyman Cable Splicer by the Union. Cable Splicers shall undertake work in connection with lead covered cables, and other high voltage cables 2300 volts and higher, involving preparation, splicing and termination.

Journeyman Electrician - Welder: When a Contractor requests an employee to perform welding, he shall be a member of the I.B.E.W., Local 2085 who has completed a recognized plate welders course recognized by the Union and received a certificate of proficiency.

If the Contractor requires any additional examining or testing, or special certificate, the employee's time required for testing and cost of the examination will be borne by the Contractor. Should an employee's special certificate expire while he is in the employ of the Contractor, the cost of the required retest and the time required to take same (up to a maximum of three (3) hours) shall be paid by the Contractor, provided the employee has worked for that Contractor for a minimum of thirty (30) days prior to the retesting. If the employee quits within thirty (30) days of the retesting he will be required to repay the total cost.

4. Vacation and Vacation Pay

Each employee shall be entitled to four (4) weeks annual vacation to be taken at a time mutually agreed upon by the Contractor and the employee.

Vacation pay allowance will be accumulated for the credit of each employee at the rate of six percent (6%) of gross earnings.

Vacation pay shall be paid every pay period or upon termination of employment, whichever is sooner.

5. Payment In Lieu of Holidays

Whether or not an employee works on any of the Holidays set out in Article 17, he shall receive in lieu of paid Holidays four and a half percent (4.5%) of his gross earnings. Gross earnings shall be exclusive of subsistence and transportation expenses. Such allowance shall be paid to an employee on his regular pay day or upon termination of employment, whichever is the sooner. If a Holiday falls on a Saturday or Sunday which is a non-working day, the closest following work day will be observed. However, this provision shall not apply to any employee who is on Christmas Leave, Isolation Leave or any other type of Leave of Absence when the Holiday occurs.

6. Trust Funds

6.1 Health and Welfare

The contractor and each employee covered by this Appendix shall respectively contribute the amounts set out below to the Local 2085 Health and Welfare Fund for all hours worked. Employee contributions shall be collected at the source as a payroll deduction.

The Employer and Employee contribution shall be:

	May 1, 2016	May 1, 2017	May 1, 2018	May 1, 2019
Employer	$1.00/hr	$1.00/hr	$1.00/hr	$1.00/hr
Employee	$0.65/hr	$0.65/hr	$0.65/hr	$0.65/hr

6.2 Pension Fund

The Contractor and each employee covered by this Appendix shall respectively contribute the amounts set out below to the Local 2085 Pension Fund for all hours worked. Employee contributions shall be collected at the source as a payroll deduction.

Employer and Journeyman Employee Contributions:

	May 1, 2016	May 1, 2017	May 1, 2018	May 1, 2019
Employer	$4.50/hr	$4.50/hr	$4.50/hr	$4.50/hr
Journeyman Employee	$1.00/hr	$1.25/hr	$1.50/hr	$1.75/hr

Effective May 1, 2007, and for the duration of this agreement, the Contractor and each **apprentice** shall respectively contribute the amounts set out below to the Local 2085 Pension Fund for all hours worked. Employee contributions shall be collected at the source as a payroll deduction:

	May 1, 2016	May 1, 2017	May 1, 2018	May 1, 2019
1st Year Apprentice				
Contractor	$1.80/hr	$1.80/hr	$1.80/hr	$1.80/hr
Employee	$0.40/hr	$0.50/hr	$0.60/hr	$0.70/hr
2nd Year Apprentice				
Contractor	$2.25/hr	$2.25/hr	$2.25/hr	$2.25/hr
Employee	$0.50/hr	$0.63/hr	$0.75/hr	$0.88/hr
3rd Year Apprentice				
Contractor	$2.93/hr	$2.93/hr	$2.93/hr	$2.93/hr
Employee	$0.65/hr	$0.82/hr	$0.98/hr	$1.14/hr
4th Year Apprentice				
Contractor	$3.60/hr	$3.60/hr	$3.60/hr	$3.60/hr
Employee	$0.80/hr	$1.00/hr	$1.20/hr	$1.40/hr

Group Registered Retirement Savings Plan

The employee shall contribute the amounts set out below to the Local 2085 Group Registered Retirement Savings Plan for all hours worked by Journeymen Electricians. Contributions shall be collected at the source as a payroll deduction.

$1.25 per hour

6.4 Industry Education Trust Fund

The Contractor shall contribute the amounts set out below to the Electrical Industry Education Trust Fund. Contributions shall apply to all hours worked by each employee covered by this Appendix:

25 cents per hour

7. Submission of Trust Funds

Payment and reporting forms shall be forwarded to the Administrator not later than the 10th of the month following the month for which contributions are being made.

8. Height Provision

Employees performing work at elevations of forty-five (45) feet (13.72 metres) or more above the immediate surroundings or when working over water on head gates, bridges and spillways, where there are no rigid platforms or scaffolds, shall be paid at the prevailing rate plus one-half times the regular rate. This shall include work performed in or above any openings of twenty-four (24) inches (60 cm) or larger at this height.

All rigid platforms, scaffolds and accesses shall meet Workplace Health and Safety Regulations. Any mobile lifts (except for scissor lifts with outriggers) shall not be considered rigid platform lifts.

Where height pay is required, there shall be a minimum of one (1) hour.

9. Callout

An employee who is called out to perform work after completing his regular shift shall be paid a minimum of two (2) hours at the prevailing overtime rate.

10. Rest Period

Employees must take a minimum rest period of eight (8) hours between shifts. Where employees are specifically requested to return to work before the expiration of eight (8) hours, all work performed shall be paid for at the applicable overtime rate, and such overtime rates shall continue for all work performed until a full eight (8) hour rest period has been observed.

11. Travel Time

Where the distance between the marshalling point and the work site exceeds sixteen (16) kilometres, any time spent travelling beyond the sixteen (16) kilometres shall be paid at the straight time rate.

12. Medical Payment

When an employee is required by the Contractor to take a medical examination he shall be reimbursed four (4) hours pay at the regular rate.

13. Personal Effects Insurance

When an employee is required to reside in a construction camp the cost for insurance against loss of his personal effects by fire, to a maximum of two thousand dollars ($2000.00) will be reimbursed on presentation of a paid premium receipt.

14. Safety Clothing

Protective clothing and safety equipment including safety hat, safety toe rubber boots, welding jackets and gloves, safety goggles, masks etc. are to be supplied at no cost to the employee.

If the Contractor requires the employees to work in the rain, wet weather clothing will be supplied at no cost to the employee.

In areas where acids, chemicals, excessive grease or dust prevail, protective clothing shall be supplied at no cost to the employee.

The employee must accept reasonable responsibility for safety equipment issued by the Contractor and must report the loss, or damage of any of the items so issued to the Contractor.

15. Safety Provisions

All work on energized circuits shall be as per the Workplace Safety and Health Act.

16. Tools

The following tools shall be supplied by the employee:

1 Hammer	1 Tool Box
1 9-inch Level	1 Hack Saw Frame
3 Blade screw Drivers	1 (8 inch) Diagonal Cutters
1 Centre Punch	3 Robertson Screw Drivers
1 10-inch water pump pliers	1 Tool Pouch
1 8-inch Linesman Type Pliers	1 Knife
1 Needle Nose Pliers	

1 (1 inch by 16) foot metric/standard Steel Tape

* 1 Current Code Book	* 1 set wrenches Combination 1/4" – 3/4 “
* 1 Voltage Tester - 110-550 Volts	* 1 nut driver set
* 1 Set Allen Wrenches - up to 1/2-inch size	* 1 Chalk Line
* 1 Stubby Screw Driver set	* 1 drywall saw
* 1 flashlight ‘AA’ (batteries supplied by Contractor)	
* 1 small wire strippers	* 1 12” combination square
* 1 Philips Screwdriver	* 1 Tap Wrench Handle
* 1 Tin Snips	

*Except first year Apprentices.

17. Loss of Tools

An Electrician's tools are his means of livelihood and the workers shall keep same in good condition at all times. Any of the tools listed under the heading "Tools" that are lost by theft resulting from breaking or entering or destroyed by fire will be replaced by the Contractor provided the tools are stored in a properly secured place designated by the Contractor.

The employee must accept reasonable responsibility for the tools furnished by the Contractor and will be given sufficient time to put these tools in their designated place. He must report the breakage or loss of any of these tools immediately to his supervisor. An employee found misusing company tools may be held responsible.

18. Isolation Leave (Return Transportation Time Periods)

The return transportation time period referred to in Article 19.2.1 for this Appendix shall be:

- after thirty-five (35) calendar days.

Travel time shall only apply on the return portion of an Isolation Leave trip (i.e. from the employee's T.D.P. to the Project Camp Site).

The amount of travel time to be paid shall be in accordance with the provisions of Article 19.1.2.5.1 or 19.1.2.5.2, as the case may be, and if applicable, the provisions of Article 19.1.2.5.3.

Travel time shall be paid at the employee's straight time rate, and an employee shall receive such payment pursuant to the provisions of Article 19.1.2.6.

19. Escalation and Reference

19.1 Wage Rate Provisions

The wage rate for the classifications set out in this Appendix will be adjusted by an amount equal to and effective on the dates of any adjustments in wage rates for corresponding classifications which may be negotiated from time to time by the International Brotherhood of Electrical Workers, Local Union 2085 and the Electrical Contractors Trade Division of the Construction Labour Relations Association of Manitoba.

Classifications eligible for adjustment may include general foreman, foreman, leadhand, chargehand, pusher, journeyman, apprentices, helpers and trainees.

19.1.1 Except as otherwise noted, the following provisions will be incorporated or adjusted to be consistent with corresponding provisions negotiated from time to time by the aforementioned Parties:

(a) definitions and qualificational requirements for applicable classifications.

(b) ratios indicating the number of apprentices, helpers, or other types of trainees who may be employed.

(c) ratios stipulating when a foreman, leadhand, chargehand, or pusher is to be appointed; however, if such a ratio is less than ten (10) to one (1) (i.e., the number of persons being supervised relative to the supervisor) when incorporating this provision in this Appendix, the ratio shall be ten (10) to one (1).

(d) height pay including that associated with swing stage work.

19.1.2 The appointment of General Foreman shall be at the sole discretion of the Contractor.

19.2 Other Conditions of Employment

Except as otherwise noted, the following conditions of employment will be incorporated or adjusted to be consistent with corresponding conditions of employment negotiated from time to time by the aforementioned Parties:

(a) overtime payments (subject to the restrictions set out in Section 19.3)

(b) shift premium but excluding any shift premium applicable to overtime hours.

(c) Vacation and Vacation Pay - such provisions may include any provisions relative to the timing of payment of vacation pay but shall not include any provisions stipulating when vacation time must be granted, and in lieu of such a provision the following shall be substituted: 'the scheduling of time off for vacation shall be arranged by mutual agreement between the Contractor and the employee'.

(d) pay in lieu of Holidays and any provisions requiring the transferring and observing of the Holiday on a day, other than the day on which the Holiday falls (subject to the restrictions set out in Section 19.2.1).

(e) registered and trusteed pension and health and welfare plans (subject to the restrictions set out in Section 19.2.2).

(f) callout provisions.

(g) rest provisions between shifts

(h) personal effects insurance provisions

(i) provisions governing welding and other special trade related tests

(j) safety clothing

(k) tool lists and provisions governing loss of such tools on the Project.

(l) the following trusteed plans, each of which shall be subject to the restrictions set out in Section 19.2.3:

(i) building fund

(ii) trade improvement plans including educational and apprenticeship funds

(iii) industrial promotion funds.

(m) the time period between Isolation Leaves (subject to the restrictions of Article 19.2.1.3).

(n) travel time associated with the taking of an Isolation Leave, and the hourly rate at which travel time will be paid (subject to the restrictions set out in Section 19.2.4).

19.2.1 A Holiday set out in Article 17 may be observed on a day, other than the day on which it falls, provided the Holiday falls on a Saturday or Sunday which is a non-working day, in which case the Holiday may be observed on the closest following working day. The transferring of a Holiday shall not apply to any employee who is on Christmas Leave, Isolation Leave or any other type of Leave of Absence when the Holiday occurs.

19.2.2 The Contractor's contribution to any pension and health and welfare plan may be applied on a per hour worked basis; however, the Contractor's contribution rate in respect of overtime hours shall not be greater than the required contribution rate for Contractors in respect of straight time hours.

19.2.3 The Contractor's contribution to any of the plans referred to in Section 19.2 (l) may be applied on a per hour worked basis; however, the Contractor's contribution rate in respect of overtime hours shall not be greater than the required contribution rate for contractors in respect of straight time hours.

19.2.4 Travel time may only apply to the return portion of an Isolation Leave trip (i.e. from the employee's T.D.P. to the Project Camp Site). The amount of travel time to be paid shall not be greater than the travel time set out in Articles 19.1.2.5.1, 19.1.2.5.2 and 19.1.2.5.3, as may be applicable. The hourly rate at which travel time may be paid shall not be greater than the employee's straight time rate. Payment of travel time shall be in accordance with the provisions of Article 19.1.2.6.

19.3 Notwithstanding anything contained in this Agreement or in this Appendix, the regular hours of work are not subject to adjustment during the life of this Agreement, and such regular hours of work shall be paid at regular rates of wages. Further, overtime payments at a rate greater than time and one-half will not be introduced in this Appendix in respect of the first two (2) hours of overtime, Monday to Friday inclusive.

19.4 The provisions of 19.1 and 19.2 above shall be dealt with by following the procedure set out in Article 30 of this Agreement.

19.2.3 The Contractor's contribution to any of the plans referred to in Section 19.2 (l) may be applied on a per hour worked basis; however, the Contractor's contribution rate in respect of overtime hours shall not be greater than the required contribution rate for contractors in respect of straight time hours.

19.2.4 Travel time may only apply to the return portion of an Isolation Leave trip (i.e. from the employee's T.D.P. to the Project Camp Site). The amount of travel time to be paid shall not be greater than the travel time set out in Articles 19.1.2.5.1, 19.1.2.5.2 and 19.1.2.5.3, as may be applicable. The hourly rate at which travel time may be paid shall not be greater than the employee's straight time rate. Payment of travel time shall be in accordance with the provisions of Article 19.1.2.6.

19.4 Notwithstanding anything contained in this Agreement or in this Appendix, the regular hours of work are not subject to adjustment during the life of this Agreement, and such regular hours of work shall be paid at regular rates of wages. Further, overtime payments at a rate greater than time and one-half will not be introduced in this Appendix in respect of the first two (2) hours of overtime, Monday to Friday inclusive.

19.5 The provisions of 19.1 and 19.2 above shall be dealt with by following the procedure set out in Article 30 of this Agreement.

Wage Rates and Conditions for Lineman's Work

At the request of either the Association or the Council, the Joint Appendix Review Committee will meet to establish wage rates and other conditions of employment for Linemen's work. If agreement cannot be reached, the procedure set out in Article 31 shall be followed

APPENDIX NO. 13a - IBEW

THE INTERNATIONAL BROTHERHOOD OF ELECTRICAL WORKERS

JOURNEYPERSON LINEMAN/CABLE SPLICER AND ASSOCIATED COLLECTOR LINE TRADES

Local Union 2085

BURNTWOOD/NELSON AGREEMENT

*** Note – See Letter of Agreement #29, for additional information regarding Appendix 13A

General Scope and Recognition

1. This Appendix shall only apply to Contracted on-site construction work associated with the installation of collector lines as defined under Article 2.1 of the Agreement

Wage Rates and Conditions for Electrician's Work

2. Hours of Work and Overtime

Eight (8) hours shall constitute a day's work for five (5) days Monday to Friday inclusive. Said hours shall normally be within the period from 7:00 a.m. until 6:00 p.m.

If more than the recognized daily hours are worked in any day or shift, Monday to Friday inclusive, such time shall be paid at the rate of time and one-half for the first two (2) hours and double time for all hours worked thereafter.

On Saturdays, except as provided in Article 15.2, Sundays and Holidays, as specified in Article 17, double time shall be paid.

3. Shift Conditions

If conditions are such that work on that particular job cannot be done within the said normal hours (7:00 a.m. to 6:00 p.m.) then eight (8) hours may be worked during any hours and may constitute a regular shift on that job.

Shift work shall be defined as scheduled work assignments lasting two (2) or more days, and in which the working hours of the shift are, in whole or in part, outside of the period from 7:00 a.m. to 6:00 p.m., Monday to Friday inclusive.

An employee shall receive 1.10 times his standard hourly rate for all hours worked at straight time. The shift differential shall not apply on overtime hours.

The starting and quitting time of all shift work shall be decided by the Contractor.

Overtime payment for shift work shall be in accordance with the provisions as set out above.

4. Wages, Definitions and Qualification Requirements

4.1 Wages

Classification	May 1, 2016	May 1, 2017	May 1, 2018	May 1, 2019
Journeyperson Lineman	42.32	43.62	44.98	46.36
Journeyperson Cablesplicer	42.32	43.62	44.98	46.36
Apprentice				
4th year – 80%	$ 33.86	$ 34.90	$ 35.98	$ 37.09
3rd year – 65%	$ 27.51	$ 28.35	$ 29.24	$ 30.13
2nd year – 50%	$ 21.16	$ 21.81	$ 22.49	$ 23.18
1st year – 40%	$ 16.93	$ 17.45	$ 17.99	$ 18.54
Goundman I	$ 27.69	$ 28.54	$ 29.42	$ 30.33
Groundman II	$24.09	$ 24.49	$ 25.24	$ 26.02
Utilityman	$ 22.36	$ 23.05	$ 23.76	$ 24.02

4.2 Definitions and Qualification Requirements

a) Journeyman Lineman

A person who has worked for (3) or more years at line work, and who is capable of undertaking any work required to construct transmission lines on poles, towers and structures.

b) Apprentice Lineman

A person who is training to become a Journeyman Lineman through a recognized training program and is governed by the Trades Qualification and Apprenticeship Act or any successor legislation. An apprentice shall be permitted to use all tools and be under the strict supervision of a Journeyman Lineman.

c) Groundman I

A person who is experienced in assisting the Lineman by performing all aspects of transmission line work which can be done from the ground including but not limited to tower assembly and erection, requisitioning, handling and transporting of materials, the setting of poles and anchors, the stringing of cables, etc.

d) Groundman II

A person who is learning the Groundman duties or who is employed on the assembly of components for erection by others and whose job experience does not encompass all of the training required of a Groundman I.

e) Utilityman

A worker without specific lineman or groundman skills who may assist linemen or groundmen, and who may perform other unskilled work as assigned.

f) Journeyman Cable Splicer

A Journeyman Powerline Technician or Journeyman Electrician who through experience and training and is in receipt of an IHSA approved certificate, or equivalent, is a specialist in all facets of splicing high voltage cable

g) Foreman

When the Contractor appoints a foreman, he shall be a Journeyman Electrician and a Member of Local 2085. The Contractor shall have discretion to appoint Foremen to suit the particular circumstances of the job. However, for every ten (10) employees so employed, the Contractor shall appoint a Foreman. A Foreman shall receive between 105% to 120% of the Journeyman rate, in the discretion of the Contractor.

h) General Foreman

When the Contractor appoints a General Foreman, he shall be Journeyman Electrician and a member of Local 2085. The Contractor shall appoint a General Forman at a minimum crew size of 45, and shall receive between 120% and 135% of the Journeyman rate, in the discretion of the Contractor.

5. Vacation and Vacation Pay

Each employee shall be entitled to four (4) weeks annual vacation to be taken at a time mutually agreed upon by the Contractor and the employee.

Vacation pay allowance will be accumulated for the credit of each employee at the rate of six percent (6%) of gross earnings.

Vacation pay shall be paid every pay period or upon termination of employment, whichever is sooner.

6. Payment In Lieu of Holidays

Whether or not an employee works on any of the Holidays set out in Article 17, he shall receive in lieu of paid Holidays four and a half percent (4.5%) of his gross earnings. Gross earnings shall be exclusive of subsistence and transportation expenses. Such allowance shall be paid to an employee on his regular pay day or upon termination of employment, whichever is the sooner.

If a Holiday falls on a Saturday or Sunday which is a non-working day, the closest following work day will be observed. However, this provision shall not apply to any employee who is on Christmas Leave, Isolation Leave or any other type of Leave of Absence when the Holiday occurs.

7. Trust Funds

7.1 Health and Welfare

The contractor and each employee covered by this Appendix shall respectively contribute the amounts set out below to the Local 2085 Health and Welfare Fund for all hours worked. Employee contributions shall be collected at the source as a payroll deduction.

Employer and Employee Contributions:

	May 1, 2016	May 1	2016	May 1
Employer	$1.00/hr	$1.00/hr	$1.00/hr	$1.00/hr
Employee	$0.65/hr	$0.65/hr	$0.65/hr	$0.65/hr

7.2 Pension Fund

The Contractor and each employee covered by this Appendix shall respectively contribute the amounts set out below to the Local 2085 Pension Fund for all hours worked. Employee contributions shall be collected at the source as a payroll deduction.

Employer and Employee Contributions:

JOURNEYPERSONS				
	May 1, 2016	May 1, 2017	May 1, 2018	May 1, 2019
Employer	$4.50/hr	$4.50/hr	$4.50/hr	$4.50/hr
Employee	$1.00/hr	$1.25/hr	$1.50/hr	$1.75/hr

APPRENTICES				
	May 1, 2016	May 1, 2017	May 1, 2018	May 1, 2019
1st Year Apprentice				
Contractor	$1.80/hr	$1.80/hr	$1.80/hr	$1.80/hr
Employee	$0.40/hr	$0.50/hr	$0.60/hr	$0.70/hr
2nd Year Apprentice				
Contractor	$2.25/hr	$2.25/hr	$2.25/hr	$2.25/hr
Employee	$0.50/hr	$0.630/hr	$0.75/hr	$0.88/hr
3rdYear Apprentice				
Contractor	$2.93/hr	$2.93/hr	$2.93/hr	$2.93/hr
Employee	$0.65/hr	$0.82/hr	$0.98/hr	$1.14/hr
4th Year Apprentice				
Contractor	$3.60/hr	$3.60/hr	$3.60/hr	$3.60/hr
Employee	$0.80/hr	$1.00/hr	$1.20/hr	$1.40/hr

7.3 Group Registered Retirement Savings Plan

The employee may contribute the amounts set out below to the Local 2085 Group Registered Retirement Savings Plan for all hours worked by Journeymen Electricians. Contributions shall be collected at the source as a payroll deduction.

$1.25 per hour

8. Submission of Trust Funds

Payment and reporting forms shall be forwarded to the Administrator not later than the 10th of the month following the month for which contributions are being made.

9. Callout

An employee who is called out to perform work after completing his regular shift shall be paid a minimum of two (2) hours at the prevailing overtime rate.

10. Rest Period

Employees must take a minimum rest period of eight (8) hours between shifts. Where employees are specifically requested to return to work before the expiration of eight (8) hours, all work performed shall be paid for at the applicable overtime rate, and such overtime rates shall continue for all work performed until a full eight (8) hour rest period has been observed.

11. Travel Time

Where the distance between the marshalling point and the work site exceeds sixteen (16) kilometres, any time spent travelling beyond the sixteen (16) kilometres shall be paid at the straight time rate.

12. Medical Payment

When an employee is required by the Contractor to take a medical examination he shall be reimbursed four (4) hours pay at the regular rate.

13. Personal Effects Insurance

When an employee is required to reside in a construction camp the cost for insurance against loss of his personal effects by fire, to a maximum of two thousand dollars ($2000.00) will be reimbursed on presentation of a paid premium receipt.

14. Safety Clothing

Protective clothing and safety equipment including safety hat, safety toe rubber boots, welding jackets and gloves, safety goggles, masks etc. are to be supplied at no cost to the employee.

If the Contractor requires the employees to work in the rain, wet weather clothing will be supplied at no cost to the employee.

In areas where acids, chemicals, excessive grease or dust prevail, protective clothing shall be supplied at no cost to the employee.

The employee must accept reasonable responsibility for safety equipment issued by the Contractor and must report the loss, or damage of any of the items so issued to the Contractor.

15. Safety Provisions

All work on energized circuits shall be as per the Workplace Safety and Health Act.

16. Tools

The following tools shall be supplied by the employee:

The following tools will be supplied by Linemen, Cable Splicer's, and Apprentices:

1 – set of belt and spurs, and a fall restricting system for pole climbing in accordance with E&USA and/or CSA Standards.
1 – harness with D in centre of back in accordance with E&USA and/or CSA Standards.
1 – skinning knife
1 – 10" adjustable wrench
1 – 12" adjustable wrench
1 – large screwdriver, 8" shank, 5" handle
1 – pair 9" offset cutting pliers
1 – ball peen hammer
1 – 6' folding wooden ruler or a non-conducting equivalent
1 – nut & bolt bag
1 – ratchet handle with sockets (sizes as required)
1* – pair of lineman gloves

These additional tools will be supplied by Splicers:

6 screwdrivers, Robertson and standard Types
1 – pair 8" diagonal pliers
1 – pair 8" long nose pliers
1 – tool box
1 – adjustable hacksaw frame
1* - set of cable preparation knives

* - the Contractor shall replace knives and gloves when they are worn out.

17. Loss of Tools

An Electrician's tools are his means of livelihood and the workers shall keep same in good condition at all times. Any of the tools listed under the heading "Tools" that are lost by theft resulting from breaking or entering or destroyed by fire will be replaced by the Contractor provided the tools are stored in a properly secured place designated by the Contractor.

The employee must accept reasonable responsibility for the tools furnished by the Contractor and will be given sufficient time to put these tools in their designated place. He must report the breakage or loss of any of these tools immediately to his supervisor. An employee found misusing company tools may be held responsible.

18. Isolation Leave (Return Transportation Time Periods)

The return transportation time period referred to in Article 19.2.1 for this Appendix shall be:

- after thirty-five (35) calendar days.

Travel time shall only apply on the return portion of an Isolation Leave trip (i.e. from the employee's T.D.P. to the Project Camp Site).

The amount of travel time to be paid shall be in accordance with the provisions of Article 19.1.2.5.1 or 19.1.2.5.2, as the case may be, and if applicable, the provisions of Article 19.1.2.5.3.

Travel time shall be paid at the employee's straight time rate, and an employee shall receive such payment pursuant to the provisions of Article 19.1.2.6.

19. Escalation and Reference

19.1 Wage Rate Provisions

19.1.1 Reference Classifications and Weighting

The Reference Classifications and the weighting of the classification shall be as follows:

Reference Classification	Factor
Appendix 13 The International Brotherhood of Electrical Workers - Local Union 2085	100%

19.1.2 Method of Calculating the Percentage Adjustment of Reference Classification

The weighted percentage adjustment of each Reference Classification shall be determined in accordance with the following formula:

$$\frac{\text{(Change in W) + (Change in P) + (Change in H\&W)}}{\text{(Expired W) + (Expired P) + (Expired H\&W)}} \times 100 \times \text{Weighting Factor}$$

Where:

- Change means the increase or decrease in that benefit.
- W means wage rate
- P and H&W means the required employers' contribution rate to the pension and/or the health and welfare plan.
- Expired means the rate in effect when the last weighted percentage adjustment was calculated.
- Weighting factor means the factor assigned to a particular Reference Classification as set out in 19.1.1.

19.1.3 In calculating the weighted percentage adjustment of a Reference classification, the arithmetic result shall be rounded to the nearest hundredth of a percent.

Classifications eligible for adjustment may include general foreman, foreman, leadhand, chargehand, journeypersons, apprentices, groundman and utility workers.

19.1.4 Except as otherwise noted, the following provisions will be incorporated or adjusted to be consistent with corresponding provisions negotiated from time to time by the aforementioned Parties:

(a) definitions and qualification requirements for applicable classifications.

(b) ratios indicating the number of apprentices, helpers, or other types of trainees who may be employed.

(c) ratios stipulating when a foreman, leadhand, chargehand, or pusher is to be appointed; however, if such a ratio is less than ten (10) to one (1) (i.e., the number of persons being supervised relative to the supervisor) when incorporating this provision in this Appendix, the ratio shall be ten (10) to one (1).

(d) height pay including that associated with swing stage work.

19.1.5 The appointment of General Foreman shall be at the sole discretion of the Contractor.

19.2 Health and Welfare and Pension

19.2.1 Subject to the conditions set out below, Health and Welfare and Pension contributions shall be adjusted to be consistent with contributions required in respect of Members of Local 2085 covered by this Appendix and participating in the Local 2085 Health and Welfare Plan and Pension Plan(s).

19.2.2 The Contractor's contribution to the Health and Welfare and Pension Plans may be applied on a per hour worked basis; however, the contractor's contributions rate in respect of overtime hours shall not be greater than the required contribution rate for contractors in respect of straight time hours.

19.2.3 Pursuant to 19.2.1, when the negotiated effective date of any adjustment to the Contractor's contribution rate to the Health and Welfare and/or Pension Plans does not occur on the effective date of an adjustment to wage rates in this Appendix, at the option of the Local 2085, the implementation of such an adjustment may be delayed so that it coincides with the effective date of the next subsequent adjustment to wage rates. Notification, in writing, specifying that Local 2085 are electing to exercise this option shall be provided by the Council

Appendix Review Committee to the Association Appendix Review Committee in accordance with the provisions of Section 19.2.5.

19.2.4 Any adjustment to the Contractor's contribution rate to the Health and Welfare and/or Pension Plans will be dealt with as follows:

19.2.4.1 When the effective date of the adjustment to the Plan coincides with an adjustment date for wage rates in this Appendix, the resultant hourly rates (i.e., the hourly rates resulting from the application of the weighted percentage adjustment factor) will be reduced by the amount of the increase (or increased by the amount of any decrease) in the Contractor's contribution rate to the Plan.

19.2.4.2 When the effective date of the adjustment to the Plan does not coincide with an adjustment date for wage rates in this Appendix, the hourly wage rates in this Appendix will be reduced by the amount of the increase (or increased by the amount of any decrease) in the Contractor's contribution rate to the Plan.

19.2.5 Notification, in writing, of any adjustment to the Health and Welfare and/or Pension Plans shall be provided by the Council Appendix Review Committee to the Association Appendix Review Committee at least twenty (20) calendar days in advance of the proposed implementation date of such adjustment. If such notification is not provided, the effective date of the adjustment shall be deemed to be twenty (20) calendar days from the date of receipt of the notification.

19.3 Other Conditions of Employment

Except as otherwise noted, the following conditions of employment will be incorporated or adjusted to be consistent with corresponding conditions of employment negotiated from time to time by the aforementioned Parties:

(a) overtime payments (subject to the restrictions set out in Section 19.3)

(b) shift premium but excluding any shift premium applicable to overtime hours.

(c) Vacation and Vacation Pay - such provisions may include any provisions relative to the timing of payment of vacation pay but shall not include any provisions stipulating when vacation time must be granted, and in lieu of such a provision the following shall be substituted: 'the scheduling of time off for vacation shall be arranged by mutual agreement between the Contractor and the employee'.

(d) pay in lieu of Holidays and any provisions requiring the transferring and observing of the Holiday on a day, other than the day on which the Holiday falls (subject to the restrictions set out in Section 19.3.1).

(e) registered and trusteed pension and health and welfare plans (subject to the restrictions set out in Section 19.3.2).

(f) callout provisions.

(g) rest provisions between shifts

(h) personal effects insurance provisions

(i) provisions governing welding and other special trade related tests

(j) safety clothing

(k) tool lists and provisions governing loss of such tools on the Project.

(l) the following trusteed plans, each of which shall be subject to the restrictions set out in Section 19.3.3:

(i) building fund

(ii) trade improvement plans including educational and apprenticeship funds

(iii) industrial promotion funds.

(m) the time period between Isolation Leaves (subject to the restrictions of Article 19.3.1.3).

(n) travel time associated with the taking of an Isolation Leave, and the hourly rate at which travel time will be paid (subject to the restrictions set out in Section 19.3.4).

19.3.1 A Holiday set out in Article 17 may be observed on a day, other than the day on which it falls, provided the Holiday falls on a Saturday or Sunday which is a non-working day, in which case the Holiday may be observed on the closest following working day. The transferring of a Holiday shall not apply to any employee who is on Christmas Leave, Isolation Leave or any other type of Leave of Absence when the Holiday occurs.

19.3.2 The Contractor's contribution to any pension and health and welfare plan may be applied on a per hour worked basis; however, the Contractor's contribution rate in respect of overtime hours shall not be greater than the required contribution rate for Contractors in respect of straight time hours.

19.3.3 The Contractor's contribution to any of the plans referred to in Section 19.3 (l) may be applied on a per hour worked basis; however, the Contractor's contribution rate in respect of overtime hours shall not be greater than the required contribution rate for contractors in respect of straight time hours.

19.3.4 Travel time may only apply to the return portion of an Isolation Leave trip (i.e. from the employee's T.D.P. to the Project Camp Site). The amount of travel time to be paid shall not be greater than the travel time set out in Articles 19.1.2.5.1, 19.1.2.5.2 and 19.1.2.5.3, as may be applicable. The hourly rate at which travel time may be paid shall not be greater than the employee's straight time rate. Payment of travel time shall be in accordance with the provisions of Article 19.1.2.6.

19.3 Notwithstanding anything contained in this Agreement or in this Appendix, the regular hours of work are not subject to adjustment during the life of this Agreement, and such regular hours of work shall be paid at regular rates of wages. Further, overtime payments at a rate greater than time and one-half will not be introduced in this Appendix in respect of the first two (2) hours of overtime, Monday to Friday inclusive.

19.4 The provisions of 19.1, 19.2, and 19.3 above shall be dealt with by following the procedure set out in Article 30 of this Agreement.

APPENDIX NO. 14 – Plumbers and Pipefitters

UNITED ASSOCIATION OF JOURNEYMEN AND APPRENTICE OF THE PLUMBING AND PIPE FITTING INDUSTRY OF THE UNITED STATES AND CANADA

Local Union 254

BURNTWOOD/NELSON AGREEMENT

Revised Aug 8, 2018

1. Hours of Work and Overtime

Eight (8) hours shall constitute a day's work for five (5) days Monday to Friday inclusive. Said hours shall normally be within the period from 7:00 a.m. to 6:00 p.m.

If more than the recognized daily hours are worked in any day or shift on Monday to Friday inclusive, such time shall be paid at the rate of time and one-half for the first two (2) hours and double time for hours worked thereafter.

On Saturdays, except as provided in Article 15.2, the first eight (8) hours will be paid at the rate of one and one-half (1½) times the applicable base rate, and double (2x) the applicable base rate thereafter.

Sundays and Holidays as set out in Article 17, double time shall be paid.

2. Shift Conditions

If conditions are such that work on that particular job cannot be done within the said normal hours (7:00 a.m. to 6:00 p.m.) then eight (8) hours may be worked during any hours and may constitute a regular shift on that job.

A shift premium of ten percent (10%) of the regular straight time rate will be paid for each shift hour worked at the straight time rate. The shift premium shall not apply on overtime hours.

The starting and quitting time of all shift work shall be decided by the Contractor.

Shifts shall be scheduled to continue for at least two (2) consecutive working days.

Overtime payment for shift work shall be in accordance with the provisions as set out above.

3. Wages

Wage rates shall be as follows:

a) Journeyman

	June 2, 2018	May 1, 2019	May 1, 2020
Journeyman	$40.84	$41.35	41.86

b) Apprentices

The scale of wages for apprentices shall be:

	June 2, 2018	May 1, 2019	May 1, 2020
Apprentice			
5th Year 93.5%	$38.19	$38.66	$39.14
4th Year 80%	$32.67	$33.08	$33.49
3rd Year 70%	$28.59	$28.95	$29.30
2nd Year 60%	$24.50	$24.81	$25.12
1st Year 50%	$20.42	$20.68	$20.93

Apprentices shall take the prescribed courses of the Piping Industry Training Committee of Manitoba. If an Apprentice fails to successfully complete each course, he shall not qualify for advancement and shall remain at the same rate of pay until he has successfully completed that course.

The ratio of Apprentices to Journeymen shall be in accordance with the Apprenticeship and Trades Qualifications Act.

c) Foreman and General Foreman

When the Contractor appoints a Foreman, he shall be paid a minimum of ten percent (10%) above the Journeyman's rate.

The first Foreman will be responsible for up to a maximum of fifteen (15) Journeymen; subsequent Foremen will be responsible for up to a maximum of thirteen (13) Journeymen.

When the Contractor appoints a General Foreman he shall be a journeyman member of Local Union 254 and will not be required to work with the tools of the trade.

The minimum rate of wages for General Foremen shall be fifteen percent (15%) above the Journeyman's rate when in charge of less than sixty (60) Journeymen and twenty five percent (25%) when in charge of sixty (60) or more Journeymen.

4. Vacation and Vacation Pay

Each employee after completing two tours of duty shall be entitled to three (3) weeks annual vacation to be taken at a time mutually agreed upon by the Contractor and the employee.

Vacation pay shall be six percent (6%) of total base rate earnings.

Vacation pay allowance will be paid to employees on their regular pay day. Such payments shall be considered as advance payment for any vacation taken by the employee under the conditions provided in the Employment Standards Code for the Province of Manitoba.

5. Payment in Lieu of Holidays

Whether or not an employee works on any of the Holidays set out in Article 17, he shall receive in lieu of paid Holidays, four percent and a half (4.5%) of his total base rate plus vacation pay earnings. Such allowance shall be paid to employees on their regular pay day.

If a Holiday falls on a Saturday which is a non working day, or Sunday, the closest following work day(s) which is not a paid Holiday will be observed. However, this provision shall not apply to any employee who is on Christmas Leave, Isolation Leave or any other type of Leave of Absence when the Holiday occurs.

6. Trust Funds

6.1 Health and Welfare

The Contractor and each employee covered by this Appendix shall contribute the amounts set out below to the Local 254 Health & Welfare Fund. The employee's contribution shall be collected at the source as a payroll deduction. Contributions shall apply to all hours earned.

Contractor's Contribution - effective May 1, 2016 -	91¢ per hour
Employee's Contribution - effective May 1, 2016 -	$1.03 per hour

6.2 Pension Fund

The Contractor and each employee covered by this Appendix shall contribute the amounts set out below to the Local 254 Pension Fund. The employee's contribution shall be collected at the source as a payroll deduction. Contributions shall apply to all hours earned.

Effective June 2, 2018		
	Contractor's Contributions	Employee's Contribution
Journeyman	$6.61	nil
Apprentice		
5th Year 93.5%	$6.18	nil
4th Year 80%	$5.29	nil
3rd Year 70%	$4.63	nil
2nd Year 60%	$3.97	nil
1st Year 50%	$3.31	nil

6.3 Training Fund

The Contractor and each employee covered by this Appendix shall contribute the amounts set out below to the Local 254 Training Fund. Employee contributions shall be collected at the source as a payroll deduction. Contributions shall apply to all hours worked.

Contractor's Contribution – effective May 1, 2016 - 51¢ per hour
Employee's Contribution – effective May 1, 2016 - 17¢ per hour

6.4 Industrial Promotion Fund

The Contractor shall contribute the amount set out below to the Industrial Promotion Fund. Contributions shall apply to all hours worked by all employees covered by this Appendix.

44¢ per hour.

6.5 Payment of all Trust Fund Contributions

Contributions to all trust funds shall be submitted monthly and will be accompanied by completed reporting forms supplied by the Administrator of the Local 254 Piping Industry Trusts Fund on or before the 10th day of the month following the month for which such contributions are payable. Such forms shall list employees and hourly contributions for each employee. A copy of the above mentioned form is to be retained by the Contractor and the remaining copies to be forwarded with one (1) cheque made payable to "The Piping Industry Trusts Fund" covering all contributions, to the Administrator of the Local 254 Piping Industry Trusts Fund.

7. Callouts

An employee who is called out to perform work after completing his regular shift, shall be paid for such work at double time, but in no case shall an employee be paid less than two (2) hours at double time.

8. Rest Period

If an employee is requested to work after the completion of his regular shift and is not provided with at least an eight (8) hour rest period between shifts, the employee shall be paid double time rates until such time as an eight (8) hour break occurs.

9. Welding Tests

A Journeyman Welder required for certified welding shall report to the job site equipped with an unexpired certificate of qualification valid under the Provincial Regulations for a minimum of forty-five (45) calendar days from the date of hire.

If the Contractor requires any additional examining or testing, or if an existing employee is requested by the Contractor to re-test for a special certificate, the employee's time required for testing and cost of the examination or test will be borne by the Contractor.

Should an employee's certificate expire while he is in the employ of a Contractor, the cost of the required annual re-test and the time required to take same (up to a maximum of three (3) hours) shall be paid by the Contractor, provided the employee has worked for that Contractor for a minimum of forty-five (45) calendar days immediately prior to the expiry date of the certificate. If the employee resigns within forty-five (45) days of the re-test, the employee will be required to repay the total cost.

When a Welder has been trained for a special certificate, and tested at the Contractor's expense, and the Welder quits within forty-five (45) days of the tests, then the cost of testing time paid by the Contractor will be deducted from monies due the employee. The costs of all testing materials and equipment shall be borne by the Contractor.

Welders who perform special tests, shall be paid a minimum of four (4) hours pay up to a maximum of eight (8) hour for each successful test.

10. Personal Effects Insurance

When an employee is required to reside in a construction camp, the cost for insurance against loss of his personal effects by fire, to a maximum of two thousand dollars ($2000.00), will be reimbursed on presentation of a paid premium receipt. To qualify for the insurance coverage an employee must submit a list of his personal effects on becoming a resident of the camp when such list is requested by the Contractor or the Operator of the camp.

11. Safety Clothing

a) When an employee is required to work in hazardous (e.g. asbestos, fiberglass) or especially dirty areas, the Contractor shall furnish proper protective clothing, including coveralls. Failure to comply, the employee must be reimbursed for loss or damage to his footwear or clothing;

b) When employees are required to do grinding, welding or other work requiring protective devices, all such protective gear will be supplied by the Contractor. Where the necessary protection devices are supplied for carrying out the work referred to above, but not utilized by the members performing the work, the employee shall first receive a written warning and if not adhered to, he shall be subject to dismissal;

c) Employees required to work in wet locations (crawl spaces, etc.) or work outdoors in inclement weather, shall be issued with sanitized rubber boots and rain gear by the Contractor;

d) Welders helmets, goggles, protective leather sleeves and welding gloves or mitts, but not Welders leather jackets and pants, shall be included in the term safety equipment and safety clothing. In the case of Metatarsal boots, the Contractor will contribute 100% of the cost.

Welders jackets shall be made available for temporary issue to Welders when engaged on work requiring additional protection such as, but not limited to, arc-air gouging and overhead welding, etc.;

e) All hard hats, sweat bands, winter liners, safety equipment, safety clothing, rainwear, etc., issued to an employee will be returned to the Contractor at the conclusion of the job for which it was issued. The Contractor accepts responsibility for normal wear and tear on receipt of the worn out articles. Any employee losing or abusing equipment, clothing, safety tools or devices issued to him, may have the cost of these articles deducted from his pay.

12. Tools

Plumbers and apprentices will supply all necessary tools of their trade up to and including a 10 inch wrench. Steamfitters and pipefitters and their apprentices will supply a 25 foot tape, torpedo level and pliers.

13. Isolation Leave (Return Transportation Time Periods)

The return transportation time period referred to in Article 19.2.1 for this Appendix shall be:

- After thirty-five (35) calendar days.

Travel time shall only apply on the return portion of an Isolation Leave trip (i.e. from the employee's T.D.P. to the Project Camp Site).

The amount of travel time to be paid shall be in accordance with the provisions of Article 19.1.2.5.1 or 19.1.2.5.2, as the case may be, and if applicable, the provisions of Article 19.1.2.5.3.

Travel time shall be paid at the employee's straight time rate, and an employee shall receive such payment pursuant to the provisions of Article 19.1.2.6.

14. Escalation and Reference

14.1 Wage Rate Provisions

The wage rate for the classifications set out in this Appendix will be adjusted by an amount equal to and effective on the dates of any adjustments in wage rates for corresponding classifications which may be negotiated from time to time by the United Association of Journeymen and Apprentices of the Plumbing and Pipe Fitting Industry of the United States and Canada Local Union 254, and the Mechanical Contractors Trade Division of the Construction Labour Relations Association of Manitoba.

Classifications eligible for adjustment may include general foreman, foreman, leadhand, chargehand, pusher, journeyman, apprentices, helpers and trainees.

14.1.1 Except as otherwise noted, the following provisions will be incorporated or adjusted to be consistent with corresponding provisions negotiated from time to time by the aforementioned Parties:

a) Definitions and qualificational requirements for applicable classifications;

b) Ratios indicating the number of apprentices, helpers, or other types of trainees who may be employed;

c) Ratios stipulating when a foreman, leadhand, chargehand, or pusher is to be appointed; however, if such a ratio is less than ten (10) to one (1) (i.e., the number of persons being supervised relative to the supervisor) when incorporating this provision in this Appendix, the ratio shall be ten (10) to one (1);

d) Height pay including that associated with swing stage work.

14.1.2 The appointment of General Foreman shall be at the sole discretion of the Contractor.

14.2 Other Conditions of Employment

Except as otherwise noted, the following conditions of employment will be incorporated or adjusted to be consistent with corresponding conditions of employment negotiated from time to time by the aforementioned Parties:

a) Overtime payments (subject to the restrictions set out in Section 14.3);

b) Shift premium but excluding any shift premium applicable to overtime hours;

c) Vacation and Vacation Pay - such provisions may include any provisions relative to the timing of payment of vacation pay but shall not include any provisions stipulating when vacation time must be granted, and in lieu of such a provision the following shall be substituted: "the scheduling of time off for vacation shall be arranged by mutual agreement between the Contractor and the employee";

d) Pay in lieu of Holidays and any provisions requiring the transferring and observing of the Holiday on a day, other than the day on which the Holiday falls (subject to the restrictions set out in Section 14.2.1);

e) Registered and trusteed pension and health and welfare plans (subject to the restrictions set out in Section 14.2.2);

f) Callout provisions;

g) Rest provisions between shifts;

h) Personal effects insurance provisions;

i) Provisions governing welding and other special trade related tests;

j) Safety clothing;

k) Tool lists and provisions governing loss of such tools on the Project;

l) The following trusteed plans, each of which shall be subject to the restrictions set out in Section 14.2.3:

   i) Building fund;

   ii) Trade improvement plans including educational and apprenticeship funds;

   iii) Industrial promotion funds.

m) The time period between Isolation Leaves (subject to the restrictions of Article 19.2.1.3);

n) Travel time associated with the taking of an Isolation Leave, and the

hourly rate at which travel time will be paid (subject to the restrictions set out in Section 14.2.4).

14.2.1 A Holiday set out in Article 17 may be observed on a day, other than the day on which it falls, provided the Holiday falls on a Saturday or Sunday which is a non-working day, in which case the Holiday may be observed on the closest following working day. The transferring of a Holiday shall not apply to any employee who is on Christmas Leave, Isolation Leave or any other type of Leave of Absence when the Holiday occurs.

14.2.2 The Contractor's contribution to any pension and health and welfare plan may be applied on a per hour worked basis; however, the Contractor's contribution rate in respect of overtime hours shall not be greater than the required contribution rate for Contractors in respect of straight time hours.

The aforementioned limitation shall not apply to a pension or health and welfare plan in effect in this Appendix on January 1, 1989 and in which higher employer contribution levels were required in respect of overtime hours compared to straight time hours. This exemption shall remain in effect provided required employer contributions to such plans do not change to a single contribution rate relative to straight time and overtime hours.

14.2.3 The Contractor's contribution to any of the plans referred to in Section 14.2 (l) may be applied on a per hour worked basis; however, the Contractor's contribution rate in respect of overtime hours shall not be greater than the required contribution rate for contractors in respect of straight time hours.

14.2.4 Travel time may only apply to the return portion of an Isolation Leave trip (i.e. from the employee's T.D.P. to the Project Camp Site). The amount of travel time to be paid shall not be greater than the travel time set out in Articles 19.1.2.5.1, 19.1.2.5.2 and 19.1.2.5.3, as may be applicable. The hourly rate at which travel time may be paid shall not be greater than the employee's straight time rate. Payment of travel time shall be in accordance with the provisions of Article 19.1.2.6.

14.3 Notwithstanding anything contained in this Agreement or in this Appendix, the regular hours of work are not subject to adjustment during the life of this Agreement, and such regular hours of work shall be paid at regular rates of wages. Further, overtime payments at a rate greater than time and one-half will not be introduced in this Appendix in respect of the first two (2) hours of overtime, Monday to Friday inclusive.

14.4 The provisions of 14.1 and 14.2 above shall be dealt with by following the

procedure set out in Article 30 of this Agreement.

APPENDIX NO. 14a – Refrigeration Section of P & P

UNITED ASSOCIATION OF JOURNEYMEN AND APPRENTICES
OF THE PLUMBING AND PIPE FITTING INDUSTRY
OF UNITED STATES AND CANADA

Local Union 254, Refrigeration Section

BURNTWOOD/NELSON AGREEMENT

1. Hours of Work and Overtime

Eight (8) hours shall constitute a day's work for five (5) days Monday to Friday inclusive. Said hours shall normally be within the period from 7:00 a.m. to 6:00 p.m.

If more than the recognized daily hours are worked in any day or shift, Monday to Friday inclusive, such time shall be paid at the rate of time and one-half for the first two (2) hours and double time for all hours worked thereafter.

On Saturdays, except as provided in Article 15.2, Sundays and holidays as specified in Article 17, double time shall be paid.

2. Shift Conditions

If conditions are such that work on that particular job cannot be done within the said normal hours (7:00 a.m. to 6:00 p.m.) then eight (8) hours may be worked during any hours and may constitute a regular shift on that job.

A premium of 0.125 of the regular straight time rate will be paid for each shift hour worked at the straight time rate. The shift premium shall not apply on overtime hours.

The starting and quitting time for shift work will be decided by the Contractor.

Overtime payment for shift work shall be in accordance with the provisions set forth above.

3. Wages

Wage rates shall be as follows:

	June 20, 2018	May 1, 2019
Journeyman Refrigeration Workers	$39.83	$40.25
Apprentice 5th year (93%)	$37.04	$37.43
Apprentice 4th year (83%)	$33.06	$33.41
Apprentice 3rd year (73%)	$29.08	$29.38
Apprentice 2nd year (65%)	$25.89	$26.16
Apprentice 1st year (55%)	$21.91	$22.14

Apprentices will be employed in accordance with the terms and conditions laid down by the Apprenticeship Division of the Department of Labour.

4. Vacation and Vacation Pay

Vacation pay shall be six percent (6%) of the employee's gross earnings.

Vacation pay allowance will be paid to employees on their regular pay day. Such payments shall be considered as advance payment for any vacation taken by the employee under the conditions provided in the Employment Standards Code for the Province of Manitoba.

5. Payment in Lieu of Holidays

Whether or not an employee works on any of the Holidays set out in Article 17, he shall receive in lieu of paid Holidays, four and a half percent (4.5%) of his gross earnings.

The employee shall receive this allowance with his regular pay.

6. Trust Funds

6.1 Health and Welfare

The Contractor and each employee covered by this Appendix shall contribute the amounts set out below to the Local 254 Health and Welfare Trust Fund. The employee’s contribution shall be collected at the source as a payroll deduction. Contributions shall apply to all hours earned.

Contractor: effective May 1, 2016 - $0.91 per hour

Employee: effective May 1, 2017 - $1.03 per hour

NOTE
For purposes of the BNA and in acknowledgement of the receipt of the most recent Refrigeration Costing Model, the amounts shown above will not be applied retroactively. May 1, 2016 will be the acknowledged effective date.

6.2 Pension Fund

The Contractor shall contribute the amounts set below to the Local 254 Pension Fund. The Contractor's Contributions shall apply to all hours earned.

Contractor's Contribution
Effective June 20, 2018 will be $7.94 per hour
Effective May 1, 2019 will be $8.03 per hour

Note: All Apprentice Pension Contributions are based on the relative percent to Journeyman rate identified in Section 3 of this Appendix.

NOTE
For purposes of the BNA and in acknowledgement of the receipt of the most recent Refrigeration Costing Model, the amounts shown above will not be applied retroactively. May 1, 2016 will be the acknowledged effective date.

6.3 Submission of Contributions

Contributions shall be submitted monthly, and will be accompanied by forms supplied by the Administrator of the Local 254 Piping Industry Trusts Fund, on or before the 10th day of the month following the month for which such contributions are payable. Such forms will list employees and hourly contributions for each employee. A copy of the above mentioned forms will be retained by the Contractor and the remaining copies will be forwarded with one cheque made payable to "The Piping Industry Trusts Fund" covering all health and welfare contributions, and one (l) cheque made payable to the Administrator of the Local 254 Refrigeration Pension Plan.

7. Rest Period

If an employee is requested to work after the completion of his regular shift and is not provided with at least an eight (8) hour rest period between shifts, the employee shall be paid double time rates until such time as an eight (8) hour break occurs.

8. Safety Clothing

The Contractor will supply all safety equipment and devices required by the Safety Regulations including respirators, goggles for grinding, welding sleeves and gloves for welders, protective rain gear and disposable hearing protection when same is required. When employees are required to work in hazardous areas, the Contractor shall furnish proper protective clothing. Should the Contractor not provide the protective clothing, the employee will be reimbursed for loss or damage to his footwear or clothing. Personal clothing is to be supplied by the employee.

The employee must accept the responsibility for the safety equipment issued by the Contractor under the same conditions as set forth for tools and must report the loss of damage of any of the items so issued to the Contractor.

9. Welding Tests

A Journeyman Welder required for certified welding shall report to the job site equipped with an unexpired certificate of qualification valid under the Provincial Regulations for a minimum of forty-five (45) calendar days from the date of hire.
If the Contractor requires any additional examining or testing, or if an existing employee is requested by the Contractor to re-test for a special certificate, the employee's time required for testing and cost of the examination or test will be borne by the Contractor.

Should an employee's certificate expire while he is in the employ of a Contractor, the cost of the required annual re-test and the time required to take same (up to a maximum of three (3) hours) shall be paid by the Contractor, provided the employee has worked for that Contractor for a minimum of forty-five (45) calendar days immediately prior to the expiry date of the certificate. If the employee resigns within forty-five (45) days of the re-test, the employee will be required to repay the total cost.

When a Welder has been trained for a special certificate, and tested at the Contractor's expense, and the Welder quits within forty-five (45) days of the tests, then the cost of testing time paid by the Contractor will be deducted from monies due the employee. The costs of all testing materials and equipment shall be borne by the Contractor.

10. Tools

The Contractor agrees to pay the employee fifty percent (50%) of the cost of tool insurance, up to a maximum of six thousand dollars ($6000.00) worth of coverage, upon submission of a receipt from the employee. If an employee leaves the employ of the Contractor within six (6) months of such payment being made, the Contractor may deduct said payment from any monies due the employee. In the event of a claim being made for lost or stolen tools, the Contractor agrees to pay one hundred percent (100%) of the deductible.

Any claim for lost or destroyed tools must be submitted in writing with a list of such tools and value thereof, and substantial evidence of loss, satisfactory to the insurance company. Such list must be submitted within ten (10) days of loss unless reason, satisfactory to the insurance company, can be shown for not having done so.

Journeymen and Apprentices shall supply the tools of the trade as per the following list:

	Description
	Tool box
	Refrigeration test manifold
	Pocket thermometer
	Crescent wrenches (set consisting of 6”, 8”, 10”)
	Refrigeration socket set
	Tube cutters (1/4” to 1 1/8”)
	Refrigeration flaring kit
	Screw drivers (complete set)
	Combination wrenches (box and open end, 3/8” to 5/8”)
	Plier (needle nose, channel locks, combination, vise grips)
	Pipe wrenches (8” and 14”)
	Side cutters
	Hammer
	Volt-ammeter
	Allen wrenches (set 1/16” to 1/2”)
	Hack saw
	Keyhole saw
	Pinch off tool
	Swedging kit (1/4”, 3/8”, 1/2”, 5/8”)
	Tinsnips
	Punch and chisel set
	Tape measure (10’)
	Flashlight
	Electronic Leak Detector
	Nut Driver (1/4 inch to 1/2 inch Sizes
	Cordless Drill

11. Isolation Leave (Return Transportation Time Periods)

The return transportation time period referred to in Article 19.2.1 for this Appendix shall be:

- After thirty-five (35) calendar days.

Travel time shall only apply on the return portion of an Isolation Leave trip (i.e. from the employee's T.D.P. to the Project Camp Site).

The amount of travel time to be paid shall be in accordance with the provisions of Article 19.1.2.5.1 or 19.1.2.5.2, as the case may be, and if applicable, the provisions of Article 19.1.2.5.3.
Travel time shall be paid at 75% of the employee's straight time rate, and an employee shall receive such payment pursuant to the provisions of Article 19.1.2.6.

12. Escalation and Reference

12.1 Wage Rate Provisions

The wage rate for the classifications set out in this Appendix will be adjusted by an amount equal to and effective on the dates of any adjustments in wage rates for corresponding classifications which may be negotiated from time to time by the United Association of Journeymen and Apprentices of the Plumbing and Pipefitting Industry of the United States and Canada, Local Union 254, Refrigeration Section, and the Refrigeration Contractors Trade Division of the Construction Labour Relations Association of Manitoba.

Classifications eligible for adjustment may include general foreman, foreman, leadhand, chargehand, pusher, journeyman, apprentices, helpers and trainees.

12.1.1 Except as otherwise noted, the following provisions will be incorporated or adjusted to be consistent with corresponding provisions negotiated from time to time by the aforementioned Parties:

a) Definitions and qualificational requirements for applicable classifications;

b) Ratios indicating the number of apprentices, helpers, or other types of trainees who may be employed.

12.2 Other Conditions of Employment

Except as otherwise noted, the following conditions of employment will be incorporated or adjusted to be consistent with corresponding conditions of employment negotiated from time to time by the aforementioned Parties:

a) Overtime payments (subject to the restrictions set out in Section 12.3);

b) Shift premium but excluding any shift premium applicable to overtime hours;

c) Vacation and Vacation Pay - such provisions may include any provisions relative to the timing of payment of vacation pay but shall not include any provisions stipulating when vacation time must be granted, and in lieu of such a provision, the following shall be substituted: "The scheduling of time-off for vacation shall be arranged by mutual agreement between the Contractor and the employee";

d) Pay in lieu of Holidays;

e) Registered and trusteed pension and health and welfare plans (subject to the restrictions set out in Section 12.2.1);

f) Callout provisions;

g) Rest provisions between shifts;

h) Provisions governing welding and other special trade related tests;

i) Safety clothing;

j) Tool lists and provisions governing loss of such tools on the Project;

k) Trusteed trade improvement plans including educational and apprenticeship funds. The Contractor's contribution to such plans may be applied on a per hour worked basis however, the Contractor's contribution rate in respect of overtime hours shall not be greater than the required contribution rate for Contractors in respect of straight time hours.

l) The time period between Isolation Leaves (subject to the restrictions of Article 19.2.1.3);

m) Travel time associated with the taking of an Isolation Leave, and the hourly rate at which travel time will be paid (subject to the restrictions set out in Section 12.2.2).

12.2.1 The Contractor's contribution to any pension and health and welfare plan may be applied on a per hour worked basis; however, the Contractor's contribution rate in respect of overtime hours shall not be greater than the required contribution rate for Contractors in respect of straight time hours.

The aforementioned limitation shall not apply to a pension or health and welfare plan in effect in this Appendix on January 1, 1989 and in which higher employer contribution levels were required in respect of overtime hours compared to straight time hours. This exemption shall remain in effect provided required employer contributions to such plans do not change to a single contribution rate relative to straight time and overtime hours.

12.2.2 Travel time may only apply to the return portion of an Isolation Leave trip (i.e. from the employee's T.D.P. to the Project Camp Site). The amount of travel time to be paid shall not be greater than the travel time set out in Articles 19.1.2.5.1, 19.1.2.5.2 and 19.1.2.5.3, as may be applicable. The hourly rate at which travel time may be paid shall not be greater than the employee's straight time rate. Payment of travel time shall be in accordance with the provisions of Article 19.1.2.6.

12.3 Notwithstanding anything contained in this Agreement or in this Appendix, the regular hours of work are not subject to adjustment during the life of this Agreement, and such regular hours of work shall be paid at regular rates of wages. Further, overtime payments at a rate greater than time and one-half will not be introduced in this Appendix in respect of the first two (2) hours of overtime, Monday to Friday inclusive.

12.4 The provisions of 12.1 and 12.2 above shall be dealt with by following the procedure set out in Article 30 of this Agreement.

APPENDIX NO. 14b – Sprinkler System Installers

UNITED ASSOCIATION OF JOURNEYMEN AND APPRENTICE OF THE PLUMBING AND PIPE FITTING INDUSTRY OF THE UNITED STATES AND CANADA

Local Union 254

BURNTWOOD/NELSON AGREEMENT

*** Note – See Letter of Agreement #25, for additional information regarding Appendix 14B

1. Hours of Work and Overtime

Eight (8) hours shall constitute a day's work for five (5) days Monday to Friday inclusive. Said hours shall normally be within the period from 7:00 a.m. to 6:00 p.m.

If more than the recognized daily hours are worked in any day or shift on Monday to Friday inclusive, such time shall be paid at the rate of time and one-half for the first two (2) hours and double time for hours worked thereafter.

On Saturdays, except as provided in Article 15.2, Sundays and Holidays as set out in Article 17, double time shall be paid.

2. Shift Conditions

If conditions are such that work on that particular job cannot be done within the said normal hours (7:00 a.m. to 6:00 p.m.) then eight (8) hours may be worked during any hours and may constitute a regular shift on that job.

A shift premium of fifteen percent (15%) of the regular straight time rate will be paid for each shift hour worked at the straight time rate. The shift premium shall not apply on overtime hours.

The starting and quitting time of all shift work shall be decided by the Contractor.

Overtime payment for shift work shall be in accordance with the provisions as set out above.

3. Wages

Wage rates shall be as follows:

a) Journeyman

Effective Date	Hourly Wage
May 1, 2019	$42.49 per hour
May 1, 2020	$43.17 per hour
May 1, 2021	$43.85 per hour

b) Apprentices

The scale of wages for apprentices, effective May 1, 2010, shall be:

1st year*	50% of the Journeyman rate
2nd year	60% of the Journeyman rate
3rd year	70% of the Journeyman rate
4th year	80% of the Journeyman rate

Apprentices shall be registered in the Province of Manitoba and work in accordance with the Manitoba Apprenticeship and Tradesmen's Qualifications Act and this Agreement. If an Apprentice fails to successfully complete an Apprenticeship level, he shall not qualify for advancement and shall remain at the same rate of pay until he has successfully completed that level.

The ratio of Apprentices to Journeymen shall be in accordance with the Apprenticeship and Trades Qualifications Act.

*The first three months for a 1st year Apprentice shall be a probationary period. During this probationary period, neither the Apprentice nor the Contractor shall make contributions to the Pension Plan.

c) Foreman and Lead Hand

The selection and appointment of Foremen is the sole responsibility of the Contractor and the Union shall not interfere in any way in the selection of Foremen. Where there are five or more men employed, a Foreman shall be designated. He shall be paid fourteen percent (14%) above the Journeyman's rate.

Where there are four men employed, a Lead Hand shall be designated. He shall be paid ten percent (10%) above the Journeyman’s rate.

It is understood and agreed that when five or more men are employed (and a Foreman is designated as provided above), there will be no Lead Hand designated.

4. Vacation and Vacation Pay

Vacation pay shall be six percent (6%) of total base rate earnings.

Vacation pay allowance will be paid to employees on their regular pay day. Such payments shall be considered as advance payment for any vacation taken by the employee under the conditions provided in the Employment Standards Code for the Province of Manitoba.

5. Payment in Lieu of Holidays

Whether or not an employee works on any of the Holidays set out in Article 17, he shall receive in lieu of paid Holidays, four percent (4%) of his total base rate earnings. Such allowance shall be paid to employees on their regular pay day.

If a Holiday falls on a Saturday which is a non working day, or Sunday, the closest following work day(s) which is not a paid Holiday will be observed. However, this provision shall not apply to any employee who is on Christmas Leave, Isolation Leave or any other type of Leave of Absence when the Holiday occurs.

6. Trust Funds

6.1 Health and Welfare

The Contractor and each employee covered by this Appendix shall contribute the amounts set out below to the Local 254 Health & Welfare Fund. The employee's contribution shall be collected at the source as a payroll deduction. Contributions shall apply to all hours earned.

Contractor's Contribution	May 1, 2019	$1.89 per hour
	May 1, 2020	$1.89 per hour
	May 1, 2021	$1.89 per hour
Employee's Contribution		Nil

Should the Trustees of the Health & Welfare Fund adjust the Contractors' contributions to the said Fund, the adjustment (increase or decrease) shall be deducted from the wage rate (in the case of an increase) or added to the wage rate (in the case of a decrease).

6.2 Pension Fund

The Contractor and each employee covered by this Appendix shall contribute the

amounts set out below to the Sprinkler Industry Pension Fund. The employee's contribution shall be collected at the source as a payroll deduction. Contributions shall apply to all hours earned.

Contractor's Contribution	May 1, 2019	$7.25 per hour
	May 1, 2020	$7.25 per hour
	May 1, 2021	$7.25 per hour
Employee's Contribution	May 1, 2009	$0.05 per hour

6.3 National Sprinkler Industry Funds

The Contractor and each employee covered by this Appendix shall contribute the amounts set out below to a variety of National Sprinkler Industry Funds. Employee contributions shall be collected at the source as a payroll deduction. Contributions shall apply to all hours worked.

Effective May 1, 2019:	Contractor Contributions:
Local Industry Promotion Fund	$0.15
Local Industry Promotion & Org	$0.10
Training Fund	$0.39
UA Sprinkler Admin. Fund	$0.05
UA P.A.C. Fund	$0.01
Helmets to Hardhats	$0.01

Effective May 1, 2019:	Employee Contributions:
Local Building Fund	$0.64
UA National Organizing Fund	$0.10

6.4 Payment of all Trust Fund Contributions

Contributions to all trust funds shall be submitted monthly and will be accompanied by completed reporting forms supplied by the Administrator of the Local 254 Piping Industry Trusts Fund on or before the 10th day of the month following the month for which such contributions are payable. Such forms shall list employees and hourly contributions for each employee. A copy of the above mentioned form is to be retained by the Contractor and the remaining copies to be forwarded with one (1) cheque made payable to "The Piping Industry Trusts Fund" covering all contributions, to the Administrator of the Local 254 Piping Industry Trusts Fund.

7. Tools

Employees shall supply 25 foot tape measure, 8" level, and 8" wrench. The Contractor shall furnish all other necessary tools of their trade, including compulsory safety equipment. Employees shall ensure that tools, equipment, and materials are put in their proper places and chests or lockers are left in a place as secure from theft or damage as possible. Any employee losing or abusing tools or safety equipment issued to him may have the cost of these articles deducted from his pay.

8. Routine Maintenance

As provided in Manitoba Regulation 29/2003 *Trade of Sprinkler System Installer Regulation,* a person is not practicing in the trade when he performs routine maintenance tasks on sprinkler or fixed fire protection systems or performs a task of the trade that he is authorized by another enactment to perform. It is understood and agreed that such work is excluded from Article 2, Scope and Recognition, under Article 2.2 l).

9. Isolation Leave (Return Transportation Time Periods)

The return transportation time period referred to in Article 19.2.1 for this Appendix shall be:

- After thirty-five (35) calendar days.

Travel time shall only apply on the return portion of an Isolation Leave trip (i.e. from the employee's T.D.P. to the Project Camp Site).

The amount of travel time to be paid shall be in accordance with the provisions of Article 19.1.2.5.1 or 19.1.2.5.2, as the case may be, and if applicable, the provisions of Article 19.1.2.5.3.

Travel time shall be paid at the employee's straight time rate, and an employee shall receive such payment pursuant to the provisions of Article 19.1.2.6.

10. Escalation and Reference

10.1 Wage Rate Provisions

The wage rate for the classifications set out in this Appendix will be adjusted by an amount equal to and effective on the dates of any adjustments in wage rates for corresponding classifications which may be negotiated from time to time by the United Association of Journeymen and Apprentices of the Plumbing and Pipe Fitting Industry of the United States and Canada Local Union 254, and the Canadian Automatic Sprinkler Association.

Classifications eligible for adjustment may include, foreman, leadhand, journeyman, apprentices, helpers and trainees.

10.1.1 Except as otherwise noted, the following provisions will be incorporated or adjusted to be consistent with corresponding provisions negotiated from time to time by the aforementioned Parties:

a) Definitions and qualificational requirements for applicable classifications;

b) Ratios indicating the number of apprentices, helpers, or other types of trainees who may be employed;

c) Number of employees stipulating when a foreman or leadhand is to be appointed; however, a leadhand need not be designated if less than four men are employed, and a foreman need not be designated if less than five men are employed, and no leadhand will be designated where more than four men are employed.

10.2 Other Conditions of Employment

Except as otherwise noted, the following conditions of employment will be incorporated or adjusted to be consistent with corresponding conditions of employment negotiated from time to time by the aforementioned Parties:

a) Overtime payments (subject to the restrictions set out in Section 10.3);

b) Shift premium but excluding any shift premium applicable to overtime hours;

c) Vacation and Vacation Pay - such provisions may include any provisions relative to the timing of payment of vacation pay but shall not include any provisions stipulating when vacation time must be granted, and in lieu of such a provision the following shall be substituted: "the scheduling of time off for vacation shall be arranged by mutual agreement between the Contractor and the employee";

d) Pay in lieu of Holidays and any provisions requiring the transferring and observing of the Holiday on a day, other than the day on which the Holiday falls (subject to the restrictions set out in Section 10.2.1);

e) Registered and trusteed pension and health and welfare plans (subject to the restrictions set out in Section 10.2.2);

f) Callout provisions;

g) Rest provisions between shifts;

h) Personal effects insurance provisions;

i) Provisions governing welding and other special trade related tests;

j) Safety clothing;

k) Tool lists and provisions governing loss of such tools on the Project;

l) The following trusteed plans, each of which shall be subject to the restrictions set out in Section 10.2.3:

   i) Trade improvement plans including educational, safety, and apprenticeship funds;

m) The time period between Isolation Leaves (subject to the restrictions of Article 19.2.1.3);

n) Travel time associated with the taking of an Isolation Leave, and the hourly rate at which travel time will be paid (subject to the restrictions set out in Section 10.2.4).

10.2.1 A Holiday set out in Article 17 may be observed on a day, other than the day on which it falls, provided the Holiday falls on a Saturday or Sunday which is a non-working day, in which case the Holiday may be observed on the closest following working day. The transferring of a Holiday shall not apply to any employee who is on Christmas Leave, Isolation Leave or any other type of Leave of Absence when the Holiday occurs.

10.2.2 The Contractor's contribution to any pension and health and welfare plan may be applied on a per hour worked basis; however, the Contractor's contribution rate in respect of overtime hours shall not be greater than the required contribution rate for Contractors in respect of straight time hours.

The aforementioned limitation shall not apply to a pension or health and welfare plan in effect in this Appendix on January 1, 1989 and in which higher employer contribution levels were required in respect of overtime hours compared to straight time hours. This exemption shall remain in effect provided required employer contributions to such plans do not change to a single contribution rate relative to straight time and overtime hours.

10.2.3 The Contractor's contribution to any of the plans referred to in Section 10.2 (l) may be applied on a per hour worked basis; however, the Contractor's contribution rate in respect of overtime hours shall not be greater than the required contribution rate for contractors in respect of straight time hours.

10.2.4 Travel time may only apply to the return portion of an Isolation Leave trip

(i.e. from the employee's T.D.P. to the Project Camp Site). The amount of travel time to be paid shall not be greater than the travel time set out in Articles 19.1.2.5.1, 19.1.2.5.2 and 19.1.2.5.3, as may be applicable. The hourly rate at which travel time may be paid shall not be greater than the employee's straight time rate. Payment of travel time shall be in accordance with the provisions of Article 19.1.2.6.

10.3 Notwithstanding anything contained in this Agreement or in this Appendix, the regular hours of work are not subject to adjustment during the life of this Agreement, and such regular hours of work shall be paid at regular rates of wages. Further, overtime payments at a rate greater than time and one-half will not be introduced in this Appendix in respect of the first two (2) hours of overtime, Monday to Friday inclusive.

10.4 The provisions of 10.1 and 10.2 above shall be dealt with by following the procedure set out in Article 30 of this Agreement.

APPENDIX NO. 15 – Office and Professional Employees

CANADIAN OFFICE AND PROFESSIONAL EMPLOYEES UNION

Local Union 342

BURNTWOOD/NELSON AGREEMENT

*** Note – See Letter of Agreement #28, for additional information regarding Appendix 15 (EMS Classifications)
*** Note – See Letter of Agreement #31, for additional information regarding Appendix 15 (Health and Welfare Trust Fund)
*** Note – See Letter of Agreement #47, for additional information regarding Appendix 15 (Relocation of COPE employees)

1. Hours of Work and Overtime

Eight (8) hours shall constitute a day's work for five (5) days, Monday to Friday inclusive. Said hours shall normally be within the period from 7:00 a.m. until 6:00 p.m.

If more than the recognized daily hours are worked in any day or shift, such time shall be paid at the rate of time and one-half for the first three (3) hours and double the regular straight time rate for all hours worked thereafter.

Except as provided in Article 15.2, when the Contractor's schedule requires an employee to work every Saturday, such time shall be paid at the rate of straight time for the first four (4) hours, time and one-half for the next seven (7) hours worked, and double time for all hours worked thereafter.

When the Contractor's schedule does not require an employee to work every Saturday, any time worked on a Saturday, except as provided in Article 15.2, shall be paid at the rate of time and one-half for the first eleven (11) hours, and double time for all hours worked thereafter.

On Sundays and Holidays as set out in Article 17, double time shall be paid for all hours worked.

When an employee is required to work in camp facilities providing a service to camp residents, and such services are generally provided on a 7 day per week basis, then that employee may be assigned a day of rest, other than Sunday. In this case, for purposes of applying the conditions set out above, the assigned day of rest shall be recognized as a Sunday and the subsequent six (6) days as Monday through Saturday.

2. Shift Conditions

If conditions are such that work on that particular job cannot be done within the said normal hours (7:00 a.m. to 6:00 p.m.) then eight (8) hours may be worked during any hours and may constitute a regular shift on that job.

A shift premium of 75¢ per hour will be paid for each shift hour worked at the straight time rate. Shift premium will not apply on any overtime hours.

The starting and quitting time of all shift work will be decided by the Contractor. Overtime payment for shift work shall be in accordance with the provisions as set out above.

3. Wages

Wage rates shall be as follows:

A) Non-Trainees (i.e., employees not covered by (B) below)

Classifications	Effective May 1, 2016	Effective May 1, 2017	Effective May 1, 2018	Effective May 1, 2019
Survey Assistant	$ 22.98	$ 23.51	$ 24.10	$ 24.71
Junior Instrumentman	$ 28.93	$ 29.60	$ 30.34	$ 31.12
Instrumentman I	$ 33.28	$ 34.05	$ 34.91	$ 35.80
Instrumentman II	$ 35.54	$ 36.36	$ 37.27	$ 38.23
Quantity Technician	$ 34.74	$ 35.54	$ 36.43	$ 37.36
Junior Draftsman	$ 26.53	$ 27.14	$ 27.82	$ 28.53
Intermediate Draftsman	$ 30.05	$ 30.75	$ 31.52	$ 32.33
Draftsman	$ 33.12	$ 33.89	$ 34.74	$ 35.63
Primacy Care Paramedic	$ 40.66	$ 41.60	$ 42.64	$ 43.73
First Aid Attendant	$ 28.36	$ 29.02	$ 29.74	$ 30.50
Emergency Medical Responder	$ 30.79	$ 31.50	$ 32.29	$ 33.11
Clerk Typist	$ 21.18	$ 21.67	$ 22.21	$ 22.78
Clerk I	$ 22.54	$ 23.06	$ 23.64	$ 24.25
Clerk II	$ 24.64	$ 25.21	$ 25.84	$ 26.50
Project Cost Clerk I	$ 28.44	$ 29.10	$ 29.83	$ 30.59
Project Cost Clerk II	$ 31.87	$ 32.61	$ 33.43	$ 34.28

The principal duties of the above classifications are as set out at the end of this Appendix.

When an employee is assigned to a higher classification, he shall receive the rate for such position from the time of assignment provided the assignment continues beyond the first shift.

When the Contractor appoints a working Instrumentman foreman, he shall be paid 10% above the Instrumentman II rate.

When the Contractor hires or appoints a Senior Draftsman, a Senior First Aid Attendant or a Senior Project Cost Clerk, that employee shall be paid a minimum of $1.00 above the rate of the person with the highest classification being supervised.

B) Trainees

a) A trainee means any employee who is hired to participate in a contractors formally structured on-the-job training program in any classifications set out in the Appendix, the nature of which are not designated trades (ie designated as being appropriate for apprenticeship or certification or both pursuant to the Apprenticeship and Tradesman's Qualification Act of the Province of Manitoba).

b) Trainees shall be paid a percentage of the rate in effect for the classification for which the employee is being trained in accordance with the following:

1 - 200 hours	60 %
201 - 400 hours	70 %
401 - 600 hours	80 %
601 or more hours	90 %

If the duration of the training program is less than 200 hours (or 400 hours or 600 hours, as the case maybe), the employee's rate shall be increased to 100 % of the rate in effect for that classification, effective on the first working day following the employee's successful completion of the training program.

c) Prior to implementing any formal on-the-job training programs for any classifications set out in the Appendix, the Contractor shall provide the Association and the Council with the following information:

i) The classification for which on-the-job training will be instituted and the schedule commencement date of the training;

ii) The duration of the training.

d) The number of trainees shall not exceed twenty percent (20%) of the total number of employees employed by a Contractor and covered by this Appendix except as may otherwise be agreed to by the Association and the Council.

e) An employee who is hired in a non-training classification may be re-assigned to a formal on-the-job training program under the following conditions:

i) An employee requests, in writing, to participate in the Contractor's formal on-the-job training program and the Contractor approves the request;

ii) The Contractor requests that an employee be re-assigned to a formal on-the-job training program and the employee and the Council are in agreement with the re-assignment.

f) An employee who is re-assigned in accordance with (e) above shall be deemed to be a trainee and paid in accordance with the provisions of (b) above;

g) The Contractor shall provide each employee who successfully completes the Contractor's formal on-the-job training program with a letter confirming the type of training received and the corresponding number of hours the employee spent in such training.

4. Vacation and Vacation Pay

Annual vacation will be arranged as provided in the Employment Standards Code for the Province of Manitoba.

Vacation Pay will be accumulated for the credit of each employee at the rate of six percent (6%) of the employee's standard hourly rate for each hour worked.

Vacation pay allowance will be paid to an employee on his regular pay day.

5. Pay in Lieu of Holidays

Whether or not an employee works on any of the Holidays set out in Article 17, he shall receive in lieu of paid Holidays, four and a half percent (4.5%**)** of his standard hourly rate for each hour worked. The employee shall be paid this amount each regular pay period.

6. Callout

An employee called to work outside his regular shift to perform unscheduled overtime shall be paid for such work at double time, but in no case shall an employee be paid less than two (2) hours at double time.

7. Rest Period

An employee shall have a minimum rest period of eight (8) hours between shifts. When employees are specifically requested to return to work before the expiration of eight (8) hours, all work performed shall be paid for at the applicable overtime rate, until a full eight (8) hour rest period has been observed.

8. Pension and Health and Welfare Trust Funds

Provided:

a) The Local Union to which employees covered by this Appendix belong establishes a pension plan in which employees covered by this Appendix are eligible to participate;

b) Written verification is forwarded to the Association and the Council by the Board of Trustees of each plan confirming:

i) Proviso (a), above;

ii) That Trust Agreements have been executed and registered.

A pension plan will be introduced into this Appendix on the following basis:

- at the time of introduction of the health and welfare plan and/or the pension plan, the hourly rates for all classifications in this Appendix shall be reduced by the amount of the contractor's contribution to the said plan or plans, less the sum of twenty cents. At the option of the Council, contributions to the plan or plans shall be made up by employee contributions or a combination of contractor and employee contributions. The Council shall advise the Association of the required contractor and/or employee contributions at the time the plan or plans are established.

  The contractor on behalf of each employee, and each employee covered by this Appendix, shall respectively contribute the amounts set out below to the Canadian Office and Professional Employees (COPE) union, local 342, Health and Welfare Trust Fund. Contributions shall apply to all hours worked (regular and overtime). Employee contributions shall be collected at the source as a payroll deduction.

  The contractor’s contribution shall be:

  Effective May 1, 2016 $0.20 per hour

  The employee’s contribution shall be:

  Effective May 17, 2015 $0.80 per hour

Submission of Trust Funds

The contractor shall forward the above Trust Fund contributions to the designated Administrator of the Plan on or before the fifteenth (15th) day of each month following the month in which contributions were made.

A form shall be supplied by the Union for the Contractor to identify the application of all contributions, and such form shall indicate the Administrator and the address to which contributions shall be forwarded.

Pension and/or health and welfare contributions shall be subject to adjustments, however all contributions shall continue to be made as outlined above and the effective date of such adjustments shall correspond to an effective date of changes to wages (See Section 9.1). Further, for all adjustments, the hourly rates for all classifications in this Appendix shall be reduced by the full amount of contractor's contribution (not less the sum of twenty cents or any other amount).

9. Escalation and Reference

9.1 Wages Rates

As provided in Section 9.2, the wage rates for all classifications in this Appendix shall be adjusted by a percentage, equivalent to the percentage adjustment in wage rates and in the employers' contribution rate to pension and health and welfare plans negotiated from time to time for the classification of "Journeyman Carpenter" (hereinafter referred to as the Reference Classification) by the United Brotherhood of Carpenters and Joiners of America, Local Union 343, and the Construction Labour Relations Association of Manitoba, as further provided in Section 9.2.

9.2 Method of Calculating Percentage Adjustment of Classifications

The percentage adjustment of the Reference Classification shall be determined in accordance with the following formula:

$$\frac{\text{(Change in W) + (Change in P) + (Change in H\&W)}}{\text{(Expired W) + (Expired P) + (Expired H\&W)}} \times 100$$

Where:

- Change means the increase or decrease in that benefit.

- W means wage rate.
- P and H&W means the required employers' contribution rate to the pension and/or the health and welfare plan.
- Expired means the rate in effect when the last percentage adjustment was calculated.

9.2.1 In calculating the percentage adjustment of the Reference Classification, the result shall be rounded to the nearest hundredth of a per cent. \

9.2.2 Effective Date of Adjustments

When any change to W or W and P and/or H&W in the agreement being used for reference purposes occur on the same date, the percentage adjustment of all such changes shall be calculated to determine the percentage adjustment by which wage rates in the Appendix are to be adjusted and the effective date of the change(s) in the agreement being used for reference purposes shall be the effective date of the wage rate change in this Appendix.

When changes to P and/or H&W are not effective on the effective date of any changes to W in the agreement being used for reference purposes, such changes shall be deemed to be effective on the date of a change to W next occurring, and the procedures set out above shall be followed, except if there are no subsequent changes to W during the remaining term of the agreement being used for reference purposes, the provisions set out below shall be followed for any changes to P and/or H&W which have not been previously calculated.

Where there are no changes to W but there are changes to P and/or H&W during the term of the agreement being used for reference purposes, the percentage adjustment of such change(s) shall be calculated and the resultant wage rate change in this Appendix shall be effective on the date of the change to P and/or H&W in the agreement being used for reference purposes.

9.2.3 In applying the percentage adjustments, the resultant wage rates shall be rounded to the nearest cent.

9.3 Vacation Pay and Pay in Lieu of Holidays

Vacation pay and pay in lieu of Holidays shall be adjusted to be consistent with corresponding conditions of employment set out in Appendix 4 of this Agreement.

9.4 Notwithstanding anything contained in this Agreement or in this Appendix, the regular hours of work are not subject to adjustment during the life of this Agreement, and such regular hours of work shall be paid at regular rates of wages.

9.5 The provisions of 9.1 to 9.3 inclusive shall be dealt with by following the procedure set out in Article 30 of this Agreement.

PRINCIPAL DUTIES*

Principal duties of the classifications set out in Section 3 will include the following:

1. Survey Assistant

To act as a Rodman in assisting an Instrumentman. May be required to clear brush, and in addition, will act as a Chainman and may use a prism or other surveying equipment.

2. Junior Instrumentman

Performs levelling work within previously established key bench marks and elementary survey work.

3. Instrumentman I

Performs survey work on construction projects utilizing all survey instruments. Survey work may include, but is not limited to, engineering surveys to determine boundaries, grades and elevations generally within previously established bearing controls. May perform topographical surveys and may be required to plot same from field notes, including electronic information.

4. Instrumentman II

Same as Instrumentman I, and in addition, may direct and coordinate work of survey crews.

5. Quantity Technician

Calculates quantities by referring to electronic information, survey notes, reports, specifications and drawings for purposes of progress payment.

6. Junior Draftsman

Performs elementary (including computer assisted) drafting duties using electronic information, topographical survey notes, and/or detailed sketches. Maintains and issues drawings. Operates printing and plotting machines.

7. Intermediate Draftsman

Same as Junior Draftsman, and in addition, prepares and revises final drawings, bills of materials and diagrams from verbal instructions, rough notes and/or sketches. May assist, as necessary, in examining structures or equipment.

8. Draftsman

Same as Intermediate Draftsman, and in addition, prepares layout designs by reference to standards, manuals and catalogues.

9. First Aid Attendant

Provides first aid treatment to sick or injured employees within the scope of first aid principles. Maintains records of occurrence and treatment and ensures the maintenance of first aid facilities and inventory. Refers cases to other medical facilities.

10. Emergency Medical Responder

Holds a valid Manitoba Emergency Medical Responder license. Performs all duties of a First Aid Attendant and in addition holds a valid Class 4 drivers license and has the ability to drive an ambulance. Is able to receive transfer of function from Medical Director for Automatic External Defibrillator, Epi-Pen, Nitro, Ventolin, and Pulse Oximetry.

11. Primary Care Paramedic

Performs all duties of an Emergency Medical Responder and holds a valid Technician-Paramedic license. In addition perform basic management of breathing dysfunctions, perform cardiac monitoring and interpret basic cardiac dysrhythmias, perform manual defibrillation, perform appropriate immobilization techniques, maintain peripheral IV locks or infusions, calculate, monitor and adjust flow rates, manage complications of IV catheters and infusions, manage emergency child birth, and provide basic care to patients with cardiac arrest, cardiovascular, respiratory, neurological, environmental, traumatic, and obstetrical, pediatric and neonate emergencies. Is able to administer ASA, Epinephrine, Narcan, Nitropatch, Entonox, Glucagon, Nitroglycerin, and Salbutamol Salbutamol with appropriate transfer of function from the Medical Director. May also be able to perform additional medical acts as specifically delegated by the Medical Director and in accordance with provincial regulations for the Technician-Paramedic licensing level.

11. Clerk Typist

Performs general clerical duties including: filing, photocopy, switchboard, fax, receptionist, and various computer related duties including compiling, word processing,

storage, retrieval and sorting of information through the use of a personal computer and/or the Contractor's computer systems.

12. Clerk I

May be required to perform any of the duties of a Clerk Typist and in addition performs arithmetic calculations, posts to records, transposes information, and in the case of the camp office, duties such as registrations and collecting and disbursement of room key monies. In addition, take shorthand, types from notes or secretarial office equipment, and prepares memos and letters of a routine nature.

13. Clerk II

May be required to perform any of the duties of a Clerk I and in addition, performs functions of the following nature: processing of time cards, invoices, billings and purchase orders, and inventory control.

14. Project Cost Clerk I

May be required to perform any of the duties of a Clerk II and in addition, performs basic accounting duties including accounts receivable, accounts payable, payroll and basic cost control.

15. Project Cost Clerk II

Same as Project Cost Clerk I, and in addition, performs bank reconciliations, ledger and journal postings, and prepares advanced accounting records, petty cash and other financial reports.

*NOTE: Notwithstanding the Principal Duties set out above, a computer may be utilized by any employee of the Contractor, including persons not covered by this Agreement, to perform any duties associated with their respective positions.

APPENDIX NO. 16 - Caterers

HOTEL, RESTAURANT EMPLOYEES AND BARTENDERS
INTERNATIONAL UNION

Local Union No. 206

BURNTWOOD/NELSON AGREEMENT

*** Note See Letter of Agreement #60, for further information regarding Pension remittances

1. Hours of Work and Overtime

A regular work week shall consist of eight (8) hours per day for five (5) consecutive days and four (4) hours on the sixth (6th) day. Except as provided in Article 15.2, if more than the recognized daily hours are worked on any day or shift on the first six (6) days, such time shall be paid for at the rate of time and one-half. On the seventh day and on Holidays (Article 17) time and one-half shall be paid for all hours worked.

Daily work schedules for all staff will be posted in a place accessible to the employees.

An employee will be assigned a minimum of one (1) day of rest per calendar week.

2. Shift Conditions

a) Split Shift

An employee required to work a split shift shall be paid at the rate of time and one-half of the standard hourly rate for all hours worked after the expiry of twelve (12) consecutive hours measured from the commencement of the shift.

Time off for meal breaks and coffee breaks shall not be considered a break which would constitute a split shift.

b) Split Shift Premium

An employee required to work a split shift shall be paid a premium 25¢ for each hour worked on that shift.

c) Night Shift Premium

An employee required to work a night shift shall be paid a premium of 35¢ for each hour worked at the straight time rate provided the majority of the shift is worked between the hours of 6 p.m. and 6 a.m.

3. Call Out

When an employee completes his regular shift, leaves the job and is subsequently called out for unscheduled work, he shall be paid a minimum of four (4) hours at the rate of time and one-half.

4. Rest Time

When an employee has not been provided with a break of at least eight (8) consecutive hours between shifts, he shall be paid time and one-half for all hours worked until a break of eight (8) hours occurs.

5. Wages

Wage rates shall be as follows:

A) Non-Trainees - (i.e., employees not covered by (B) below)

Classification	Effective May 1, 2016	Effective May 1, 2017	Effective May 1, 2018	Effective May 1, 2019
Chef	$28.32	$29.01	$29.75	$30.52
1st Cook	$27.61	$28.29	$29.01	$29.76
2nd Cook	$24.80	$25.41	$26.06	$26.73
3rd Cook/Short Order Cook	$23.37	$23.94	$24.55	$25.18
Baker	$26.22	$26.86	$27.54	$28.26
Butcher	$26.22	$26.86	$27.54	$28.26
Tapman	$19.38	$19.85	$20.36	$20.88
Head Camp Attendant	$19.38	$19.85	$20.36	$20.88
Head Mess Hall Attendant	$19.38	$19.85	$20.36	$20.88
Head Dishwasher	$19.38	$19.85	$20.36	$20.88
Salad/Sandwich Maker	$18.67	$19.13	$19.62	$20.13
Commissary Attendant	$18.67	$19.13	$19.62	$20.13
Snack Bar Attendant	$18.67	$19.13	$19.62	$20.13
Pot and Dishwasher	$18.52	$18.97	$19.46	$19.96
General Help *	$18.36	$18.81	$19.29	$19.79
Camp Attendant (Janitor)	$18.15	$18.59	$19.07	$19.56

* Includes Laundry Washer, Porter, Mess Hall Attendant, Waiter/Waitress.

When an employee is assigned to a higher hourly rated classification, he shall be paid the higher rate from the time of assignment provided the assignment

continues beyond the first shift.

B) Trainees

a) A trainee means any employee who is hired to participate in a contractor's formally structured on-the-job training program in any classifications set out in the Appendix, the nature of which are not designated trades (ie designated as being appropriate for apprenticeship or certification or both pursuant to the Apprenticeship and Tradesman's Qualification Act of the Province of Manitoba);

b) Trainees shall be paid a percentage of the rate in effect for the classification for which the employee is being trained in accordance with the following:

1 - 200 hours	60 %
201 - 400 hours	70 %
401 - 600 hours	80 %
601 or more hours	90 %

If the duration of the training program is less that 200 hours (or 400 hours or 600 hours, as the case maybe), the employee's rate shall be increased to 100 % of the rate in effect for that classification, effective on the first working day following the employee's successful completion of the training program;

(c) Prior to implementing any formal on-the-job training programs for any classifications set out in the Appendix, the Contractor shall provide the Association and the Council with the following information:

1) The classification for which on-the-job training will be instituted and the schedule commencement date of the training;

2) The duration of the training.

d) The number of trainees shall not exceed twenty percent (20%) of the total number of employees employed by a Contractor and covered by this Appendix except as may otherwise be agreed to by the Association and the Council;

e) An employee who is hired in a non-training classification may be re-assigned to a formal on-the-job training program under the following conditions:

i) An employee requests, in writing, to participate in the Contractor’s formal on-the-job training program and the Contractor approves the request;

ii) The Contractor requests that an employee be re-assigned to a formal on-the-job training program and the employee and the Council are in agreement with the re-assignment.

f) An employee who is re-assigned in accordance with (e) above shall be deemed to be a trainee and paid in accordance with the provisions of (b) above;

g) The Contractor shall provide each employee who successfully completes the Contractor's formal on-the-job training program with a letter confirming the type of training received and the corresponding number of hours the employee spent in such training.

6. Vacation and Holiday Pay

a) Vacation Pay and Holiday Pay shall be combined in an amount equal to ten percent (10%) of gross wages of which four percent (4%) shall be paid in lieu of the Holidays specified in Article 17;

b) Gross wages shall be defined as being all straight time hourly wages plus all overtime premium wages and all shift work premium wages;

c) The Vacation and Holiday Pay Allowance shall be paid to employees on their regular pay day.

7. Health and Welfare and Pension Plan Trust Funds

a) Health and Welfare

The Contractor shall contribute the amount set out below for each hour worked by each employee covered by this Appendix to the Health and Welfare Plan provided for by the Hotel and Restaurant Employees and Bartenders International Union, Local 206:

Effective	October 1, 2013	75¢ per hour worked

b) Pension Plan

The Contractor shall contribute the amount set out below for each hour worked by each employee covered by this Appendix to the Hotel and Restaurant Employees and Bartenders International Union, Local 206 Pension Plan:

Effective	March 3, 2019	65¢ per hour worked

c) Submission of Trust Funds

The Contractor shall forward the above Trust Fund Contributions to the designated Administrators of each plan on or before the 15th day of each month following the month in which contributions were made.

A form shall be supplied by the Union for the Contractor to identify the application of all contributions and such form shall indicate the Administrator and the address to which contributions shall be forwarded.

8. Joint Liaison Committee Fund

The Contractor shall contribute the amount of fifteen (15) cents for each hour worked by each employee covered by this Appendix to the Hotel and Restaurant Employees and Bartenders International Union, Local 206 Joint Liaison Committee.

The Contractor shall forward the above contribution to the Authority designated by the Trustees of the Joint Liaison Committee on or before the 15th day of each month following the month in which the contributions were made. A form shall be supplied by the Union for the Contractor to identify the application of all contributions and such form shall indicate the Authority to which the contributions shall be forwarded.
In the event the Joint Liaison Committee Fund ceases to be a trusteed plan, it shall be deleted from this Appendix effective on the date it ceased to be a trusteed plan. The Council shall notify the Association, in writing, immediately upon the said fund ceasing to be a trusteed plan.

9. Uniforms

The Contractor shall supply, on loan, all uniforms to be worn by an employee. The Contractor will launder and repair same free of charge to the employee. However, when the Contractor cannot reasonably arrange to have uniforms laundered, the Contractor will provide a washing machine and accessories for the use of employees.

10. Medical Examinations

A pre employment medical examination, which will be at the expense of the Contractor, will be required for all employees. This examination will normally be given prior to the employee journeying to the Project by a physician designated by the Contractor.

11. Single Rooms

An employee who is hired as a camp attendant (janitor), will be assigned to a single room, provided space is available.

12. Escalation and Reference

12.1 Wage Rate Provisions

12.1.1 General Approach

Subject to and in accordance with the conditions set out below, and subject to any adjustments arising from the application of Section 12.2, the wage rates set out in this Appendix will be adjusted by a percentage equivalent to the weighted percentage adjustment in wage rates and in the employers' contribution rate to pension and health and welfare plans negotiated from time to time for each of the Reference Classifications set out in 12.1.2.

12.1.2 Reference Classifications and Weighting

The Reference Classifications and the weighting of these classifications shall be as follows:

Reference Classification	**Weighting Factor**
The General Construction Labourer classification as set out in the Agreement negotiated and executed by the Construction Labour Relations Association (CLRA) of Manitoba and the Construction and Specialized Workers' Union, Local Union 1258	60%
The Journeyman Carpenter Classification as set out in the Agreement negotiated and executed by the CLRA of Manitoba and the United Brotherhood of Carpenters and Joiners of America, Local Union 343.	40%

12.1.3 Method of Calculating Weighted Percentage Adjustment of Reference Classifications

The weighted percentage adjustment of each Reference Classification shall be determined in accordance with the following formula:

$$\frac{\text{(Change in W) + (Change in P) + (Change in H\&W)}}{\text{(Expired W) + (Expired P) + (Expired H\&W)}} \times 100 \times \text{Weighting Factor}$$

Where:

- Change means the increase or decrease in that benefit.
- W means wage rate.
- P and H&W means the required employers' contribution rate to the pension and/or the health and welfare plan.
- Expired means the rate in effect when the last weighted percentage adjustment was calculated.
- Weighting factor means the factor assigned to a particular Reference Classification as set out in 12.1.1.

12.1.3.1 In calculating the weighted percentage adjustment of a Reference Classification, the arithmetic result shall be rounded to the nearest hundredth of a percent.

12.1.4 Effective Date of Wage Rate Adjustments and Adjustments to Pension and Health and Welfare Plans and Application of the Formula

12.1.4.1 Effective Date of Wage Rate Adjustments

When the wage rate adjustment of a Reference Classification(s) is effective on the first of any month, then the wage rate adjustment of the hourly rates in this Appendix shall be effective on that date.
When the wage rate adjustment of a Reference Classification(s) is not effective on the first of any month, it shall be deemed to be effective on the first of the month following, and the wage rate adjustment of hourly rates in this Appendix shall be effective on that date.

12.1.4.2 Effective Date of Adjustments to the Employers' Contribution Rate to Pension and/or Health and Welfare Plans

When the adjustment to the employers' contribution to the pension and/or health and welfare plans of a Reference Classification(s) is effective on the effective date, or pursuant to 12.1.4.1 the deemed effective date, of any wage rate adjustment of any Reference Classification, then such adjustment shall be calculated and taken into account on that date. If this is not the case, then such adjustment shall be calculated and taken into account on the closest

following effective date of a wage rate adjustment.

12.1.4.3 In applying the weighted percentage adjustment, the resultant wage rate shall be rounded to the nearest cent, following which, any adjustment required by virtue of Section 12.3 shall be introduced to yield the new wage rate schedule that will apply in this Appendix.

12.2 Pension and Health and Welfare

12.2.1 The Contractor's responsibility for contributions to the Pension and Health and Welfare Trust Funds referenced in Section 7 of this Appendix shall be no greater than 65 cents per hour worked , and 35 cents per hour worked, respectively. In the event that the Hotel and Restaurant Employees and Bartenders International Union, Local 206, requires increased contributions to its Health and Welfare Trust Funds, the total amount of said increase will be deducted from the employees' wages or become an employee contribution.

12.2.2 The Contractor's contribution to the Pension and Health and Welfare Plans may be applied on a per hour worked basis; however, the Contractor's contributions rate in respect of overtime hours shall not be greater than the required contribution rate for Contractors in respect of straight time hours.

12.3 Notwithstanding anything contained in this Agreement or in this Appendix, the regular hours of work are not subject to adjustment during the life of this Agreement, and such regular hours of work shall be paid at regular rates of wages.

12.4 The provisions of Sections 12.1 and 12.2 shall be dealt with by following the procedure set out in Article 30 of this Agreement.

APPENDIX NO. 17 – Elevator Constructors

INTERNATIONAL UNION OF ELEVATOR CONSTRUCTORS

Local Union No. 102

BURNTWOOD/NELSON AGREEMENT

1. Hours of Work and Overtime

Eight (8) hours shall constitute a day's work for five (5) days, Monday to Friday inclusive. Said hours shall normally be within the period from 7:00 a.m. until 6:00 p.m.

If more than the recognized daily hours are worked in any day or shift Monday to Friday inclusive, such time shall be paid at the rate of time and one-half for the first two (2) hours and double time for all hours worked thereafter.

On Saturdays, except as provided in article 15.2, Sundays, and holidays as specified in Article 17, double time shall be paid.

2. Wages

Hourly wage rates shall be as follows:

	Effective Dec 7, 2013	Effective Dec 1, 2014	Effective Dec 1, 2015
Mechanic In-Charge (Adjustor) - 112.5%	$48.05	$49.73	$51.31
Mechanic	$42.71	$44.20	$45.61
Helper 3 – 80%	$34.17	$35.36	$36.49
Helper 2 – 70%	$29.90	$30.94	$31.93
Helper 1 – 60%	$25.63	$26.52	$27.37
Helper – 55%	$23.49	$24.31	$25.09
Probationary Helper – 50%	$21.36	$22.10	$22.81

When the Contractor appoints a Mechanic as a Foreman, the person so appointed shall be paid the rate set out above for Foreman.

3. Definitions, Qualifications and Ratios

a) General Conditions

i) There shall be no restrictions placed on the character of work which a Helper may perform under the direction of an Elevator Constructor Mechanic;

ii) The total number of Helpers employed shall not exceed the number of Elevator Constructor Mechanics employed on any one (1) job, except on jobs where two (2) teams or more are working. In such cases, one (1) extra Helper may be employed for the first two (2) teams and an extra Helper for each additional three (3) teams.

However, the Contractor may employ additional Helpers, provided they are under the direction of a Mechanic, for handling and hoisting material and on foundation work. When removing old and installing new cables on existing elevator installations, a contractor may use two (2) Helpers to one (1) Mechanic;

iii) A Helper will not qualify or be raised to the capacity of Mechanic until he has worked for a period of four (4) years in the Elevator Industry and has passed an examination administered by the Joint Examining Committee (a committee consisting of three (3) representatives from the employers referred to in the Escalation and Reference Section of this Appendix and three (3) from the Union);

iv) It is understood that probationary employees (as defined below) may be discharged by the Contractor and such discharges shall not be grievable.

b) Probationary Helper

A newly hired employee without previous mechanical experience shall be deemed to be a probationary employee and classified as a Probationary Helper for a period or periods totalling six (6) months within the aggregate period of not more than nine (9) months. Such a person must be physically fit and possess a high school diploma or the equivalent thereof. He must possess an Emergency Level First Aid Certificate and a C.P.R. Certificate.

The Contractor and the Union will test the ability of a probationary employee during this six (6) month period and if they agree that the employee does not display sufficient aptitude to become a Helper, he shall be discharged.

The probationary period may be worked with more than one (1) employer, and the period of six (6) months probation may cover an aggregate period of not more than nine (9) months;

c) Helper

Upon completion of 6 months in the industry, to the satisfaction of the Employer and the Union, a Probationary Helper shall be classified as a Helper. He shall receive 55% of the Mechanics Rate. For further advancement in the Industry, he shall successfully complete the recognized courses of training as designated by the Local Area Committee;

d) Helper One

Upon completion of 12 months work in the Industry and successful completion of the courses mentioned in c) above, this employee will be classified as Helper One. For further advancement in the Industry, he shall successfully complete the recognized courses of training as designated by the Local Area Committee. He shall receive 60% of the Mechanics Rate and remain in this classification for a further 12 months in the Industry;

e) Helper Two

Upon completion of 24 months work in the Industry and successful completion of the courses mentioned in d) above, this Employee will be classified as Helper Two. For further advancement in the Industry, he shall successfully complete the recognized courses of training as designated by the Local Area Committee. He shall receive 70% of the Mechanics Rate and remain in this classification for a further 12 months in the Industry;

f) Helper Three

Upon completion of 36 months work in the Industry and successful completion of the courses mentioned in e) above, this Employee will be classified as Helper Three. For further advancement in the Industry, he shall successfully complete the recognized courses of training as designated by the Local Area Committee. He shall receive 80% of the Mechanics Rate and remain in this classification for a further 12 months in the Industry.

An individual with one (1) year's previous mechanical experience in the Elevator Industry may be hired as a probationary employee and employed either as a Helper or be paid at the hourly wage rate for a Mechanic for a period of six (6) months at which time he shall be given an examination by the Joint Examining Committee to ascertain if he qualifies as a Mechanic.

If the employee does not pass the examination, he may be discharged if such action is recommended by the Examining Committee, or the Contractor may elect to retain him as a Helper. At the discretion of the Examining Committee, he may be given another examination to qualify as a Mechanic at the end of a further one (1) year period.

The Helper Three must avail himself to be tested as a Mechanic within two years of receiving Helper Three status. Failure to write or successfully complete the Mechanics Exam (as administered by C.E.I.E.P) after the second Attempt, an Employees status will revert to the level of Helper.

4. Vacation and Holiday Pay

The Contractor shall credit each employee with twelve percent (12%) of gross earnings, and this amount shall represent the combined holiday and vacation pay credits. This amount shall be paid to an employee with his regular pay.

For purposes of clarification, the following amounts will be excluded when calculating gross earnings: Contractor contributions to Welfare, Pension and Education Plans.

For accounting purposes, eight percent (8%) shall be deemed to be vacation pay and four percent (4%) shall be deemed to be pay in lieu of Holidays.

The scheduling of time off for vacation shall be arranged by mutual agreement between the Contractor and the employee.

When a Holiday falls on a Saturday or Sunday, which is a non-working day, such Holiday shall be observed on the next regular work day. However, this provision shall not apply to any employee who is on Christmas Leave, Isolation Leave or any other type of Leave of Absence when the Holiday occurs.

5. Welfare Plan

The Contractor, and each Mechanic and Helper in his employ shall respectively contribute the amounts set out below to the Canadian Elevator Industry Welfare Plan. Contributions shall apply to all hours worked and employee contributions shall be collected at the source as a payroll deduction.

Contractor's Contribution	Employee's Contribution
$1.18 per hour worked	$1.68 per hour worked

6. Pension Plan

The Contractor, and each Mechanic and Helper in his employ shall respectively contribute the amounts set out below to the Canadian Elevator Industry Pension Plan. Contributions shall apply to all hours worked and employee contributions shall be collected at the source as a payroll deduction.

Contractor's Contributions	Employee's Contribution
$2.25 per hour worked	$3.71 per hour worked

7. Educational Fund

The Contractor shall contribute the amount set out below for all hours worked, by all Elevator Constructor Mechanics and Helpers in his employ to the Canadian Elevator Industry Educational Programme:

Contractor's Contributions	Employee's Contribution
$0.31 per hour worked	$0.225 per hour worked

8. Payment for Lost Clothes and Tools

The Contractor will provide a secured area for employees to store tools and clothing and likewise the employee recognizes his responsibility to protect company tools. The Contractor will reimburse Mechanics and Helpers for 75% of the value of tools or clothing lost on the job, subject to the following maximum amounts:

Overcoat	$ 50.00
Other Clothing	$ 60.00
Tools	$600.00

An affidavit, must be submitted to the Local Union and the Contractor by the employee claiming the loss.

9. Isolation Travel (Return Transportation Time Periods) - Expenses

The return transportation time period referred to in Article 19.2.1 for this Appendix shall be:

- After sixty (60) calendar days.

Travel time shall only apply on the return portion of an Isolation Leave trip (i.e. from the employee's T.D.P. to the Project Camp Site).

The amount of travel time to be paid shall be in accordance with the provisions of Article 19.1.2.5.1 or 19.1.2.5.2, as the case may be, and if applicable, the provisions of Article 19.1.2.5.3.

Travel time shall be paid at the employee's straight time rate, and an employee shall receive such payment pursuant to the provisions of Article 19.1.2.6.

10. Escalation and Reference

10.1 Wage Rate Provisions

The wage rate for the classifications set out in this Appendix will be adjusted by an amount equal to and effective on the dates of any adjustments in wage rates for corresponding classifications which may be negotiated from time to time by the International Union of Elevator Constructors, on behalf of Local Union 102, the Member Firms of the National Elevator and Escalator Association.

Classifications eligible for adjustment may include general foreman, foreman, leadhand, chargehand, pusher, journeyman, apprentices, helpers and trainees.

10.1.1 Except as otherwise noted, the following provisions will be incorporated or adjusted to be consistent with corresponding provisions negotiated from time to time by the aforementioned Parties:

a) Definitions and qualificational requirements for applicable classifications;

b) Ratios indicating the number of apprentices, helpers, or other types of trainees who may be employed.

10.2 Other Conditions of Employment

Except as otherwise noted, the following conditions of employment will be incorporated or adjusted to be consistent with corresponding conditions of employment negotiated from time to time by the aforementioned Parties:

a) Overtime payments (subject to the restrictions set out in Section 10.3);

b) Shift premium but excluding any shift premium applicable to overtime hours;

c) Vacation and Vacation Pay - such provisions may include any provisions relative to the timing of payment of vacation pay but shall not include any provisions stipulating when vacation time must be granted, and in lieu of such a provision, the following shall be substituted: "The scheduling of time off for vacation shall be arranged by mutual agreement between the Contractor and the employee";

d) Pay in lieu of Holidays and any provisions requiring the transferring and observing of the Holiday on a day, other than the day on which the Holiday falls (subject to the restrictions set out in Section 10.2.1);

e) Registered and trusteed pension and health and welfare plans (subject to the restrictions set out in Section 10.2.2);

f) Callout provisions;

g) Rest provisions between shifts;

h) Personal effects insurance provisions;

i) Provisions governing welding and other special trade related tests;

j) Safety clothing;

k) tool lists and provisions governing loss of such tools on the Project.

l) The following trusteed plans, each of which shall be subject to the restrictions set out in Section 10.2.3:

   i) building fund;

   ii) trade improvement plans including educational and apprenticeship funds;

   iii) industrial promotion funds.

m) The time period between Isolation Leaves (subject to the restrictions of Article 19.2.1.3);

n) Travel time associated with the taking of an Isolation Leave, and the hourly rate at which travel time will be paid (subject to the restrictions set out in Section 10.2.4).

10.2.1 A Holiday set out in Article 17 may be observed on a day, other than the day on which it falls, provided the Holiday falls on a Saturday or Sunday which is a non-working day, in which case the Holiday may be observed on the closest following working day. The transferring of a Holiday shall not apply to any employee who is on Christmas Leave, Isolation Leave or any other type of Leave of Absence when the Holiday occurs.

10.2.2 The Contractor's contribution to any pension and health and welfare plan may be applied on a per hour worked basis; however, the Contractor's contribution rate in respect of overtime hours shall not be greater than the required contribution rate for Contractors in respect of straight time hours.

10.2.3 The Contractor's contribution to any of the plans referred to in Section 10.2(l) may be applied on a per hour worked basis; however, the Contractor's contribution rate in respect of overtime hours shall not be greater than the required contribution rate for contractors in respect of straight time hours.

10.2.4 Travel time may only apply to the return portion of an Isolation Leave trip (i.e. from the employee's T.D.P. to the Project Camp Site). The amount of travel time to be paid shall not be greater than the travel time set out in Articles 19.1.2.5.1, 19.1.2.5.2 and 19.1.2.5.3, as may be applicable. The hourly rate at which travel time may be paid shall not be greater than the employee's straight time rate. Payment of travel time shall be in accordance with the provisions of Article 19.1.2.6.

10.3 Notwithstanding anything contained in this Agreement or in this Appendix, the regular hours of work are not subject to adjustment during the life of this Agreement, and such regular hours of work shall be paid at regular rates of wages. Further, overtime payments at a rate greater than time and one-half will not be introduced in this Appendix in respect of the first two (2) hours of overtime, Monday to Friday inclusive.

10.4 The provisions of 10.1 and 10.2 above shall be dealt with by following the procedure set out in Article 30 of this Agreement.

SCHEDULES

SCHEDULE "A" – ALLIED HYDRO COUNCIL MEMBER UNIONS

ALLIED HYDRO COUNCIL MEMBER UNIONS

CONSTRUCTION & SPECIALIZED WORKERS' UNION OF NORTH AMERICA, and Local Union 1258 of this International Union.

INTERNATIONAL UNION OF OPERATING ENGINEERS, and Local 987 of this International Union.

INTERNATIONAL BROTHERHOOD OF TEAMSTERS, CHAUFFEURS, WAREHOUSEMEN AND HELPERS OF AMERICA, and Local Union 979 of this International Union.

UNITED BROTHERHOOD OF CARPENTERS AND JOINERS OF AMERICA, and Local Union 343 (Carpenters) of this International Union, and Local Union 1443 (Millwrights, Machine Erectors, Industrial Mechanics Maintenance) of this International Union.

INTERNATIONAL UNION OF PAINTERS & ALLIED TRADES, GLASS-WORKERS DIVISION, SIGNWORKERS & CARPET & FLOOR TILE LAYERS DIVISION, and Local Union 739 of this International Union.

INTERNATIONAL ASSOCIATION OF HEAT AND FROST INSULATORS AND ASBESTOS WORKERS, and Local Union 99 of this International Union.

INTERNATIONAL UNION OF BRICKLAYERS AND ALLIED CRAFTWORKERS, and Local Union No. 1 of this International Union.

SHEET METAL WORKERS INTERNATIONAL ASSOCIATION, and Local Union 511 of this International Union.

INTERNATIONAL BROTHERHOOD OF BOILERMAKERS, IRON SHIPBUILDERS & HELPERS OF AMERICA, and Local Union 555 of this International Union.

INTERNATIONAL ASSOCIATION OF BRIDGE, STRUCTURAL, ORNAMENTAL & REINFORCING IRONWORKERS, and Local 728 of this International Union.

INTERNATIONAL BROTHERHOOD OF ELECTRICAL WORKERS, and Local Union 2085 of this International Union.

UNITED ASSOCIATION OF JOURNEYMEN AND APPRENTICES OF THE PLUMBING AND PIPEFITTING INDUSTRY OF THE UNITED STATES AND CANADA, and Local Union 254 of this International Union.

CANADIAN OFFICE AND PROFESSIONAL EMPLOYEES UNION, Local Union 342.

UNITEHERE, Local Union 206.

INTERNATIONAL UNION OF ELEVATOR CONSTRUCTORS, and Local 102 of this International Union.

SCHEDULE “B” – CHECK-OFF AUTHORIZATION FORM (AHC)

See next page for full form

SCHEDULE "B"

ALLIED HYDRO COUNCIL OF MANITOBA

Check-Off Authorization: for use on the _____Project

Job Order No._____ _____, 20_____
(Date)

Employed as _____

I hereby authorize _____(Company Name)
deduct from my wages each pay period (every two weeks) and pay to the Allied Hydro Council of Manitoba the sum 25¢ per hour for each hour worked or the amount as may be adjusted from time to time by the proper authorized officers, in accordance with the Allied Hydro Council of Manitoba Constitution and By-laws, and I am a member of or will join the appropriate Local Union of the Council.

Why is This Amount Deducted?
It is to help in defraying the expense of the Council, to provide communications, administration of the Union Agreement and assistance to the Union Members employed on the Project.

(Name and Local Union number of the Union)

I also authorize the above named Company to deduct from my wages the required Union Dues and amounts that may be set and adjusted from time to time by the proper authorized officers of the Local Union and toward same to the above named Local Union of which I am a member, or will join.

Initiation Fees, Assessments and/or Back Dues in the amount of _____ (or as adjusted). In equal payments spread over _____pay periods.

and

Monthly dues in the amount of _____(or as adjusted) in equal payments each pay period.

Employee: Please keep this form, it is your receipt for having signed the Check- Off Form. All new employees who are not members in good standing with their Union must see their Job Steward or Business Representative. All employees working on this project are required to sign a check-off form and become union members as a condition of employment. Failure to be a Union Member subjects the new employee to dismissal. (See your union agreement).

Payroll No_____ Social Security No. _____

Name_____
(Please Print)

Witness_____ Signature_____

Address _____
_____
(For Local Union Use)

Protecting your personal information, the Allied Hydro Council recognized and respects every individual's right to privacy. When personal information is provided to us, we establish a confidential file that is kept in the office of the Allied Hydro Council. We limit access to information in your file to union staff or persons authorized by the Allied Hydro Council or to person to whom you have granted access and to persons authorized by law. I hereby authorize the Allied Hydro Council of Manitoba the use of my Social Insurance Number for the purposes of government reporting, identification and administration purposes.

SCHEDULE "C" – UNION ASSESSMENTS, INITIATION AND DUES STRUCTURE

ALLIED HYDRO COUNCIL OF MANITOBA

This is a revised, up—to—date listing of the Allied Hydro Council of Manitoba Assessments, initiations and dues structure of Local Unions that are part of the Council:

DUES MUST BE SUBMITTED THE SECOND WEEK OF THE FOLLOWING MONTH

Allied Hydro Council of Manitoba
Assessments: $0.35 each hour worked

MUST BE PAID BY ALL MEMBERS IN ADDITION TO AFFILIATE UNION DUES

Allied Hydro Council
1 – 225 McPhillips Street
Winnipeg, MB R3E 2K3

1. Labourers International Union of North America, Local Union #1258

Last Updated: May 1, 2018

Initiation Fee: $450.00

Monthly Dues: $ 40.00 (plus Work Dues of 75¢ per hour)

1A. Security Guards, Labourers International Union of North America Local #1258

Last Updated: January 1, 2018

Initiation Fees: $100.00
Monthly Dues: $40.00 (plus Work Dues of 75¢ per hour)

Submit To: 541 Waterfront Drive, Winnipeg, MB R3B 0H1

2. International Union of Operating Engineers, Local #987

Last Updated: January 1st, 2020

Initiation Fee: $116.00
Working Dues: $13.25 plus 2% of gross pay with a Minimum payment of 32.00.

2A. Equipment Operators

Last Updated: January1st , 2020

Initiation Fee: $116.00
Working Dues: $13.25 plus 2% of gross pay with a Minimum payment of 32.00.

Submit To: 244 Cree Crescent, Winnipeg, MB R3J 3W1

3. General Teamsters, Local Union #979
Last Updated: December 7, 2016

Initiation Fee: $100.00

Monthly Dues: $ 28.00 (plus 24¢ per hour for each hour worked)

Industry Advancement Fund: $0.10 for each hour worked

Submit To: B1 - 1680 Dublin Avenue, Winnipeg, MB R3H 1A8

4. United Brotherhood of Carpenters and Joiners of America, Local Union #343
Last Updated: May 1, 2018

Initiation Fee: $125.00
Monthly Dues: (Journeyman) $ 25.00 (plus 3% per hour each hour worked)
International Dues: $0.05/hr

Apprentices Initiation Fees:
1st Year – $40.00
2nd Year – $60.00
3rd Year – $80.00
4th Year – $100.00

Monthly Dues (Apprentices): $ 25.00 (plus 3% per hour for each hour worked)

Submit to: 87 Cole Avenue, Winnipeg, MB R2L 1J3

4A. Millwrights Local Union #1443
Last Updated: May 1, 2018

Initiation Fee: $300.00

Re-initiation Fee $350.00

Monthly Dues: $25.00 & 3% of hours worked (Journeyman & Apprentices)

Submit To: 95 Cole Avenue, Winnipeg, MB R2J 1J3

5. International Union of Painters and Allied Trades, Local Union #739, Painters Division
Last Updated: May 1, 2017

Initiation Fee: $150.00 (Journeyman & Apprentices)
Monthly Dues: $30.70 Plus 3% of all hours worked

5A. International Union of Painters and Allied Trades, Local Union #739, Glassworkers Division
Last Updated: May 1st, 2017

Initiation Fee: $100.00
Monthly Dues: $30.70 Plus 3% of all hours worked

5B. International Brotherhood of Painters and Allied Trades, Local Union #739, Floor Covering Division
Last Updated: May 1st, 2017

Initiation Fee: $100.00
Monthly Dues: $30.70 Plus 3% of all hours worked

Submit To: 168 Higgins Avenue, Winnipeg, MB R3B 0B8

6. International Association of Heat and Frost Insulators & Allied Workers, Local Union #99
Last Updated: Mar. 5/14

Initiation Fee: $400.00
Monthly Dues: $ 30.00 Plus 3.75% of total compensation package including employer paid benefits per hour worked.

Submit To: 946 Elgin Avenue, Winnipeg, MB R3E 1B4

7. United Brotherhood of Carpenters & Joiners of America, Local Union #343 (Lathing Trade)
Last Updated: January 1, 2013

Initiation Fee: (Journeyman) $125.00
Monthly Dues: $ 26.50 plus 3% per hour worked
Initiation Fee: (Apprentice) $100.00

Monthly Dues: $ 20.00

Submit To: 87 Cole Avenue, Winnipeg, MB R2L 1J3

8. Operative Plasterers and Cement Masons International Association of the United States and Canada, Local Union #222
Last Updated: April 8, 2019

Initiation Fee Journeyman Plasterer: $390.00

Initiation Fee Journeyman Cement Masons: $1,200.00

Monthly Dues: $5.00 per month

Field Dues: 2.5% of gross earnings

Building Trade Council Dues: 8¢ per hour

International Working Dues: 1% of total wage package

Apprentices initiation fees:

	Plasterers	Cement Masons
Trainee	$195	$248.25
1st year	$234	$279.75
2nd year	$273	$311.25
3rd year	$312	$342.75

Submit To: #42 4004-97 street Edmonton Alberta T6E 6N1

9. International Union of Bricklayers & Allied Craftsmen, 4 Local #1

Initiation Fee: (Journeyman) $ 450.00
Initiation Fee: (Apprentices) $ 175.00

Bricklayers, Stone Masons, Cement Block Layers

Monthly Dues: $25.00 plus $1.00 for each hour worked plus 5¢ promotion fund

Tilesetters and Terrazzo Workers

Monthly Dues: $25.00 plus 65¢ for each hour worked

Submit To: 68 - 1313 Border Street, Winnipeg, MB R3H 0X4

10. Sheetmetal Workers International Association, Local Union #511
Last Updated: May 1, 2016

Sheet Metal Workers Initiation Fee:
Journeyman $100.00

New Journeyman (90%) $90.00
Fourth Year (75%) $75.00
Third Year (60%) $60.00
Second Year (50%) $50.00
First Year (45%) $ 45.00
Pre-Apprentice (35%) $ 35.00
Classified Worker (40%) $ 40.00

Union Due: July 1, 2016 4x hrly rate per month plus 18¢ per hour worked

10A. Roofers
***Last Updated:* May 1, 2016**

Initiation Fees: All Classifications $50.00
Union Dues: July 1, 2016 4x hrly rate per month plus 18¢ per hour worked

10B. Sheeters, Deckers and Cladders
Last Updated: May 1, 2016

Initiation Fees:
Journeyman A $100.00
Journeyman B (96%) $96.00
SDC Skilled Tradesperson 2 (85%) $85.00
SDC Skilled Tradesperson 1 (80%) $80.00
SDC General Construction Labourer 2 (75%) $75.00
SDC General Construction Labourer 1 (67%) $67.00
SDC General Construction Labourer Trainee 2 (55%) $55.00
SDC General Construction Labourer Trainee 1 (45%) $45.00

Union Dues: July 1, 2016 $30.00 per month plus 18¢/hr

Submit To: 438 Higgins Avenue, Winnipeg, MB R3A 1S5

11. International Brotherhood of Boilermakers, Iron Ship Builders, Blacksmith, Forgers and Helpers, Local Union #555
Last Updated: February 20, 2019

Initiation Fee: $500.00
Monthly Dues: $55.40 and 4.25% of gross taxable earnings
Industrial Promotion Fund: Helmets to Hardhats (H2H) $.01 for every hour worked

Submit To: 110 Haarsma Road, East St. Paul, MB R3E 0M8

12. International Association of Bridge, Structural and Ornamental Ironworkers, Local Union #728 Structural Ironworkers, Riggers & Welders
Last Updated: May 1st, 2018

Initiation Fees: J/M: $500.00
Apprentice: $100.00

Monthly Union Dues:
J/M: $37.00 plus 2.8% of total J/M wage package (equaling $1.51) per hour worked.
Apprentice: $36.00 plus 2.8% of total J/M wage package (equaling $1.51) per hour worked.
Travel Card Workers: $5.00 per week, plus 2.8% of total J/M wage package (equaling $1.51) per hour worked.

12A. Rodmen, Rebar Placers

Initiation Fees: J/M: $500.00
Apprentice: $100.00

Monthly Union Dues:J/M: $37.00 plus 2.8% of total J/M wage package (equaling $1.36) per hour worked.
Apprentice: $36.00 plus 2.8% of total J/M wage package (equaling $1.36) per hour worked.
Travel Card Workers: $5.00 per week, plus 2.8% of total J/M wage package (equaling $1.36) per hour worked.

Submit To: 895 A Century Street, Winnipeg, MB R3H 0M3

13. International Brotherhood of Electrical Workers, Local Union #2085
Last Updated: January 1, 2020

Initiation Fee: Journeyman Wireman: $82.00
Apprentices: $82.00 (Plus an additional $50 Apprentice Manitoba required fee)
All Other Classifications: $22.00
Monthly Union Dues: All Classifications $56.70 Plus 3% of gross Pay (Gross Pay is defined as base rate plus 4.5% S.H.P & 6% V.P.)

Submit To:
556 Notre Dame Avenue, Winnipeg, MB R3G 1S4

14. United Association of Journeymen and Apprentices of the Plumbing and Pipefitting Industry of the United States and Canada, Local #254
Last Updated: January 1, 2018

Initiation Fee: (Journeyman & Apprentices) $250.00
Monthly Union Dues: $45.00 (plus 2.5% of Gross wages)

Monthly Dues: 1st year, 2nd year, 3rd year, 4th year, 5th year all the same :Year Monthly Dues $43.00 (plus 2.5% of Gross Pay)

14A. Refrigeration Workers
Last Updated: January 1, 2018

Initiation Fee: (Journeyman & Apprentices) $250.00
Monthly Dues: $45.00 plus 2.5% of Gross Pay

Submit To: 34 Higgins Avenue, Winnipeg, MB R3B 0A5

15. Canadian Office and Professional Employees Union, Local#342

Initiation Fee: $50.00
Monthly Union Dues: 2% of gross monthly Earnings

Submit To: 403D – 275 Broadway, Winnipeg, MB R3C 4M6

16. Workers United, Local Union #206
Last Updated: January 20th 2017

Initiation Fee: $ 275.00
Monthly Dues: 2% of gross weekly wages starting January 2016, plus $9.00 per month**,** and 10¢ per hour working dues for all hours worked, with minimum dues of $35.00 per month
Defence Fund: $5.00 (one time deduction)

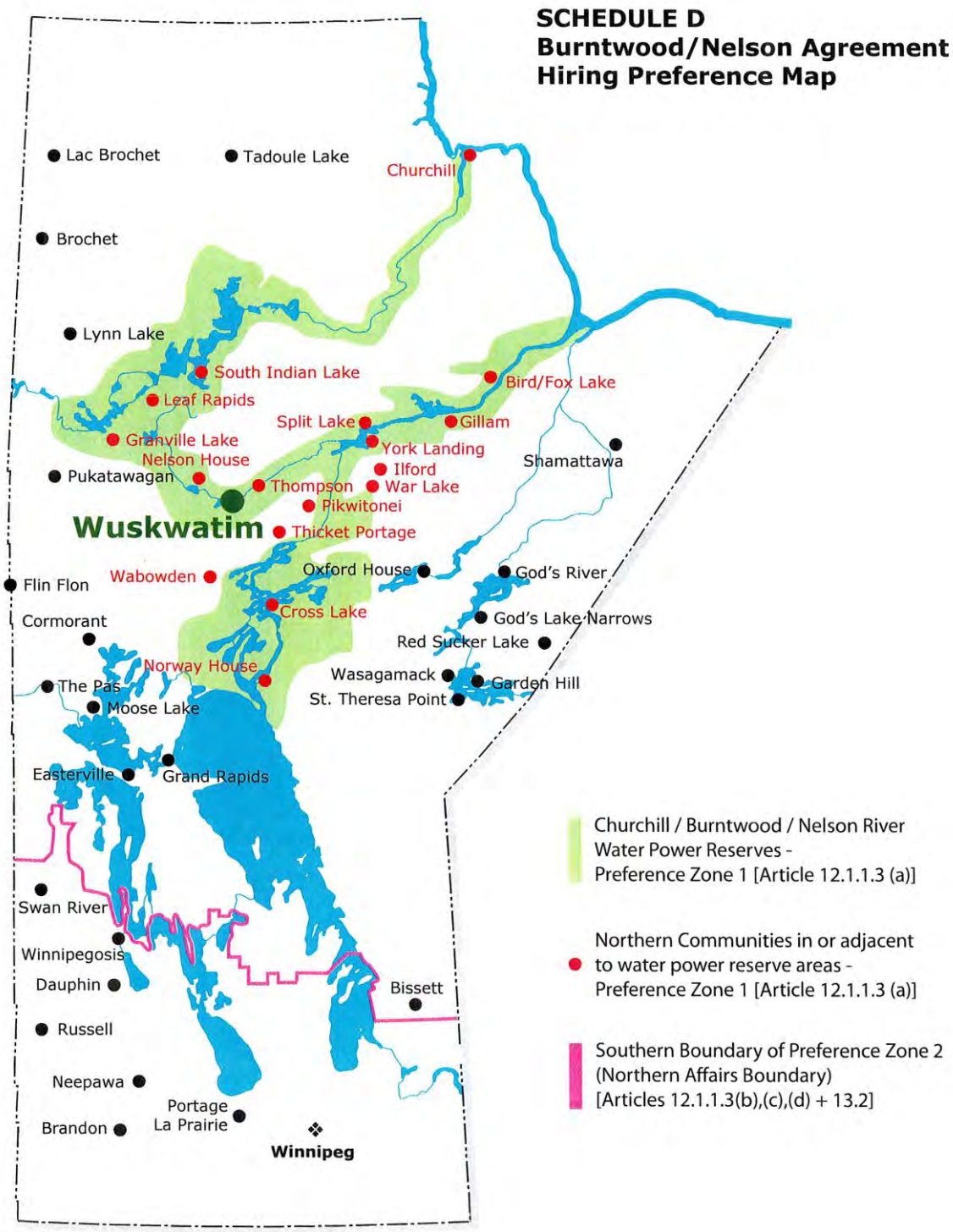
Submit To: 4 – 1000 Notre Dame Avenue, Winnipeg, MB R3E 0N3

17. International Union of Elevator Constructors, Local Union#102
Last Updated: February 10th, 2017

Initiation Fee: $1000.00
Union Dues: 1 hour at Mechanic's wage rate per week.

Submit To:
1794 St. Matthew's Avenue, Winnipeg, MB R3H 0A5

SCHEDULE "D" – EMPLOYMENT PREFERENCE AREA



SCHEDULE "E"" – LETTERS OF AGREEMENT

TABLE OF CONTENTS

REFERENCE	SUBJECT MATTERS
Letter of Agreement No. 1	Implementation of Special Employment Measures for Specific Projects
Letter of Agreement No. 2	Transfer of Day Off From Sunday to Saturday
Letter of Agreement No. 3	Security Guards Union Affiliation and Related Matters
~~Letter of Agreement No. 4~~	~~Wuskwatim Project - Special Measures~~ Deleted as Per HPMA/AHC 11/13/2013
Letter of Agreement No. 5	Provisions for the Review and Adjustment of Isolation Leave Frequency Set out in Article 19.2.1.1 and 19.2.1.3
Letter of Agreement No. 6	Radiography Work
~~Letter of Agreement No. 7~~	~~Application of the BNA to Work Associated With The Construction of Collector Lines (See Article 2.1)~~ Deleted as Per LOA #29
Letter of Agreement No. 8	Scaffolding Specialist Contractors
Letter of Agreement No. 9	Schedule A - Operative Plasterers & Cement Masons International Association, Local Union 222
Letter of Agreement No. 10	Appendix No. 3 - Teamsters - Introduction of Pension Plan
Letter of Agreement No. 11	Louis Riel Day
~~Letter of Agreement No. 12~~	~~Wuskwatim Project - Wages in Certain Classifications~~ Deleted as Per HPMA/AHC 11/13/2013
~~Letter of Agreement No. 13~~	~~Wuskwatim Project - O.N.E. Isolation Leave~~ Deleted as Per HPMA/AHC 11/13/2013

~~Letter of Agreement No. 15~~	~~Wuskwatim Project – O.N.E Wage Enhancements Labourers (Appendix 1)~~ Deleted as Per HPMA/AHC 11/13/2013
~~Letter of Agreement No. 16~~	~~Wuskwatim Project – O.N.E Wage Enhancements Operating Engineers (Appendix 2a)~~ Deleted as Per HPMA/AHC 11/13/2013
~~Letter of Agreement No. 17~~	~~Wuskwatim Project – O.N.E Wage Enhancements Carpenters (Appendix 4)~~ Deleted as Per HPMA/AHC 11/13/2013
~~Letter of Agreement No. 18~~	~~Wuskwatim Project – O.N.E Wage Enhancements Teamsters (Appendix 3)~~ Deleted as Per HPMA/AHC 11/13/2013
~~Letter of Agreement No. 19~~	~~Wuskwatim Project – O.N.E Wage Enhancements Ironworkers (Appendix 12)~~ Deleted as Per HPMA/AHC 11/13/2013
~~Letter of Agreement No. 20~~	~~Wuskwatim Project – O.N.E Wage Enhancements Rodmen (Appendix 12a)~~ Deleted as Per HPMA/AHC 11/13/2013
~~Letter of Agreement No. 21~~	~~Wuskwatim Project – O.N.E Wage Enhancements Cement Masons (Appendix 21)~~ Deleted as Per HPMA/AHC 11/013/2013
~~Letter of Agreement No. 22~~	~~Wuskwatim Project – O.N.E Wage Enhancements Office and Professional Employees (Appendix 15)~~ Deleted as Per HPMA/AHC 11/13/2013
Letter of Agreement No. 23	Special Measures for the Keeyask Generating Station Project
~~Letter of Agreement No. 24~~	~~Wuskwatim Project - Application of Letters of Agreement No. 15 thru No. 22, Inclusive~~ Deleted as Per HPMA/AHC 11/13/2013
Letter of Agreement No. 25	Introduction of Appendix 14b) - Sprinkler System Installers
Letter of Agreement No. 26	Adjustment of Isolation Leave Frequency Set out in Article 19.2.1.1 and 19.2.1.3

Letter of Agreement No. 27	Keeyask and Keewatinoow - Article 19 Isolation Leave Frequency, Travel Time Associated with Isolation Leaves, and Travel Costs Associated with the Transportation Departure Point (T.D.P) c)
Letter of Agreement No. 28	Emergency Medical Classifications Found Within Appendix 15
Letter of Agreement No. 29	Journeyperson Lineman/cable splicer and Associated Collector Line Trades
Letter of Agreement No. 30	Blasters and Drillers (Appendix 1)
Letter of Agreement No. 31	Appendix No. 15 - COPE - Introduction of Health and Welfare Trust Fund
Letter of Agreement No. 32	Appendix No. 1A – Security Guards
Letter of Agreement No. 33	Appendix No. 2 - Introduction of Classification to Appendix 2 Crane Operator – Telebelt Operator
Letter of Agreement No 34	Commissioning Work
Letter of Agreement No 35	Completion Bonus
Letter of Agreement No 36	Isolation Leave Frequency
Letter of Agreement No 37	Ability to Regularly Schedule Sundays
Letter of Agreement No 38	Utilization of Supplementary Workers
Letter of Agreement No 39	Project Labour Management Services Agreement
Letter of Agreement No 40	Amendment to Hiring Procedure and Referral System to Maximize Utilization of Qualified Manitobans
Letter of Agreement No 41	Work Teams
Letter of Agreement No 42	Tower Crane Trade Improvement Trust Fund
Letter of Agreement No 43	Power Engineer Classification
Letter of Agreement No 44	Special Measures for Hiring of Apprentices and Trainees
Letter of Agreement No 45	Concrete Finisher and Read Seal Cement Finisher Classifications

Letter of Agreement No 46	Personnel Risk Assessment - PRA
Letter of Agreement No 47	COPE Relocation of employees
Letter of Agreement No 48	Layoff Subject to Recall
Letter of Agreement No 49	Labourers Trust Fund
Letter of Agreement No 50	Scaffolder Classification
Letter of Agreement No 51	Carpenter Foreman Coordinator Classification
Letter of Agreement No 52	Labourer Foreman Coordinator Classification
Letter of Agreement No 53	Duration of Isolation Leaves
Letter of Agreement No 54	Work Team / Composite Crew
Letter of Agreement No 55	Article 15 – Breaks
Letter of Agreement No 56	Trade Flexibility
Letter of Agreement No 57	Project Labour Management Services Agreement LOA 39
Letter of Agreement No 58	Project Labour Management Services Agreement (new)

BURNTWOOD/NELSON AGREEMENT

Letter of Agreement No. 1- Special Employment Measures for Specific Projects

Subject: Implementation of Special Employment Measures for Specific Projects

Whereas:

a) During 2000 and 2001, Manitoba Hydro signed Agreements in Principle (AIPs) with certain First Nations living in the vicinity of the proposed Wuskwatim Generating Station on the Burntwood River and the proposed Gull (Keeyask) Generating Station on the Nelson River and, based on the principles in each AIP, is proceeding to develop Project Development Agreements (PDAs).

b) Each PDA will address, amongst other things, matters related to construction and ownership of the relevant generating station and will identify any special measures to be implemented during construction to facilitate the employment, training and retention of First Nations members and other Northern Aboriginals.

c) PDAs may also be utilized in respect of the development of other new generating stations on the Nelson and Burntwood Rivers, including Notigi. At this time, the sequence and timing of such projects has not been finalized.

d) The signing of any PDA may occur subsequent to the signing and/or effective date of a renewed BNA.

Now therefore, in consideration of the foregoing, the Association and the Council hereby agree as follows:

1. The Association will notify the Council, in writing, of the particulars respecting any employment related matters referenced in a PDA which:

    a) Address referral, recruitment or placement procedures, retention, and/or on-the-job training provisions, and;

    b) Are adjudged by the Association to be in conflict with existing BNA provisions and accordingly, would require an amendment to the BNA in order to be implemented.

2. Within 20 calendar days of the date of notification as provided above, the Association and the Council will arrange to meet and draft a mutually acceptable, project-specific Letter of Agreement, and the Parties further endeavor to finalize and sign the Letter of Agreement within a further period of 30 calendar days measured from the date of the initial meeting.

3. The Association and the Council will participate, if requested, in any meetings or committees established by Manitoba Hydro to discuss, renew, or assess any of the special measures intended for Northern Aboriginals. In the event meetings are held outside of Winnipeg, the Association shall be responsible for reasonable travel and accommodation expenses incurred by Council representatives.

4. The Association shall defend and indemnify the Council from and against any costs arising from a suit or proceeding that is attributable to special employment measures for Northern Aboriginals as set out in the Collective Agreement or a Letter of Agreement thereto. However, the Association shall have the right to assume full control of any action initiated against either the Association or the Council, or both, including the appointment of legal counsel.

5. The Parties recognize that Article 1.2 enables the Parties to amend any provision in the BNA at any time.

Agreed to this 7th day of October 2005

Allied Hydro Council of Manitoba	Hydro Projects Management Association
G. Bentley	T. Moffat
D. Martin	D. E. Rogalsky

BURNTWOOD/NELSON AGREEMENT

Letter of Agreement No. 2 - Transfer of Day Off From Sunday to Saturday

Subject: Transfer of Day Off From Sunday to Saturday.

Whereas the Association and the Council are desirous of amending the Agreement to enable those employees working the second and/or night shift to have a more appropriate night off with a view to enhancing social, recreational and other aspects of camp life.

Now therefore, the Association and the Council hereby agree as follows:

1. Subject to (3) below, the Contractor may advance the commencement of the work week for such employees from Monday to Sunday and pay for work performed on Sunday as if it had been performed on Monday and so on, with the result that Saturday would become the normal day of rest. If such an arrangement is initiated and an employee is requested to work on Saturday, such work shall be paid for as if the work was performed on Sunday, except as noted in (2) below.

2. During the calendar work week in which the arrangements set out in (1) above are introduced or discontinued, work on Saturday of that work week shall be paid for as set out in the Appendices of the B.N.A. and work on Sunday of that work week shall be treated as set out in (1) above.

3. Implementation of the foregoing modifications to the work week shall be contingent on:

    a) The Contractor agreeing to such modifications, and;

    b) The Council advising the Contractor that the majority of employees employed by that Contractor are in agreement with such modifications.

4. If the modification to the work week is to be implemented, it shall apply to all applicable shift employees of that Contractor. Further, but subject to (3) above, if a prime Contractor has engaged any Subcontractors, the prime Contractor will encourage such Subcontractors to adopt its work week arrangements.

5. If the modifications to the work week are found to be appropriate, the Association and the Council will promote and encourage its continuance from year to year.

6. If the modifications to the work week are found to be inappropriate, the Council, on behalf of the employees of a Contractor or the Association, on behalf of a Contractor Member, shall advise the other in writing in which case the work week shall be adjusted to be consistent with provisions in the Applicable Appendix of the B.N.A. and this adjustment shall be effected within fifteen (15) working days measured from the date the notification is received.

Agreed to this 7th day of October 2005

Allied Hydro Council of Manitoba	Hydro Projects Management Association T. Moffat
G. Bentley	
D. Martin	D. E. Rogalsky

BURNTWOOD/NELSON AGREEMENT

Letter of Agreement No. 3 - Security Guards Union Affiliation

Subject: Security Guards - Union Affiliation and Related Matters

Whereas the Association and the Council have agreed that security guards employed on the Project and covered by the Burntwood/Nelson Collective Agreement shall be affiliated with a member Union of the Council.

And Whereas, the Association and the Council have agreed that security guards shall be members of the Labourers' International Union of North America and Local 1258 of this International Union (hereinafter called the 'Union') and will be covered by Appendix 1a of the Collective Agreement.

And Whereas, the Association, the Council and the Union are desirous of prohibiting any impact on the duties of security guards in their employment by virtue of provisions of Constitutions, By Laws, rules or agreements of the Union;

Now Therefore in consideration of the foregoing and the covenants hereinafter set forth, the Association, the Council and the Union hereby agree as follows:

1. The Executive Board of Local Union 1258 and the General Executive Board of the International Union shall not process a charge laid by a union member or officer under the Constitution, By Laws, rules or agreements of the union in respect of the performance of the assigned employment duties of the security guards.

2. Union business and the servicing of Union members shall be conducted separately in respect of employees covered by Appendix No. 1 and Appendix No. 1a.

3. Notwithstanding any provision in the Collective Agreement to the contrary, the Union and the Council shall not require a Contractor to terminate the employment of any security guard by reason of loss of membership in the Union unless such loss of membership is by the employee's own request.

Agreed to this 7th day of October 2005

Allied Hydro Council of Manitoba	Hydro Projects Management Association
G. Bentley	T. Moffat
D. Martin	D. E. Rogalsky

With the concurrence of:

Labourers' International Union of North America and Local Union 1158 of this International Union

International Representative

President or Business Manager

BURNTWOOD/NELSON AGREEMENT

Letter of Agreement No. 5 - Adjustment of Isolation Leave Frequency

Subject: Provisions for the Review and Adjustment of Isolation Leave Frequency Set out in Article 19.2.1.1 and 19.2.1.3

1. During the months of January, 2011, January, 2014, and January, 2017, Isolation Leave (Return Transportation Time Periods) provisions in agreements being used for reference purposes for Appendices 2, 4, 4a, 10, 11, 12, 13, 14, and 14a will be reviewed by the Joint Appendix Review Committee. If the frequency of Isolation Leave in not less than two thirds (2/3) of the said agreements being used for reference purposes is 30 calendar days or less on either a first or second tour of duty, then the following sub-articles of Article 19 shall be amended to read as follows:

   19.2.1.1 Frequency When Isolation Leave Frequency Is Not Stipulated In An Appendix

   An employee working on the Project who is covered by an Appendix which does not stipulate Isolation Leave frequency shall have the option of taking an Isolation Leave after forty (40) calendar days from the commencement of his first tour of duty, and after thirty-five (35) calendar days from the commencement of each consecutive tour of duty thereafter. An employee who resigned or was laid-off or discharged and then is re-hired shall be considered to be serving his first tour of duty.

   19.2.1.3 Limitation Relative to Frequency of Isolation Leaves

   Notwithstanding any other provisions set out in this Agreement, the time period between Isolation Leaves may be greater than but shall not be less than thirty-five (35) calendar days from the commencement of an employee's first tour of duty, and thirty (30) calendar days from the commencement of each consecutive tour of duty thereafter. An employee who resigned or was laid-off or discharged and then is re-hired shall be considered to be serving his first tour of duty.

2. Any amendments arising from the application of paragraph 1 above shall be effective on March 1, 2011, March 1, 2014, or March 1, 2017, as the case may be, and will apply to tours of duty which commence on or after the said date.

3. Should the Joint Appendix Review Committee be unable to agree on any matter set out in paragraph 1 above, the procedure set out in Article 31 shall be followed.

Agreed to this 7th day of October 2005

Allied Hydro Council of Manitoba	Hydro Projects Management Association
G. Bentley	T. Moffat
D. Martin	D. E. Rogalsky

BURNTWOOD/NELSON AGREEMENT

Letter of Agreement No. 6 - Radiography Work

Subject: Radiography Work

Whereas the Council and the Association are desirous of amending the Agreement to establish wage rates and other conditions of employment for employees of Contractors performing radiography work which is not otherwise excluded from this Agreement by virtue of Article 2.2(l) i;

Now therefore the Parties hereby agree as follows:

1. Prior to the arrival of the said employees on the Project, the Joint Appendix Review Committee shall meet and establish wage rates and other conditions of employment.

2. In the event the Joint Appendix Review Committee are unable to agree on wage rates and other conditions of employment, the procedure set out in Article 3l shall be followed.

Agreed to this 7th day of October 2005

Allied Hydro Council of Manitoba	Hydro Projects Management Association
G. Bentley	T. Moffat
D. Martin	D. E. Rogalsky

BURNTWOOD / NELSON AGREEMENT

Letter of Agreement No. 8 - Scaffolding Specialist Contractors

Revised April 4, 2019

Subject: Scaffolding Specialist Contractors

Whereas the Council has advised the Association that in the event that a sub-contract is awarded to a scaffolding specialist contractor for erecting scaffolding, an additional classification may be required in Appendix 4 (Carpenters).

Now therefore, in consideration of the foregoing, the Association and the Council hereby agree as follows:

1. If a sub-contract is awarded to a scaffolding specialist contractor, at the request of either party, the Joint Appendix Review Committee shall meet under the provisions of Article 28 to determine if an additional classification is required. In addition, if it is agreed that a new classification should be established, the Joint Appendix Review Committee shall also consider the introduction of height premium provisions for this classification, if such provisions are unique to this classification.

2. The following amendments will be made to Appendix 4, section 12.1

   12.1 Wage Rate Provisions

   The wage rate for the Carpenter classifications set out in this Appendix will be adjusted by an amount equal to and effective on the dates of any adjustments in wage rates for corresponding classifications which may be negotiated from time to time by the United Brotherhood of Carpenters and Joiners of America, Local Union 343 and the Construction Labour Relations Association of Manitoba.

   The wage rate for the Industrial Scaffolder classification set out in this Appendix will be adjusted by an amount equal to and effective on the dates of any adjustments in wage rates for corresponding classifications which may be negotiated from time to time by the United Brotherhood of Carpenters and Joiners of America, Local Union 343 and the Signatory Scaffold Contractors in Manitoba.

   Initially agreed to this 7th day of October 2005, and the revision on this 4th day of April 2019.

Allied Hydro Council of Manitoba	Hydro Projects Management Association
_____	_____
_____	_____

BURNTWOOD / NELSON AGREEMENT

Letter of Agreement No. 9 - Schedule A - add Cement Masons

Subject: Schedule A - Operative Plasterers & Cement Masons International Association, Local Union 222

Whereas the Council has advised the Association that the Operative Plasterers & Cement Masons International Association, Local Union 222, should be added to Schedule A of this Agreement;

Now therefore, in consideration of the foregoing, the Association and the Council hereby agree as follows:

1. Schedule A of this Agreement is hereby amended to add and include the Operative Plasterers & Cement Masons International Association, Local Union 222.

Agreed to this 5th day of September 2006

Allied Hydro Council of Manitoba	Hydro Projects Management Association
Jason Rowe	Don E. Rogalsky
David Martin	Tom Moffat

BURNTWOOD / NELSON AGREEMENT

Letter of Agreement No. 10 - Teamsters - Introduction of Pension Plan

Subject: Appendix No. 3 - Teamsters - Introduction of Pension Plan

Whereas the Council has advised the Association that Local Union 979 has established a pension plan in which the employees covered by Appendix No. 3 are eligible to participate;

And whereas written verification has been forwarded to the Association and the Council confirming that Trust Agreements have been executed and registered;

Now therefore, in consideration of the foregoing, the Association and the Council hereby agree as follows:

1. Appendix No. 3 of this Agreement is hereby amended to delete the following from Section 7 (B):

"Provided:

(a) Local Union 979 establishes a pension plan in which employees covered this Appendix are eligible to participate.

(b) written verification is forwarded to the Association and the Council by the Board of Trustees of the plan confirming:

i) proviso (a), above

ii) that Trust Agreements have been executed and registered,a pension plan will be introduced into this Appendix on the basis that the Contractor's contribution rate to such a plan may be less than but shall not exceed two dollars and thirty-five cents ($2.35) per hour worked. At the time of introduction of the pension plan, the hourly rates for all classifications in this Appendix shall be reduced by the amount the Contractor's contribution to the said plan exceeds the sum of two dollars and thirty-five cents ($2.35).

Subject to the foregoing, at the option of the Council, contributions to the plan shall be made up by employee contributions or a combination of Contractor and employee contributions. The Council shall advise the Association of the required Contractor and/or employee contributions at the time the plan is established.

Pension plan contributions shall be subject to adjustments, however all contributions shall continue to be made as outlined above and the effective date of such adjustments shall correspond to an effective date of changes to wages (See Section 9.3). Further, for all adjustments, the hourly rates for all classifications in this Appendix shall be reduced by the full amount of Contractor's contribution [not less the sum of two dollars and thirty-five cents ($2.35) or any other amount]."

2. Appendix No. 3 of this Agreement is hereby further amended to add the following to Section 7 (B):

"The Contractor on behalf of each employee, and each employee covered by this Appendix shall respectively contribute the amounts set out below to the Teamsters, Local 362 Pension Plan. Contributions shall apply to all hours worked. Employee contributions shall be collected at the source as a payroll deduction.

The Contractor's contribution shall be:

- Effective March 1, 2007, $2.35 per hour.

The employee's contribution shall be: nil.

Submission of Trust Funds

The Contractor shall forward the above Trust Fund contributions to the designated Administrator of the Plan on or before the fifteenth day (15th) of each month following the month in which contributions were made.

A form shall be supplied by the Union for the Contractor to identify the application of all contributions, and such form shall indicate the Administrator and the address to which contributions shall be forwarded."

3. Appendix No. 3 of this Agreement is hereby further amended by deleting the word "a" between the words "and" and "pension" and deleting the words "[see Section 7 (B)]" in Section 9.3.1 such that Section 9.3.1 will now read:

"Subject to the conditions set out below, Health and Welfare and Pension contributions shall be adjusted to be consistent with contributions required in respect of Members of Local 979 covered by this Appendix and participating in the Teamsters Local 362 Health and Welfare Plan and Pension Plan."

Burntwood Nelson Agreement – Schedules

Agreed to this 30th day of May, 2007.

Allied Hydro Council of Manitoba	Hydro Projects Management Association
"David Martin"	"Angie Adams"
"Jason Rowe"	"Don E. Rogalsky"

BURNTWOOD / NELSON AGREEMENT

Letter of Agreement No. 11 - Louis Riel Day

Subject: Louis Riel Day

Whereas Article 17, Statutory and General Holidays, provides that any day proclaimed by the Provincial Government shall be observed as a Holiday;

And whereas Louis Riel Day (the third Monday in February) has been proclaimed by the Provincial Government as a Holiday;

Now therefore, in consideration of the foregoing, the Association and the Council hereby agree as follows:

3. Article 17.1 is hereby amended to add Louis Riel Day (the third Monday in February) as a Holiday that shall be observed each year, commencing in 2008.

Agreed to this 8th day of January, 2008.

Allied Hydro Council of Manitoba	Hydro Projects Management Association
"David Martin"	"Don E. Rogalsky"
"Jason Rowe"	"Angie Adams"

BURNTWOOD / NELSON AGREEMENT

Letter of Agreement No. 23 – Keeyask specifics

BETWEEN:

HYDRO PROJECTS MANAGEMENT ASSOCIATION
(hereinafter referred to as the "Association")

OF THE FIRST PART

- and -

ALLIED HYDRO COUNCIL OF MANITOBA
(hereinafter referred to as the "Council")

OF THE SECOND PART.

Letter of Agreement No. 23

Subject: Special Measures for the Keeyask generating station project (the "Project")

WHEREAS on October 7, 2005 the Association and the Council entered into a renewed and revised Collective Bargaining Agreement commonly known as the Burntwood/Nelson Agreement (hereinafter referred to as the "BNA").

AND WHEREAS the Association and the Council recognize that the Project will be owned by a unique partnership (hereinafter called the "Limited Partnership"), consisting of a wholly owned subsidiary of Manitoba Hydro, as general partner, and Manitoba Hydro, and an investment entity owned by Tataskweyak Cree Nation and War Lake First Nation, and investment entities owned by either or both of York Factory First Nation and Fox Lake Cree Nation, as limited partners;

AND WHEREAS in entering into the BNA, the Association and the Council recognized in Letter of Agreement No. 1 that specific projects undertaken under the BNA, and in particular, the Gull (Keeyask) Project, will require, in a project development agreement, special measures to be implemented during construction to facilitate the employment, training, and retention of First Nations members and other Northern Aboriginals which measures might be in conflict with existing BNA provisions relating to referral, recruitment or placement procedures, and/or on-the-job training provisions, and would require an amendment to the BNA in order to be implemented.

AND WHEREAS the Association and Council recognize that the Project will be built in the Split Lake Resource Management Area, in the vicinity of the Tataskweyak Cree Nation, War Lake First Nation, York Factory First Nation and Fox Lake Cree Nation (hereinafter referred to as the "**KCN**");

AND WHEREAS the Association and the Council recognize that 25% of the new entrants to the Manitoba labour force are estimated and expected to be Aboriginal people;

AND WHEREAS the Council and the Association recognize that recruitment, referral, placement, training and retention of Aboriginal employees on the Project as members of the Trade Unions comprising the Council is in their mutual and best interest;

AND WHEREAS the Association and the Council recognize that a successful Aboriginal employment strategy requires Aboriginal input and strategic alliances with Aboriginal organizations in its design and implementation and such an employment strategy must recognize and address important Aboriginal cultural issues at all stages in the recruitment, referral, placement, training and retention process;

AND WHEREAS the Council and the Association recognize that a necessary first step towards achieving positive employment outcomes lies in developing qualified Aboriginal employees in an appropriate learning environment and by providing active on-the-job experience as employee and management representatives on a major project;

AND WHEREAS the success of a recruitment, referral, placement, training and retention strategy for Aboriginal employees requires a reliable and accurate selection process that identifies and hires qualified candidates for appropriate positions;

AND WHEREAS the Association and the Council agree that a successful retention strategy for Aboriginal employees requires an inclusive workplace for Aboriginal employees;

NOW THEREFORE to this end, the Association and the Council hereby agree to amend the BNA, in relation to the Gull (Keeyask) Project only, as follows:

1. The Association membership will include the Limited Partnership for the purposes of Article 3.4 of the BNA.

2. The KCN shall appoint two representatives from their communities (one from Tataskweyak Cree Nation or War Lake First Nation, and one from York Factory First Nation or Fox Lake Cree Nation) to the Project site (hereinafter referred to as the "**Keeyask Site Representatives**") as advisors to the resident Site Manager/Engineer. The Keeyask Representatives shall report to the resident Site Manager/Engineer while on the site, but otherwise shall report to the KCN. The Keeyask Representatives shall be entitled to receive reasonable notice of and to attend pre-job meetings and meetings of any Committee constituted under the BNA for the purposes of the Project in an advisory, non-voting capacity.

3. The Council agrees to appoint a representative to the Advisory Group on Employment (hereinafter called the "AGE") to attend its meetings and to participate in the AGE in accordance with its terms of reference.

4. The Association shall fund the hiring by the Council of an Aboriginal union representative whose function will be to work under the direction of the Council's site representative and within the scope and intent of the AHC mandate for the purposes of, among other things, facilitating union interactions with Aboriginal employees, assisting Aboriginal employees in matters related to discipline directly affecting Aboriginal employees, including assisting with the initiation and advocacy of grievances on behalf of an aggrieved Aboriginal employee, liaising with the major contractors' human relations representatives, liaising with the Keeyask Representative, participating in the AGE and liaising with the Project's third-party retention support provider. One representative of CNP and one representative of both Fox Lake and York Factory will be entitled to participate in the selection process for the hiring of the individual, although the final decision for such hiring will rest with the AHC.

5. The parties agree that no person covered by the BNA shall be subject to discrimination or harassment on the basis of any characteristic referred to in subsection 9(2) of the Human Rights Code of the Province of Manitoba.

   The following procedure shall apply regarding claims of discrimination or harassment:

   (a) The complainant shall contact the site representative of the Council or the Council's Aboriginal representative with the particulars of the complaint. The appropriate Council representative shall forthwith speak to the appropriate representative of the contractor to resolve the complaint;

   (b) If the complaint is not resolved to the satisfaction of the complainant, the site representative of the Council shall forthwith contact the site representative of the Association, in writing, outlining the particulars of the complaint. The two site representatives shall then jointly investigate the complaint, utilizing the assistance of anyone they deem appropriate. Once the investigation is complete, each site representative shall issue a report containing their respective findings and recommendations for actions by the contractor. If the findings and recommendations are the same, they may issue the report jointly;

   (c) Discrimination and harassment complaints shall be governed solely by the above procedures and shall not be subject to Grievance/Arbitration. If the above procedures do not resolve the complaint to the satisfaction of the complainant, his/her recourse shall be to the Human Rights Commission under the *Human Rights Code*.

6. An employee may request June 21st off, without pay, in order to celebrate Aboriginal Solidarity Day. The employee shall make the request, in the manner prescribed by the contractor, at least five calendar days prior to June 21st. The request shall be granted unless, in the opinion of the contractor, the job is required to maintain essential services or complete critical activities. Where the request is granted, the employee will not forfeit any time toward his next isolation leave.

7. The parties acknowledge that the Limited Partnership intends to contract with a third-party service provider to provide retention support services to Aboriginal employees on the Project, both on the job site and in the camp site. These services must be provided without interfering with the progress of work on the Project and in compliance with camp site and safety rules.

8. The parties wish to maximize the number of Aboriginal apprentices and trainees and provide them with an opportunity to complete their apprenticeship or training program. The Association and the Council agree that where practical, contractors and their subcontractors shall combine journeypersons/non-trainees on related subcontracts, so that sufficient journeypersons/non- trainees will be available to permit the maximum number of apprentices/trainees pursuant to the applicable journeypersons/non-trainees to crew ratio stipulated in each Appendix to the BNA, for both designated trades and non-designated trades and services.

9. The Council shall encourage its member unions to approach and recruit Aboriginal apprentices, trainees, and journeypersons to be referred for employment on the Project by the member unions where applicable.

10. The parties agree to discuss and review the journeypersons to apprentice/trainee ratios set out in the Appendices to the BNA. Where agreed, in consultation with the KCN, the Association, the Council, the affected Union and the affected contractor will make joint representations to the Province of Manitoba to adjust apprentice ratios in order to maximize the development of Aboriginal employees in the designated trades.

11. Union site representatives will be required to take appropriate cross-cultural sensitivity and awareness training.

12. Notwithstanding the provisions of Article 13.2 to 13.7 inclusive, all candidates who are members of a KCN, are residents of Manitoba, and are registered with the Province of Manitoba (as the job placement and referral agency for the Project) shall be deemed to be Northern Aboriginals residing within the Churchill/Burntwood/Nelson River Area as described in Article 12.1.1.3(a).

13. In the event of a conflict between this Letter of Agreement and the terms of the Burntwood Nelson Collective Agreement, the terms of this Letter of Agreement shall prevail.

Dated at the City of Winnipeg, in the Province of Manitoba, this 24th day of July, 2009.

HYDRO PROJECTS MANAGEMENT ASSOCIATION

Per: _”Don E. Rogalsky_____

Per: _”Craig Michaluk”_____

ALLIED HYDRO COUNCIL OF MANITOBA

Per: _”Jim Murphy”_____

Per: _”David Martin”__ _____

BURNTWOOD / NELSON AGREEMENT

Letter of Agreement No. 25 - Introduction of Sprinkler System Installers

Subject: Introduction of Appendix 14b) - Sprinkler System Installers

Whereas the Association and the Council have discussed establishing the classification of Sprinkler System Installer, which is a compulsory certification trade in the Province of Manitoba;

And whereas they have concluded that establishing such a classification is warranted and necessary;

And whereas they have agreed on wage rates and other conditions of employment for Sprinkler Systems Installers,

Now therefore, in consideration of the foregoing, the Association and the Council hereby agree as follows:

1. Appendix 14b), Sprinkler System Installers, Attachment 1 to this Letter of Agreement No. 25, shall be established and added to the Agreement.

Agreed to this __7th____day of _October__, 2009.

Allied Hydro Council of Manitoba	Hydro Projects Management Association
"Jim Murphy"_____	"Don E. Rogalsky"_____
"David Martin"_____	"Angie Adams"_____

BURNTWOOD/NELSON AGREEMENT

Letter of Agreement No. 26 - Adjustment of Isolation Leave

Subject: Adjustment of Isolation Leave Frequency Set out in Article 19.2.1.1 and 19.2.1.3.

Whereas Letter of Agreement No. 5 provided for the review of Isolation Leave (Return Transportation Time Periods) in agreements being used for reference purposes for Appendices 2, 4, 4a), 10, 11, 12, 13, 14, and 14a) during the month of January, 2011;

And Whereas the frequency of Isolation Leave in not less than two thirds (2/3) of the said agreements being used for reference purposes was determined to be 30 calendar days or less on either a first or second tour of duty;

Now therefore, in accordance with the provisions of the said Letter of Agreement No. 5, the Association and the Council hereby amend the following sub-articles of Article 19, effective as of March 1, 2011, to the following:

1. 19.2.1.1 Frequency When Isolation Leave Frequency Is Not Stipulated In Appendix

An employee working on the Project who is covered by an Appendix which does not stipulate Isolation Leave frequency shall have the option of taking an Isolation Leave after forty (40) calendar days from the commencement of his first tour of duty, and after thirty-five (35) calendar days from the commencement of each consecutive tour of duty thereafter. An employee who resigned or was laid-off or discharged and then is re-hired shall be considered to be serving his first tour of duty.

19.2.1.3 Limitation Relative to Frequency of Isolation Leaves

Notwithstanding any other provisions set out in this Agreement, the time period between Isolation Leaves may be greater than but shall not be less than thirty-five (35) calendar days from the commencement of an employee's first tour of duty, and thirty (30) calendar days from the commencement of each consecutive tour of duty thereafter. An employee who resigned or was laid-off or discharged and then is re-hired shall be considered to be serving his first tour of duty.

2. The amendments arising from the application of paragraph 1 above shall be effective on March 1, 2011, and will apply to tours of duty which commence on or after the said date.

Agreed to this 31st day of January, 2011.

Hydro Projects Management Association	Allied Hydro Council of Manitoba Hydro
"Don E. Rogalsky"	"Jim Murphy"
"Angie Adams"	"David Martin"

BURNTWOOD/NELSON AGREEMENT

Letter of Agreement No. 27 - Isolation Leave Frequency

Subject: Keeyask and Keewatinoow - Article 19 Isolation Leave Frequency, Travel Time Associated with Isolation Leaves, and Travel Costs Associated with the Transportation Departure Point (T.D.P) c)

Whereas the Association and the Council have discussed Isolation Leave frequencies and Travel Costs found within Article 19 of the Burntwood Nelson Agreement in light of a potential shortage of workers which may occur from time to time on the Keeyask and Keewatinoow projects;

And whereas they have concluded that, in order to secure job qualified workers the Isolation Leave and Travel costs need to be enhanced for the duration of the Keeyask and Keewatinoow projects;

Now therefore, in consideration of the foregoing, the Association and the Council hereby agree that for the duration of the Keeyask and Keewatinoow projects:

1.) Articles 19.2.1.1, 19.2.1.2 shall be amended and read as follows:

Article 19.2.1.1 Frequency When Isolation Leave Frequency is Not Stipulated in an Appendix

An employee working on the Project who is covered by an Appendix which does not stipulate Isolation Leave frequency shall have the option of taking an isolation leave after twenty one (21) calendar days from the commencement of his first and each subsequent tour of duty.

Article 19.2.1.2 Frequency When Isolation Leave Provisions are Set Out in an Appendix

An employee working on the Project who is covered by an Appendix which stipulates Isolation Leave frequency shall have the option of taking an isolation leave after twenty one (21) calendar days from the commencement of his first and each subsequent tour of duty.

2.) The operation of Article 19.2.1.3 will be suspended for the duration of this Letter of Understanding;

3.) The minimum number of unpaid working days granted as isolation leave under Article 19.2.1.5 shall be amended from six (6) to seven (7).

4.) Article 19.2.4 shall be amended and read as follows:

19.2.4 Travel Time Associated with Isolation Leaves

Travel time shall only apply on the return portion of an Isolation Leave trip (ie from the employee's T.D.P. to the Project Camp Site).

The amount of travel time to be paid shall be in accordance with the provisions of Article 19.1.2.5.1 or 19.1.2.5.2, as the case may be, and if applicable, the provisions of Article 19.1.2.5.3.

Travel time shall be paid at the employee's straight time rate, and an employee shall receive such payment pursuant to the provisions of Article 19.1.2.6.

5. The definition of "T.D.P. or Method of Determining T.D.P." shall be amended at item c) to read as follows:

> c) Where a person's normal place of residence at time of hire or rehire is located outside of Manitoba: the Canadian city serviced by an international airport which is closest to a person's normal place of residence, except if that person's normal place of residence is located in a province or territory adjacent to Manitoba and is closer to a T.D.P. located within the area described in b) above, in which case the closest T.D.P. will be utilized.

6. The operation of article 19.1.2.3 (Maximum travel costs payable) is suspended.

7. These amendments shall take effect August 4, 2013;

Agreed to this 17 day of July, 2013.

Allied Hydro Council of Manitoba	Hydro Projects Management Association
David Martin	Jason Peterson
Heiko Wiechern	Rob Elder

BURNTWOOD/NELSON AGREEMENT

Letter of Agreement No. 28 - Emergency Medical Classifications

Subject: Emergency Medical Classifications Found Within Appendix 15

Whereas the Association and the Council have discussed the specialized skills and accreditation of the Medical Classifications found within Appendix 15 of the Agreement;

And whereas there is a provincial requirement to provide a standard level of medical care on the Projects covered by the Agreement;

It has been determined that the classifications of First Aid Attendant, Emergency Medical Responder and Primary Care Paramedic have those specific accredited skills that meet the provincial requirement;

Now therefore, in consideration of the foregoing, the Association and the Council hereby agree to amend the Agreement as follows:

2.7.1 Notwithstanding any other provision of this Agreement, the provisions of Article 12.1 may be waived by the Emergency Medical and Ambulance Services (EMS) Contractor when hiring First Aid Attendant, Emergency Medical Responder and Primary Care Paramedic, except the Emergency Medical and Ambulance Services (EMS) Contractors shall advise the Council of the names of the persons hired within three (3) working days.

Agreed to this 23 day of April, 2014

Hydro Projects Management Association	Allied Hydro Council of Manitoba Hydro
Jason Peterson	David Martin
_____	_____
Glen Schick	Heiko Wiechern
_____	_____
Rob Elder	
_____	

BURNTWOOD / NELSON AGREEMENT

Letter of Agreement No. 29 – Addition of Journeyperson Lineman

Subject: Introduction of Appendix 13 a) - Journeyperson Lineman/Cable Splicer and Associated Collector Line Trades

Whereas the Association and the Council have discussed establishing the classification of Journeyperson Lineman/Cable Splicer and Associated Collector Line Trades.

And whereas they have concluded that establishing such a classification is warranted and necessary;

And whereas they have agreed on wage rates and other conditions of employment for Journeyperson Lineman/Cable Splicer and Associated Collector Line Trades,

Now therefore, in consideration of the foregoing, the Association and the Council hereby agree as follows:

1. Contracted on-site construction work associated with the installation of collector lines ("the work") shall be covered by the terms and conditions of the Burntwood/Nelson Agreement except as hereinafter stated. The work shall be under the jurisdiction of the I.B.E.W., Local 2085 and the I.U.O.E. Local 987.

2. Article 4 of the Burntwood/Nelson Agreement will not apply to the work, however the contractor, prior to the commencement of the work, shall hold a pre-job conference, attended by representatives of the Council and the Association, to advise all parties of the contractor's work plan.

3. Appendix 13 a), Journeyperson Lineman/Cable Splicer and Associated Collector Line Trades, Attachment 1 to this Letter of Agreement No. 29, shall be established and added to the Agreement;

4. Letter of Agreement 7 – Application of the BNA to work Associated with the Construction of Collector Lines, shall be removed from the Agreement;

5. Crane Operators doing the work shall be covered by Appendix 2 Crane Operators, and Heavy Duty Equipment Operators, Light Equipment Operators, Heavy Duty Mechanics and Servicepersons doing the work shall be covered by Appendix 2a Equipment Operators.

Agreed to this 23 day of May, 2014:

Allied Hydro Council of Manitoba	Hydro Projects Management Association
D. Martin	J. Peterson
	G. Schick

BURNTWOOD / NELSON AGREEMENT (BNA)

Letter of Agreement No. 30 - Blasters and Drillers compensation

Subject: Burntwood Nelson Agreement – Blasters and Drillers (Appendix 1)

Whereas the Association and the Council have discussed the availability of job qualified workers in certain Burntwood Nelson Agreement (BNA) Classifications;

And whereas they have concluded that there is a shortages of job qualified workers in the below Classifications and the present wage rates in those Classifications need to be enhanced in order to attract and retain job qualified workers;

Now therefore, in consideration of the foregoing, the Association and the Council hereby agree to the following for the remainder of the Keeyask and Keewatinohk Projects:

1. Effective October 15, 2014, the wage rate for the following classifications in Appendix 1, Labourers, shall be enhanced to the following:

	April 1, 2015	May 1, 2015
Blaster (with Provincial Blaster Certificate)	$30.00	$30.85
Powderman	$29.65	$30.49
Drillers (Diamond, Wagon & Air Track Etc.)	$29.65	$30.49

Agreed to this 17___day of March, 2015.

Allied Hydro Council of Manitoba — Hydro Projects Management Association

Sudhir Sandhu — Jason Peterson

Victor DaSilva — Rob Elder

BURNTWOOD / NELSON AGREEMENT (BNA)

Letter of Agreement No. 31 - COPE - Health and Welfare Trust Fund

Subject: Appendix No. 15 - COPE - Introduction of Health and Welfare Trust Fund

Whereas the Council has advised the Association that Local Union 342 has established a Health and Welfare plan, in which the employees covered by Appendix No. 15 are eligible to participate;

And whereas written verification has been forwarded to the Association and the Council confirming that Trust Agreements have been executed and registered;

Now therefore, in consideration of the foregoing, the Association and the Council hereby agree as follows:

4. Appendix No. 15 of this Agreement is hereby amended to delete the following from Section 8:

   Provided:

   a) The Local Union to which employees covered by this Appendix belong establishes a health and welfare plan and/or a pension plan in which employees covered by this Appendix are eligible to participate;

   b) Written verification is forwarded to the Association and the Council by the Board of Trustees of each plan confirming:

      i) Proviso (a), above;

      ii) That Trust Agreements have been executed and registered.

   A health and welfare plan and/or a pension plan will be introduced into this Appendix on the following basis:

   - at the time of introduction of the health and welfare plan and/or the pension plan, the hourly rates for all classifications in this Appendix shall be reduced by the amount of the contractor's contribution to the said plan or plans, less the sum of twenty cents. At the option of the Council, contributions to the plan or plans shall be made up by employee contributions or a combination of contractor and employee contributions. The Council shall advise the Association of the required contractor and/or employee contributions at the time the plan or plans are established.

5. Appendix No. 15 of this Agreement is hereby further amended to add the following to Section 8:

Provided:

a) The Local Union to which employees covered by this Appendix belong establishes a pension plan in which employees covered by this Appendix are eligible to participate;

b) Written verification is forwarded to the Association and the Council by the Board of Trustees of each plan confirming:

i) Proviso (a), above;

ii) That Trust Agreements have been executed and registered.

A pension plan will be introduced into this Appendix on the following basis:

- at the time of introduction of the pension plan, the hourly rates for all classifications in this Appendix shall be reduced by the amount of the contractor's contribution to the said plan or plans, less the sum of twenty cents. At the option of the Council, contributions to the plan or plans shall be made up by employee contributions or a combination of contractor and employee contributions. The Council shall advise the Association of the required contractor and/or employee contributions at the time the plan or plans are established.

The contractor on behalf of each employee, and each employee covered by this Appendix, shall respectively contribute the amounts set out below to the Canadian Office and Professional Employees (COPE) union, local 342, Health and Welfare Trust Fund. Contributions shall apply to all hours worked (regular and overtime). Employee contributions shall be collected at the source as a payroll deduction.

The contractor’s contribution shall be:

Effective May 17, 2015 $0.20 per hour

The employee’s contribution shall be:

Effective May 17, 2015 $0.80 per hour

Submission of Trust Funds

The contractor shall forward the above Trust Fund contributions to the designated Administrator of the Plan on or before the fifteenth (15th) day of each month following the month in which contributions were made.
A form shall be supplied by the Union for the Contractor to identify the application of all contributions, and such form shall indicate the Administrator and the address to which contributions shall be forwarded.

Agreed to this 15th day of May, 2015.

Hydro Projects Management Association	Allied Hydro Council
Angie Adams	Sudhir Sandhu
Jason Peterson	Dustin Czmola

BURNTWOOD / NELSON AGREEMENT (BNA)

Letter of Agreement No. 32 – Security guard compensation

Subject: Burntwood Nelson Agreement – Security Guards (Appendix 1A)

Whereas the Association and the Council have discussed the availability of job qualified workers in certain Burntwood Nelson Agreement (BNA) Classifications;

And whereas they have concluded that there is a shortage of job qualified workers in the below Classification and the present total compensation in that Classification needs to be enhanced in order to attract and retain job qualified workers;

Now therefore, in consideration of the foregoing, the Association and the Council hereby agree to the following for the remainder of the Keeyask and Keewatinohk Projects:

1. Effective November 15, 2015, the wage rate for the following classification in Appendix 1A, Security Guards (other than trainees), shall be enhanced to the following:

Effective date	Starting Rate	Rate after 90 Days
November 15, 2015	$16.76	$17.42

And whereas the Council has advised the Association that Local Union 1258 has established Health and Welfare and Pension plans, in which the employees covered by Appendix No. 1A are eligible to participate;

And whereas written verification has been forwarded to the Association and the Council confirming that Trust Agreements have been executed and registered;

Now therefore, in consideration of the foregoing, the Association and the Council hereby agree as follows:

6. Appendix No. 1A of this Agreement is hereby amended to delete the following from Section 11:

Provided:

a) The Local Union to which Security Guards belong establishes a health and welfare plan and/or a pension plan in which employees covered by this Appendix are eligible to participate.

b) Written verification is forwarded to the Association and the Council by the Board of Trustees of each plan confirming;

i) Proviso (a), above;

ii) That Trust Agreements have been executed and registered.

A health and welfare plan and/or a pension plan will be introduced into this Appendix on the following basis:

- At the time of introduction of the health and welfare plan and/or the pension plan, the hourly rates for all classifications in this Appendix shall be reduced by the amount of the contractor's contribution to the said plan or plans. At the option of the Council, contributions to the plan or plans shall be made up by employee contributions or a combination of contractor and employee contributions. The Council shall advise the Association of the required contractor and/or employee contributions at the time the plan or plans are established.

- Pension and/or health and welfare contributions shall be subject to adjustments, however all contributions shall continue to be made as outlined above and the effective date of such adjustments shall correspond to an effective date of changes to wages (See Section 12.1).

7. Appendix No. 1A of this Agreement is hereby further amended to add the following to Section 11:

Trust Funds

Pension Plan

The contractor on behalf of each employee, and each employee covered by this Appendix, shall respectively contribute the amounts set out below to the Plan Administrator. Contributions shall apply to all hours worked (regular and overtime). Employee contributions shall be collected at the source as a payroll deduction

The Contractor's contribution shall be:

Effective	November 15, 2015	$0.50 per hour

The Employee's contribution shall be:

Effective	November 15, 2015	$0.50 per hour

Health & Welfare

The contractor on behalf of each employee, and each employee covered by this Appendix, shall respectively contribute the amounts set out below to the Plan Administrator. Contributions shall apply to all hours worked (regular and overtime). Employee contributions shall be collected at the source as a payroll deduction

The Contractor's contribution shall be:

Effective	November 15, 2015	$0.60 per hour

The Employee's contribution shall be:

Effective	November 15, 2015	$0.60 per hour

Submission of Trust Funds

The Contractor shall forward the above Trust Fund contributions to the designated Administrators of each plan on or before the fifteenth day (15th) of each month following the month in which contributions were made.

A form shall be supplied by the Union for the Contractor to identify the application of all contributions, and such form shall indicate the Administrator and the address to which contributions shall be forwarded

Agreed to this 15th day of June, 2015.

Allied Hydro Council of Manitoba	Hydro Projects Management Association
Sudhir Sandhu	Jason Peterson
Victor DaSilva	Rob Elder

BURNTWOOD / NELSON AGREEMENT (BNA)

Letter of Agreement No. 33 – Telebelt operator classification

Subject: Burntwood Nelson Agreement – Introduction of Classification to Appendix 2 Crane Operator – Telebelt Operator

Whereas the Association and the Council have discussed establishing the classification of Telebelt Operator.

And whereas they have concluded that establishing such a classification is warranted and necessary;

And whereas they have agreed on wage rates and other conditions of employment for a Telebelt Operator,

Now therefore, in consideration of the foregoing, the Association and the Council hereby agree as follows:

1. That the classification of Telebelt Operator is to be added to Appendix 2 Crane Operator – Mobile Crane Operator Class 2 50-99 ton and Class 3 100-199 ton. The wage rate will be dependent upon chassis capacity (i.e. original truck crane capacity) of the equipment.

2. Appendix shall be modified to include the following clarification
   Note: The above classifications include operators of cranes converted for the placing of concrete (creter, telebelt or similar) and cranes adapted for pile driving and foundation boring. *** For these positions a hoisting ticket and/or red seal are not required for their operation.

Agreed to this 27 day of October, 2015.

Allied Hydro Council of Manitoba	Hydro Projects Management Association
Sudhir Sandhu	Jason Peterson
Marc Lafond	Dave Bowen

BURNTWOOD / NELSON AGREEMENT (BNA)

Letter of Agreement No. 34 – Commissioning work

Subject: Commissioning Work

WHEREAS the Association and the Council agree that commissioning activities are important to the success of project work conducted under the BNA;

Now therefore, in consideration of the foregoing, the Association and the Council agree to amend Article 2.12 of the Collective Agreement to include the following:

2.0 (i) During the commissioning process, the Contractor or the vendor of equipment or system being commissioned, may utilize non-bargaining unit employees with specific equipment or systems knowledge and/or specialized skills or abilities required for commissioning or to ensure performance guarantees and warranty obligations are maintained. Commissioning work performed by non-bargaining unit employees shall fall outside the scope of the Agreement. Bargaining unit employees required to perform commissioning work may be required to work in composite crews. Commissioning work executed by bargaining unit employees shall fall within the scope of the Agreement.

(ii) Commissioning is the process by which equipment or facility is tested to verify it functions according to its design objectives or specifications and place into service, which includes work to calibrate, introduce and or release any form of energy (examples; liquid, gas, electricity) and/or test equipment, instruments, processes, systems or a portion of the generating station, spillway structures, switchyards, converter station, electrodes, synchronous condensers or any related structures or equipment.

(iii) That any contractor or manufacturer representatives engaged to perform commissioning work satisfy the terms and provisions of the Apprenticeship Act where applicable to a trade practiced by such personnel.

(iv) It is understood that this Letter is intended to record past practice between the parties and not meant to diminish existing rights of either party.

Agreed to this 1 day of January, 2016

Allied Hydro Council of Manitoba — Hydro Project Management Association

Sudhir Sandhu — Jason Peterson

Heiko Wiechern — David W. Clark

BURNTWOOD / NELSON AGREEMENT (BNA)

Letter of Agreement No. 35 – Completion bonus

Subject: Completion Bonus Percentage of Base Rate

WHEREAS the Association and the Council have discussed the importance of attracting and retaining a highly skilled workforce to ensure the success of work conducted under the BNA;

Now therefore, in consideration of the foregoing, the Association and the Council agree to amend Article 14.7 of the Collective Agreement to include the following:

ARTICLE 14 – PAYMENT OF WAGES, PREMIUMS AND BONUSES

14.7 The parties agree that given the competitive labour market and the challenges of attracting and retaining a highly skilled workforce, a Completion Bonus of thirteen percent (13%) of an employees' base wage rate shall be paid subject to the following:

i. The Completion Bonus is not part of the wage package and does not attract payment of vacation pay and recognized holiday pay.

ii. The Completion Bonus will be paid for all hours worked.

iii. The Completion Bonus shall be paid accrued as follows:
   a. January 1st – March 31st
   b. April 1st – June 30th
   c. July 1st – September 30th
   d. October 1st– December 1st
   e. December 2nd – December 31st

iv. The Completion Bonus shall be paid as follows:
   a. The amount accrued between January 1st – March 30th shall be paid on the 1st payday after July 1st
   b. The amount accrued between April 1st – June 30th shall be paid on the 1st payday after October 1st
   c. The amount accrued between July 1st – December 1st shall be paid on the 1st payday after December 1st
   d. The amount accrued between December 2nd – December 31st shall be paid on the 2nd payday after December 31st
   e. All amounts owed shall be paid in full at time of layoff

v. Should an employee quit, resign or be terminated for just cause, such employee shall not be eligible for any unpaid Completion Bonus; however, should an employee be required to resign or quit as a result of a medical condition and the employee provides a medical certificate in a form

satisfactory to the Contractor, in these exceptional circumstances the Completion Bonus, subject to the approval of the HPMA and Contractor, will be paid. Further, in the event an employee is required to quit or resign for compassionate reasons, in these exceptional circumstances the Completion Bonus, subject to the approval of the HPMA and Contractor, will be paid. Approval will not be unreasonably withheld.

Agreed to this 1 day of January, 2016

Allied Hydro Council of Manitoba	Hydro Project Management Association
Sudhir Sandhu	Jason Peterson
Heiko Wiechern	David W. Clark

BURNTWOOD / NELSON AGREEMENT (BNA)

Letter of Agreement No. 36 – Isolation leave frequency

Subject: Isolation Leave Frequency

The Association and Council agree to amend LOA Number 27 so that the Contractor, upon agreement of the Association and consent of the Council, which consent will not be unreasonably withheld, may choose any of the Isolation Leave Frequency options as set out below.

In the event the Council withholds consent, the Contractor may refer the matter in writing to the panel established under Article 4.8. The panel in adjudicating the dispute shall follow the procedure set out in Article 4.11(b) and the jurisdiction of the panel shall be limited to determining whether the Union has unreasonably withheld consent. Should the panel determine that the Union has unreasonably withheld consent, the Contractor may implement any of the following Isolation Leave Frequency options.

Appendix Which Stipulates Isolation Leave Frequency

i) An employee working on the Project who is covered by an Appendix which stipulates Isolation Leave frequency shall have the option of taking an Isolation Leave after twenty-one (21) calendar days from the commencement of his or her first and each subsequent tour of duty in which case the Isolation Leave shall be seven (7) days.

ii) An employee working on the Project who is covered by an Appendix which stipulates Isolation Leave frequency shall have the option of taking an Isolation Leave after twenty (20) calendar days from the commencement of his or her first and each subsequent tour of duty in which case the Isolation Leave shall be eight (8) days.

iii) An employee working on the Project who is covered by an Appendix which stipulates Isolation Leave frequency shall have the option of taking an Isolation Leave after nineteen (19) calendar days from the commencement of his or her first and each subsequent tour of duty in which case the Isolation Leave shall be nine (9) days.

Appendix Which Does Not Stipulates Isolation Leave Frequency

i) An employee working on the Project who is covered by an Appendix which does not stipulates Isolation Leave frequency shall have the option of taking an Isolation Leave after twenty-one (21) calendar days from the commencement of his or her first and each subsequent tour of duty in which case the Isolation Leave shall be seven (7) days.

ii) An employee working on the Project who is covered by an Appendix which does not stipulates Isolation Leave frequency shall have the option of taking an Isolation Leave after twenty (20) calendar days from the commencement of his or her first and each subsequent tour of duty in which case the Isolation Leave shall be eight (8) days.

iii) An employee working on the Project who is covered by an Appendix which does not stipulates Isolation Leave frequency shall have the option of taking an Isolation Leave

after nineteen (19) calendar days from the commencement of his or her first and each subsequent tour of duty in which case the Isolation Leave shall be nine (9) days.

Agreed to this 1 day of January, 2016

Allied Hydro Council of Manitoba	Hydro Project Management Association
Sudhir Sandhu	Jason Peterson
Heiko Wiechern	David W. Clark

BURNTWOOD / NELSON AGREEMENT (BNA)

Letter of Agreement No. 37 - Ability to Regularly Schedule Sundays

Subject: Ability to Regularly Schedule Sundays

WHEREAS the Association and the Council, given construction needs, agree Sunday may be a scheduled workday;

Now therefore, in consideration of the foregoing, the Association and the Council agree to amend Article 15.1 of the Collective Agreement to include the following:

15.1 Except as provided in Appendix 1.a, due to the nature of the Project, employees will normally be required, if directed, to work up to ten (10) hours per day for six (6) days per week. Unless otherwise provided in the Appendices, Sundays may be a regularly scheduled work day.

Agreed to this 1 day of January, 2016

Allied Hydro Council of Manitoba	Hydro Project Management Association
Sudhir Sandhu	Jason Peterson
Heiko Wiechern	David W. Clark

BURNTWOOD / NELSON AGREEMENT (BNA)

Letter of Agreement No. 38 - Supplementary Workers

Subject: Utilization of Supplementary Workers

Whereas the Council and the Association are parties to the Burntwood Nelson Agreement (BNA); and

Whereas the BNA sets out the terms of conditions of employment for the workers employed for Manitoba Hydro projects; and

Whereas the Council and the Association are in agreement that Manitoba Hydro projects present significant employment opportunities for workers in Manitoba and Canada; and

Whereas the Council and the Association are committed to maintaining a competitive wage and benefits framework to attract and retain the best qualified Manitobans first and then other Canadian workers for the duration of Manitoba Hydro projects; and

Whereas the Council and the Association are committed to maintaining a positive and welcoming project environment that is conducive to attracting and retaining a qualified Canadian workforce;

Whereas the Council and the Association may, from time to time, as circumstances necessitate have dialogue and discussions to review the competitive position of BNA provisions relative to the prevailing conditions in Manitoba and other Canadian jurisdictions; and
The Council and the Association agree that the successful completion of Manitoba Hydro projects may require supplementary labour from other sources to address shortages of skilled and qualified workers;

Whereas the Association and the Council agree that the labour from supplementary sources will only be accessed if qualified Canadian workers are not available;

Now therefore, in consideration of the foregoing, the Association and the Council agree to include LOA 38 to the Collective Agreement, which will include the following:

The Association and the Council agree that should Supplementary Workers be required for employment under the Agreement, the following will apply:

a) Supplementary Workers employed by Contractor(s) on Site shall be permitted mobility from one Contractor on Site to another Contractor on Site should another Contractor on Site require the services of such Supplementary Worker, provided there are no qualified Manitoban workers or qualified Canadian workers available at the time of hire or transfer.

b) Supplementary Workers, if required, will be initially accessed from affiliate American unions, and if such unions cannot supply Supplementary Workers within

six (6) weeks, such Supplementary Workers may then be accessed from other sources.

c) Supplementary Workers will be subject to the same financial package and other terms and conditions of this Agreement as other bargaining unit members, with the exception of, if necessary, adjustment to the financial allocation of benefits, provided there is no change to the gross hourly package. Such adjustments shall be agreed upon with the applicable Local Union, and such Local Union will not unreasonably withhold their consent.

If Supplementary Workers are to be engaged form outside Canada, the Council and its member Unions will cooperate in the Temporary Foreign Worker application process, including the execution of any documents that are reasonably necessary to support an application for utilization of Temporary Foreign Workers to Employment and Social Development Canada or any other regulatory agency.

Agreed to this 1 day of January, 2016

Allied Hydro Council of Manitoba	Hydro Project Management Association
Sudhir Sandhu	Jason Peterson
Heiko Wiechern	David W. Clark

BURNTWOOD / NELSON AGREEMENT (BNA)

Letter of Agreement No. 39 - Project Labour Management Services Agreement

*** Note – See Letter of Agreement #57, for additional information regarding Letter of Agreement 39 (Management Agreement)

Subject: Project Labour Management Services Agreement

WHEREAS the Council will be the largest supplier of skilled and support labour to contractor members of the Association for construction of Keeyask Generating Station (Keeyask) and Keewatinohk Convertor Station (Keewatinohk), collectively referred to as the Projects;

AND WHEREAS the Association will depend on the efficient supply of qualified labour primarily from members of the Council;

AND WHEREAS the Association and the Council share a mutual interest in the successful and timely completion of the Projects;

AND WHEREAS the Association will require support from the Council in addressing significant project issues such as Aboriginal employment, workplace training, including safety, efficient management of labour issues and managing project labour flow to achieve highest possible efficiency and productivity;

AND WHEREAS the capacity of the Council to support project schedules and delivery objectives is a function of available resources;

AND WHEREAS the Council is currently funded through dues levied on its members assigned to work at the Projects with such dues only being sufficient for service delivery for members;

AND WHEREAS the business relationship between the Association and the Council makes no allowance for project related services provided by the Council, which benefit the Association and Manitoba Hydro;

Now in consideration of the foregoing, the Association agrees to provide direct funding to the Council in accordance with the provisions contained herein.

1. The Council shall administer the funds as set out in paragraph 2 below, as it deems appropriate for initiatives that benefit the Projects. The Council undertakes to only use the funds for services rendered to benefit the Projects and may include the following:

    a) Maintain personnel resource capacity to support the Projects' labour relations in a timely and efficient manner.
    b) Offer a Supervisory Training Program with an objective of providing supervisors with skills, tools and knowledge to maximize the performance of their team in the areas of safety, quality and production while maintaining a work environment based on trust, respect and accountability.

c) Develop and implement training to provide the skills to resolve issues before they become a grievance and to utilize the grievance process as a positive tool to resolve issues without undue resort to arbitration. Other stakeholders will also support this aim. The funds will not be utilized to pay for expenses arising from the arbitration process, nor for any purpose that is contrary to the provisions of the *Manitoba Labour Relations Code*.
d) Develop internal capacity in the Council to support various Association initiatives that will benefit the Projects including workplace safety, respectful workplace policies, diversity and Aboriginal employment initiatives and effective project management.
e) Develop and maintain systems to enhance coordination and communication between its affiliated unions to reduce process delays in matters of importance to the Association, Manitoba Hydro and individual Contractors.
f) Develop capacity to maintain closer liaison between the Association, Contractors and affiliated unions to support timely and efficient labour supply in accordance with the Projects' requirements.
g) Implement systems to maintain closer and more regular contact with the Projects' labour, pre and post-employment, to emphasize and communicate project related issues.
h) Such further and other initiatives related to the success of the Projects, and the advancement of the relationships between the Council, Association, affiliated Unions and effected contractors.

2. The Association shall provide funding to the Council as per the schedule below:

	2016	**2017**	**2018**	**2019**	**2020**	**TOTAL *(over 5 years)***
AHC Administrative Funding	$280,000	$280,000	$230,000	$180,000	$130,000	**$1,100,000**

3. No later than 60 calendar days from the commencement of each calendar year of this Agreement, the HPMA shall provide the annual funding herein to the Council. No later than 30 calendar days from the commencement of each calendar year of this Agreement the Council shall, by letter, outline in reasonable detail the services rendered by the Council to benefit the Projects in the previous year and services planned to be rendered to the benefit of the Projects in the subsequent year. Further the Council shall provide such assurances as may be necessary indicating that its use of the funds has been in accordance with this Agreement.

   In the event of a disagreement in respect of the advancement of funds or of the reporting obligation of the Council, either Party may give a notice to the other to settle the dispute, in an expeditious, final and binding way as per Article 4.10, by referring the matter in writing to the panel established under Article 4.8. The panel shall follow the procedures as set out in Article 4.11(b). The Parties agree that in the event of a dispute, to make best efforts to

resolve the dispute failing which they shall cooperate to schedule and complete such an expedited resolution process.

4. The funding agreement shall expire upon the provision of the final Council report in 2020 and shall only be renewed by mutual agreement of the Association and the Council.

5. In the event that the Projects are cancelled this LOA shall become null and void.

Agreed to this 1 day of January, 2016

Allied Hydro Council of Manitoba	Hydro Project Management Association
Sudhir Sandhu	Jason Peterson
Heiko Wiechern	David W. Clark

BURNTWOOD / NELSON AGREEMENT (BNA)

Letter of Agreement No. 40 - Amendment to Hiring Procedure

Subject: Article 12 – Amendment to Hiring Procedure and Referral System to Maximize Utilization of Qualified Manitobans

WHEREAS the Parties have agreed in order to maximize utilization of Manitobans, Article 12.1.1.5 should be amended to facilitate the maximization of qualified Manitobans on the Projects.

AND WHEREAS the Parties have agreed that it is important that prior to the Contractor exercising the right pursuant to Article 12.1.1.7, to hire from any sources, the Contractor must consider the resumes of qualified Building Trade members from other parts of Canada.

Now therefore, in consideration of the foregoing the Association and Council agree to amend Article 12 of the Collective Agreement as follows:

12.1.1.5 The Union, on notification of such job vacancies, may then refer any job qualified Manitoban's to the Contractor through a designated office of M.A.E.T.

12.1.1.7 The Contractor may recruit persons to fill job order vacancies where:

a) Job order vacancies remain after following the procedures set out in Article 12.1.1.1 to 12.1.1.6;

or

b) Persons referred pursuant to Article 12.1.1.5 and Article 12.1.1.6 do not report to the Project Site within the stipulated time period; and

c) Contractor has provided notice to the Union within forty-eight (48) hours of the job order vacancy caused by 12.1.1.7(a) or (b). The Union shall have an additional twenty-four (24) hours, measured from the time the Union is notified of the vacancy, to provide resumes of qualified Canadian residents to be considered, which workers identified in their resume, the Contractor may accept or reject at the Contractor's absolute discretion.

Agreed to this 1 day of January, 2016

Allied Hydro Council of Manitoba	Hydro Project Management Association
Sudhir Sandhu	Jason Peterson
Heiko Wiechern	David W. Clark

BURNTWOOD / NELSON AGREEMENT (BNA)

Letter of Agreement No. 41 – Work teams

*** Note – See Letter of Agreement #54, for additional information regarding Letter of Agreement 41 (Work Teams)

Subject: Work Teams

WHEREAS the Association and the Council have discussed the utilization of Work Teams to support a productive work environment;

WHEREAS the Association and Council acknowledged in the past the Council members have worked cooperatively with Contractors to create Composite Crews to improve productivities and efficiencies;

WHEREAS all parties agree that upon the Council and the affected Council members receiving a written notice of a request for a Work Team from the Contractor or the Association, the Contractor and affected Unions will be provided a reasonable period of time to attempt to achieve an agreement as to the composition of a Work Team;

WHEREAS the parties agree that in the Notice of Implementation of Work Teams the Council and the affected Council members will be provided as much detail as to the scope of the Work Team as reasonably possible and the anticipated duration of the Work Team;

AND WHEREAS the Association and the Council are in agreement that the compilation of Work Teams must be fair;

Now therefore, in consideration of the foregoing, the Association and the Council agree to amend Article 4 of the Collective Agreement to include the following:

4.7 Where a Work Team is to be utilized by the Association and/or Contractor, the following procedures shall be employed:

a) The full process of the mark-up as is set out in this Article shall be applied. This process shall be used to establish the Unions involved in the Work Team;

b) The Association and/or Contractor shall provide fourteen (14) days' notice in writing to the Council and affected Unions designated by the mark-up process of the establishment of a Work Team which notice shall contain the following:

i. A description of the scope of work for which the Work Team is requested with as much detail as reasonably possible;
ii. The proposed composition of the Work Team, including the number of workers per trade and proposed supervision; and
iii. Anticipated duration of the Work Team.

c) The Association and Council agree that during the seven (7) day period following the Notice of Implementation of Work Teams, the affected Unions and Contractor may meet to attempt to achieve agreement as to the composition of the Work Team.

d) Should the parties be unable to achieve written agreement as to the composition of the Work Team, the composition of the proposed Work Team shall be based on the overall percentage each Union has relative to the overall scope of work to be performed by the Work Team as determined by the Association and/or Contractor; The Contractor shall provide to the affected Unions a description of the composition of the proposed Work Team and the implementation date of the Work Team.

e) Any affected Union upon receipt of the Notice of Implementation of the Work Team may dispute the composition of the Work Team or whether there is a material benefit to the Contractor, by referring such dispute to the panel as per Article 4.11(a); and

f) It is understood that Work Teams shall not be implemented unless there is agreement between the affected Unions and the Contractor or until such time a panel convened pursuant to Article 4.8 has made a decision pursuant to a referral by either party.

g) If, during the execution of the work, the nature of the work changes which impacts the composition of the team, a panel may be requested to review the numbers and change them to comply with the percentages deemed appropriate.

4.8 The panel shall consist of three persons who shall serve for the duration of the Project. In the event that any one of the panellists can no longer serve for whatever cause, the Parties agree to forthwith replace their nominee. The Parties shall agree to an independent third party (ITP). If the Parties cannot agree to an ITP, they shall apply to the Minister of Labour and Immigration for the Province of Manitoba, for the appointment of the ITP. The panel shall consist of three persons:

a) One appointed by the Association;

b) One appointed by the Council ; and

c) An ITP who is neither a lawyer nor an arbitrator under the Agreement and is familiar with jurisdiction.

4.9 The panel's jurisdiction is limited to determining the following:

a) The initial or subsequent composition of the Work Team, when and if requested by one of the Parties in accordance with the provisions of this Article.

b) Whether or not there is a material benefit to the Contractor in implementing the requested Work Team. Should the panel determine there is a material benefit to the Contractor through either cost savings, improved efficiencies or other material benefits, the panel shall approve the Work Team.

4.10 Decisions of the panel, by agreement of the Parties, shall be final, binding and not subject to appeal, judicial review or any other form of judicial intervention.

4.11 Decisions of the panel shall be made on an expedited basis:

a) Any dispute as to the initial composition of a Work Team as established under Article 4.7 or as to whether there are material benefits to the Contractor in implementing the Work Team will be referred in writing to the panel within seven (7) days of the Contractor advising the Union in writing of the initial composition of the Work Team. The referral must itemize the issues in dispute. Should a panel be requested, notice in writing of such request shall be provided to each affected Union, the Association and Council;

b) All referrals to the panel will be heard within seven (7) days of such written referral. Each Party shall have the right to present evidence and make representations to the panel, which presentation of evidence and/or making of representation shall be limited to two (2) hours unless such period is extended by a majority of the panel. The panel will render its decision within forty-eight (48) hours of the completion of the hearing. All decisions must be by a majority of the panel;

c) Should the panel determine that there is no material benefit to the Contractor in implementing the proposed Work Team, the Contractor will not be permitted to implement such Work Team and may not submit a request for the same or similar Work Team within ninety (90) days after the panel has rendered its decision and should the panel determine there is a material benefit to the Contractor for the proposed Work Team, the Contractor may implement such Work Team;

d) From time to time, as work advances, the composition of a Work Team may be revisited and adjusted as appropriate by the panel upon request of the Contractor or any Union providing workers to the Work Team. In no event shall a Work Team be revisited within ninety (90) days after the panel has rendered a decision as to the composition of a specific Work Team except in the event there has been a material change in circumstances; and

e) There will be no claims permitted for lost wages, other benefits or premiums as a result of an adjustment to the Work Team, and Work Teams will continue to work cooperatively, without disruption, while any claim to adjust a Work Team is being adjudicated.

4.12 The following shall apply to each Work Team:

a) Each Union shall provide members to work on the Work Team on a pro-rated basis as per the distribution determined by the Contractor or in accordance with this Article;

b) The Union that provides the greatest number of employees to the Work Team shall normally provide the first requested foreperson/general foreperson provided such foreperson/general foreperson has the necessary skills, abilities and experience to lead the Work Team. If more forepersons are requested, such forepersons shall be provided on a pro-rated basis if practical; and

c) All workers assigned to a Work Team will be provided orientation by the Contractor as to the expectations of working on a Work Team, in which orientation the AHC Site Representative and HPMA Site Representative may participate.

A willingness to work on a flexible basis if the needs of the work so dictate, is the essential element of a Work Team. It is understood that while on a Work Team an employee will predominantly perform work in his/her trade or craft but may be required to work outside of his/her trade or craft.

4.13 Work Assignments performed while on a Work Team may not be utilized at subsequent Pre-Job Conferences to claim jurisdiction.

Agreed to this 1 day of January, 2016

Allied Hydro Council of Manitoba	Hydro Project Management Association
Sudhir Sandhu	Jason Peterson
Heiko Wiechern	David W. Clark

BURNTWOOD / NELSON AGREEMENT (BNA)

Letter of Agreement No. 42 – Tower crane trade improvement trust fund

Subject: Amendments to the Trade Improvement Trust Fund in Appendices 2 and 2A

WHEREAS it is estimated that the Keeyask Project will require twenty (20) tower crane operators per year over the next four (4) years, and the Association and the Council are concerned that the Manitoba labour market does not currently have a sufficient supply of qualified tower crane operators to meet this need;

AND WHEREAS the International Union of Operating Engineers, Local 987 ("Operating Engineers") has proposed a training\upgrading program to address the need for qualified Manitoba based tower crane operators, which program requires the acquisition of a tower crane;

And whereas BBE has agreed to provide additional funding to assist the Operating Engineers in the purchase of the tower crane;

NOW therefore, in consideration of the above, the Association and the Council agree as follows, for the Keeyask General Civil Contract only:

1. Effective the date of signing of an agreement governing the acquisition of a tower crane by the Operating Engineers and the development of the training\upgrading program ("the Training Agreement") the contribution by BBE to the Trade Improvement Trust Fund in Appendices 2 and 2A respectively will increase by an additional $0.35;

2. To make a joint recommendation to Manitoba Apprenticeship respecting the required ratio of journeymen to apprentices reflected in Appendix 2 in the event the current ratio is not achievable during the currency of the Training Agreement;

3. The purpose of the enhanced contributions is to offset the purchase price of the tower crane as contemplated in the Training Agreement;

4. It is understood and agreed that these enhanced contributions shall expire on the earliest of the following events:

    a. Once the balance of the purchase price of the tower crane as defined under the Training Agreement has been recovered by the Operating Engineers;
    b. December 31, 2020;
    c. The Training Agreement is terminated by any of the parties to that Agreement.

Agreed to this 4 day of March, 2016

Hydro Projects Management Association	Allied Hydro Council of Manitoba Hydro
_____	_____
_____	_____

BURNTWOOD / NELSON AGREEMENT (BNA)

Letter of Agreement No. 43 – Power engineer classification

Subject: Introduction of Classification to Appendix 2a – Equipment Operator – Power Engineer Classification

Whereas the Association and the Council have discussed establishing the classification of Power Engineer – Class 4 Operator.

And whereas they have concluded that establishing such a classification is warranted and necessary:

And whereas they have agreed on wage rates and other conditions of employment for a Power Engineer Class 4.

Now therefore, in consideration of the foregoing, the Association and the Council hereby agree as follows:

1. That the classification of Power Engineer is to be added to Appendix 2-a Equipment Operator:

Group 24	April 5, 2016		
Power Engineer Class 4	$37.47		

Agreed to this 5 day of April, 2016.

Allied Hydro Council of Manitoba Hydro Projects Management Association

Sudhir Sandhu	Jason Peterson
Marc Lafond	Dave Bowen

BURNTWOOD/NELSON AGREEMENT

Letter of Agreement No. 44 – Special measures for hiring apprentices and trainees

Subject: Special Measures for Hiring of Apprentices and Trainees

Whereas the parties share a mutual interest and obligation to support measures necessary to facilitate the employment and retention of Aboriginal workers by facilitating apprenticeship and training programs;

AND Whereas the parties are seeking to expedite the employment and engagement of Aboriginal workers at Manitoba Hydro projects;

Now therefore, in consideration of the foregoing, the Association and the Council hereby agree to the following:

i. Notwithstanding any other provision of this agreement, the provisions of Article 12.1 may be waived by Contractors and\or subcontractors when hiring apprentice's and\or trainees into an apprenticeship or training program, provided that the person to be hired is a Northern Aboriginal as defined in Article 13 of the BNA and paragraph 12 of LOA #23.

ii. The Association shall submit to the Council, for consideration, a list of candidates and their corresponding Appendix classification. The Council shall inform the Association within three (3) working days of their decision to approve or deny, in whole or in part, the names found on said list of candidates.

iii. The Association shall advise the Job Referral Service of the names of the candidates within three (3) working days from any approval granted by the Council.

Agreed to this 14 day of April, 2016

Hydro Projects Management Association	Allied Hydro Council of Manitoba Hydro
_____	_____
_____	_____

BURNTWOOD / NELSON AGREEMENT (BNA)

Letter of Agreement No. 45 – Concrete finisher and red seal cement finisher classification

Subject - Introduction of Classifications to Appendix 1 (Labourers) – Concrete Finishers and Red Seal Cement Finishers

Whereas the Association and the Council have discussed establishing the classifications of Concrete Finishers and Red Seal Cement Finishers.

And whereas they have concluded that establishing such classifications is warranted and necessary;

And whereas they have agreed on wage rates and other conditions of employment for Concrete Finishers and Red Seal Cement Finishers,

Now therefore, in consideration of the foregoing, the Association and the Council hereby agree as follows:

1. That the classifications of Concrete Finishers and Red Seal Cement Finishers is to be added to Appendix 1 Labourers, with the following wage rates.

Classification	Effective April 11, 2016
Concrete Finisher	$28.69
Red Seal Cement Finisher	$32.43

Agreed to this 9 day of April, 2016.

Allied Hydro Council of Manitoba — Hydro Projects Management Association

Sudhir Sandhu — Jason Peterson

Victor DaSilva — Rob Elder

BURNTWOOD / NELSON AGREEMENT (BNA)

Letter of Agreement No. 46 – Personal Risk Assessments
Original July 7, 2016
Amended August 2, 2018

Subject: Personal Risk Assessment/Criminal Record Checks

WHEREAS the onsite workforce required for the Keeyask and Keewatinohk Projects is principally housed in remote camps owned and operated by Manitoba Hydro and the Association and the Council are concerned with the health and safety of all workers both at the worksite and while housed in camp;

And whereas it has been determined that in a very small number of cases, workers engaged to work at the Projects may pose a risk to accepted workplace safety standards;

And whereas Manitoba Hydro is a member of the North American Electric Reliability Corporation (NERC), which requires some positions to be compliant to its regulations through the completion of a PRA;

NOW therefore, in consideration of the above, the Association and the Council agree as follows:

1. All foremen and general foremen covered by the BNA who are hired or re-hired after August 1, 2016 will be required to complete and submit a Personal Risk Assessment Form ("PRA Form") and to provide the required identification to permit the criminal record check to be performed.

2. All employees, including foremen and general foremen, covered by the BNA who were hired prior to August 1, 2016, and who have-not had a break in service exceeding three (3) months will only be required to complete and submit a PRA Form if reasonable cause exists for that request. The Council shall be provided the reasons that lead to a finding of reasonable cause.

3. Employees working in positions deemed to be 'NERC sensitive', as determined by the contractor, will be required to complete and submit a Personal Risk Assessment Form ("PRA Form"). Including providing the required identification to permit the criminal record check, which will be performed prior to employment commencing. A 'Clear' result will be required in order for the potential employee to continue in the hiring process.

NERC Sensitive position is defined as:

- having unescorted physical access or cyber/electronic access to restricted areas within Manitoba Hydro facilities;
- having access to confidential information, including but not limited to procurement information, management strategies, and/or intellectual property;
- access to information and/or technology systems and/or networks;
- the ability to make or influence procurement decisions; and/or
- the apparent authority to speak on behalf of the contractor or Manitoba Hydro

4. Where a PRA Form and supporting identification is required as above, submission of the Form and identification, as well as cooperation with any follow up inquiries generated by the PRA Form or the checks performed is a condition of continuing employment with the HPMA contractor member.

5. To ensure privacy of all employees required to submit a PRA Form, submissions will be made to, and results will be held by Manitoba Hydro Corporate Security. In the event that the results of the PRA are relevant to the employee's continued employment, such information as is reasonably required by the Employer (HPMA contractor member) will be communicated to that Employer and to HPMA.

6. Any employee covered under the BNA who does not have a "Clear" PRA status shall not be eligible for employment. The following table shall be used to determine a “Clear” PRA status.

Clear	Not Clear
• No criminal convictions on record, or • Criminal history present but not serious enough to meet criteria for "Not Clear" • Any conviction for which a pardon has been granted.	• 3 or more summary convictions within the last 10 years • 3 or more summary convictions with more than 10 years from the date of most recent conviction - If there is an unacceptable risk that individual could reoffend in a way that jeopardizes safety or security • Conviction within the last 7 years for an indictable offence(s) punishable by 10 or more years (for example, assault causing bodily harm, drug trafficking. firearms-related offences, other • Crimes of serious violence regardless of the sentence handed out • The applicant has misrepresented their credentials or has provided false information

7. The cost of any requested PRA will be borne by HPMA and the Council or its Affiliated Unions shall not be required to provide any administrative services to support PRA requests.

8. The AHC and its affiliated Unions shall maintain all rights of grievance pursuant to the Burntwood Nelson Agreement respecting the administration of this LOA and the rights of individual workers involved.

9. The HPMA reserves the right, in the future, to require all employees covered by the BNA to undergo a PRA and the AHC reserves its right to challenge such a requirement.

Agreed to this _____ day of _____, 2018

Jason Peterson
Hydro Projects Management Association

Sudhir Sandhu
Allied Hydro Council

Dave Bowen
HPMA Executive

Council Member
Allied Hydro Council

BURNTWOOD/NELSON AGREEMENT

Letter of Agreement No. 47 – COPE relocation of employees

Subject: Appendix 15 – Office and Professional Employees – Relocation of Employees

WHEREAS the workforce required for the Keeyask Project is principally housed in remote camps owned and operated by Manitoba Hydro:

AND WHEREAS due to the number of individuals required to be housed within camp, the general civil contractor, BBE, may temporarily re-assign certain positions covered under Appendix 15 to its' Winnipeg facility. The Contractor shall limit this activity to employees who have indicated Winnipeg as their home community:

AND WHEREAS the Council, the Association, and the Contractor will review any concerns raised by effected employees to determine any adverse effects and address them accordingly:

NOW therefore, in consideration of the above, the Association and the Council agree as follows for the duration of the Keeyask Project:

1. Appendix 15 will continue to apply and to govern the terms and conditions of employment of any positions that are re-assigned;

2. The BNA will continue to apply to any positions that are re-assigned, with the exception of the following articles:

    a. Article 9 Room and Board, however article 9.8 (meal allowance) remains in effect with an agreed upon meal allowance of $20.00 ;
    b. Article 10 Housing Allowance;
    c. Article 19 Transportation and Travel; however Article 19.4 (Christmas Leave) remains in effect;
    d. Article 26.7 Termination of Employment.
    e. LOA 35 – Completion Bonus remains in effect.

Agreed to this 1 day of September, 2016

Hydro Projects Management Association	Allied Hydro Council of Manitoba Hydro
_____	_____
_____	_____

BURNTWOOD/NELSON AGREEMENT

Letter of Agreement No. 48 – Layoff subject to recall

Subject: Article 12.4 Layoff subject to Recall

WHEREAS it is anticipated that the length of winter layoffs during the remainder of the Keeyask Project will exceed the existing recall period in article 12.4.2 and it is recognized that greater efficiency during spring ramp up benefits all parties:

NOW therefore, in consideration of the above, the Association and the Council agree as follows for the duration of the Keeyask Project:

1. Article 12.4.2.2 will be amended to read as follows;

   Pursuant to 12.4.2.1 an employee may be recalled for employment by the Contractor provided:

   a) The employee is advised in writing at the time of the lay-off that he is eligible for recall and a copy of this notification is concurrently forwarded to the appropriate Local Union and M.A.E.T. and;
   b) The recall is initiated by the Contractor prior to the expiry of 180 calendar days measured from the date of lay-off.

2. Article 12.4.2.3 will be amended to read as follows:

   When more than one employee in a particular classification (i.e. classifications set out in the Appendices) is on lay-off subject to recall and,

   a) Such employees are involved in a common or collective work assignment, and;
   b) Such employees are not recalled on the same date.

   Then the order of recall shall be the same as the order of employment preference set out in Article 12.1

Agreed to this 28 day of October, 2016

Hydro Projects Management Association	Allied Hydro Council of Manitoba Hydro
_____	_____
_____	_____

BURNTWOOD / NELSON AGREEMENT (BNA)

Letter of Agreement No. 49 – Labourers training trust fund

Subject: Appendix No. 1 – Construction and Specialized Workers Union Local 1258 - Introduction of Training Trust Fund

Whereas the Council has advised the Association that Local Union 1258 has established a Training Trust Fund, in which the employees covered by Appendix No. 1 are eligible to participate;

And whereas written verification has been forwarded to the Association and the Council confirming that Trust Agreements have been executed and registered;

Now therefore, in consideration of the foregoing, the Association and the Council hereby agree as follows:

8. Appendix No. 1 of this Agreement is hereby amended to delete the following from Section 8:

Provided:

a) The Local Union to which Labourers belong establishes a trusteed training fund, and;

b) Written verification is forwarded to the Association and the Council by the Board of Trustees of the fund confirming:

i) Proviso (a), above;

ii) That Trust Agreements have been executed and registered.

A trusteed training fund will be introduced into this Appendix on the following basis:

- The Contractors' contributions to the fund may be less than but shall not exceed 25 cents per hour worked throughout the term of this Agreement,

- Contractor and Employee contributions to the fund will be discontinued immediately if one or more of the following occurs:

i) The fund ceases to be governed by a trust;

ii) The provisions of the trust are not fulfilled;

iii) Employers are no longer represented on the Board of Trustees.

- In the event either the Association or the Council has reason to believe that one or more of the conditions described in (i), (ii), or (iii) above have occurred, the matter

shall be referred to the Joint Appendix Review Committee. Until the matter is resolved, Contractors shall hold all Contractor and Employee contributions in trust.

- Contributions to the trusteed training fund shall be adjusted to be consistent with that negotiated between the Labourers' International Union of North America, Local 1258, and the Construction Labour Relations Association of Manitoba. However, the Contractors' contributions shall not exceed 25 cents per hour worked.

9. Appendix No. 1 of this Agreement is hereby further amended to add the following to Section 8:

Provided:

a) The Local Union to which employees covered by this Appendix belong establishes a Training Trust Fund in which employees covered by this Appendix are eligible to participate;

b) Written verification is forwarded to the Association and the Council by the Board of Trustees of each plan confirming:

i) Proviso (a), above;

ii) That Trust Agreements have been executed and registered.

As the above conditions have been met, a trusteed training fund will be introduced into this Appendix on the following basis:

The contractor, on behalf of each employee, shall respectively contribute the amounts set out below to the Construction and Specialized Workers Union Local 1258, Training Trust Fund. Contributions shall apply to all hours worked (regular and overtime).

The contractor's contribution shall be:

Effective October 17, 2016 $0.25 per hour

Contractor contributions to the fund will be discontinued immediately if one or more of the following occurs:

i) The fund ceases to be governed by a trust;

ii) The provisions of the trust are not fulfilled;

iii) Employers are no longer represented on the Board of Trustees.

- In the event either the Association or the Council has reason to believe that one or more of the conditions described in (i), (ii), or (iii) above have occurred, the

matter shall be referred to the Joint Appendix Review Committee. Until the matter is resolved, Contractors shall hold all Contractor contributions in trust.

Submission of Trust Funds

The Contractor shall forward the above Trust Fund contributions to the designated Administrators of each plan on or before the fifteenth day (15th) of each month following the month in which contributions were made.

A form shall be supplied by the Union for the Contractor to identify the application of all contributions, and such form shall indicate the Administrator and the address to which contributions shall be forwarded.

Agreed to this 17th day of October, 2016.

Hydro Projects Management Association	Allied Hydro Council
David Bowen	Sudhir Sandhu
Jason Peterson	Victor DaSilva

BURNTWOOD / NELSON AGREEMENT (BNA)

Letter of Agreement No. 50 – Scaffolder classification

Subject - Introduction of Classification to Appendix 4 (Carpenters) – Scaffolding Classification

Whereas the Association and the Council have discussed establishing the classification of Scaffolder.

And whereas they have concluded that establishing such a classification is warranted and necessary:

And whereas they have agreed on wage rates and other conditions of employment for a Journeyman Scaffolder and Apprentices.

Now therefore, in consideration of the foregoing, the Association and the Council hereby agree as follows:

1. That the classification of Journeyman Scaffolder is to be added to Appendix 4 Carpenters:

	May 1, 2016	May 1, 2017
Industrial	$37.26	$38.12

   a. That the pay rates for Scaffolder Apprentices also be added to Appendix 4 Carpenters, with the applicable pay scale percentage:

Pre-apprentice *	1 – 450 hours	50% of journeyman rate
1st year	451 – 1350 hours	60% of journeyman rate
2nd year	1351 – 2700 hours	70% of journeyman rate
3rd year	2701 – 4050 hours	80% of journeyman rate
4th year	4051 – 5400 hours	90% of journeyman rate

Note the addition of this classification does not supersede any ‘pre-job’ or ‘markup’ assignments for the applicable power rigging of equipment.

Agreed to this 7th day of November, 2016.

Allied Hydro Council of Manitoba Hydro Projects Management Association

Sudhir Sandhu Jason Peterson

BURNTWOOD / NELSON AGREEMENT (BNA)

Letter of Agreement No. 51 – Carpenter foreman coordinator

Re: Introduction of Premium to Appendix 4 Carpenters – Foreman Coordinator Premium

Whereas the Association and the Council have discussed establishing a role and premium for a Foreman Coordinator.

And whereas they have concluded that establishing such a role and associated wage premium is warranted and necessary:

And whereas they have agreed on wage premiums and other conditions of employment for a Foreman Coordinator.

And whereas they have agreed this role and premium will be in place only for the construction of the Keeyask Generating Station and Keewatinohk Converter Station.

Now therefore, in consideration of the foregoing, the Association and the Council hereby agree as follows:

1. That the role of, and wage premium for, a Foreman Coordinator is to be added to Appendix 4 – Carpenters (section 4) with the following description and wages.

   Foreman Coordinator:
   When the contractor appoints a working Foreman Coordinator, s/he shall be paid the percentage set out below above the Certified Carpenter Journeyman rate.

   22% above Certified Journeyman rates, per following:

January 20, 2017	May 1, 2017	May 1, 2018	May 1, 2019
$43.29	$44.44	$45.73	$47.08

2. That the identified span of control will be revised for ‘Lead Hands’ and ‘Foreman’, and a span of control will be added for ‘Foreman Coordinators’, as follows:

   - Foreman Coordinators will be responsible for more than 30 workers
   - Foreman will be responsible for supervising between 11 – 30 workers
   - Lead Hands will be responsible for supervising up to 10 workers

Agreed to this _____ day of _____, 2017.

Allied Hydro Council of Manitoba Hydro Projects Management Association

Sudhir Sandhu	Jason Peterson
Sean Ramsay	Dave Bowen

BURNTWOOD / NELSON AGREEMENT (BNA)

Letter of Agreement No. 52 – Labourer foreman coordinator

Re: Introduction of Premium to Appendix 1 Labourers – Foreman Coordinator Premium

Whereas the Association and the Council have discussed establishing a role entitled a Foreman Coordinator.

And whereas they have concluded that establishing such a role and associated wage premium is warranted and necessary:

And whereas they have agreed on wage premiums and other conditions of employment for a Foreman Coordinator.

And whereas they have agreed this role and premium will be in place only for the construction of the Keeyask Generating Station and Keewatinohk Converter Station.

Now therefore, in consideration of the foregoing, the Association and the Council hereby agree as follows:

1. That the wage premium of a Foreman Coordinator is to be added to Appendix 1 – Labourers (section 4) with the following description:

   When a contractor appoints a working Foreman Coordinator, s/he shall be paid 20% over the wage of the highest classification level working under his/her direct supervision.

2. That the following span of control will be added for 'Lead Hands', 'Foreman', and 'Foreman Coordinators', as follows:

   - Foreman Coordinators will be responsible for more than 30 workers
   - Foreman will be responsible for supervising between 11 – 30 workers
   - Lead Hands will be responsible for supervising up to 10 workers

Agreed to this _____ day of _____, 2017.

Allied Hydro Council of Manitoba Hydro Projects Management Association

Sudhir Sandhu	Jason Peterson
Victor DaSilva	Dave Bowen

BURNTWOOD/NELSON AGREEMENT

Letter of Agreement No. 53 – Duration of Isolation leave

Subject: Article 19.2.1.5 – Duration of Isolation Leave

WHEREAS all workers covered by the BNA have the right to take four (4) days of additional leaves in certain circumstances in accordance with Article 19.2.1.5;

AND WHEREAS the ability to request an additional four (4) days leave as of right in certain circumstances causes scheduling and productively issues;

AND WHEREAS all parties concerned accept the importance of rights under Article 19.2.1.5 and are committed to providing workers additional time off as and when essential to attend to family emergencies;

AND WHEREAS the Council is prepared to support the project by addressing scheduling and productively issues arising from the utilization of the four-day provision under Article 19.2.1.5;

NOW THEREFORE, in consideration of the above, the Association and the Council agree:

1. The following provisions set out at Article 19.2.1.5 shall be suspended for the duration of and effective dates of this Letter of Agreement:

   "Additionally, provided an employee requests same in writing at least fourteen (14) calendar days prior to the commencement of his Isolation Leave, the Contractor shall grant an additional four (4) calendar days leave without pay in the following circumstances:

   a) When the employee is eligible for his second consecutive Isolation Leave, and every second (2nd) consecutive Isolation Leave thereafter.

   b) When the employee is eligible for an Isolation Leave but elects to continue working and to defer commencement of the Leave for a period equal to the period the employee would have otherwise been required to work to be eligible for consecutive Isolation Leave.

   c) On other occasions the employee is eligible for an Isolation Leave, provided the Contractor and employee mutually agree."

2. In order to establish efficient and productive work crews on the Keeyask Project, BBE Hydro Constructors LP ("BBE"), and their sub-contractors, shall apply LOA 36 sub-paragraph i) to all workers covered by an Appendix to the BNA whether or not the workers are covered by an Appendix which stipulates Isolation Leave frequency.

3. In carrying out the scheduling of Isolation Leaves referred to in paragraph 2 of this LOA, BBE shall make every effort to schedule all in-scope workers for travel on weekdays, which shall mean between Monday to Friday, with the sole exception of any unforeseen circumstances such as weather or other extenuating circumstances.
4. Notwithstanding paragraphs 1, 2 and 3 of this LOA, Contractors and Subcontractors will make every effort to grant additional leave requests by employees as stipulated under Article 19.3. Leave requests made under Article 19.3 shall be reasonably considered and granted provided the employee has submitted the request 49 calendar days prior to commencement of the requested leave. Unexpected leave requests for family emergencies shall be given priority and shall not be unreasonably denied.
5. Employees who are entitled to vacation time shall be required to request the said vacation at least 49 calendar days prior to the commencement of the vacation and shall be limited to taking 7 calendar days of vacation time between June 1st to October 31 of each year.
6. Employees returning from approved leave or vacation, may have their working rotation reduced by the equivalent number of days, at the contractors discretion, either at the beginning or end of their scheduled work rotation to enable the employee to remain on the same working crew
7. For the purposes of paragraph 2 of this LOA, "calendar days" shall be calculated on the same basis as set out at Article 19.2.1.4 a). Specifically, the day on which an employee is scheduled to arrive in camp shall be deemed the first day of his/her rotation.
8. The LOA is subject to the termination clause and conditions of LOA 54 Article 3.
9. All requests for four additional days of leave pursuant to Article 19.2.1.5 approved prior to the effective date of this Letter of Agreement shall remain in effect.
10. The Letter of Agreement shall take effect on April 15, 2017.

Agreed to this _____ day of _____, 2017

Hydro Projects Management Association	Allied Hydro Council of Manitoba Hydro
_____	_____
_____	_____

BURNTWOOD/NELSON AGREEMENT

Letter of Agreement No. 54 – Work team / Composite crew

Subject: Work Team/Composite Crew

The Hydro Projects Management Association (HPMA) and the Allied Hydro Council (AHC), the "Parties", are committed to working together to facilitate the safe and successful completion of the Keeyask Generating Station and Keewatinohk Converter Station ("the Projects") within schedule and budget;

THEREFORE, the Parties agree as follows:

1. The HPMA and BBE Hydro Constructors (BBE) agree to suspend the implementation of LOA 41 (Work Teams), as it applies to BBE, to allow for meaningful engagement and discussions relating to seeking additional opportunities for project efficiencies. In exchange for this the AHC agrees to execute LOA 53 concurrent with the execution of this LOA.

2. The HPMA and BBE will work with the AHC to seek composite crew work arrangements to improve productivity and efficiencies. Composite crew opportunities may be identified by either party. Their implementation is subject to the mutual agreement of the parties. It is understood that any composite crew(s) in effect prior to the execution of this LOA 54 shall remain in effect and not be subject to the conditions of LOA 54.

3. The HPMA and AHC agree this LOA may be terminated by either party through the service of at least 180 days written notice to the opposing party. In the event of termination, HPMA and BBE reserve its right to execute LOA 41 and in such case the AHC reserves its right to terminate LOA 53. Both Parties agree that the notice to terminate shall not be given prior to September 30, 2017.

4. This Agreement shall come into full force and effect on April 15, 2017.

Agreed to this_day of March 17, 2017

Hydro Projects Management Association Allied Hydro Council of Manitoba Hydro

BURNTWOOD/NELSON AGREEMENT

Letter of Agreement No. 55 – Breaks

Subject: Article 15 - Breaks

WHEREAS the Association, the Council, the Contractors and the Unions ("the Parties") are desirous of carrying out the work under the BNA in an manner which is orderly, harmonious, promotes productivity, is cost effective, and promotes favorable work practices;

AND WHEREAS it is agreed that the Parties desire is to assist Contractors with providing another option in the administration of coffee and lunch breaks;

Now therefore, in consideration of the above, the Association and the Council agree to add the following to Article 15:

15.7 Keeyask contractors may follow the express language of Article 15.5 and Article 15.6 of the BNA or, in lieu thereof, provide breaks in accordance with the following:

a. One (1) paid break and one (1) unpaid break per shift, each of which shall be thirty (30) minutes in duration. The specific timing of each break shall be determined by the Contractor, acting reasonably.

b. Employees shall be provided a total of thirty-five (35) minutes for each break including a maximum of five (5) minutes unpaid walking time between the workstation and the break location (the "Walking Time"). Employees must be back at their tools no later than thirty-five (35) minutes after the break commenced.

c. The Contractor will extend the work day to a maximum of ten (10) minutes. This shall not attract shift premiums stipulated under the appendices.

d. In all cases employees will remain actively engaged in work at their workstation until scheduled breaks begin and be at their workstation ready to resume work at the end of the break period. There will be no further extension of break time or Walking Time.

e. Should the Contractor provide a third break as a result of overtime hours being worked, employees shall receive the allotted break time, plus an additional five (5) minutes unpaid walking time for each break.

f. When an employees is required to work twelve 12 hours or more in any one day the Contractor shall abide by Article 9.8 of the BNA.

15.8 In accordance with 15.7, Contractors may revert to the provision of the BNA by providing the HPMA, AHC, and employees with twenty-one (21) working days' notice of the change.

The effective date of this Letter of Agreement shall be mutually agreed to by the Parties but shall not be any later than 30 days from the signing of this Agreement.

Agreed to this 24 day of January, 2018

Hydro Projects Management Association	Allied Hydro Council of Manitoba Hydro
_____Jason Peterson_____	__Sudhir Sandhu____
_____Dave Bowen__	__Heiko Wiechern___

BURNTWOOD/NELSON AGREEMENT

Letter of Agreement No. 56 – Trade Flexibility

Subject: Trade Flexibility

WHEREAS the Hydro Projects Management Association (the "Association") and the Allied Hydro Council (the "Council") are committed to working together to facilitate the safe and successful completion of the Keeyask Generating Station (the "Project") within schedule and budget;

NOW THEREFORE, in consideration of the above, the Association and the Council agree to

amend the BNA as follows:

1. The nature and flow of work may at times require employees to perform work that is not normally within the purview of an individual employee's trade classification. To avoid material productive time losses per shift, a Contractor may assign an employee to perform work within the employee's skills, abilities, qualifications and competencies that the Contractor deems necessary to achieve the efficiencies contemplated by the parties , regardless of the employee's union affiliation or trade classification on a temporary or, where agreed in paragraph 3 on a permanent basis. Any assignment made under this Agreement shall be deemed not to be in a violation of Article 4 of the BNA and employees may not refuse such assignments on the basis that the work assigned to him belongs within the jurisdiction of another Union.

2. Subject to Article 5 of the BNA, nothing in this Letter of Agreement shall be used to materially reduce the relative proportions of any trades classification.

3. The following is a non-exhaustive list of Flex Assignments that the Contractor may assign to employees:

    a. De-watering – maintenance of de-watered areas (currently in place–permanent);
    b. Light Plants and Generators – maintenance of fuels and other products on various site light plants and generators (currently in place-permanent);
    c. Rock Crushing and Sand Processing – plant based production of concrete materials of rock and sand (currently in place-permanent);
    d. Maintenance Fuel and Lube – maintenance of fuels and other products on various vehicles and other equipment;
    e. Infrastructure Materials Delivery Team – delivery of various materials to and from lay down areas to production areas, and within production areas (currently in place–permanent);
    f. Formwork, Rebar, Embed, Placement (Clean up and fixes) -
    g. Batch Plant – operate and maintain the batch plant in the most timely and

efficient manner possible;

h. Maintenance shop / Field mechanics – repairs and maintenance of light duty vehicles and heavy equipment, both in the maintenance garage, and in the field;
i. Forming and Stripping – receiving, hooking on, stripping, and releasing of formwork at various points of installation.

4. It is acknowledged that Flex Assignments are work dependent and may occur daily and within short succession of one another. It is further acknowledged that Flex Assignments will be made for the purpose of improving productive time in a fair, reasonable and good faith manner.

5. When an employee performs a Flex Assignment pursuant to this Agreement, he shall be paid based on his home classification's rate of pay in accordance with the Appendix to the BNA that applies to his home Union.

6. The Council shall assign a Trade Flexibility Advisor to be the primary point of contact for matters concerning Flex Assignments. The Contractor will notify the Council's designated Trade Flexibility Advisor of any Flex Assignment being made as soon as is reasonably practical and in any event no later than the end of the working day in which the Flex Assignment occurred.

7. If a Contractor experiences lacking cooperation related to Flex Assignments, the Contractor shall immediately notify the Council's designated Trade Flexibility Advisor and the employee's affiliated union such that the Trade Flexibility Advisor and/or Union may counsel the employee(s). Nothing in this Article restricts the Contractor's right to implement corrective or non-corrective action. Up to and including termination of employment, to the employee in response to his behavior.

8. BBE Hydro Constructors' ("BBE") right to utilize Letter of Agreement 41 (Work Teams) and Letter of Agreement 54 (Composite Crews) is hereby suspended.

9. Nothing in this Agreement alters work assignments resulting from the operation of Article 4 of the BNA. However, Flex Assignments made pursuant to this Letter of Agreement are deemed not to be in violation of Article 4 or Article 8 of the BNA or any other document governing the division of work between unions or trades, including the Green Book, and may not be challenged by the Council or any of its member Unions Affiliates under the BNA or any other forum.

10. Starting the month following the month in which this Agreement is executed, the Association shall provide the Council $10,000.00 per month (the "Monthly Funding") for as long as the Agreement is in force. This funding will be made in concert with, and in addition to, Letter of Agreement 39 of the BNA.

11. After every third payment of the Monthly Funding the Council will provide the Association with a receipt reflecting the Monthly Funding received in the previous three months.

12. The Council must use the Monthly Funding to employ a Flex Assignment Advisor. That Advisor will be identified as a site position and work a scheduled rotation set by the Council.

13. The Flex Assignment Advisor shall:

    Role and Function

    - Educate employees on the principles of the BNA; specifically, with respect to the application of trade flexibility on the Project and LOA 56, as detailed below.

    - Relay the expectations of the Project's owner, the Association, the Contractor and the Council with respect to the performance of Flex Assignments.

    - Provide visible site based representation to each of the Unions while ensuring the benefits of productivity and efficient time management are fully achieved through the appropriate utilization available labour.

    - Jointly identify workplace opportunities for improved productivity and efficiency in the utilization of labour based upon individual skills, capability and competencies regardless of jurisdictional assignments.

    Reporting Structure

    - The Flex Assignment Advisor shall report to the Council's CEO.

    - Have authority to liaison, coach and advise all Parties, subject to the ultimate authority of the incumbent and each individual Union.

    - Have no traditional Labour Relations responsibilities or vested authority under the BNA as a Site Representative.

    - Be independent of any Union so that information can be represented without bias.

Duties and Accountabilities

- Provide new and existing employees an overview of LOA 56 and the Contractor's ability to implement Flex Assignments on the Project. Specific attention and education of new/existing employees, including out of province employees operating on travel cards will be paramount to avoid jurisdictional disputes.

- Educate employees on, and promote the Flex Assignment model's execution on the Project site, the drivers for it (trade pride; demonstration of quality, adaptability and value provided by provincial building trade affiliates) and the expectation of employee support and adherence to its principles.

- Participate in joint planning and development of the Flex Assignment roll out program advising on the documents provided by Contractors, Manitoba Hydro, the Association.

- Provide Contractor, Manitoba Hydro and the Association with any and all presentations and documentation prepared by the Council and the Trades Flexibility Advisor for their respective review.

- Actively participate with project leadership in the joint identification and realization of opportunities to obtain 'best for project' outcomes as they relate to both direct and indirect labour and material management programs.

- Provide professional assistance and support in the communication of the progress and status of the Flex Assignment program to key stakeholders.

- Make themselves available to attend scheduled and ad-hoc meetings, specific to BBE Hydro Constructors, including but not be limited to:

    - Daily
        - POD (Plan Of the Day)
        - Superintendent activity and planning review

    - Weekly
        - Management
        - BBE Stewards

    - Monthly
        - Project progress and challenges discussion (general) with MH/HPMA/AHC/BBE

- Monthly (min TBD may move to alternating)
  - Forum with AHC/Affiliate Unions/HPMA/MH/BBE and/or other BBE Sub-Contractors

Goals and Expectations

- Support the implementation of the existing nine (9) initial combined crew efficiency programs and facilitate and identify future opportunities within the Powerhouse structure (and other identified facilities);

Benchmarks and Feedback

- Provide the following benchmarks and feedback:
  - the number of confirmed crew efficiencies implemented (from the existing nine (9) currently in process);
  - demonstrated performance improvement as a result of implementing the new role; and
  - continued Labour Relations harmony in concert with improved productivity.

15 In the event the Association terminates this Letter of Agreement pursuant to this paragraph, it may cease Monthly Funding Payments effective the date of termination, except that it shall provide the Council with a pro-rated Monthly Funding Payment for the month in which termination of this Letter of Agreement occurred.

16 Prior to the implementation of the Letter of Agreement, and every six months thereafter the Association shall provide the Council with its latest projected workforce estimates by trades classification. The Association shall continue to provide the Council the actual hours utilized by each trade classification on a quarterly basis.

17 The Association and Council agree this Letter of Agreement may be terminated by either party through the service of at least 180 days written notice to the other party. Both parties agree that the notice to terminate the Letter of Agreement shall not be given prior to July 1, 2019.

18 The effective date of this Letter of Agreement shall be mutually agreed to by the parties but shall not be any later than 30 days from the signing of this Agreement.

Agreed to this _____ day of _____, 2018

Hydro Projects Management Association	Allied Hydro Council of Manitoba Hydro
_____	_____
_____	_____

BURNTWOOD / NELSON AGREEMENT (BNA)

Letter of Agreement No. 57 – Cancel LOA No 39

Subject: Project Labour Management Services Agreement LOA 39

The Association and the Council hereby rescind and replace Letter of Agreement 39 with Letter of Agreement 58.

Agreed to this 24 day of January, 2018.

Hydro Project Management Association	Allied Hydro Council of Manitoba
_____Jason Peterson_____	__Sudhir Sandhu_____
_____Dave Bowen_____	__Heiko Weichern_____

BURNTWOOD / NELSON AGREEMENT (BNA)

Letter of Agreement No. 58 – Project Labour Management Services Agreement

*** Note – See Letter of Agreement #57, for additional information regarding Letter of Agreement 39 and 57 (Management Agreements)

Subject: Project Labour Management Services Agreement

WHEREAS the Council will be the largest supplier of skilled and support labour to contractor members of the Association for construction of Keeyask Generating Station (Keeyask) and Keewatinohk Convertor Station (Keewatinohk), collectively referred to as the Projects;

AND WHEREAS the Association will depend on the efficient supply of qualified labour primarily from members of the Council;

AND WHEREAS the Association and the Council share a mutual interest in the successful and timely completion of the Projects;

AND WHEREAS the Association will require support from the Council in addressing significant project issues such as Aboriginal employment, workplace training, including safety, efficient management of labour issues and managing project labour flow to achieve highest possible efficiency and productivity;

AND WHEREAS the capacity of the Council to support project schedules and delivery objectives is a function of available resources;

AND WHEREAS the Council is currently funded through dues levied on its members assigned to work at the Projects with such dues only being sufficient for service delivery for members;

AND WHEREAS the business relationship between the Association and the Council makes no allowance for project related services provided by the Council, which benefit the Association and Manitoba Hydro;

AND WHEREAS the Council and their Affiliate Unions shall take all reasonable measures and exercise best efforts to ensure the successful implementation and ongoing operation of: LOA 55 – Work Breaks and LOA 56 - Trade Flexibility;

Now in consideration of the foregoing, the Association agrees to provide direct funding to the Council in accordance with the provisions contained herein.

1. The Council shall administer the funds as set out in paragraph 2 below, as it deems appropriate for initiatives that benefit the Projects. The Council undertakes to only use the funds for services rendered to benefit the Projects and may include the following:

    a) Maintain personnel resource capacity to support the Projects' labour relations in a timely and efficient manner.

b) Offer a Supervisory Training Program with an objective of providing supervisors with skills, tools and knowledge to maximize the performance of their team in the areas of safety, quality and production while maintaining a work environment based on trust, respect and accountability.
c) Develop and implement training to provide the skills to resolve issues before they become a grievance and to utilize the grievance process as a positive tool to resolve issues without undue resort to arbitration. Other stakeholders will also support this aim. The funds will not be utilized to pay for expenses arising from the arbitration process, nor for any purpose that is contrary to the provisions of the *Manitoba Labour Relations Code*.
d) Develop internal capacity in the Council to support various Association initiatives that will benefit the Projects including workplace safety, respectful workplace policies, diversity and Aboriginal employment initiatives and effective project management.
e) Develop and maintain systems to enhance coordination and communication between its affiliated unions to reduce process delays in matters of importance to the Association, Manitoba Hydro and individual Contractors.
f) Develop capacity to maintain closer liaison between the Association, Contractors and affiliated unions to support timely and efficient labour supply in accordance with the Projects' requirements.
g) Implement systems to maintain closer and more regular contact with the Projects' labour, pre and post-employment, to emphasize and communicate project related issues.
h) Such further and other initiatives related to the success of the Projects, and the advancement of the relationships between the Council, Association, affiliated Unions and effected contractors.

2. The Association shall provide funding to the Council as per the schedule below:

a)

	2016	**2017**	**2018**	**2019**	**2020**	**TOTAL *(over 5 years)***
AHC Administrative Funding	$280,000	$280,000	$230,000	$180,000	$130,000	**$1,100,000**

b)

	2018*	**2019**	**2020**	**2021**	**Total (over 4 years)**
AHC Administrative Funding	$1,000,000	$1,000,000	$1,000,000	$1,000,000	$4,000,000

*Due 60 days past the signing of this LOA

3. No later than 60 calendar days from the commencement of each calendar year of this Agreement, the HPMA shall provide the annual funding herein to the Council. No later than 30 calendar days from the commencement of each calendar year of this Agreement the Council shall, by letter, outline in reasonable detail the services rendered by the Council to benefit the Projects in the previous year and services planned to be rendered to the benefit of the Projects in the subsequent year. Further the Council shall provide such assurances as may be necessary indicating that its use of the funds has been in accordance with this Agreement.

   In the event of a disagreement in respect of the advancement of funds or of the reporting obligation of the Council, either Party may give a notice to the other to settle the dispute, in an expeditious, final and binding way as per Article 4.10, by referring the matter in writing to the panel established under Article 4.8. The panel shall follow the procedures as set out in Article 4.11(b). The Parties agree that in the event of a dispute, to make best efforts to resolve the dispute failing which they shall cooperate to schedule and complete such an expedited resolution process.

4. The funding agreement shall expire upon the provision of the final Council report in 2021 and shall only be renewed by mutual agreement of the Association and the Council.

5. In the event that the Projects are cancelled this LOA shall become null and void.

Agreed to this 24 day of January, 2018

Allied Hydro Council of Manitoba	Hydro Project Management Association
_____Jason Peterson_____	__Sudhir Sandhu_____
_____Dave Bowen_____	__Heiko Wiechern_____

BURNTWOOD/NELSON AGREEMENT

Letter of Agreement No. 59 – Appendix 8A – Cement Masons Apprenticeship changes

Subject: Article 8A – Cement Masons – Adjust Apprenticeship Training levels

WHEREAS Hydro Projects Management Association (the "Association") and the Allied Hydro Council (the "Council") have discussed amendments to regulations for the trade of Cement Masons.

And whereas they have concluded the amendments of Cement Masons Apprentices is warranted and necessary.

And whereas they have agreed on the necessary changes to apprenticeship levels, wage rates and other conditions of employment for Cement Masons Apprentices.

Now therefore, in consideration of the foregoing, the Association and the Council hereby agree as follows:

10. Appendix No. 8A is hereby amended to delete the following from Section 3:

ii) The scale of wages for apprentices shall be:

Level 1 - 60% of the Journeyman's rate
Level 2 - 70% of the Journeyman's rate
Level 3 - 85% of the Journeyman's rate

11. Appendix No. 8A is hereby amended to add the following to Section 3:

iii) The term of apprenticeship in the trade is two levels, with each level consisting of a period of at least 12 months during which the apprentice must complete 1,800 hours of technical training and practical experience.

iii) The scale of wages for apprentices shall be:

Level 1 (0-1800 hrs) - 65% of the Journeyman's rate
Level 2 (1801 – 3600 hrs) - 80% of the Journeyman's rate

12. Further, the following addition has also been made to Section 3:

(c) Pre-apprentice;

iv) The contractor may employ one (1) pre-apprentice for each Journeyperson employed.

v) Pre-apprentices may be employed for a maximum of 500 hours. The employer shall maintain a log book for all hours worked as a pre-apprentice. The contractor shall forward a copy of the employee's log book to the union upon their request.

vi) The wage scale of pre-apprentices shall be;
First 500 hours (55% of the Journeyperson rate.)

13. Appendix No. 8A is hereby further amended to add the following to Section 6:

(c) Employee contributions for pre-apprentice workers shall be optional.

Agreed to this __19_____ day of _December_, 2018.

Allied Hydro Council of Manitoba Hydro Projects Management Association

Sudhir Sandhu	Jason Peterson
George Emery	Dave Bowen

BURNTWOOD / NELSON AGREEMENT (BNA)

Letter of Agreement No. 60 – Workers United – Pension deduction changes

Subject: Appendix No. 16 – Workers United, Local 206 - Caters

Whereas the Council and Local 206 has advised the Association that the employee contribution of the Pension Fund is no longer an eligible deduction under the Plan;

Now therefore, in consideration of the foregoing, the Association and the Council hereby agree as follows:

14. Appendix No. 16 of this Agreement is hereby amended to the following:

a) That the employee contribution of $0.20 (twenty cents) per hour shall cease to be a deduction on March 3, 2019
b) The employer contribution under Section 7b) shall be reduced to $0.65 (sixty-five cents) per hour, in accordance to Section 12.2.1.

Agreed to this _____ day or February, 2019.

Hydro Projects Management Association	Allied Hydro Council
Jason Peterson	Sudhir Sandhu
	Andy Spence

BURNTWOOD / NELSON AGREEMENT (BNA)

Letter of Agreement No. 61 – Burntwood Nelson Agreement – Blasters wage enhancement

Whereas the Association and the Council have discussed the availability of job qualified workers in certain Burntwood Nelson Agreement (BNA) Classifications;

And whereas they have concluded that there is a shortages of job qualified workers in the below Classification and the present wage rate requires to be enhanced in order to attract and retain job qualified workers;

That LOA 30 shall be deemed to be null and void as the wage adjustments for Powderman and Drillers have been formally incorporated into Appendix 1 Section 4. Subsequently, the wage rate noted below for Blasters shall continue to be escalated based on the CLRAM reference agreements to be negotiated in 2019.

Now therefore, in consideration of the foregoing, the Association and the Council hereby agree to the following for the remainder of the Keeyask Projects:

1. Effective April 21, 2019, the wage rate for the following classifications in Appendix 1, Labourers, shall be enhanced to the following:

	April 21, 2019
Blaster (with Provincial Blaster Certificate)	$41.30

Agreed to this 12th day of April, 2019.

Allied Hydro Council of Manitoba

Hydro Projects Management Association

BURNTWOOD / NELSON AGREEMENT (BNA)

Letter of Agreement No. 62 – Heavy Duty Gas and Diesel Mechanics Wage Enhancement

Whereas the Association and the Council have discussed the availability of job qualified workers in certain Burntwood Nelson Agreement (BNA) Classifications;

And whereas they have concluded that there is a shortages of job qualified workers in the below Classification and the present wage rate requires to be enhanced in order to attract and retain job qualified workers;

And Whereas the HPMA and BBE recognize that this work is the proper jurisdiction of the Operating Engineers (OE);

Now therefore, in consideration of the foregoing, the Association and the Council hereby agree to the following for the remainder of the Keeyask Projects:

1. Effective June 30, 2019, the wage rate for the following classifications in Appendix 2a Group 18, shall be amended to the following:

	June 30, 2019
Group 18	
Heavy Duty Diesel Mechanics	
a) with a certificate of qualification	$ 41.19
b) without a certification of qualification	$ 38.77

2. Effective June 30, 2019 a new classification will be added to Group 18:

c. with Licensed Service vehicle	$70.00 per hour * i, ii

i. This per hour add-on is not subject to the conditions of Appendix 2a: sections 5, 6, 7, 8, or 9. Furthermore, it is agreed that the add-on is not subject to Schedule C (calculations of union dues) or LOA 35 Completion Bonus.

ii. Individuals under this classification shall be required to supply their own Licensed Service vehicle which will have the following minimum equipment items in good working order:
   a. Service truck with GVW of 8.8tonne or greater
   b. Deck mounted, securable tool storage
   c. Powered crane with minimum capacity of 2,500LBS
   d. Air compressor (Minimum 30CFM) and associated hose-ware
   e. 12-24 volt battery booster/charger
   f. Oxy-Acetylene torches and gas retaining rack
   g. Arc welder with generator power capacity
   h. Air powered tools wrenches, sockets etc.
   i. Mechanical hand-tools (Metric and Imperial) required

iii. The contractor and individual hired under this classification shall meet upon arrival at the Project site to determine the following:

a. The contractor shall inspect and photograph the service truck to ensure it meets the qualifications as outlined under sub section ii and is in good working order;

b. The individual shall supply the contractor with a complete inventory of tools in compliance with Article 21. The Contractor shall not be responsible for any theft of tools. The individual employee must take all reasonable steps to secure them within the rig and hold his/her own insurance for same. Premiums being covered within the service truck rate.

3. Vendor Technicians/HD Mechanics - BBE Hydro Constructors LP has sub-contracted SMS and Toromont Cat who will perform regular maintenance work outside of their current warrantee work of the Kamatsu and Cat fleet vehicles. These subcontracted third party service providers will be limited to four rigs to conduct their operations (two day shift two night shift). Work may be performed both in the workshop and in the field. The OE agree to the use of the third party service providers on a without precedent and prejudice basis for any other purpose other than the intent of this LOA.

4. BBE agrees to pay a $250.00 (two hundred and fifty dollars and zero cents) permit fee per vendor service vehicle per week on the 15th of every month, beginning from January, 1, 2019 until the requirement of supplemental rig units is no longer required. This fee will be paid directly to OE 987.

5. The permit fee under section 4 shall remain in effect until December 31, 2020 or upon 30 days' notice of cancellation.

6. The HPMA, AHC and OE agree to discuss the applicability and the terms of the LOA prior to October 1, 2020 to determine if it should be renewed for another year. If the Parties do not engage on or before the October 1, 2020 the LOA shall automatically be considered null and void as of Dec.31, 2020 (for all provisions of the LOA including the use of the third party service providers).

Agreed to this 28 day of June, 2019.

Allied Hydro Council of Manitoba	Hydro Projects Management Association
_____	_____
_____	_____

BURNTWOOD/NELSON AGREEMENT

Letter of Agreement No. 63 - Article 8A – Cement Masons – Adjust Reference Classifications for Escalations

WHEREAS Hydro Projects Management Association (the "Association") and the Allied Hydro Council (the "Council") have discussed amendments to the Escalation and Reference process for the trade of Cement Masons.

And whereas they have concluded that amendments to the Cement Masons Escalation process is warranted and necessary.

And whereas the JARC committees identified in Appendix 30 of the BNA have agreed on changes to the Reference Classification used for escalations in the Cement Masons Appendix.

Now therefore, in consideration of the foregoing, the Association and the Council hereby agree as follows:

1. This Letter of Agreement will take effect for any escalations to be calculated on May 1, 2020 and later.

2. The Allied Hydro Council and Cement Masons union local 222, and the Hydro Projects Management Association have agree to reduce the number of reference classifications noted in Appendix 8a, article 8.1.2., from three to one.

3. Appendix No. 8a, Article 8.1.2 of this Agreement is hereby amended to remove the weighting and use of the Reference Classifications of General Construction Labourer and Journeyman Sheet Metal Worker. The weighting used for the Journeyman Carpenter shall be amended from 30% to 100%.

Agreed to this 26 day of February 2020.

Allied Hydro Council of Manitoba Hydro Projects Management Association

Sudhir Sandhu	Tony Landry
George Emery	Bo Hancox

BURNTWOOD / NELSON AGREEMENT (BNA)

Letter of Agreement No. 64 - COVID 19 Special Measures

WHEREAS the Association and the Council have discussed the importance of maintaining a safe and healthy work environment for all workers;

AND WHEREAS the Association and Council agree it is desirable to continue construction work at the site during this infectious disease travel restricted and temporary scale back;

AND WHEREAS appropriate government entities (Federal, Provincial, and/or Municipal), or the project owner, have recommended or restricted travel to and from site, large gatherings of people, or other strategies to stem the spread of infectious disease, the Association and Council agree to create specific terms and conditions in the workplace, including a temporary compensation stipend under the BNA for employees voluntarily agreeing to remain at site for this undetermined and temporary scale back period;

Now therefore, in consideration of the foregoing, the Association and the Council agree to add the following Articles to the Collective Agreement which state the following:

1. This LOA regarding special measures resulting from the COVID 19 pandemic lock down will take effect on March 19, 2020 and remain in effect till May 19, 2020, inclusive. Extensions to this timeframe may be agreed to by both parties anytime prior to the expiry of this Agreement.

2. Reasonable efforts shall be made to provide transportation, or allow employees to make their own arrangements, permitting the worker to exit Site on request. Exiting employees unable to return to site due to ongoing access restrictions will be laid off. Per LOA 35, article 14.7. All Completion Bonus amounts and earned Stipend payments owed shall be paid out at time of layoff, or as reasonably practicable thereafter.

3. Any employee agreeing to stay on site to continue work during the COVID 19 infectious disease scale back, will be provided with a $100 daily stipend. Scheduled days off (noted in Article 4) work where the employee remains at the project site, but does not work, would accrue the stipend.
   To enact this stipend, the Association will identify the effective start and end dates when this stipend will be provided by contractors.

   As a stipend, this payment will not accrue any fringe benefits as required under an employee's Appendix. Although not an exhaustive list, this stipend will not accrue such benefits as Pension, Health and Welfare, Vacation and Statutory Holiday Pay, or various training or union promotion Funds. Union dues will not be deducted. It is a taxable benefit and will be subject to regulatory deductions such as Income Tax, CPP, and EI.

4. For the duration of this Agreement, contractors, in consultation with crews, shop stewards, and employees remaining at Site, can elect to work one of the following work rotation options:

a) Work six consecutive days followed by one mandatory day off provided the day off does not fall on a Saturday or Sunday (exception NMS who has regularly worked a 6/1 schedule with a weekend day off); or
b) Work 21 consecutive days followed by a minimum of two days off. In the event an off day(s) is scheduled on a Saturday and/or Sunday, the next one and/or two days worked will be paid at the applicable overtime premium.

5. Employees have the right to use up to five (5) personal wellness days, consecutive or non-consecutive, during the term of this Agreement. These days shall accrue the stipend, but not accrue wages. Any sick days taken pursuant to a note issued by the Site Nurse Practitioner, shall also accrue the stipend, but not accrue wages.

6. The parties agree that should medical exigencies, provincial or federal regulations, or any other special measure so dictate, all necessary action shall be taken to follow any direction or orders issued by governing authorities in Canada.

7. Nothing in this LOA shall be construed as a waiver of work jurisdiction of each trade and any jurisdictional issues shall continue to be managed pursuant to LOA 56 – Trade Flexibility.

Agreed to this 20th day of March, 2020.

Allied Hydro Council of Manitoba	Hydro Project Management Association
Sudhir Sandhu	Tony Landry
	Bo Hancox

BURNTWOOD / NELSON AGREEMENT (BNA)

Letter of Agreement No. 65- COVID 19 Return to Operational Continuance – Enhanced Normal Protocol

Original May 20, 2020
Revised May 28, 2020

Subject: COVID 19 Return to Operational Continuance – Enhanced Normal Protocol

WHEREAS the Association and the Council have discussed the importance of maintaining a safe and healthy work environment for all workers;

AND WHEREAS the Association and Council agree it is desirable to continue construction work at the site while creating safe operational and travel practices;

AND WHEREAS the project owner has developed enhanced travel safety protocols for entry onto the Project site to stem the spread of infectious disease;

AND WHEREAS the parties intend to maximize the complement of Manitobans with non-Manitobans and out of country workers and/or travellers to be limited to meet essential and unavoidable requirements, all travellers may be subject to specific travel recommendations and/or restrictions, the Association and Council agree to create specific terms and conditions in the workplace;

Now therefore, in consideration of the foregoing, the Association and the Council agree to add the following Articles to the Collective Agreement which state the following:

1. With the exception under Part 1(a) herein, Letter of Agreement 64 is rescinded in full effective May 19, 2020 and replaced with this revised Letter of Agreement 65, effective May 29, 2020.

    a. The one-hundred ($100) dollar stipend payable to employees pursuant to LOA 64 will remain in effect for individual(s) who remain on Site beyond May 19, 2020 and shall continue to be paid until the individual(s) leave Keeyask or voluntarily revert to another work rotation permitted under the BNA or LOA 65. However, such payment shall not continue under any circumstances after June 15, 2020.

2. Employees from within and outside of the Province of Manitoba will be required to follow enhanced travel and safety protocols as follows: (All steps have been created in consultation with, and vetted by Province of Manitoba Public Health officials). The sufficiency and appropriateness of these protocols is solely the discretion and responsibility of Manitoba Public Health.

    a. Manitobans and non-Manitobans who have remained in Manitoba for the past twenty-one (21) days or more and travel to Keeyask by air transportation arranged by contractors or the project owner, shall be required to complete a health screening questionnaire and undergo a COVID-19 (namely ‘PCR testing’) screening prior to

boarding the scheduled flight. Presence of the COVID-19 virus shall disqualify an individual from travelling to Site and the individual(s) shall be provided medical assistance as needed.

b. Manitobans and non-Manitobans who have remained in Manitoba for the past twenty-one (21) days or more and travel to Keeyask by ground transportation from within Manitoba shall be required to complete a health screening questionnaire and undergo a COVID-19 (namely 'PCR testing') screening immediately upon arriving at Keeyask. Following screening, employees shall be isolated in a Keeyask dormitory room until the results are returned by the lab. Presence of the COVID-19 virus shall disqualify an individual from working and arrangements shall be made to safely transport the affected individual(s) for treatment.

c. Manitobans who have travelled outside Manitoba within fifteen (15) days of date of scheduled return to work and non-Manitobans who are travelling to Manitoba for work at Keeyask shall, to be eligible for work at Keeyask, undergo a health screening questionnaire and shall be required to self-isolate at their home residence or in Winnipeg for a combined fourteen (14) days or other period of time as recommended by Manitoba Public Health officials.

   Following the period of self-isolation, the individual(s) shall undergo a COVID-19 (namely 'PCR testing') screening and upon confirmation being deemed 'clear' of the COVID-19 virus, the individual(s) shall be transported by charter flight to Keeyask. Presence of the COVID-19 virus shall disqualify an individual from travelling to Site and the individual(s) shall be provided medical assistance as needed.

PCR screening – Polymerase Chain Reaction (PCR) screening can detect very small amounts of viral genetic material in a sample. The sample is taken as a nasal swab, which will be administered for Manitoba Hydro and its contractors by a third-party organization.

Self-Isolate – Used to help prevent the spread of disease to other people, though you have no symptoms. During self-isolation, you are responsible for yourself and are to avoid situations with other people (practice physical/social distancing 2 meters). If you need to go outside of the home or room, it should be by yourself, and physical/social distancing (2 meters) must be followed. For further information on self-isolation please refer to the following Government of Manitoba fact sheet. https://www.gov.mb.ca/asset_library/en/coronavirus/factsheet-isolation-selfmonitoring-returningtravellers-contacts.pdf

Isolate – You have been directed to isolate in a designated room i.e. assigned room in hotel or camp. You are required to stay in your room, not go in public areas i.e. arctic corridor, hotel lobby, outside (unless approved) and not have contact with other people. Behave as if you have been infected, especially if you have symptoms. You are treated as if you are infected until test result proves otherwise.

3. Payment of Travel time, hotel accommodation and meals, and screening and transportation to site

Manitobans with a TDP of Winnipeg and travelling to Keeyask by air shall have their travel time paid in accordance with Article 19.1.2.5.3 increased to eight (8) hours pay at straight time rates for the day of travel into or within Winnipeg followed by screening and transportation to Keeyask, where all steps are conducted in one day. The eight-hour payment will be considered travel time and eligibility for benefits is as currently practiced. Presence of the COVID-19 virus shall disqualify an individual from working and arrangements shall be made to safely transport the affected individual(s) for treatment.

Manitobans with a TDP of Winnipeg and travelling to Keeyask by air where screening and transportation are conducted on separate days will require an overnight stay in hotel and shall be paid an additional eight (8) hours pay. This payment shall be in addition to the regular travel allowance of five (5) hours. Accommodation and meal reimbursement will be completed in accordance with Article 19.1.2.4 unless otherwise provided by the project owner or contractor. The payments will be considered travel time and eligibility for benefits is as currently practiced. Presence of the COVID-19 virus shall disqualify an individual from working and arrangements shall be made to safely transport the affected individual(s) for treatment.

Non-Manitobans requiring overnight accommodations prior to screening and transportation to Keeyask by air will be paid travel time from their TDP to Winnipeg in accordance with Article 19.1.2.5, plus eight (8) hours pay at straight time rates for the day of screening and travel to Keeyask (note, screening may occur the day prior to transportation to site). Accommodation and meal reimbursement will be completed in accordance with Article 19.1.2.4 unless otherwise provided by the project owner or contractor. Other than BNA Appendices that require application of some benefits to TDP, both the travel hours (5 hours) and the eight-hour payment for screening and transportation will be considered travel time and eligibility for benefits will be as currently practiced.

4. Manitobans, and non-Manitobans who qualify under Part 2b., who are required to isolate at the Keeyask project camp after completing a COVID 19 test and prior to reporting for work, shall receive a daily stipend of $350.00 for days they are not otherwise paid travel hours and/or wages. Employees will be paid travel time from their TDP to the project site in accordance with Article 19.1.2.5. This will largely apply to employees who self-drive to site or are transported to site by shuttle and are required to complete a COVID 19 test upon arrival.

   As a stipend, these payments will not accrue any fringe benefits as required under an employee's Appendix. Although not an exhaustive list, this stipend will not accrue such benefits as Pension, Health and Welfare, Vacation and Statutory Holiday Pay, or various training or union promotion Funds. Union dues will not be deducted. It is a taxable benefit and will be subject to regulatory deductions such as Income Tax, CPP, and EI.

5. Article 19 and Letters of Agreement 5, 26, 27, 36, and 53 will be adjusted to reflect the following.

   In order to maintain eligibility for employment at Keeyask, Non-Manitobans upon first recall and after each turnaround thereafter, shall repeat the applicable self-isolation period up to 14 days at the employee's residence. As such, the regular rotation of 21 days shall be followed 14 days of self-isolation to establish eligibility for return to Keeyask. Each employment period of 21 days shall be followed by 7 days (BNA Isolation Leave) and 7 days of COVID

19 self-isolation. The 7 days of BNA Isolation Leave must be as self-isolated time for eligibility to return to the project site (this totals the required 14 days of self-isolation time as required).

6. All employees while working at site may elect to waive their option for Isolation Leave under Article 19 and various Letters of Agreement such as 27 and 36, as well as Article 4 if this LOA. Employees choosing to waive the option for an Isolation Leave as approved by their contractor, will work a six (6) day per week schedule. The scheduled off day will be at the discretion of the contractor.

7. Letter of Agreement 35 will be subject to a one-time adjustment in accrual dates.

   The completion bonus payment targeted for the 1st payday after July 1st (per LOA 35, Article 14.7, section iv.) a.)), will be adjusted on a one-time basis in 2020. The adjustment is to pay accrued completion bonus earnings from January 1 – May 19, 2020, instead of January 1 – March 31.

8. Employees have the right to use up to three (3) personal wellness days, consecutive or non-consecutive, during the term of this Agreement. These days shall be unpaid.

9. Should COVID 19 continue to evolve and authorized public health or government officials impose additional restrictions that render this LOA inoperable or impermissible under prevailing law, the Association may terminate this LOA with 96 hours written notice to the Council. However, any individuals who remain working at Keeyask after such termination shall continue to be paid in accordance with this LOA until their next turnaround.

Agreed to this revision on 28th day of May 2020.

Allied Hydro Council of Manitoba	Hydro Project Management Association
Sudhir Sandhu	Tony Landry
	Bo Hancox

BURNTWOOD/NELSON AGREEMENT (BNA)

Letter of Agreement No. 66- Introduction of Classification to Appendix 13 – Winders & Brazers

Subject: Introduction of Classification to Appendix 13 – Winders & Brazers

WHEREAS the Association and the Council have agreed to create a new classification within Appendix 13 for Winders and Brazers recognizing the specialized and specific work they perform;

AND WHEREAS they have discussed the availability of job qualified workers with these skills and abilities;

AND WHEREAS they have concluded that there is a shortage of job qualified workers with these skills and abilities both Provincially and Nationally, and requires independent conditions to enhance the ability to attract and retain job qualified workers;

AND WHEREAS they have concluded that establishing such classification is warranted and necessary;

Now therefore, in consideration of the foregoing, the Association and the Council hereby agree to the following, specific to Winders & Brazers classification only, for the remainder of the Keeyask Projects:

1. The job classification of 'Winder / Brazer' shall be added to Appendix 13, Article 3.1. The established wage level will be equal to the wage level for an Electrical Journeyperson.

2. In consideration of lay-off exceptions outlined in Article 12.4.1.2, when a reduction of workers is required, the contractor and IBEW 2085 union hall representative will meet to discuss a proposed layoff order. Consideration will be given to productivity; however, the contractor will endeavor to retain externally recruited Winder / Brazers (via transfer in or stage 4 named hire processes) and union referred members on a 1:1 ratio basis. Specifically, for every one externally recruited and retained Winder / Brazer, one union hall referred member will also be retained. The order of which will be determined by the contractor.

Agreed to this 26th day of August 2020.

Allied Hydro Council of Manitoba Hydro Projects Management Association

_____	_____
Sudhir Sandhu	Tony Landry
_____	_____
	Bo Hancox

Available in accessible formats upon request.

INTRODUCTION

PURPOSE

This guide contains job descriptions and related information for classifications of workers likely to be required by contractors for the construction of a Northern Hydro Development Project.

This information package is intended to provide information to:

- Persons considering employment opportunities on a Project in order to understand the general nature of the work required, the types of jobs that could be available and the qualifications required for these jobs
- Persons involved in the referral services for the Project to understand the various occupations in order to be better able to match potential applicants with contractors' job orders
- Persons involved in the planning of training programs and for individual job seekers who are arranging their educational and career plans and are considering potential employment on the construction of hydroelectric generating stations and other large civil construction-type projects

CONTENTS

The Burntwood/Nelson Agreement (BNA) is the collective agreement that applies to construction of Northern Hydro Development Projects. The information on the various occupations is organized according to the relevant occupational group appendix under the BNA. All jobs described in this information package must be filled in accordance with the referral and hiring provisions of the BNA. A table of contents is included for quick reference to specific occupations. For each occupation, a job description is provided that includes the designated title of the occupation and the BNA Appendix to which it belongs. The job description also provides a general overview of the duties, responsibilities, qualifications and experience anticipated to be required of applicants for the position.

The information presented in this package represents an estimation only, based on current trade regulations and past experience on Northern Hydro Development Projects. It is important to note that these job descriptions will be subject to review and revision by individual project contractors after the work has been awarded. In some cases the duties and qualifications will vary from what is found in these descriptions. This will depend on factors such as the type and size

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

of equipment, and the methods, procedures and technology used on a Project. Contractors will determine specific job qualifications and requirements when a Project is being built.

NATURE OF THE WORK

All potential applicants should be aware that construction of a Northern Hydro Development Project is demanding work. Candidates must be physically fit and willing and able to perform challenging work in a high productivity environment, often under inclement weather conditions. Work weeks typically consist of 6 consecutive 9-hour days followed by one day off. Work on a Project typically requires extended periods (e.g. up to 40 calendar days) at the Project site.

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

TABLE OF CONTENTS

INTRODUCTION 1

(BNA APPENDIX 1 - Labourers) 8

BLASTER 8
CONCRETE WORKER: VIBRATOR OPERATOR, SCREEDMAN, PUDDLER, FLOATMAN, GREEN CUTTER 9
DRILLER (DIAMOND, AIR TRACK, WAGON AND HYDRAULIC) 10
DRILLER'S HELPER 11
FLAGMAN SPOTTER 12
GENERAL CONSTRUCTION LABOURER A (BUILDING CONSTRUCTION) 13
GENERAL CONSTRUCTION LABOURER B (BUILDING CONSTRUCTION) 14
HEAVY CONSTRUCTION LABOURER – EXCAVATION WORK 15
JACKHAMMER OPERATOR / AIR TOOL OPERATOR 16
POWDERMAN 17
SMALL PUMP OPERATOR (2" and under) 18
TRAINEE – LABOURER CLASSIFICATIONS 19

(BNA APPENDIX 1a – Security Guards) 20

SECURITY GUARD 20
SECURITY GUARD – LEAD HAND 21
TRAINEE - SECURITY GUARD CLASSIFICATION 22

(BNA APPENDIX 2 – Operating Engineers (Crane Operators) ... 23

JOURNEYMAN BRIDGE CRANE OPERATOR 23
JOURNEYMAN MOBILE AND CRAWLER CRANE OPERATOR INCLUDING BOOM TRUCKS 7300 KG AND GREATER 24
JOURNEYMAN TOWER & CLIMBING CRANE OPERATOR 25

(BNA APPENDIX 2a – Operating Engineers (Equipment Operators & Allied Support Services) 26

BACKHOE AND SHOVEL OPERATOR 26
BATCH PLANT OPERATOR 27
BIT SHARPENER 28
CONCRETE PUMP OPERATOR 29
DOZER OPERATOR 30
DRILL DOCTOR (DRILL MECHANIC) 31
FRONT END LOADER OPERATOR 32
GRADER OPERATOR 33
HEAVY DUTY DIESEL MECHANIC APPRENTICE 34
JOURNEYMAN DRAGLINE OPERATOR 35
JOURNEYMAN HEAVY DUTY AND DIESEL MECHANIC 36
MATERIAL HOIST OPERATOR 37
OPERATOR OF CONVEYOR BELTS 38

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

OPERATOR OF CRUSHER, SCREENING AND WASHING PLANTS 39
PACKER OPERATOR 40
PUMPMAN (OVER 2") 41
SCRAPER OPERATOR 42
SERVICEMAN 43
TRAINEE – EQUIPMENT OPERATOR CLASSIFICATION 44
WELDER - FLAT, VERTICAL, OVERHEAD (C.W.B.) 45

(BNA APPENDIX 3 - Teamsters) 46
BELLY DUMP DRIVER 46
BUS DRIVER 47
END DUMP DRIVER (ROCK WAGON) 48
FORKLIFT OPERATOR 49
FUEL TRUCK DRIVER 50
JOURNEYMAN TRUCK MECHANIC 51
PARTSMAN 52
SEMI-TRAILER (HIGH OR LOW BED) DRIVER 53
TANDEM TRUCK AND TRANSIT MIX TRUCK DRIVER 54
TRAINEE – TEAMSTERS CLASSIFICATION 55
TRUCK DRIVER (UP TO 5 TON CAPACITY) 56
TRUCK MECHANIC APPRENTICE (MOTOR VEHICLE MECHANIC APPRENTICE)) 57
UTILITY DRIVER 58
WAREHOUSE FOREMAN 59
WAREHOUSEPERSON (MATERIAL HANDLER GENERAL) 60

(BNA APPENDIX 4 - Carpenters) 61
CARPENTER APPRENTICE 61
CARPENTER FORMAN 62
CARPENTER – OTHER 63
JOURNEYMAN CARPENTER 64

(BNA APPENDIX 4a -Millrights) 65
MILLWRIGHT APPRENTICE 65
MILLWRIGHT FOREMAN 66
JOURNEYMAN MILLWRIGHT 67

(BNA APPENDIX 5 – Painters Division) 68
JOURNEYMAN PAINTER (BRUSH AND ROLLERS) 68
JOURNEYMAN PAINTER (SPRAYING AND SANDBLASTING) 69
PAINTER APPRENTICE 70

(BNA APPENDIX 5a –Glassworkers Division) 71
JOURNEYMAN GLASS AND METAL MECHANICS 71

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

(BNA APPENDIX 5b – Floor Covering Division) 72
CARPET AND RESILIENT FLOOR TILE LAYER 72

(BNA APPENDIX 6 – Insulator Workers) 73
JOURNEYMAN INSULATION MECHANIC 73

(BNA APPENDIX 7 –Lathers) 74
DRYWALL APPLICATOR APPRENTICE 74
JOURNEYMAN DRYWALL APPLICATORS 75

(BNA APPENDIX 8 – Plasterers) 76
JOURNEYMAN PLASTERER 76

(BNA APPENDIX 8a – Cement Masons) 77
CEMENT MASON APPRENTICE 77
JOURNEYMAN CEMENT MASON 78

(BNA APPENDIX 9 - Bricklayers) 79
BRICKLAYER AND MASON APPRENTICES 79
BRICKLAYING FOREMAN 80
JOURNEYMAN BRICKLAYER 81
JOURNEYMAN STONEMASON 82
MASONRY FOREMAN 83

(BNA APPENDIX 10 – Sheet Metal) 84
JOURNEYMAN SHEET METAL WORKER 84
SHEET METAL WORKER APPRENTICE 85

(BNA APPENDIX 10a - Roofers) 86
JOURNEYMAN ROOFER 86
ROOFER APPRENTICE AND CLASSIFIED WORKER 87

(BNA APPENDIX 10b – Sheeters, Deckers and Cladders) 88
JOURNEYMAN SHEETER, DECKER OR CLADDER 88
SHEETER, DECKER OR CLADDER TRAINEES 89

(BNA APPENDIX 11 - Boilermakers) 90
BOILERMAKER APPRENTICE 90
BOILERMAKER FOREMAN 91
BOILERMAKER HELPER 92
JOURNEYMAN BOILERMAKER 93

(BNA APPENDIX 12 – Iron Workers) 94
JOURNEYMAN STRUCTURAL IRON WORKER 94
JOURNEYMAN STRUCTURAL IRON WORKER – WELDER 95
STRUCTURAL IRON WORKER APPRENTICE 96
STRUCTURAL IRON WORKER FOREMAN 97

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

(BNA APPENDIX 12a – Rodman)..... 98
JOURNEYMAN REINFORCING RODMAN – (REBAR)..... 98
REINFORCING RODMAN APPRENTICE AND TRAINEE – (REBAR)..... 99
REINFORCING RODMAN FOREMAN – (REBAR)..... 100

(BNA APPENDIX 13 – Electrical Workers)..... 101
ELECTRICAL APPRENTICE..... 101
ELECTRICAL FOREMAN..... 102
JOURNEYMAN ELECTRICIAN – (CONSTRUCTION)..... 103

(BNA APPENDIX 14 - Plumbers and Pipefitters) 104
JOURNEYMAN PIPE FITTER / STEAM FITTER / SPRINKLER INSTALLER..... 104
JOURNEYMAN PIPE FITTER – WELDER..... 105
JOURNEYMAN PLUMBER 106
PIPE FITTER / STEAM FITTER / PLUMBER AND SPRINKLER FOREMAN..... 107
PIPE FITTER / STEAM FITTER / SPRINKLER INSTALLER APPRENTICE 108

(BNA APPENDIX 14a – Refrigeration Section of Plumbers and Pipefitters)..... 109
JOURNEYMAN REFRIGERATION WORKER..... 109
REFRIGERATION WORKER APPRENTICE 110

(BNA APPENDIX 15 – Office and Professional Employees)..... 111
CLERK – TYPIST 111
CLERK I..... 112
CLERK II..... 113
DRAFTSMAN 114
EMERGENCY MEDICAL RESPONDER (EMR)..... 115
FIRST AID ATTENDANT (MEDICAL) 116
INSTRUMENTMAN I 117
INSTRUMENTMAN II 118
JUNIOR INSTRUMENTMAN..... 119
PROJECT COST CLERK I 120
PROJECT COST CLERK II 121
QUANTITY TECHNICIAN..... 122
SURVEY ASSISTANT (RODMAN)..... 123
TRAINEE – OFFICE & TECHNICAL CLASSIFICATION..... 124

(BNA APPENDIX 16 - Caterers) 125
BAKER..... 125
BAKER'S HELPER (GENERAL HELP) 126
BUTCHER 127
BUTCHER HELPER (GENERAL HELP) 128
CAMP ATTENDANT (JANITOR) 129
CHEF 130

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

COMMISSARY ATTENDANT 131
DISHWASHER 132
FIRST COOK 133
HEAD CAMP ATTENDANT 134
HEAD MESS HALL ATTENDANT 135
MESS HALL ATTENDANT (GENERAL HELP) 136
POT WASHER 137
SALAD MAKER 138
SANDWICH MAKER 139
SECOND COOK 140
SHORT ORDER COOK 141
SNACK BAR ATTENDANT 142
TAPMAN (BARTENDER) 143
THIRD COOK 144
TRAINEE – CATERING CLASSIFICATION 145
WAITER / WAITRESS (GENERAL HELP) 146

(BNA APPENDIX 17 – Elevator Constructors) 147

ELEVATOR CONSTRUCTOR FOREMAN 147
ELEVATOR CONSTRUCTOR HELPER 148
ELEVATOR CONSTRUCTOR MECHANIC 149

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 1 - Labourers)

JOB TITLE:

BLASTER

DUTIES & RESPONSIBILITIES:

- Assembles, plants and detonates explosive charges to loosen soil and rock
- Loads explosives in blast holes by hand or directs the movement of bulk explosives trucks to lead holes
- Determines quality, type and amount of explosives required
- Marks location and stakes out pattern of holes to be drilled
- Issues drilling instructions for depth and placement of blast holes
- Selects and arranges detonators to control the blast
- Assembles primer charges and blasting cap and places them with main explosive charges in drill holes
- Fills collar of drill hole with mud or clay and tamps
- Connects wires, detonating cord or fuses into series
- Directs helpers to place safety mat over charge to suppress rock fragments during blast
- Extends lead wires away from charge and tests electrical circuits with portable galvanometer
- Ensures that explosives and accessories are handled and stored in accordance with regulations
- Ensures that safety regulations are being observed and sounds horn, whistle or other signal for area to be cleared of workers and equipment
- Connects wires to blasting machine and pushes handle or button or lights fuse to detonate charge
- May be required to compile records of blasting and keep inventory of blasting agents on hand
- Supervises Powderman

QUALIFICATIONS & OTHER REQUIREMENTS:

- Must have unlimited Provincial Blaster's Certificate
- Must have additional experience in rock blasting on large civil construction projects, including experience with sequential blasting

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 1 - Labourers)

JOB TITLE:

CONCRETE WORKER: VIBRATOR OPERATOR, SCREEDMAN, PUDDLER, FLOATMAN, GREEN CUTTER

DUTIES & RESPONSIBILITIES:

VIBRATOR OPERATOR:

- Operates a portable vibrating machine up to 6” to properly consolidate fresh concrete

PUDDLER:

- Tamps freshly poured concrete with hand tools or machine vibrator

FLOATER:

- Smoothes exposed surfaces of freshly poured concrete with hand tools or trowelling machine
- May pull screed or template over surface to spread concrete to specified depth
- May install bolts or other fixtures in concrete

GREEN CUTTER:

- Cuts lines in concrete using power cutter, edging tools, jointers and straightedges

QUALIFICATIONS & OTHER REQUIREMENTS:

- Physically able to hold and operate the machines
- Willingness to perform physically demanding work
- Able to work at heights
- Experience on larger concrete pours may be required

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 1 - Labourers)

JOB TITLE:

DRILLER (DIAMOND, AIR TRACK, WAGON AND HYDRAULIC)

DUTIES & RESPONSIBILITIES:

- Operates rotary or percussion type mobile drills powered by air, electric or diesel hydraulic systems to bore blast holes in rock or obtain soil and rock samples
- Couples water or air hose or electric line to drill
- Adjusts controls to start drill and to govern rotary speed or percussion rate, feed pressure and air pressure according to type of rock being drilled
- Positions additional rods by hand and operates drill to attach rod to drill string
- Changes bits or sampling equipment using wrenches and drill controls
- Reports and describes drill malfunctions and breakdowns

QUALIFICATIONS & OTHER REQUIREMENTS:

- Experience as a drill operator, operating specific types of equipment being used on the project

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 1 - Labourers)

JOB TITLE:

DRILLER'S HELPER

DUTIES & RESPONSIBILITIES:

- Assists Driller in setting and levelling drill, replacing bits, adding/removing rods, core barrels or other sampling equipment, connecting cables and hoses, and pulling water and air hoses away from equipment
- Observes ground surface and machine operation for indications of unsafe conditions
- Cleans and lubricates equipment

QUALIFICATIONS & OTHER REQUIREMENTS:

- May require experience as a construction labourer or as driller helper on similar type of equipment

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 1 - Labourers)

JOB TITLE:

FLAGMAN SPOTTER

DUTIES & RESPONSIBILITIES:

- Signals operators of trucks and other equipment to dump, move, and load materials
- Controls traffic in and around the construction site.

QUALIFICATIONS & OTHER REQUIREMENTS:

- Physically fit

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 1 - Labourers)

JOB TITLE:

GENERAL CONSTRUCTION LABOURER A (BUILDING CONSTRUCTION)

DUTIES & RESPONSIBILITIES:

- Performs a variety of building construction labouring tasks including:
- Loads and unloads construction materials and moves materials to work areas
- Cleans up scrap, burns surplus materials, and cleans equipment and tools
- Signals truck drivers and other operators to dump on excavation sites
- Erects barricades
- Cleans, sorts and piles materials
- Uses simple tools such as wrecking bars, strippers, etc.
- Tends conveyor belts
- Strips concrete forms and disassembles other structures
- Provides assistance in other activities on site as directed

QUALIFICATIONS & OTHER REQUIREMENTS:

- Less than six months experience performing labouring tasks on building construction in the industrial, commercial or institutional sectors
- Willing and able to do heavy manual labour
- Willing to take instructions from a variety of personnel
- May be required to work at heights

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 1 - Labourers)

JOB TITLE:

GENERAL CONSTRUCTION LABOURER B (BUILDING CONSTRUCTION)

DUTIES & RESPONSIBILITIES:

- Performs a variety of building construction labouring tasks including:
- Loads and unloads construction materials and moves materials to work areas
- Cleans up scrap, burn surplus materials, and cleans equipment and tools
- Signals truck drivers and other operators to dump on excavation sites
- Erects barricades
- Cleans, sorts and piles materials
- Uses simple tools such as wrecking bars, strippers, etc.
- Tends conveyor belts
- Strips concrete forms and disassembles other structures
- Provides assistance in other activities on site as directed

QUALIFICATIONS & OTHER REQUIREMENTS:

- Minimum six months experience performing labouring tasks on building construction in the industrial, commercial or institutional sectors
- Willing and able to do heavy manual labour
- Willing to take instructions from a variety of personnel
- May be required to work at heights

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 1 - Labourers)

JOB TITLE:

HEAVY CONSTRUCTION LABOURER – EXCAVATION WORK

DUTIES & RESPONSIBILITIES:

- Performs a variety of manual duties including: clearing, excavating and grading on construction site and related works
- Burns brush, removes sticks and rocks and drives stakes
- Signals operators of trucks and other equipment to dump, move and load materials
- May operate a chain saw

QUALIFICATIONS & OTHER REQUIREMENTS:

- Good physical condition
- Willing and able to do heavy manual labour
- Working knowledge of safe chainsaw operating procedures

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 1 - Labourers)

JOB TITLE:

JACKHAMMER OPERATOR / AIR TOOL OPERATOR

DUTIES & RESPONSIBILITIES:

- Operates a jackhammer or other similar air-driven hammers or hand held air-powered drills
- Chooses and installs proper bits
- Changes bits as required
- Connects air hoses
- Carries out basic maintenance of tools

QUALIFICATIONS & OTHER REQUIREMENTS:

- Physically capable to hold and operate the tools
- Willingness to do physically demanding work
- For certain work, previous experience may be required

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 1 - Labourers)

JOB TITLE:

POWDERMAN

DUTIES & RESPONSIBILITIES:

- Under the supervision of the Blaster:
  - Carries explosives to blasting area
  - Measures depth of blast hole
  - Pours or places specified explosives into drilled holes
  - Cuts specified lengths of detonating cord or wire
  - Attaches detonating cord or wire to the end of the primer and lowers the cord into the blast hole
  - Fills holes with clay or mud and tamping material
  - Places safety mats and helps to clear the blasting area

QUALIFICATIONS & OTHER REQUIREMENTS:

- Unlimited Blasting Certificate preferred
- Depending on the type of experience and complexity of blasting, a Limited Blasting Certificate may be acceptable

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 1 - Labourers)

JOB TITLE:

SMALL PUMP OPERATOR (2" and under)

DUTIES & RESPONSIBILITIES:

- Operates a diesel or gas-powered portable pumping system to move water from below grade excavations or to supply water for concrete mixing, flushing and cleaning
- Performs pre-start checks
- Starts and tends engine and pumping equipment
- Reports and describes machine malfunctions and breakdowns
- May perform basic maintenance and adjustments
- Lays out hose to water supply and to receiving pond or receptacles

QUALIFICATIONS & OTHER REQUIREMENTS:

- May require experience in machine operating and tending or in construction labouring

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 1 - Labourers)

JOB TITLE:

TRAINEE – LABOURER CLASSIFICATIONS

DUTIES & RESPONSIBILITIES:

- Through participation in a Contractor's formally structured on-the-job training program, performs the duties associated with a classification covered by Appendix 1 on a progressive basis.

QUALIFICATIONS & OTHER REQUIREMENTS:

- Demonstrated interest in the scope of work covered by a classification and willing to undergo such training.
- Physically fit and willing and able to perform physically demanding work.
- Able to work at heights.

NOTE: The Trainee category applies only to those classifications that are non-designated trades (i.e. training is not governed by the Apprenticeship and Trades Qualification Act).

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 1a – Security Guards)

JOB TITLE:

SECURITY GUARD

DUTIES & RESPONSIBILITIES:

- Guards construction site against fire, theft, vandalism and illegal entry
- Patrols assigned area of construction site at predetermined intervals
- Records inspection rounds made
- Observes windows, doors, gates, equipment and machinery to ensure they are properly secured and have not been tampered with
- Reports to Lead Hand on any fire hazards, malfunction of machine or equipment, interruption of utility services, leaking pipes and security doors unlocked
- Sounds alarm, contacts Lead Hand, fire department or RCMP in case of fire or presence of unauthorized persons
- Permits authorized persons to enter property and records time of entry and departure
- Issues passes and directs visitors to appropriate area
- Checks alarms and fire extinguishers and other fire control systems to ensure that they are set to operate
- Checks credentials of persons at large on the construction site

QUALIFICATIONS & OTHER REQUIREMENTS:

- Completion of a recognized industrial security training course or a combination of training and experience equivalent thereto
- For some positions, minimum of one year experience as a security guard
- Must possess a valid Driver's License
- Must have a valid First Aid Certificate
- Must be bondable as per *The Private Investigation and Security Guard Act*, Province of Manitoba

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 1a – Security Guards)

JOB TITLE:

SECURITY GUARD – LEAD HAND

DUTIES & RESPONSIBILITIES:

- Supervises and coordinates activities of guard force on the construction site
- Inspects or directs inspection of premises to test alarm systems, detect safety hazards and ensure safety equipment is serviceable
- Cooperates with RCMP and fire department in problems affecting the construction site
- Directs activities of subordinates during fires, storms and other emergencies
- Communicates with Contractor's personnel using radio system
- Issues keys for buildings to authorized personnel and keeps records of keys issued

QUALIFICATIONS & OTHER REQUIREMENTS:

- Completion of a recognized industrial security training course or a combination of training and experience equivalent thereto
- Minimum of two years experience as a security guard, including a minimum of six months experience as a Lead Hand
- Must possess a valid Driver's License
- Must have a valid First Aid Certificate
- Must be bondable as per *The Private Investigation and Security Guard Act*, Province of Manitoba

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 1a – Security Guards)

JOB TITLE:

TRAINEE - SECURITY GUARD CLASSIFICATION

DUTIES & RESPONSIBILITIES:

- Through participation in a Contractor's formally structured on-the-job training program, performs the duties of a Security Guard on a progressive basis.

QUALIFICATIONS & OTHER REQUIREMENTS:

- Demonstrated interest in Security Guard work and willing to undergo such training.
- Must posses a valid Driver's Licence.
- Must be bondable.
- Must be willing to obtain a valid First Aid Certificate.
- Physically fit.

NOTE: The Trainee category applies only to those classifications that are non-designated trades (i.e. training is not governed by the Apprenticeship and Trades Qualification Act).

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 2 – Operating Engineers (Crane Operators)

JOB TITLE:

JOURNEYMAN BRIDGE CRANE OPERATOR

DUTIES & RESPONSIBILITIES:

- Operates bridge, whirley or gantry crane, consisting of hoist and operator's cab mounted on a bridge that runs along tracks to lift, move and load/off-load, place and install machinery, concrete forms, concrete buckets and other loose construction materials
- Controls levers and activates buttons to regulate direction of crane and hoist movement in response to signals from worker on ground level
- Observes load hook-up and verifies the safety of the load
- Inspects crane for defective parts and notifies supervisor of mechanical or electrical malfunctions
- Performs routine maintenance work

QUALIFICATIONS & OTHER REQUIREMENTS:

- Must have significant operating experience on the type and size of bridge crane to be utilized
- Must be physically fit and able to climb and work above ground

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 2 – Operating Engineers (Crane Operators)

JOB TITLE:

JOURNEYMAN MOBILE AND CRAWLER CRANE OPERATOR INCLUDING BOOM TRUCKS 7300 KG AND GREATER

DUTIES & RESPONSIBILITIES:

- Operates crane mounted on crawler treads or trucks and incorporating a boom capable of moving in the vertical and horizontal planes to lift and move materials and objects. For boom trucks, the load may also be conveyed on the deck of the truck
- Activates controls (levers, pedals etc.) in response to hand or radio signals to raise and lower crane boom and loadline
- Monitors crane loading to ensure weight of load is within lifting capacity of crane (Note: Crane capacities may vary from less than 10 tonnes up to 200 tonnes)
- Drives and positions crane to reach objects within range of boom.
- Reports and describes machine breakdowns and malfunctions.
- Performs routine maintenance work

QUALIFICATIONS & OTHER REQUIREMENTS:

- Certificate of Qualification corresponding to the type of crane to be operated, with additional experience appropriate for the job conditions and equipment type and capacity
- May be required to possess an appropriate valid Driver's Licence

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 2 – Operating Engineers (Crane Operators)

JOB TITLE:

JOURNEYMAN TOWER & CLIMBING CRANE OPERATOR

DUTIES & RESPONSIBILITIES:

- Operates electrically powered stationary and/or rail mounted travelling tower crane to lift, move and place heavy construction materials such as large wooden and metal concrete forms, staging, re-bar, gates and guides, metal plates, machinery, pre-cast concrete beams or blocks, structural iron and concrete buckets during pours
- Moves levers in response to signals provided by the signalman manually or by radio in order to activate the power source that enables the operator to rotate the jib (boom), travel the loadline trolley to the desired position along the jib, rotate the hoist drum to raise or lower loadline and move the crane along tracks to the desired work locations
- Maintains proper voltage within the power source, to ensure that overload cut out and brake release solenoid devices are functioning properly and to ensure that equipment is operated within its capacity
- Ensures that materials to be hoisted are within the capacity of the crane and that equipment is properly maintained

QUALIFICATIONS & OTHER REQUIREMENTS:

- Certificate of Qualification with extensive additional experience as a Tower Crane Operator
- Must be physically fit and able to climb and work above ground

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 2a – Operating Engineers (Equipment Operators & Allied Support Services)

JOB TITLE:

BACKHOE AND SHOVEL OPERATOR

DUTIES & RESPONSIBILITIES:

- Operates large construction backhoes and shovels with bucket size up to 15 cu. meters, to excavate, move and load material such as silt, sand, gravel, aggregate and rock

QUALIFICATIONS & OTHER REQUIREMENTS:

- Must be able to operate from right hand and left hand control seats
- Must have previous operating experience with a minimum of 3 years operating experience normally required for machines $10m^3$ and over

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 2a – Operating Engineers (Equipment Operators & Allied Support Services)

JOB TITLE:

BATCH PLANT OPERATOR

DUTIES & RESPONSIBILITIES:

- Operates concrete batch plant with capacities up to 300m^3 per hour
- Keeps material inventories
- Works with aggregate heating and cooling systems and ice plants

QUALIFICATIONS & OTHER REQUIREMENTS:

- Must have significant experience with all aspects of operating large capacity batch plants including material handling and sampling
- Must be proficient with computerized systems
- Must be familiar with aggregate heating and cooling systems and ice plants
- Must have a working knowledge of concrete mixes and be capable of meeting required specifications

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 2a – Operating Engineers (Equipment Operators & Allied Support Services)

JOB TITLE:

BIT SHARPENER

DUTIES & RESPONSIBILITIES:

- Sharpens bits and chisels used on drills and jack hammers to desired angles and edges using both power and hand tools
- May inspect bits and chisels for quality to determine discards and needs for replacements

QUALIFICATIONS & OTHER REQUIREMENTS:

- Must have previous experience and be competent to perform the tasks noted above
- Must be familiar with modern hydraulic or pneumatic tools and equipment

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 2a – Operating Engineers (Equipment Operators & Allied Support Services)

JOB TITLE:

CONCRETE PUMP OPERATOR

DUTIES & RESPONSIBILITIES:

- Operates truck mounted pump used to force concrete mixture through pipeline or hose from hopper to concrete forms
- Moves truck to proper position and sets for operation, including laying pipe and hose from pump to discharge point
- Disconnects and connects pipes and hoses as job requires
- Cleans hoppers, pipes and hoses

QUALIFICATIONS & OTHER REQUIREMENTS:

- Must have previous experience operating larger capacity concrete pumps

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 2a – Operating Engineers (Equipment Operators & Allied Support Services)

JOB TITLE:

DOZER OPERATOR

DUTIES & RESPONSIBILITIES:

- Operates dozers (D4 – D10) or equivalent
- Maintains grades and works in shot or blasted rock
- Works in area congested with heavy equipment traffic

QUALIFICATIONS & OTHER REQUIREMENTS:

- Must be familiar with earth moving techniques associated with large civil construction type projects
- Minimum of two years experience on large earth and rock moving projects such as dams, hydroelectric stations, open pit mines, etc.

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 2a – Operating Engineers (Equipment Operators & Allied Support Services)

JOB TITLE:

DRILL DOCTOR (DRILL MECHANIC)

DUTIES & RESPONSIBILITIES:

- Repairs and maintains pneumatic tools such as hammers, reamers, concrete vibrators and air track drills

QUALIFICATIONS & OTHER REQUIREMENTS:

- Must have significant experience repairing air trac drills and pneumatic tools
- May be required to supply applicable tools

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 2a – Operating Engineers (Equipment Operators & Allied Support Services)

JOB TITLE:

FRONT END LOADER OPERATOR

DUTIES & RESPONSIBILITIES:

- Operates large front end loaders, bucket size up to 15 cu. meters, to move or load earth, rock, sand or other materials
- Works in extremely congested areas loading large rockwagons, bottom dumps and other large trucks

QUALIFICATIONS & OTHER REQUIREMENTS:

- Must have operating experience, and a minimum of two years experience on larger capacity units
- Must be able to maintain a high level of productivity in loading of trucks with a variety of material including shot rock

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 2a – Operating Engineers (Equipment Operators & Allied Support Services)

JOB TITLE:

GRADER OPERATOR

DUTIES & RESPONSIBILITIES:

- Operates Caterpillar Graders up to 14G Cat or equivalent to scrape and level earth on construction sites, including experience building and maintaining dirt haul roads
- Drives grader in successive passes over terrain to raise or lower terrain to specified grade following markings on grade stakes or hand signals
- Works in congested heavy equipment areas
- May work in rock quarry or similar areas

QUALIFICATIONS & OTHER REQUIREMENTS:

- Must have operating experience, and for some work a minimum of three years experience is required

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 2a – Operating Engineers (Equipment Operators & Allied Support Services)

JOB TITLE:

HEAVY DUTY DIESEL MECHANIC APPRENTICE

DUTIES & RESPONSIBILITIES:

- Performs the duties of Heavy Duty Equipment Mechanic on a progressive basis in accordance with the regulations under *The Apprenticeship and Trades Qualification Act*

QUALIFICATIONS & OTHER REQUIREMENTS:

- Must meet the requirements of the regulations for entry and progression in the trade

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 2a – Operating Engineers (Equipment Operators & Allied Support Services)

JOB TITLE:

JOURNEYMAN DRAGLINE OPERATOR

DUTIES & RESPONSIBILITIES:

- Operates a crawler or truck mounted dragline (with bucket capacity up to 15m^3) to excavate or move gravel, loose rock or other materials
- Starts, stops and operates machine to move to proper site, scoop materials according to instructions given verbally or via survey stakes and dumps material at prescribed location
- Reports and describes machine malfunctions and breakdowns
- Performs routine maintenance work
- May direct workers engaged in placing blocks and outriggers to prevent capsizing of machine when lifting heavy loads

QUALIFICATIONS & OTHER REQUIREMENTS:

- Certificate of Qualification (or equivalent combination of training and experience) and additional previous operating experience is required with a minimum of three years experience on larger capacity machines
- Experience on large civil construction type projects is required, including experience with shot or blasted rock

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 2a – Operating Engineers (Equipment Operators & Allied Support Services)

JOB TITLE:

JOURNEYMAN HEAVY DUTY AND DIESEL MECHANIC

DUTIES & RESPONSIBILITIES:

- Inspects and diagnoses malfunctions in cranes, graders and other heavy construction equipment to determine extent of repairs required
- Repairs, rebuilds and adjust engines and other mechanical components of heavy construction equipment, powered conveyors and light vehicles
- Tests repaired equipment for proper performance and to ensure that work meets manufacturers' specifications

QUALIFICATIONS & OTHER REQUIREMENTS:

- Certificate of Qualification and several years years additional experience repairing all types of heavy construction equipment
- Contractor may accept education, training and experience equivalent to Journeyman qualifications

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 2a – Operating Engineers (Equipment Operators & Allied Support Services)

JOB TITLE:

MATERIAL HOIST OPERATOR

DUTIES & RESPONSIBILITIES:

- Operates tugger, power hoist or electrical hoisting equipment, fixed or travelling, with remote or suspended controls up to 30 tonne capacity
- Responds to audio or visual signals to position cage or load as required
- Inspects, lubricates and adjusts equipment using hand tools

QUALIFICATIONS & OTHER REQUIREMENTS:

- Certification of Qualification for Hoisting Equipment Operator

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 2a – Operating Engineers (Equipment Operators & Allied Support Services)

JOB TITLE:

OPERATOR OF CONVEYOR BELTS

DUTIES & RESPONSIBILITIES:

- Operates a conveyor or conveyor system to transfer materials to processing and loading points
- Conducts pre-start checks and starts the machine
- Adjusts chutes and deflectors to convey materials to proper points
- Checks materials for proper size and composition
- May also operate related equipment such as mixers, hoppers, scales, vibrators and pollution control devices
- May also collect samples of materials for quality control
- May keep records and make reports on operations

QUALIFICATIONS & OTHER REQUIREMENTS:

- Must have experience operating conveyors and conveyor systems, including aggregate production, material handling and sampling and concrete placement

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 2a – Operating Engineers (Equipment Operators & Allied Support Services)

JOB TITLE:

OPERATOR OF CRUSHER, SCREENING AND WASHING PLANTS

DUTIES & RESPONSIBILITIES:

- Operates a plant utilized for the production of construction materials such as concrete aggregate and involving crushing, screening and washing operations which may be separate or interconnected systems. On larger projects, plant capacity normally exceeds 250 tons per hour
- Supervises other workers assisting in the operation of such plants

QUALIFICATIONS & OTHER REQUIREMENTS:

- Must have significant experience operating large capacity crushing plants
- Must be proficient with the use of computerized systems
- Must have experience supervising other workers

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 2a – Operating Engineers (Equipment Operators & Allied Support Services)

JOB TITLE:

PACKER OPERATOR

DUTIES & RESPONSIBILITIES:

- Operates power-driven roller to compact and smooth layers of material such as rock, gravel, earth and asphalt to construct roads, pavements, runways and other surfaces
- Drives machine in successive overlapping passes over surface to be compacted
- Determines speed and direction of machine, based on knowledge of compressibility of material under changing temperatures, so that ridges are not formed by excessive pressure

QUALIFICATIONS & OTHER REQUIREMENTS:

- Operating experience is normally required, particularly on larger capacity units

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 2a – Operating Engineers (Equipment Operators & Allied Support Services)

JOB TITLE:

PUMPMAN (OVER 2")

DUTIES & RESPONSIBILITIES:

- Operates gasoline or electric model pumps for supply and drainage of water to or from work areas as required
- Keeps sections free from debris to prevent plugging
- Performs pre-start checks
- Starts, stops and tends engine and pumping equipment
- Reports and describes machine malfunctions and breakdowns
- Performs routine maintenance and adjustments
- May assist in the installation and removal of supply and discharge lines

QUALIFICATIONS & OTHER REQUIREMENTS:

- Previous experience as a Pumpman on other construction jobs is required
- Mechanically inclined
- Dependable and able to work without supervision

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 2a – Operating Engineers (Equipment Operators & Allied Support Services)

JOB TITLE:

SCRAPER OPERATOR

DUTIES & RESPONSIBILITIES:

- Operates self-propelled machine to scrape, load, haul, dump and spread earth, rock and other material on construction site to construct access roads, diking, dams and other assorted works (Note: Scraper capacities may vary from 10 to 60 cu. metres)

QUALIFICATIONS & OTHER REQUIREMENTS:

- Must have operating experience, with a minimum of one year experience for larger capacity machines

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 2a – Operating Engineers (Equipment Operators & Allied Support Services)

JOB TITLE:

SERVICEMAN

DUTIES & RESPONSIBILITIES:

- Lubricates and services construction equipment and vehicles
- Injects grease into units, such as universal joints and steering knuckles, using a pneumatic grease gun
- Inspects fluid levels, and adds specified lubricants as required
- Maintains service records

QUALIFICATIONS & OTHER REQUIREMENTS:

- Must have experience servicing various types of construction equipment
- Mechanically inclined
- Must posses a valid Driver's Licence. For driving of larger service vehicles a Class 3 Licence is normally required
- Must be physically fit and able to climb and service equipment
- Must be familiar with and able to understand service manuals

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 2a – Operating Engineers (Equipment Operators & Allied Support Services)

JOB TITLE:

TRAINEE – EQUIPMENT OPERATOR CLASSIFICATION

DUTIES & RESPONSIBILITIES:

- Through participation in a Contractor's formally structured on-the-job training program, performs the duties associated with a classification covered by Appendix 2a on a progressive basis.

QUALIFICATIONS & OTHER REQUIREMENTS:

- Demonstrated interest/aptitude in the scope of work covered by a classification and willing to undergo such training.
- Physically fit.
- A valid Driver's Licence my be required for training in certain classifications.

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 2a – Operating Engineers (Equipment Operators & Allied Support Services)

JOB TITLE:

WELDER - FLAT, VERTICAL, OVERHEAD (C.W.B.)

DUTIES & RESPONSIBILITIES:

- May be required to read and interpret drawings, blueprints or welding process specifications
- May be required to repair and fabricate from drawings
- Operates manual or semi-automatic welding equipment to fuse metal segments for flat, vertical and overhead positions
- Operates manual or semi-automatic flame-cutting equipment
- Operates brazing and soldering equipment

QUALIFICATIONS & OTHER REQUIREMENTS:

- Must have valid Canadian Welding Bureau tickets for flat, vertical and overhead positions
- Must have a Certificate of Qualification and additional experience welding all types of heavy construction equipment on a construction site
- Contractor may accept education, training and experience equivalent to Journeyman qualification

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 3 - Teamsters)

JOB TITLE:

BELLY DUMP DRIVER

DUTIES & RESPONSIBILITIES:

- Operates heavy diesel-powered earth and rock moving trucks with bottom discharge (e.g. 30 ton Kenworth 510 and 100 ton Atlas trucks or equivalent) to haul a variety of granular type fill such as silt, sand, gravel, etc.

QUALIFICATIONS & OTHER REQUIREMENTS:

- Significant previous experience is required operating belly dumps on large civil construction type projects
- Must posses an appropriate valid Driver's Licence consistent with size/capacity of vehicle and an air brake endorsement. For larger capacity belly dumps a Class 1 Driver's Licence will be required

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 3 - Teamsters)

JOB TITLE:

BUS DRIVER

DUTIES & RESPONSIBILITIES:

- Operates gasoline or diesel bus to transport passengers (Note: Bus capacity up to 44 passengers)
- Drives over difficult terrain, steep grades and in congested construction areas
- Reports delays, malfunctions and accidents

QUALIFICATIONS & OTHER REQUIREMENTS:

- Significant previous experience is required driving a bus on construction sites
- Must possess a valid Class 2 Drivers License with air brake endorsement, and a good driving record

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 3 - Teamsters)

JOB TITLE:

END DUMP DRIVER (ROCK WAGON)

DUTIES & RESPONSIBILITIES:

- Operates large diesel-powered Rockwagon (e.g. Cat 773-50 ton or similar) to move and haul rock and other construction materials
- Drives under difficult conditions such as rough terrain, steep grades and congested construction areas

QUALIFICATIONS & OTHER REQUIREMENTS:

- Significant previous experience is required operating large capacity haul vehicles on large civil construction type projects
- Must possess an appropriate valid Driver's Licence consistent with size/capacity of vehicle and an air brake Endorsement. For larger capacity End Dumps, a valid Class 3 Driver's Licence is normally required

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 3 - Teamsters)

JOB TITLE:

FORKLIFT OPERATOR

DUTIES & RESPONSIBILITIES:

- Operates powered forklift (e.g.15 ton Hyster forklift or equivalent) to lift, stack or move merchandise, equipment parts or bulk materials in warehouses, storage yards or other locations

QUALIFICATIONS & OTHER REQUIREMENTS:

- Must have previous experience working in a construction warehouse environment
- Must possess a valid Driver's Licence

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 3 - Teamsters)

JOB TITLE:

FUEL TRUCK DRIVER

DUTIES & RESPONSIBILITIES:

- Operates gasoline or diesel Tandem Tanker unit
- Fuels construction equipment such as dozers, loaders, cranes and other construction equipment
- Drives over difficult terrain, steep grades and in congested construction areas
- Maintains fuel records

QUALIFICATIONS & OTHER REQUIREMENTS:

- Must be physically fit and able to climb and fuel a variety of heavy construction equipment
- Experience fueling construction equipment noted above may be requested
- Must possess an appropriate valid Driver's Licence consistent with size/capacity of vehicle and an air brake endorsement. For larger capacity fuel trucks, a Class 2 Driver's Licence will be required

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 3 - Teamsters)

JOB TITLE:

JOURNEYMAN TRUCK MECHANIC

DUTIES & RESPONSIBILITIES:

- Services, repairs and overhauls trucks and buses used for various purposes on the construction project
- Diagnoses faults in engines using various test equipment and repairs to specifications
- Orders or requisitions spare parts and supplies for shop
- Adjusts, repairs or replaces parts and components of automotive systems including fuel, brake, steering and suspension systems, transmissions, differentials, drive axles and shafts, emission control and exhaust systems, engines and electrical systems, cooling and climate control systems and dumping and hoisting systems using hand tools and other specialized automotive repair equipment
- May perform routine body repairs (e.g. repairing doors, locks and glass)

QUALIFICATIONS & OTHER REQUIREMENTS:

- Certificate of Qualification and several years experience at the Journeyman level
- Must possess a valid Class 1 Drivers License with air brake endorsement
- Contractor may accept a combination of education, training and experience equivalent to Journeyman qualifications

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 3 - Teamsters)

JOB TITLE:

PARTSMAN

DUTIES & RESPONSIBILITIES:

- Counts and sorts incoming articles to verify receipt of items on requisitions or invoices
- Examines incoming articles for conformance to specifications
- Stores articles in an orderly and accessible manner in containers, bins or on shelves
- Processes incoming requisitions, fills orders and issues or distributes parts and supplies from stock
- Controls inventory and maintains records of amount, type and location of parts and supplies on hand
- Keeps parts area clean and in order
- May be required to operate vehicles associated with warehousing and distribution systems

QUALIFICATIONS & OTHER REQUIREMENTS:

- Must have significant previous experience in large construction site warehouses
- Must be familiar with parts for large construction equipment (e.g. Caterpillar, Grove, Atlas Copco, Link Belt and Manitowac, etc.)
- Must possess a valid Driver's Licence. For larger warehouse operations a class 3 Driver's Licence is normally required

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 3 - Teamsters)

JOB TITLE:

SEMI-TRAILER (HIGH OR LOW BED) DRIVER

DUTIES & RESPONSIBILITIES:

- Operates gasoline or diesel tractor trailer units to transport large equipment or material including granular (eg. sand, gravel, aggregate, etc.), depending on trailer configuration
- Directs proper load placement
- Oversees the condition of equipment, loading and unloading, and safety and security of the cargo including tying down loads to ensure safe transport
- May keep records of cargo information, distance travelled, fuel consumption and other information

QUALIFICATIONS & OTHER REQUIREMENTS:

- Significant previous experience is required driving semi-trailers on and off construction sites
- Must possess an appropriate valid Driver's Licence consistent with size/capacity of vehicle to be operated and if both highway and off-highway travel is required, a Class 1 Driver's Licence with air brake endorsement is normally required

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 3 - Teamsters)

JOB TITLE:

TANDEM TRUCK AND TRANSIT MIX TRUCK DRIVER

DUTIES & RESPONSIBILITIES:

- Operates gasoline or diesel tandem trucks with capacity up to $20m^3$ to haul gravel, sand and other construction materials
- Transit mix truck driver operates transit mix trucks 5 cu. yards in capacity and over (e.g. 510 Kenworth)
- Drives over difficult terrain, steep grades and in congested construction areas

QUALIFICATIONS & OTHER REQUIREMENTS:

- Significant previous experience is required driving tandem trucks and transit mix trucks on large civil construction projects
- Must possess an appropriate valid Driver's Licence consistent with size/capacity of vehicle and an air brake endorsement. On larger capacity vehicles, a Class 2 Driver's Licence will be required

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 3 - Teamsters)

JOB TITLE:

TRAINEE – TEAMSTERS CLASSIFICATION

DUTIES & RESPONSIBILITIES:

- Through participation in a Contractor's formally structured on-the-job training program, performs the duties associated with a classification covered by Appendix 3 on a progressive basis.

QUALIFICATIONS & OTHER REQUIREMENTS:

- Demonstrated interest/aptitude in the scope of work covered by a classification and willing to undergo such training.
- Must possess or be able to obtain a valid Driver's Licence; for some classifications a Class 3 licence or higher may be required along with an air brake endorsement (i.e. depending on size/capacity of vehicle and operating conditions).
- Physically fit.

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 3 - Teamsters)

JOB TITLE:

TRUCK DRIVER (UP TO 5 TON CAPACITY)

DUTIES & RESPONSIBILITIES:

- Operates light trucks up to five ton capacity
- Drives over difficult terrain, steep grades and in congested construction areas

QUALIFICATIONS & OTHER REQUIREMENTS:

- Must have previous experience driving a truck, a significant portion of which must have been in a heavy construction environment
- Must possess a valid Driver's Licence. For larger capacity trucks a Class 3 Driver's Licence with air brake endorsement may be required

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 3 - Teamsters)

JOB TITLE:

TRUCK MECHANIC APPRENTICE (MOTOR VEHICLE MECHANIC APPRENTICE))

DUTIES & RESPONSIBILITIES:

- Performs the duties of Truck Mechanic on a progressive basis in accordance with the regulations under *The Apprenticeship and Trades Qualification Act*

QUALIFICATIONS & OTHER REQUIREMENTS:

- May be required to possess or obtain a valid Class 1 Drivers License with air brake endorsement
- Must meet the requirements of the regulations for entry and progression in the trade

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 3 - Teamsters)

JOB TITLE:

UTILITY DRIVER

DUTIES & RESPONSIBILITIES:

- Operates as directed by the contractor, generally larger capacity buses and trucks such as belly dumps, rock wagons and tractor trailer units etc., all of which are covered by Appendix 3, Teamsters.
- Performs other duties associated with the class of vehicle being operated.

QUALIFICATIONS & OTHER REQUIREMENTS:

- Significant previous experience is required for operating the type/capacity of vehicles stipulated by the Contractor.
- Must possess a Class 1 Driver's Licence and an air brake endorsement.

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 3 - Teamsters)

JOB TITLE:

WAREHOUSE FOREMAN

DUTIES & RESPONSIBILITIES:

- Supervises, organizes, controls and coordinates the operations of the warehouse including the supervision of warehousepersons and other workers involved in loading, unloading, sorting, carrying, stacking and storing goods and materials either manually or using handtrucks and forklifts
- May be assigned responsibilities to plan, organize and direct administrative services such as cleaning, maintenance, safety and security in a warehouse environment
- May prepare reports related to warehouse operations and inventory
- May be required to operate vehicles associated with warehousing and distribution systems

QUALIFICATIONS & OTHER REQUIREMENTS:

- Must have significant experience in all aspects of construction warehouse operations
- Must have supervisory experience
- May be required to possess an appropriate valid Driver's Licence with an air brake endorsement consistent with the capacity/size of vehicles to be operated
- For larger warehouse operations a Class 3 Driver's Licence is normally required

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 3 - Teamsters)

JOB TITLE:

WAREHOUSEPERSON (MATERIAL HANDLER GENERAL)

DUTIES & RESPONSIBILITIES:

- Loads, unloads, conveys and distributes materials within the warehouse
- Receives, stores, orders and issues supplies and merchandise
- Keeps records of inventory and operations
- May perform other material handling activities such as counting, weighing, sorting, packing, unpacking and checking materials
- Keeps warehouse clean and in order

QUALIFICATIONS & OTHER REQUIREMENTS:

- Must have previous experience with construction warehouse operations, including a good working knowledge of warehouse accounting procedures
- Must be physically fit

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 4 - Carpenters)

JOB TITLE:

CARPENTER APPRENTICE

DUTIES & RESPONSIBILITIES:

- Performs the duties of a Carpenter on a progressive basis in accordance with the regulations under *The Apprenticeship and Trades Qualification Act*

QUALIFICATIONS & OTHER REQUIREMENTS:

- Must meet the requirements of the regulations for entry and progression in the trade
- Must have own tools as specified in the BNA Appendix

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 4 - Carpenters)

JOB TITLE:

CARPENTER FORMAN

DUTIES & RESPONSIBILITIES:

- Supervises and coordinates activities of workers engaged in the trade of carpentry including but not limited to measuring, cutting, shaping and assembly of wood and other materials, fabricating forms, installing metal frame forms, reading and interpreting blueprints

QUALIFICATIONS & OTHER REQUIREMENTS:

- Must have a Certificate of Qualification and significant additional experience at the Journeyman level
- Must have experience supervising other workers

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 4 - Carpenters)

JOB TITLE:

CARPENTER – OTHER

DUTIES & RESPONSIBILITIES:

- Measures, cuts, shapes, assembles and joins materials made of wood, wood substitutes and other materials
- Reads, interprets and works from blueprints, drawings, sketches and other specifications on a variety of structures related to the construction project
- May supervise and instruct Carpenter Apprentices and labourers
- May be required to rig and signal form placement
- Prepares layouts in conformance to building codes using measuring tools
- Fits and installs trim items such as doors, stairs, moulding and hardware
- May specialize in one or more types of work including metal frame forms, cantilevered forms, large construction draught tube forms, scroll case forms, interior trimming on camp buildings, framing, maintenance and exterior cladding

QUALIFICATIONS & OTHER REQUIREMENTS:

- Must have a minimum of four years experience with all aspects of the carpentry trade plus 1-2 years experience on major construction sites where the main responsibility of the carpenter is to fabricate, assemble and install concrete forms for vertical concrete pours
- Must be able to read and work from blueprints
- Must be willing and able to climb and work at heights
- Must have own tools as specified in BNA Appendix

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 4 - Carpenters)

JOB TITLE:

JOURNEYMAN CARPENTER

DUTIES & RESPONSIBILITIES:

- Measures, cuts, shapes, assembles and joins materials made of wood, wood substitutes and other materials
- Reads, interprets and works from blueprints, drawings, sketches and other specifications on a variety of structures related to the construction project
- Supervises and instructs Carpenter Apprentices and labourers
- May be required to rig and signal form placement
- Prepares layouts in conformance to building codes using measuring tools
- Fits and installs trim items such as doors, stairs, moulding and hardware
- May specialize in one or more types of work including metal frame forms, cantilevered forms, large construction draught tube forms, scroll case forms, interior trimming on camp buildings, framing, maintenance and exterior cladding

QUALIFICATIONS & OTHER REQUIREMENTS:

- Must have a Certificate of Qualification and previous experience as a carpenter on heavy industrial type construction projects
- Must be able to read and work from blueprints
- Must be willing and able to climb and work at heights
- Must have own tools as specified in BNA Appendix

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 4a -Millrights)

JOB TITLE:

MILLWRIGHT APPRENTICE

DUTIES & RESPONSIBILITIES:

- Performs the duties of a Millwright on a progressive basis in accordance with the regulations under *The Apprenticeship and Trades Qualification Act*

QUALIFICATIONS & OTHER REQUIREMENTS:

- Must meet the requirements of the regulations for entry and progression in the trade
- Must have own tools as specified in BNA Appendix

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 4a -Millrights)

JOB TITLE:

MILLWRIGHT FOREMAN

DUTIES & RESPONSIBILITIES:

- Supervises and coordinates the activities of construction Millwrights involved in the assembly, installing and setting up of machinery and equipment and in particular turbines and generators

QUALIFICATIONS & OTHER REQUIREMENTS:

- Must have a Certificate of Qualification and significant additional experience at the Journeyman level
- Must have experience supervising other workers

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 4a -Millrights)

JOB TITLE:

JOURNEYMAN MILLWRIGHT

DUTIES & RESPONSIBILITIES:

- Installs and aligns turbines, generators and related machinery
- Lays out foundations from blueprints
- Sets up and lines shafts and pulleys
- Erects conveyor lines, belts, etc.
- Sets up and operates various machine tools such as lathes and grinders to fabricate parts required during overhaul, maintenance or set-up of machinery

QUALIFICATIONS & OTHER REQUIREMENTS:

- Certificate of Qualification; previous experience in the installation of turbines and generators may be required
- Contractor may accept an combination of education, training and experience equivalent to Journeyman status
- Must have own tools as specified in BNA Appendix

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 5 – Painters Division)

JOB TITLE:

JOURNEYMAN PAINTER (BRUSH AND ROLLERS)

DUTIES & RESPONSIBILITIES:

- Applies paint, varnish, stain, enamel or lacquer to colour, decorate or protect from deterioration, the surfaces of buildings, towers and other structures
- Prepares and cleans surfaces to be painted by methods such as scraping, sanding, hydro-blasting and steam-cleaning
- Prepares surfaces by filling cracks and holes with filler materials
- Cleans and maintains equipment
- May work on scaffolding, ladders and other types of rigging
- Supervises and instructs Painter Apprentices and supervises helpers

QUALIFICATIONS & OTHER REQUIREMENTS:

- Certificate of Qualification
- Must be willing and able to climb and work at heights
- Contractor may accept a combination of education, training and experience equivalent to Journeyman qualifications
- Must have own tools as specified in BNA Appendix

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 5 – Painters Division)

JOB TITLE:

JOURNEYMAN PAINTER (SPRAYING AND SANDBLASTING)

DUTIES & RESPONSIBILITIES:

- Applies paint, varnish, stain, enamel or lacquer to colour, decorate or protect from deterioration, the surfaces of buildings, towers and other structures using spray painting equipment
- Prepares and cleans surfaces to be painted using methods including scraping, sanding, sand-blasting, hydro-blasting and steam-cleaning
- Prepares surfaces by filling cracks and holes with filler materials
- Cleans and maintains equipment
- May work on scaffolding, ladders and other types of rigging
- Supervises and instructs Painter Apprentices and supervises helpers

QUALIFICATIONS & OTHER REQUIREMENTS:

- Certificate of Qualification
- Must be willing and able to climb and work at heights
- Contractor may accept a combination of education, training and experience equivalent to Journeyman qualifications
- Must have own tools as specified in BNA Appendix

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 5 – Painters Division)

JOB TITLE:

PAINTER APPRENTICE

DUTIES & RESPONSIBILITIES:

- Performs duties of Painter on a progressive basis in accordance with the regulations under *The Apprenticeship and Trades Qualifications Act*

QUALIFICATIONS & OTHER REQUIREMENTS:

- Must meet the requirements under the regulations for entry and progression in the trade
- Must have own tools as specified in BNA Appendix

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 5a –Glassworkers Division)

JOB TITLE:

JOURNEYMAN GLASS AND METAL MECHANICS

DUTIES & RESPONSIBILITIES:

- Cuts, fits and installs glass in windows and doors and on interior walls and ceilings of buildings
- Reads and interprets specifications for required type and thickness of glass, frame and materials
- May fabricate metal frames for glass installation

QUALIFICATIONS & OTHER REQUIREMENTS:

- Certificate of Qualification
- Contractor may accept a combination of education, training and experience equivalent to Journeyman qualifications

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 5b – Floor Covering Division)

JOB TITLE:

CARPET AND RESILIENT FLOOR TILE LAYER

DUTIES & RESPONSIBILITIES:

- Inspects, measures and marks surfaces to be covered
- Measures, cuts and fastens underlay and underpadding
- Measures, cuts and installs carpeting using hand or machine stitcher, seaming iron, bonding tape or other bonding materials
- Stretches carpeting using knee-kicker or power stretcher and secures carpeting to floor or other surfaces using staple gun or other devices
- Measures, cuts and installs vinyl resilient floor covering using adhesive, rollers and other hand tools

QUALIFICATIONS & OTHER REQUIREMENTS:

- Must have a Certificate of Qualification and experience installing a wide variety of floor covering materials or has acquired the skills of the trade for a period of not less than six years and is proficient in performing the key tasks of the trade as set out in Appendix 5b of the BNA

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 6 – Insulator Workers)

JOB TITLE:

JOURNEYMAN INSULATION MECHANIC

DUTIES & RESPONSIBILITIES:

- Insulates heat, water, steam or other piping
- Insulates hot and cold air ducts
- Works from blueprints, drawing and sketches to determine insulation requirements
- Measures and cuts insulating material to required dimensions using hand and power tools
- Applies and secures insulation using spraying, blowing, pasting, strapping, taping and other application and installation methods
- Installs various types of vapour barriers and waterproofing

QUALIFICATIONS & OTHER REQUIREMENTS:

- Must have a Certificate of Qualification and additional experience at the Journeyman level or at least four years experience with all aspects of the insulation trade and be recognized by contractors in the industry as having attained the requisite skills and proficiencies.
- May be required to pass an efficiency test administered by the contractor
- Must have own tools as specified in BNA Appendix

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 7 –Lathers)

JOB TITLE:

DRYWALL APPLICATOR APPRENTICE

DUTIES & RESPONSIBILITIES:

- Performs the duties of a Drywall Applicator on a progressive basis in accordance with the Regulations under the Apprenticeship and Trades Qualification Act

QUALIFICATIONS & OTHER REQUIREMENTS:

- Must meet the requirements of the Regulations for entry and progression in the trade
- Must have own tools as specified in BNA Appendix

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 7 –Lathers)

JOB TITLE:

JOURNEYMAN DRYWALL APPLICATORS

DUTIES & RESPONSIBILITIES:

- Measures, cuts, fits and fastens drywall sheets to metal or wooden studs or joists on interior walls and ceilings of buildings
- Cuts and installs metal corner beads to protect exterior corners
- Tapes and finishes all joints between drywall sheets

QUALIFICATIONS & OTHER REQUIREMENTS:

- Certificate of Qualification and additional experience at the Journeyman level
- Contractor may accept a combination of education, training and experience equivalent to Journeyman qualifications
- Must have own tools as specified in BNA Appendix

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 8 – Plasterers)

JOB TITLE:

JOURNEYMAN PLASTERER

DUTIES & RESPONSIBILITIES:

- Applies coats of plaster to interior walls and ceilings of buildings to produce a finished surface using trowels, floats, brushes or spraying equipment
- Sprays acoustic materials or texture finish over walls and ceilings
- Installs corner beads and wire mesh around beams to which plaster is to be applied

QUALIFICATIONS & OTHER REQUIREMENTS:

- Certificate of Qualification and additional experience at the Journeyman level
- Contractor may accept a combination of education, training and experience equivalent to Journeyman qualifications
- Must have own tools as specified in BNA Appendix

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 8a – Cement Masons)

JOB TITLE:

CEMENT MASON APPRENTICE

DUTIES & RESPONSIBILITIES:

- Performs duties of Cement Mason on a progressive basis according to standards established by the industry

QUALIFICATIONS & OTHER REQUIREMENTS:

- Must have an aptitude and interest in the trade and be wiling and able to serve as an Apprentice

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 8a – Cement Masons)

JOB TITLE:

JOURNEYMAN CEMENT MASON

DUTIES & RESPONSIBILITIES:

- Spreads concrete to specified depth
- Smooths and finishes exposed surfaces of poured concrete according to grade and depth specifications using straightedge, float, trowels or power float
- Forms expansion joints and edges
- May direct setting of forms
- Directs the placement of concrete into forms or onto surfaces according to grade
- Applies hardening and sealing compounds to cure surface of concrete
- Repairs, resurfaces and replaces worn or damaged sections of floors, walls, roads and other concrete structures
- Supervises and instructs Cement Mason Apprentices

QUALIFICATIONS & OTHER REQUIREMENTS:

- Must have Certificate of Qualification and experience at the Journeyman level or at least three years experience with all aspects of concrete finishing and curing and be recognized by contractors in the industry as having the equivalent of Journeyman status

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 9 - Bricklayers)

JOB TITLE:

BRICKLAYER AND MASON APPRENTICES

DUTIES & RESPONSIBILITIES:

- Performs the duties of a Bricklayer on a progressive basis in accordance with the regulations under *The Apprenticeship and Trades Qualification Act*

QUALIFICATIONS & OTHER REQUIREMENTS:

- Must meet the requirements of the regulations for entry and progression in the trade
- Must have own tools as specified in BNA Appendix

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 9 - Bricklayers)

JOB TITLE:

BRICKLAYING FOREMAN

DUTIES & RESPONSIBILITIES:

- Supervises and coordinates the activities of workers engaged in preparing and laying brick and natural stone and blocks of concrete and related materials

QUALIFICATIONS & OTHER REQUIREMENTS:

- Must have a Certificate of Qualification and significant additional experience at the Journeyman level
- Must have experience supervising other workers
- Must have own tools as specified in BNA Appendix

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 9 - Bricklayers)

JOB TITLE:

JOURNEYMAN BRICKLAYER

DUTIES & RESPONSIBILITIES:

- Prepares and lays brick, concrete, cinder, terra cotta or other types of building blocks, structural tiles and similar materials, except stone and marble, to construct walls, partitions, sewers and other structures
- Examines plans and specifications to obtain details for construction
- Measures distances from reference point and erects guidelines on working surface to lay out work
- Directs helpers erecting scaffold and setting out materials

QUALIFICATIONS & OTHER REQUIREMENTS:

- Must have a Manitoba Certificate of Qualification and additional experience at the Journeyman level
- Contractor may accept education, training and experience equivalent to Journeyman qualifications
- Must have own tools as specified in BNA Appendix

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 9 - Bricklayers)

JOB TITLE:

JOURNEYMAN STONEMASON

DUTIES & RESPONSIBILITIES:

- Builds stone structures, such as walls, piers and abutments
- Prepares and lays walks, curbstones or special types of masonry such as acid-resistant soapstone for vats, tanks and floors
- Directs and assists helper setting stone in place by hand, using pry-bar or with aid of a lifting device

QUALIFICATIONS & OTHER REQUIREMENTS:

- Must have a Certificate of Qualification and additional experience at the Journeyman level
- Contractor may accept a combination of education, training and experience equivalent to Journeyman qualifications
- Must have own tools as specified in BNA Appendix

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 9 - Bricklayers)

JOB TITLE:

MASONRY FOREMAN

DUTIES & RESPONSIBILITIES:

- Supervises and coordinates the activities of workers engaged in the building of stone structures such as walls, piers and abutments
- Supervises and coordinates the activities of workers engaged in the laying of walks, curbstones or special types of masonry such as acid-resistant soapstone for vats, tanks and floors

QUALIFICATIONS & OTHER REQUIREMENTS:

- Must have a Certificate of Qualification and significant additional experience at the Journeyman level
- Must have experience supervising other workers
- Must have own tools as specified in BNA Appendix

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 10 – Sheet Metal)

JOB TITLE:

JOURNEYMAN SHEET METAL WORKER

DUTIES & RESPONSIBILITIES:

- Fabricates, assembles and installs sheet metal items such as drainpipes, ventilator shafts, furnace casings, eavestroughs, air and heat ducts and metal partitions
- Reads drawings and sketches of work to be performed and lays out, measures and marks sheet metal
- Operates light metalworking machines such as shears, brakes, punches and drill presses to cut, bend, punch, drill, shape or straighten sheet metal
- Fits and joins sheet metal parts using riveter, soldering and other fastening methods
- Supervises and instructs Sheet Metal Apprentices

QUALIFICATIONS & OTHER REQUIREMENTS:

- Must have a Certificate of Qualification and additional experience at the Journeyman level
- Contractor may accept a combination of education, training and experience equivalent to Journeyman qualifications
- Must have own tools as specified in BNA Appendix

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 10 – Sheet Metal)

JOB TITLE:

SHEET METAL WORKER APPRENTICE

DUTIES & RESPONSIBILITIES:

- Performs the duties of a Sheet Metal Worker on a progressive basis in accordance with the regulations under *The Apprenticeship and Trades Qualifications Act*

QUALIFICATIONS & OTHER REQUIREMENTS:

- Must meet the requirements under the regulations for entry and progression in the trade
- Must have own tools as specified in BNA Appendix

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 10a - Roofers)

JOB TITLE:

JOURNEYMAN ROOFER

DUTIES & RESPONSIBILITIES:

- Selects materials according to plans and specifications
- Applies roofing paper, hot tar and gravel, and other roofing materials such as shingles, to roof surface
- Cuts, fits and nails strips of sheet metal, insulating material or preformed flashings in angles between walls, chimneys or vents and roof surface
- Supervises and instructs Roofer Apprentices and supervises helpers (For further information see classification in BNA Appendix)

QUALIFICATIONS & OTHER REQUIREMENTS:

- Must have a Certificate of Qualification and additional experience at the Journeyman level
- Contractor may accept a combination of education, training and experience equivalent to Journeyman qualifications
- Must have own tools as specified in BNA Appendix

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 10a - Roofers)

JOB TITLE:

ROOFER APPRENTICE AND CLASSIFIED WORKER

DUTIES & RESPONSIBILITIES:

- Performs the duties of a Roofer on a progressive basis in accordance with the regulations under *The Apprenticeship and Trades Qualifications Acts*
- A Classified Worker means a person with limited or no roofing experience capable of performing entry level tasks or single job specific skills

QUALIFICATIONS & OTHER REQUIREMENTS:

- Must meet the requirements under the regulations for entry and progression in the trade (currently, an Apprentice must have a minimum of 2000 hours of working experience prior to registration

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 10b – Sheeters, Deckers and Cladders)

JOB TITLE:

JOURNEYMAN SHEETER, DECKER OR CLADDER

DUTIES & RESPONSIBILITIES:

- Lays out, fabricates and erects building framework such as sub-flooring, exterior walls, interior partitions and roofs
- Applies siding materials such as metal wall panels and insulated roof panels to provide a protective, insulating surface
- Reads blueprints or work order specifications to determine layout and installation procedures
- Measures and marks guidelines to be used for installations
- Installs, repairs and services exterior prefabricated products such as siding, shutters, awnings, fences and decks using hand and power tools

QUALIFICATIONS & OTHER REQUIREMENTS:

- Must have a Certificate of Qualification and a minimum of 7500 hours working at the trade (or as otherwise specified from time to time in Appendix 10b of the BNA
- Must have own tools as specified in BNA Appendix

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 10b – Sheeters, Deckers and Cladders)

JOB TITLE:

SHEETER, DECKER OR CLADDER TRAINEES

DUTIES & RESPONSIBILITIES:

- Performs the duties of a Sheeter, Decker and Cladder on a progressive basis. The classification system for Trainees including probationary employees is set out in Section 4 of Appendix 10b

QUALIFICATIONS & OTHER REQUIREMENTS:

- Must meet the requirements of the regulations and the training provisions of this Appendix for entry and progression in the trade
- Must have own tools as specified in the BNA Appendix

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 11 - Boilermakers)

JOB TITLE:

BOILERMAKER APPRENTICE

DUTIES & RESPONSIBILITIES:

- Performs duties of Boilermaker on a progressive basis in accordance with the regulations under *The Apprenticeship and Trades Qualifications Act*

QUALIFICATIONS & OTHER REQUIREMENTS:

- Must meet the requirements under the regulations for entry and progression in the trade

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 11 - Boilermakers)

JOB TITLE:

BOILERMAKER FOREMAN

DUTIES & RESPONSIBILITIES:

- Supervises and coordinates activities of workers engaged in fabricating, assembling, erecting and repairing boilers and pressure vessels

QUALIFICATIONS & OTHER REQUIREMENTS:

- Must have a Certificate of Qualification and significant additional experience at the Journeyman level
- Must have experience supervising other workers

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 11 - Boilermakers)

JOB TITLE:

BOILERMAKER HELPER

DUTIES & RESPONSIBILITIES:

- Helps workers to fabricate and assemble boilers and steel-plate vessels such as tanks and vats
- Uses power machines such as the drill press, punch press, boring mill, power shears, and portable and pedestal grinders
- Uses hand tools

QUALIFICATIONS & OTHER REQUIREMENTS:

- Must be physically capable of heavy construction labour work

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 11 - Boilermakers)

JOB TITLE:

JOURNEYMAN BOILERMAKER

DUTIES & RESPONSIBILITIES:

- Lays out, fabricates, assembles, rigs, erects and welds boilers, tanks and pressure vessels
- Develops layout and plans sequence of operations
- Cuts metal plates and brackets
- Sets up and operates heavy-metal working machines such as brakes, rolls, shears, flame cutters and drill presses to cut, shape and form metal into parts or sections
- Repairs and performs maintenance work on boilers and other heavy-metal products
- May direct activities of hoist or crane operators and other workers during fabrication, assembly, installation or repair of heavy-metal products
- Supervises and instructs Boilermaker Apprentices and supervises helpers

QUALIFICATIONS & OTHER REQUIREMENTS:

- Must have Certificate of Qualification and additional experience at the Journeyman level
- Boilermaker-Welders must have a current Provincial Government Welding Certificate

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 12 – Iron Workers)

JOB TITLE:

JOURNEYMAN STRUCTURAL IRON WORKER

DUTIES & RESPONSIBILITIES:

- Erection of structural steel for buildings, bridges, tanks, towers, etc.
- Assembles and reeves erecting cranes, travellers, guy and stiff leg derricks and moves travellers
- Hooks on, climbs, connects and signals the Hoisting Engineer
- Erects scaffold, fits joints and performs bolting operations
- Carries out all the miscellaneous tasks that arise on erection jobs such as tying knots, burning, drilling and reaming, etc.
- Supervises and instructs Iron Worker Apprentices

QUALIFICATIONS & OTHER REQUIREMENTS:

- Must have a Certificate of Qualification and additional experience at the Journeyman level
- Contractor may accept a combination of education, training and experience equivalent to Journeyman qualifications
- Must be willing and able to climb and work at heights

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 12 – Iron Workers)

JOB TITLE:

JOURNEYMAN STRUCTURAL IRON WORKER – WELDER

DUTIES & RESPONSIBILITIES:

- Performs welding operations for structural ironwork including erection of scaffolding, fit-up work and burning & chipping
- Able to read and understand welding symbols and procedures
- May perform all other duties as a Journeyman Iron Worker

QUALIFICATIONS & OTHER REQUIREMENTS:

- Must have a Certificate of Qualification and additional experience at the Journeyman level. Contractor may accept a combination of education, training and experience equivalent to Journeyman qualifications
- Must possess the appropriate C.W.B. ticket(s) and qualify under Class “C” of the current Canadian Standards Association Code
- Must be willing and able to climb and work at heights

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 12 – Iron Workers)

JOB TITLE:

STRUCTURAL IRON WORKER APPRENTICE

DUTIES & RESPONSIBILITIES:

- Performs duties of Structural Iron Worker on a progressive basis in accordance with the regulations under *The Apprenticeship and Trades Qualifications Act*

QUALIFICATIONS & OTHER REQUIREMENTS:

- Must meet the requirements under the regulations for entry and progression in the trade
- Must be willing and able to climb and work at heights

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 12 – Iron Workers)

JOB TITLE:

STRUCTURAL IRON WORKER FOREMAN

DUTIES & RESPONSIBILITIES:

- Supervises and coordinates activities of workers engaged in raising, positioning and joining pre-fabricated metal members and parts on all kinds of steel erection, including buildings, bridges, tanks, towers, etc.

QUALIFICATIONS & OTHER REQUIREMENTS:

- Must have a Certificate of Qualification and significant previous experience at the Journeyman level. Contractor may accept a combination of education, training and experience equivalent to Journeyman qualifications
- Must have previous experience supervising other workers
- May be required to have appropriate C.W.B welding ticket
- Must be willing and able to climb and work at heights

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 12a – Rodman)

JOB TITLE:

JOURNEYMAN REINFORCING RODMAN – (REBAR)

DUTIES & RESPONSIBILITIES:

- Applies proper ties efficiently using Klein side cutting pliers
- Slings, climbs and signals the Hoist Operator to position steel units
- Erects scaffolding and when required ties necessary knots and sling scaffolds
- Places reinforcing steel in accordance with recognized ACI Standards under the direction of the Foreman or Superintendent
- Reads and interprets bar lists, placing drawings and cutting sheets
- Operates bending and cutting machines under the direction of the Foreman
- Works with a hickey
- Measures off work under the direction of the Foreman or Superintendent
- Supervises and instructs Rodman Apprentices

QUALIFICATIONS & OTHER REQUIREMENTS:

- Must have a Certificate of Qualification and experienced in the fabrication, placing and tying of reinforcing steel in all types of reinforced concreate structures. Contractor may accept a combination of education, training and experience equivalent to Journeyman status
- Must have a thorough working knowledge of tools and equipment used in the trade as laid down in the CRSI Recommended Practice for Placing Reinforcing Bars, 1959
- Must be in physical condition to pack steel efficiently and safely

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 12a – Rodman)

JOB TITLE:

REINFORCING RODMAN APPRENTICE AND TRAINEE – (REBAR)

DUTIES & RESPONSIBILITIES:

- Performs duties of Rodman on a progressive basis according to standards established by the industry (Rodman Trainee is an entry level Apprentice Classifcation – for further details, see Section 5 of Appendix 12a)

QUALIFICATIONS & OTHER REQUIREMENTS:

- Must have an aptitude and interest in the trade and be willing and able to serve as an apprentice
- Must be willing and able to work at heights

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 12a – Rodman)

JOB TITLE:

REINFORCING RODMAN FOREMAN – (REBAR)

DUTIES & RESPONSIBILITIES:

- Supervises and coordinates activities of workers engaged in placing reinforcing steel (rebar)
- May perform some or all of the duties of a Journeyman Reinforcing Rodman

QUALIFICATIONS & OTHER REQUIREMENTS:

- Must have a Certificate of Qualification and experience in the fabrication, placing and typing of reinforcing steel in all types of reinforced concrete structures. Contractor may accept a combination of education, training and experience equivalent to Journeyman status
- Must have experience supervising other workers
- Must be in physical condition to carry out all aspects of the trade

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 13 – Electrical Workers)

JOB TITLE:

ELECTRICAL APPRENTICE

DUTIES & RESPONSIBILITIES:

- Performs the duties of Electrician (Construction) on a progressive basis in accordance with the regulations under *The Apprenticeship and Trades Qualifications Act*

QUALIFICATIONS & OTHER REQUIREMENTS:

- Must meet the requirements under the regulations for entry and progression in the trade
- Must have own tools as specified in BNA Appendix

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 13 – Electrical Workers)

JOB TITLE:

ELECTRICAL FOREMAN

DUTIES & RESPONSIBILITIES:

- Supervises and coordinates the activities of Journeymen and Apprentices engaged in installing and repairing electrical wiring and equipment on construction sites

QUALIFICATIONS & OTHER REQUIREMENTS:

- Must have a Certificate of Qualification and significant additional experience at the Journeyman level
- Must have experience supervising Journeymen and Apprentices
- May require C.W.B. ticket(s)

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 13 – Electrical Workers)

JOB TITLE:

JOURNEYMAN ELECTRICIAN – (CONSTRUCTION)

DUTIES & RESPONSIBILITIES:

- Lays out, assembles, installs, splices and replaces electrical wiring, receptacles, switch boxes, conduits, feeders, cable assemblies, lighting fixtures and other electrical components in industrial establishments in accordance with drawings
- Performs electrical work related to heavy construction installation including conduit cable trays, fan motors, heaters, lights, control panels and transformers
- Maintains, repairs, installs and tests switchgears, transformers, switchboard meters, regulators, reactors, electrical motors, generators, industrial storage batteries and hydraulic and pneumatic electrical control systems
- Inspects and tests installed electrical equipment and apparatus to locate electrical faults and check their operation, using volt meters, ammeters and other electrical test instruments and equipment
- May complete test and maintenance reports
- Tests continuity of circuits using test equipment to ensure compatibility and safety of system, following installation, replacement or repair
- Supervises and instructs Electrical Apprentices

QUALIFICATIONS & OTHER REQUIREMENTS:

- Must have a Certificate of Qualification
- May require C.W.B. ticket(s)
- Additional experience at the Journeyman level may be required for some positions
- Must have own tools as specified in BNA Appendix

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 14 - Plumbers and Pipefitters)

JOB TITLE:

JOURNEYMAN PIPE FITTER / STEAM FITTER / SPRINKLER INSTALLER

DUTIES & RESPONSIBILITIES:

- Lays out, fabricates, installs and maintains high- and low-pressure systems of piping and fittings for conducting steam, water, oil and other liquids and gases used in heating, cooling, lubricating and other industrial processing systems
- Reads and interprets drawings and specifications to determine layout and material requirements
- Cuts openings for pipe in walls, floors and ceilings using hand or power tools or machines
- Measures, cuts, threads and bends pipe to required shape using hand and power tools
- Welds, brazes, cements, solders or threads joints to join pipes and fabricate sections of piping system
- Tests system for leaks using testing equipment
- Supervises and instructs Pipe Apprentices

QUALIFICATIONS & OTHER REQUIREMENTS:

- Must have a Certificate of Qualification
- Additional experience at the Journeyman level may be required for some positions
- May require C.W.B. ticket(s)
- Must have own tools as specified in Appendix

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 14 Plumbers and Pipefitters)

JOB TITLE:

JOURNEYMAN PIPE FITTER – WELDER

DUTIES & RESPONSIBILITIES:

- Assembles and installs piping and fittings and fuses joints using acetylene, arc, atomic and oxy-hydrogen welding equipment
- Examines drawings and other specifications to determine the piping layout and type and the standard of the welding joint
- May be required to perform some or all of the duties of a Journeyman Pipe Fitter

QUALIFICATIONS & OTHER REQUIREMENTS:

- Must have a Certificate of Qualification
- Additional experience at the Journeyman level may be required for some positions
- Must have necessary C.W.B. ticket(s)

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 14 Plumbers and Pipefitters)

JOB TITLE:

JOURNEYMAN PLUMBER

DUTIES & RESPONSIBILITIES:

- Assembles, Installs and repairs pipes, fixtures and fittings used for water distribution and waste disposal in private, public and industrial buildings, according to local plumbing codes
- Examines building plans and specifications to determine the layout for plumbing system components such as water supply network, sewage waste drainage and plumbing fixtures
- Locates positions and cuts openings for pipe connections, passage holes and fixtures in walls and floors
- Measures, cuts and threads pipes using hand and power tools
- Joins pipes using couplings, clamps, screws, bolts, cement or soldering, brazing and welding equipment
- Tests pipes for leaks using air and water pressure gauges

QUALIFICATIONS & OTHER REQUIREMENTS:

- Must have a Certificate of Qualification
- Additional experience at the Journeyman level may be required for some positions
- Must supply basic tools of the trade as specified by Appendix

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 14 Plumbers and Pipefitters)

JOB TITLE:

PIPE FITTER / STEAM FITTER / PLUMBER AND SPRINKLER FOREMAN

DUTIES & RESPONSIBILITIES:

- Supervises and coordinates the activities of workers engaged in installing and repairing pipeline, plumbing, sprinkler systems and related equipment for water, gas, steam, sewage or other systems

QUALIFICATIONS & OTHER REQUIREMENTS:

- Must have Certificate of Qualification relevant to the trade being supervised, and significant additional experience at the Journeyman level
- Must have experience supervising Journeymen and Apprentices

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 14 Plumbers and Pipefitters)

JOB TITLE:

PIPE FITTER / STEAM FITTER / SPRINKLER INSTALLER APPRENTICE

DUTIES & RESPONSIBILITIES:

- Performs duties of Pipe Fitters/Steam Fitters/Sprinkler Installer on a progressive basis in accordance with the regulations under *The Apprenticeship and Trades Qualifications Act*

QUALIFICATIONS & OTHER REQUIREMENTS:

- Must meet the requirements under the regulations for entry and progression in the trade
- Must supply own tools as specified in Appendix

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 14a – Refrigeration Section of Plumbers and Pipefitters)

JOB TITLE:

JOURNEYMAN REFRIGERATION WORKER

DUTIES & RESPONSIBILITIES:

- Measures, lays-out, assembles and installs refrigeration and/or air conditioning components and attendant piping using welding and brazing equipment.
- Performs testing and commissioning tasks
- Performs routine maintenance and servicing including recharging system with refrigerant
- Supervises and instructs Apprentices

QUALIFICATIONS & OTHER REQUIREMENTS:

- Must have a Certificate of Qualifications and additional experience at the Journeyman level
- May require CWB tickets
- Must have own tools as specified in appendix

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 14a – Refrigeration Section of Plumbers and Pipefitters)

JOB TITLE:

REFRIGERATION WORKER APPRENTICE

DUTIES & RESPONSIBILITIES:

- Performs the duties of a Refrigeration Worker on a progressive basis in accordance with the regulations under the Apprentice and Trades Qualification Act

QUALIFICATIONS & OTHER REQUIREMENTS:

- Must meet the requirements under the regulations for entry and progression in the trade
- Must have own tools as specified in the Appendix

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 15 – Office and Professional Employees)

JOB TITLE:

CLERK – TYPIST

DUTIES & RESPONSIBILITIES:

- Performs general clerical work where majority of duties require the use of word processing software on a personal computer, and in some cases the use of a typewriter
- Prepares correspondence, reports, statements, invoices forms and other administrative documents in hard copy and electronic file format
- Receives and registers correspondence, reports, text and other written material for typing or word processing
- Files documents and compiles information for records
- May photocopy and collate documents, sorts and distributes mail and answer the telephone
- May use an adding machine, calculator, spreadsheet software as well as photocopiers and facsimile (FAX) machines
- Labels, copies and stores diskettes and other electronic data storage mediums and maintains inventory of stored material

QUALIFICATIONS & OTHER REQUIREMENTS:

- Must be able to type at a speed of not less than 40 words per minute
- May require completion of secondary school, college or other courses in word processing and/or office software applications
- Must be proficient with personal computers and other office equipment such as facsimile (FAX) machines, photocopiers

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 15 – Office and Professional Employees)

JOB TITLE:

CLERK I

DUTIES & RESPONSIBILITIES:

- Performs general clerical and computer related duties consistent with that performed by a Clerk–Typist
- Performs mathematical calculations
- Posts to records and transposes information
- Prepares memos and letters of a routine nature
- Undertakes registrations and collecting and disbursement of room key monies if assigned to camp office duties

QUALIFICATIONS & OTHER REQUIREMENTS:

- Must be able to type at a speed of not less than 40 words per minute
- May require completion of secondary school, college or other courses in word processing and/or office software applications including basic accounting. Contractor may accept an equivalent combination of education, training and experience
- Must be proficient with personal computers and other office equipment such as facsimile (fax) machines, photocopiers etc.
- May require relevant past experience

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 15 – Office and Professional Employees)

JOB TITLE:

CLERK II

DUTIES & RESPONSIBILITIES:

- Performs clerical functions within generally defined procedures relating to payroll, accounts payable, accounts receivable, purchasing and inventory control

QUALIFICATIONS & OTHER REQUIREMENTS:

- Must be able to work with limited supervision
- May require completion of college or other courses in business administration, accounting, bookkeeping, payroll administration or computer operation
- Contractor may accept an equivalent combination of education, training and experience
- Must be proficient with personal computers and other office equipment such as facsimile (FAX) machines, photocopiers
- May require relevant past experience

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 15 – Office and Professional Employees)

JOB TITLE:

DRAFTSMAN

DUTIES & RESPONSIBILITIES:

- Develops and prepares engineering drawings, plans, diagrams or layouts from preliminary concepts, sketches, engineering calculations, specification sheets, field surveys and other data for structures including hydraulic structure and dikes (these structures may involve the use of structural steel, bridge trusses, plate girders, columns and other structural components)
- Prepares drawings showing profiles, cross-sections and rights-of-way
- Operates computer aided drafting equipment and/or a conventional drafting station

QUALIFICATIONS & OTHER REQUIREMENTS:

- Successful completion of a recognized technology course with several years additional experience
- Contractor may accept an equivalent combination of education, training and experience

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 15 – Office and Professional Employees)

JOB TITLE:

EMERGENCY MEDICAL RESPONDER (EMR)

DUTIES & RESPONSIBILITIES:

- Assess extent of injuries or illness of trauma victims to determine emergency medical treatment
- Administer pre-hospital emergency care
- Transport patients to hospital or other medical facility for further medical care
- Document and record nature of injuries and treatment provided
- Maintain emergency care equipment and supplies
- Assist hospital personnel with provision of medical treatment, if necessary

QUALIFICATIONS & OTHER REQUIREMENTS:

- Must be a licenced EMR from a Manitoba Health approved course
- Able to receive transfer of function from Medical Director for the following medical acts: AED, EPI-PEN, NITRO, VENTOLIN & PULSE OXIMETRY
- Valid Class 4 Driver's Licence

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 15 – Office and Professional Employees)

JOB TITLE:

FIRST AID ATTENDANT (MEDICAL)

DUTIES & RESPONSIBILITIES:

- Gives first aid to injured or ill employees at construction site and accident scenes including cleaning, disinfecting and bandaging minor cuts and burns and applies Cardio-pulmonary Respiration (CPR) or administers oxygen in cases of suffocation or asphyxiation
- Keeps records of patients attended
- May assist the Emergency Medical Responder with the handling of patients as directed

QUALIFICATIONS & OTHER REQUIREMENTS:

- Must have a valid First Aid Certificate of the level necessary for the medical services to be provided and a heart saver CPR Certificate as per the regulations under the Workplace Safety and Health Act

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 15 – Office and Professional Employees)

JOB TITLE:

INSTRUMENTMAN I

DUTIES & RESPONSIBILITIES:

- Uses transit level and other surveying instruments and devices to establish and maintain horizontal and vertical controls in general and obtaining data pertaining to angles, elevations, directions and points and contours used for construction in particular
- Compiles notes, sketches and records of data obtained and work performed by members of the survey crew
- Makes necessary calculations from data to establish location and elevation of surface features and plots information on maps being developed on plane table
- Locates and marks sites selected for construction activities concerned with building hydroelectric generating station
- Makes or revises maps in the field from data gathered by means of plane table and alidade
- May be assigned one particular instrument or with one particular aspect of surveying and be designated accordingly
- Directs work of survey crew members

QUALIFICATIONS & OTHER REQUIREMENTS:

- Successful completion of recognized surveying course and 2-3 years experience in construction/engineering surveying
- The contractor may accept an equivalent combination of education, training and experience

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 15 – Office and Professional Employees)

JOB TITLE:

INSTRUMENTMAN II

DUTIES & RESPONSIBILITIES:

- Will act as the surveyor responsible for directing one or more survey crews involved in establishing horizontal and vertical controls for a project, utilizing electronic distance measuring devices, instruments or tellurometers
- May perform all the duties as set out for an Instrumentman I

QUALIFICATIONS & OTHER REQUIREMENTS:

- Must have successfully completed recognized surveying course and have extensive additional experience with all aspects of surveying on construction/engineering projects
- Contractor may accept and equivalent combination of education, training and experience
- Must have experience supervising survey crews on construction/engineering type projects

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 15 – Office and Professional Employees)

JOB TITLE:

JUNIOR INSTRUMENTMAN

DUTIES & RESPONSIBILITIES:

- Performs work of a levelling nature within key benchmarks
- Performs rudimentary transit work in laying out profiles and cross-sections
- Directs work of survey assistant as required
- Prepares field notes and sketches in performance of the above

QUALIFICATIONS & OTHER REQUIREMENTS:

- Successful completion of a recognized surveying course or 1-2 years experience in construction/engineering surveying

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 15 – Office and Professional Employees)

JOB TITLE:

PROJECT COST CLERK I

DUTIES & RESPONSIBILITIES:

- Performs basic accounting duties for the accounts receivable, accounts payable and cost control functions
- Performs duties within the scope of work performed by a Clerk II

QUALIFICATIONS & OTHER REQUIREMENTS:

- May require completion of college or other recognized courses in business administration, accounting, bookkeeping or computer applications
- Must be proficient with personal computers
- May require relevant past experience

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 15 – Office and Professional Employees)

JOB TITLE:

PROJECT COST CLERK II

DUTIES & RESPONSIBILITIES:

- Computes operating and other related costs such as labour, material time, depreciation, unit etc.
- Performs ledger and journal entries
- Prepares advanced accounting records (i.e. general ledger, trial balances) and carries out costing and budgeting
- Performs bank reconciliations and petty cash control
- May also be assigned duties within the scope of work performed by a Project Cost Clerk I

QUALIFICATIONS & OTHER REQUIREMENTS:

- Successful completion of college or other recognized educational institution in courses in business administration, accounting, bookkeeping and computer applications supported by relevant work experience is normally required. The Contractor may accept an equivalent combination of education, training and experience
- Must be proficient with personal computers and other office equipment

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 15 – Office and Professional Employees)

JOB TITLE:

QUANTITY TECHNICIAN

DUTIES & RESPONSIBILITIES:

- Determines quantities of material excavated or required on construction projects including those of an electrical, mechanical and/or civil nature by utilizing inspector or recorder's reports, survey reports and specifications and drawings
- Calculates the quantities of materials used for establishing or confirming progress and payment claims

QUALIFICATIONS & OTHER REQUIREMENTS:

- Successful completion of recognized surveying or electrical, mechanical and/or civil technology course and extensive experience with quantity calculations
- Contractor may accept an equivalent combination of education, training and experience

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 15 – Office and Professional Employees)

JOB TITLE:

SURVEY ASSISTANT (RODMAN)

DUTIES & RESPONSIBILITIES:

- Helps Instrumentman as member of crew surveying land areas
- Cuts, marks, tags and drives stakes into the ground to indicate grade settings, markers or boundaries
- Assists Instumentman in measuring distance between survey points using mechanical or electronic equipment
- Marks points and holds rod at point indicated by Instrumentman to determine elevation
- May be required to clear brush and trees for survey lines using chainsaws or axes

QUALIFICATIONS & OTHER REQUIREMENTS:

- Some experience is normally required for the Survey Assistant position
- Should have high school diploma and an aptitude for math, surveying and drawing
- Must be physically fit and willing and able to perform clearing in a safe and efficient manner

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 15 – Office and Professional Employees)

JOB TITLE:

TRAINEE – OFFICE & TECHNICAL CLASSIFICATION

DUTIES & RESPONSIBILITIES:

- Through participation in a Contractor's formally structured on-the-job training program, performs the duties associated with a classification covered by Appendix 15 on a progressive basis.

QUALIFICATIONS & OTHER REQUIREMENTS:

- Demonstrated interest/aptitude in the scope of work covered by a classification and willing to undergo such training.
- Education level sufficient to readily enable, understanding and applying required elements of the position and facilitating progression to fully trained status.

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 16 - Caterers)

JOB TITLE:

BAKER

DUTIES & RESPONSIBILITIES:

- Prepares and bakes bread and pastries
- Responsible to the Chef for quantities of food and kitchen supplies required and delivered for bakery operations
- Operates mechanical mixing and kneading machines
- Performs other related duties as assigned by supervisor

QUALIFICATIONS & OTHER REQUIREMENTS:

- Must have a Certificate of Qualification and not less than three years experience in a medium volume (approximately 300-500 persons) construction camp or institutional setting
- The contractor may accept a combination of education, training and experience equivalent to Journeyman status
- Should have supervisory skills
- Must undergo and pass a medical exam prior to starting work
- May be required to work shifts, including split shifts

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 16 - Caterers)

JOB TITLE:

BAKER'S HELPER (GENERAL HELP)

DUTIES & RESPONSIBILITIES:

- Assists Baker in the production of baked goods
- Moves and distributes bakery supplies and products
- Performs other related duties as assigned by Baker

QUALIFICATIONS & OTHER REQUIREMENTS:

- Must be physically fit and able to do heavy lifting
- Should have some knowledge of bakery operations
- Must undergo and pass a medical exam prior to starting work
- May be required to work shifts, including split shifts

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 16 - Caterers)

JOB TITLE:

BUTCHER

DUTIES & RESPONSIBILITIES:

- Selects and prepares meats, fowl, fish and seafood and portions cooked meats for serving in construction camps
- Cuts, saws, chops and grinds meats into pieces of different sizes using equipment such as cleavers, knives and grinders
- Shapes and ties roasts and fowl
- Slices and trims steaks, chops, fowl, fish and shellfish for individual servings or sandwiches according to established portion-controlled procedures
- Requisitions supplies
- Assists in menu planning and other related duties
- May be required to supervise other staff

QUALIFICATIONS & OTHER REQUIREMENTS:

- Must have a Certificate of Qualification and additional experience at the Journeyman level with all aspects of the butcher trade a portion of which must have been in a high volume operation or the contractor may accept an equivalent combination of education, training and experience
- Must undergo and pass a medical exam prior to starting work
- May be required to work shifts, including split shifts

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 16 - Caterers)

JOB TITLE:

BUTCHER HELPER (GENERAL HELP)

DUTIES & RESPONSIBILITIES:

- Receives, stores and grinds meat
- Manually unloads delivery truck
- Cleans grinder meat containers and storage room with water, hose and broom
- Performs other related duties as assigned by Butcher

QUALIFICATIONS & OTHER REQUIREMENTS:

- Must be physically fit and able to do heavy lifting
- Should have knowledge of a butcher shop operations and experience as a Butcher Helper
- Should be familiar with proper sanitary meat handling procedures
- Must undergo and pass a medical exam prior to starting work
- May be required to work shifts, including split shifts

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 16 - Caterers)

JOB TITLE:

CAMP ATTENDANT (JANITOR)

DUTIES & RESPONSIBILITIES:

- Maintains bunkhouse accommodations
- Makes and changes beds
- Vacuums, sweeps and washes all floors
- Cleans washrooms, shower / tub rooms and laundry rooms
- Collects and disposes garbage and debris on a daily basis
- Reports to Head Camp Attendant any damage done in bunkhouses
- Performs other related duties as assigned

QUALIFICATIONS & OTHER REQUIREMENTS:

- Must have experience as a Camp Attendant, Janitor, or Chambermaid, in a commercial setting
- Contractor may accept other types of relevant work experience
- Must be able to work independently with a minimum of supervision
- Must undergo and pass a medical exam prior to starting work
- May be required to work shifts, including split shifts

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 16 - Caterers)

JOB TITLE:

CHEF

DUTIES & RESPONSIBILITIES:

- Plans menus and ensures food meets quality standards
- Estimates food requirements and costs
- Supervises, instructs and coordinates the activities of cooks and other kitchen staff in the preparation, cooking and presentation of food
- Requisitions and monitors food and kitchen supplies and equipment
- Discusses management or supervisory issues with managers
- May recommend the hiring or dismissal of workers
- May prepare and cook food on a regular basis or for special functions

QUALIFICATIONS & OTHER REQUIREMENTS:

- Must have a Certificate of Qualification, preferably with Interprovincial 'Red Seal', and not less than five years of high volume (approximately 700-1,000 persons) camp or institutional experience
- Must be able to organize on-the-job training programs
- Must have the ability to plan or modify kitchen layouts
- Must undergo and pass a medical examination prior to starting work
- May be required to work shifts, including split shifts

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 16 - Caterers)

JOB TITLE:

COMMISSARY ATTENDANT

DUTIES & RESPONSIBILITIES:

- Performs functions of a sales clerk, including sales transaction, balancing cash register and tracking inventory
- Sets up displays and stocks shelves based on stock rotation
- Fills out shift reports and other forms as required

QUALIFICATIONS & OTHER REQUIREMENTS:

- Must have a Grade 12 education with a minimum one year experience working in a retail operation
- Contractor may accept an equivalent combination of education, training and experience
- Must be bondable and able to balance cash
- Must have knowledge of stock rotation and displays
- Must undergo and pass a medical exam prior to starting work
- May be required to work shifts, including split shifts

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 16 - Caterers)

JOB TITLE:

DISHWASHER

DUTIES & RESPONSIBILITIES:

- Washes dishes and other kitchenware
- Loads and unloads dishwasher, inspects dishes for cleanliness and places them in designated storage areas
- Cleans washing machine and work area
- Assists with the training of new employees
- Performs other duties to assist cook and kitchen staff as assigned by supervisor

QUALIFICATIONS & OTHER REQUIREMENTS:

- Must have working knowledge of proper dishwashing procedures in accordance with current health regulations
- Must have a minimum of six months experience with side feeding commercial dishwashing machines
- Must undergo and pass a medical exam prior to starting work
- May be required to work shifts, including split shifts

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 16 - Caterers)

JOB TITLE:

FIRST COOK

DUTIES & RESPONSIBILITIES:

- Plans menus utilizing knowledge of foods in season and local availability
- Cooks foodstuffs in quantities according to menu and number of persons to be served
- Cleans, cuts and cooks meats, fish and poultry
- Prepares stocks, soups, sauces as well as specialty soups and sauces
- Prepares primary as well as secondary cuts of meat and poultry
- Prepares salads and dressings as well as cold foods including buffet and display
- Mixes ingredients according to recipe or uses prepared mixes
- Washes, peels, cuts, seeds and cooks vegetables
- May prepare cafeteria style foods

QUALIFICATIONS & OTHER REQUIREMENTS:

- Must have a Certificate of Qualification, preferably with Interprovincial “Red Seal”, and not less than three years of high volume (approximately 500-1,000 persons) camp or institutional experience
- Must have the ability to train, supervise and schedule staff
- Must be able to order and requisition food products for up to 3,000 meals per day on a proper rotation basis
- Must have supervisory experience
- Must have a basic knowledge of baking sufficient to supervise bakery operations
- Must have working knowledge advanced kitchen management techniques
- Must undergo and pass a medical exam prior to starting work
- May be required to work shifts, including split shifts

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 16 - Caterers)

JOB TITLE:

HEAD CAMP ATTENDANT

DUTIES & RESPONSIBILITIES:

- Supervises and coordinates the activities of Camp Attendants engaged in keeping the camp site in a clean and orderly condition
- Sweeps and cleans sleeping quarters and other camp facilities as directed
- Cleans washrooms and replaces expendable supplies
- Issues linen to Camp Attendants and ensures that bedding is changed on a regular basis
- Collects and disposes of garbage and debris

QUALIFICATIONS & OTHER REQUIREMENTS:

- Must have experience as a camp attendant, janitor, or chambermaid, in a commercial setting
- Must be able to work on own with a minimum of supervision
- Should have supervisory experience
- Must undergo and pass a medical exam prior to starting work
- May be required to work shifts, including split shifts

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 16 - Caterers)

JOB TITLE:

HEAD MESS HALL ATTENDANT

DUTIES & RESPONSIBILITIES:

- Supervises and coordinates the activities of Mess Hall Attendants involved in the cleaning and maintenance of dining room tables, cold salad table(s) and steam and salad tables
- Monitors general cleaning of dining room area
- Assists in the training of new employees
- Maintains records of time worked by Mess Hall Attendants
- Performs other related duties as assigned by supervisor

QUALIFICATIONS & OTHER REQUIREMENTS:

- Must have experience as Head Mess Hall Attendant in a larger construction camp or institutional setting
- Must have supervisory experience and experience in training staff
- Must undergo and pass a medical exam prior to starting work
- May be required to work shifts, including split shifts

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 16 - Caterers)

JOB TITLE:

MESS HALL ATTENDANT (GENERAL HELP)

DUTIES & RESPONSIBILITIES:

- Cleans and maintains dining room area including shelves and floors
- Cleans and sets dining room tables and fills beverage, salt, sugar and other condiment containers
- Cleans and maintains supplies for steam and salad tables, such as dishes and utensils
- Prepares coffee and cold beverages, and may be required to work on steam tables from time to time
- Performs other related duties as assigned by supervisor

QUALIFICATIONS & OTHER REQUIREMENTS:

- Must have experience as a Mess Hall Attendant in a larger construction camp or institutional setting
- Must be physically fit and capable of lifting heavy items
- Must undergo and pass a medical exam prior to starting work
- May be required to work shifts, including split shifts

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 16 - Caterers)

JOB TITLE:

POT WASHER

DUTIES & RESPONSIBILITIES:

- Washes pots, pans and utensils and stores items in designated areas
- Cleans work area, floors and garbage receptacles
- Performs other duties as assigned by supervisor

QUALIFICATIONS & OTHER REQUIREMENTS:

- Must be physically fit
- Must be able to work with heavy duty grease cutting soaps and detergents (i.e. cannot have sensitive skin or allergies)
- Must undergo and pass a medical exam prior to starting work
- May be required to work shifts, including split shifts

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 16 - Caterers)

JOB TITLE:

SALAD MAKER

DUTIES & RESPONSIBILITIES:

- Prepares a variety of salads
- Cleans, peels, slices and trims foodstuffs
- Portions and wraps food or places food directly onto plates
- Forwards finished food items to designated areas
- Performs other related duties as assigned by supervisor

QUALIFICATIONS & OTHER REQUIREMENTS:

- Must have experience preparing large quantities of a variety of salads in an institutional or commercial setting
- Must undergo and pass a medical exam prior to starting work
- May be required to work shifts, including split shifts

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 16 - Caterers)

JOB TITLE:

SANDWICH MAKER

DUTIES & RESPONSIBILITIES:

- Prepares a variety of sandwiches primarily for use in bag lunches
- Cleans, peels, slices and trims foodstuffs, and prepares sandwich fillings
- Portions and wraps food
- Forwards finished food items to designated areas
- Performs other related duties as assigned by supervisor

QUALIFICATIONS & OTHER REQUIREMENTS:

- Must have experience preparing large quantities of a variety of sandwiches in an institutional or commercial setting
- Must undergo and pass a medical exam prior to starting work
- May be required to work shifts, including split shifts

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 16 - Caterers)

JOB TITLE:

SECOND COOK

DUTIES & RESPONSIBILITIES:

- Under the general supervision of the First Cook, prepares and cooks foodstuffs in quantities according to menu and number of persons to be served
- Cleans, cuts and cooks meats, fish and poultry
- Prepares stocks, soups, sauces as well as specialty soups and sauces
- Prepares primary as well as secondary cuts of meat and poultry
- Prepares salads and dressings as well as cold kitchen work including buffet and display
- Mixes ingredients according to recipe or uses prepared mixes
- Washes, peels, cuts, seeds and cooks vegetables
- Performs other related duties as assigned by supervisor

QUALIFICATIONS & OTHER REQUIREMENTS:

- Must have a Certificate of Qualification and not less than two years additional experience at the Journeyman level in a medium volume (approximately 300-500 persons) camp or institutional setting
- Contractor may accept an equivalent combination of education, training and experience
- Supervisory experience may be required
- Must undergo and pass a medical exam prior to starting work
- May be required to work shifts, including split shifts

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 16 - Caterers)

JOB TITLE:

SHORT ORDER COOK

DUTIES & RESPONSIBILITIES:

- Prepares and cooks breakfast, lunch items and simple meals
- Places cooked items on plates, transfers them to serving staff or serves customers cafeteria style
- Stores and checks food supplies and maintains records
- Performs other related duties

QUALIFICATIONS & OTHER REQUIREMENTS:

- Must have successfully completed a recognized pre-employment training course in cooking
- Should have not less than one year experience in a commercial establishment performing the duties described above
- Contractor may accept and equivalent combination of education, training and experience
- Must undergo and pass a medical exam prior to starting work
- May be required to work shifts, including split shifts

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 16 - Caterers)

JOB TITLE:

SNACK BAR ATTENDANT

DUTIES & RESPONSIBILITIES:

- Under supervision of a Short Order Cook, prepares lunch items and simple meals
- Places cooked items on plates, transfers them to service employees or serves customers at tables
- Stores and checks food supplies and maintains records
- Performs other related duties as assigned by supervisor
- May be required to operate a cash register

QUALIFICATIONS & OTHER REQUIREMENTS:

- Should have experience as a Snack Bar Attendant
- Contractor may accept other types of relevant work experience
- Must undergo and pass a medical exam prior to starting work
- May be required to work shifts, including split shifts

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 16 - Caterers)

JOB TITLE:

TAPMAN (BARTENDER)

DUTIES & RESPONSIBILITIES:

- Tends bar to sell beer, liquor, mix and other non-alcoholic beverages to serving personnel in a beverage room
- Prepares mixed drinks, wine, draft or bottled beer and non-alcoholic beverages for serving personnel
- Operates automatic glass washer or washes glassware by hand
- Maintains records of all cash transactions, operating cash register, maintaining inventory and control of bar stock and ordering supplies
- Provides direction to serving personnel

QUALIFICATIONS & OTHER REQUIREMENTS:

- Must have successfully completed a college or other recognized program in bartending and have a minimum of six months experience as a Tapman in a high volume establishment
- Contractor may accept an equivalent combination of education, training and experience
- Must be able to handle cash and prepare daily reports
- Must have a good knowledge of the Manitoba Liquor Control Act
- Must undergo and pass a medical exam prior to starting work
- May be required to work shifts, including split shifts

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 16 - Caterers)

JOB TITLE:

THIRD COOK

DUTIES & RESPONSIBILITIES:

- Prepares and cooks grill work for breakfast, lunch and dinner
- Prepares and cooks vegetables, potatoes and gravy
- Sets up and prepares steam table(s)
- Assists in all aspects of cooking with Second Cook (including preparation)
- Works with guidance of Second Cook
- Performs other related duties as assigned by supervisor

QUALIFICATIONS & OTHER REQUIREMENTS:

- Must have successfully completed a recognized pre-employment training course in cooking
- Should have work experience in a commercial or industrial kitchen (approximately 50-100 persons)
- Contractor may accept an equivalent combination of education, training and experience
- Must undergo and pass a medical exam prior to starting work
- May be required to work shifts, including split shifts

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 16 - Caterers)

JOB TITLE:

TRAINEE – CATERING CLASSIFICATION

DUTIES & RESPONSIBILITIES:

- Through participation in a Contractor's formally structured on-the-job training program, performs the duties associated with a classification covered by Appendix 16 on a progressive basis.

QUALIFICATIONS & OTHER REQUIREMENTS:

- Demonstrated interest in the scope of work covered by a classification and willing to undergo such training.
- Physically fit – for some classification training, individual must be capable of lifting heavy items.
- Grade 12 may be required for some training positions.
- Must undergo and pass a medical exam prior to starting work.
- May be required to work shifts including split shifts.

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 16 - Caterers)

JOB TITLE:

WAITER / WAITRESS (GENERAL HELP)

DUTIES & RESPONSIBILITIES:

- Takes food orders and serves food and beverages
- Prepares tables for meals
- Removes dishes and cleans tables after meals

QUALIFICATIONS & OTHER REQUIREMENTS:

- Must have experience as a Waiter/Waitress
- Must be neat in appearance
- Must be familiar with safe food handling procedures
- Must undergo and pass a medical exam prior to starting work
- May be required to work shifts, including split shifts

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 17 – Elevator Constructors)

JOB TITLE:

ELEVATOR CONSTRUCTOR FOREMAN

DUTIES & RESPONSIBILITIES:

- Supervises and coordinates the activities of workers engaged in installing and repairing elevators, walkways, and related equipment

QUALIFICATIONS & OTHER REQUIREMENTS:

- Must have Certificate of Qualification relevant to the trade being supervised, and significant additional experience at the Journeyman level
- Must have experience supervising Journeymen and Apprentices

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 17 – Elevator Constructors)

JOB TITLE:

ELEVATOR CONSTRUCTOR HELPER

DUTIES & RESPONSIBILITIES:

- Performs the duties of an Elevator Contractor Mechanic on a progressive basis. The Canadian Elevator Industry currently utilizes 3 training classifications namely:
  a. Probationary Helper
  b. Helper
  c. Improver Helper

QUALIFICATIONS & OTHER REQUIREMENTS:

- Probationary Helper
  Must possess a high school diploma or the equivalent and must be physically fit
- Helper
  Must have a minimum of one years previous mechanical experience in the elevator industry
- Improver Helper
  Must have a minimum of three years in the industry and successfully completed the recognized courses of training of the C.E.I.E. Program (ie.e Modules 1 through 8)

For additional details relative to training and progression of these classifications, refer to Section 3 of Appendix 17

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

JOB DESCRIPTION

(BNA APPENDIX 17 – Elevator Constructors)

JOB TITLE:

ELEVATOR CONSTRUCTOR MECHANIC

DUTIES & RESPONSIBILITIES:

- Installs elevators, moving walkways and related equipment including cables and electric and safety control devices
- Tests operation of newly installed equipment
- Disassembles and carries out repairs to existing elevator/walkway equipment
- Supervises work of helpers

QUALIFICATIONS & OTHER REQUIREMENTS:

- Must have Elevator Constructor Trade Certification or Canadian Elevator Industry Education Certificate and several years experience at the Journeyman level
- May be required to read or work from blueprints

CAUTION: These job descriptions will be subject to review and possible revisions by individual project contractors after the work is awarded, and the duties and qualifications may vary from what is found in these descriptions. *For a detailed explanation of the possibility for changes see the Introduction to this information package.*

Press **Home** to return to the TABLE OF CONTENTS

Tab 72

Do Unions Cause Business Failures?*

John DiNardo

University of Michigan, Ann Arbor and NBER

David S. Lee

UC Berkeley and NBER

March 2003

Abstract

Estimating the causal effect of unionization on business survival rates is difficult in the absence of large, representative data on establishments with union status information. It is also confounded by selection bias, because unions may tend to organize at highly profitable enterprises that are more likely to survive. Using new data on more than 27,000 establishments that faced organizing drives in the U.S. during 1983-1999, this paper utilizes a regression discontinuity design to estimate the impact of unionization on the probability of employer dislocation. Survival probabilities of employers where unions *barely* won the election (e.g. by one vote) are compared to those where the unions *barely* lost. The analysis yields a surprising result: *little or no* union effect on business dislocation rates over 1- to 18-year horizons.

* An earlier version of the paper "The Impact of Unionization on Establishment Closure: A Regression Discontinuity Analysis of Representation Elections" is on-line as *NBER Working Paper #8993*, June 2002. We thank David Card, Larry Katz, Enrico Moretti, Morris Kleiner, participants of the University of Michigan Labor Workshop and the NBER Labor Studies Summer Institute for helpful comments and suggestions, Matthew Butler and Francisco Martorell for outstanding research assistance, Hank Farber for providing election data, and Christina Lee for reading previous drafts.

1 Introduction

It is widely understood that unions raise the cost of labor by raising members' wages above market rates.[1] Unions also impose other costs on employers - limiting discretion in hiring and firing, for example, and altering the structure of pay differentials across skill groups. A key question for understanding the social costs of unionization is whether the wage premiums and other costs of unionism create large or small distortions in the allocation of labor.[2] These distortions can take the form of reduced employment at unionized firms, or most dramatically, an accelerated pace of business failures.

The potentially adverse effects of unions on firm survival are acknowledged by employers and employees alike. During union organizing drives, firms routinely threaten to close a plant if the union drive is successful [Bronfenbrenner 2000]. Employees seem to take these threats seriously: the risk of plant closure is cited as the leading cause of union withdrawal from organizing attempts [Commission for Labor Cooperation 1997]. Such risks are arguably higher now, in light of rapidly expanding trade with low-wage countries such as China and Mexico, and increasing international capital mobility.[3]

Despite the clear theoretical presumption and strong anecdotal evidence, the magnitude of the effect of unions on establishment or firm survival is uncertain. One limiting factor is the absence of large, representative data sets that track establishments over time and provide information on union status.[4] A second and even more important concern is the fact that unionization is nonrandom. Depending on the correlation between factors associated with higher or lower risks of survival, and higher or lower likelihood

[1] See Lewis [1986].

[2] The presence of a "deadweight welfare loss" to unionization is a staple of textbook treatments of unionization. Even Freeman and Medoff [1984] - whose emphasis is on the possible "efficiency enhancing" aspect of trade unionism - stipulate the existence of such a welfare loss. More recently, the cross-country analysis of Nickell and Layard [1999] suggest that a change from 25 to over 70 percent of the workers covered by collective bargaining is associated with a doubling of the unemployment rate. Lalonde, Marschke, and Troske [1996], using a "difference-in-difference" approach with LRD data, find successful organization is associated with significant declines in subsequent employment and output.

[3] The Commission for Labor Cooperation, a tri-national organization created under the North American Agreement on Labor Cooperation ("NAALC") in response to labor issues related to NAFTA, called for a study on the impact of plant closings on union organizing in the three countries.

[4] This has led researchers to use creative data collection methods to examine these questions. For example, Freeman and Kleiner [1990] conducted on-site interviews of 364 establishments that experienced representation elections in the Boston and Kansas City NLRB districts. Bronars and Deere [1993] construct a dataset of NLRB elections to COMPUSTAT data to construct a panel of 85 firms over a 20-year period. Freeman and Kleiner [1999] also use COMPUSTAT to construct a sample of 319 firms. Lalonde, Marschke, and Troske [1996] match NLRB representation elections to a subset of manufacturing establishments that are continuously operating in the LRD to create samples with 500 to about 1100 observations.

of unionization, the observed correlation between union status and survival may overstate or understate the true effects of unions. Two competing phenomena may induce opposite selectivity biases. On the one hand, unions may tend to organize at highly profitable enterprises that are more likely to survive. On the other, a union organizing drive may be more likely to succeed when a firm is poorly managed, or has faced recent difficulties.

In this paper, we present quasi-experimental evidence on the causal effect of unionization on the probability of business failures/re-locations, using a new database that is representative of U.S. establishments at risk of being unionized. Our analysis is based on the fact that most new unionization occurs as a result of a secret ballot election. By law, a majority vote in favor of the union requires management to recognize the union and bargain "in good faith". This process creates a natural set of comparisons between establishments that faced elections where the union *barely* won (say, by one vote) and those that faced elections where the union *barely* lost (by one vote). As in other regression discontinuity designs, the comparison between near winners and near losers eliminates any confounding selection and omitted variable biases, and allows us to devise credible and transparent estimates of the effect of unions on firm survival.[5]

Our analysis yields a surprising result: we estimate a very small union recognition effect on employer survival, on the order of 1 percent. The estimates are stable across different time horizons (from 1- to 18-years), and across industry, and different establishment sizes. Moreover, we find strong empirical support for the basic requirement of our research design. Close winners and losers look similar in industry composition, size of the bargaining unit, and other pre-determined characteristics.

A potential concern is that unions that barely lose elections nonetheless have a relatively good chance of eventually becoming recognized, while those that barely win face a high risk of decertification. The "treatment" of a *close* union victory would have little long-run consequence to the firm, which would naturally lead to small long-run effects on business survival. We find no empirical support for this hypothesis. There is a striking discontinuity in the relationship between the union vote share and our independent

[5] Regression discontinuity designs are described in Thistlethwaite and Campbell [1960] and Campbell [1969], and formally examined as an identification strategy recently in Hahn, Todd, and van der Klaauw [2001]. More recent examples include Angrist and Lavy [1998], and van der Klaauw [1996].

proxy for union presence (the filing of a contract expiration notice) many years after the election.

One explanation for the small effect of unions on firm survival is that the costs imposed by newly organized unions are small.[6] This possibility would seem at odds with the extensive literature on union wage premiums and other research showing significant effects on profitability.[7] It would also be at odds with the fact that NLRB representation elections are nearly always contentious. Why would employers spend resources on resisting an organizing drive if unions did not impose significantly higher future costs? And why would unions spend resources on organizing if there were nothing to gain from a victory? A simple model of optimal union organizing actually suggests that these potential gains should be *larger* when the vote is close than when the union is certain to prevail. A larger wage gain is needed to offset the lower probability of winning the election, in order to justify the fixed costs of an organizing drive. All of this suggests that the costs of new unionization are likely to be important.

We therefore conclude that unions likely do not affect businesses by making them more susceptible to failure or re-location, despite the fears of many employers and employees. While not affecting the survivability of a firm, unions could nonetheless cause slower employment growth. Our data provide limited evidence on this "within-firm" effect: we estimate a negative employment response of 7 percent among surviving establishments, but with standard errors of the same magnitude. Our estimates on employment can rule out the large magnitudes that would be needed to fully explain the decline in union density since the early 1980s. On the other hand, even with the more than 27,000 establishments in our data set, we cannot rule out either small or moderate-sized elasticities.

The paper is organized as follows. Section 2 describes our empirical strategy, and summarizes our main findings. Section 3 discusses the conditions for a valid regression discontinuity design in our context, and outlines a simple economic model to describe the interaction of employers, unions, and workers in the context of a representation election. Section 4 places our analysis in the context of industrial relations in the U.S., and describes some important aspects of our data. We present the main results in Section 5, discuss

[6] Freeman and Kleiner [1990] find in their survey of 364 firms, quite modest wage effects associated with new unionization, in contrast to that implied by the typical study based on micro data on individuals.

[7] For example, see Ruback and Zimmerman [1984], and Abowd [1989].

their economic implications in Section 6, and suggest directions for future research in Section 7.

2 Regression Discontinuity Analysis of Establishment Survival and Unionization: Basic Facts

We begin by briefly describing our research design and summarizing our main results. Our regression discontinuity analysis suggests that there is virtually no *causal* impact of unionization on survival rates of business establishments.

The primary challenge of identifying the impact of unionization is one of isolating exogenous variation in the union "status" of an establishment, while keeping all other pre-determined characteristics of the establishment "constant". A simple comparison of survival rates between unionized and non-unionized firms suffers from the potential endogeneity of union status. For example, firms with larger economic rents may be more likely to survive, and *because* of those rents, are more likely to generate worker demand for a union.

In this paper, we exploit a distinctive feature of the union recognition process in the U.S. that we argue generates "as good as randomized" variation in union status. In the U.S. the obligation of employers to bargain "in good faith" with a union is almost alwasy determined through a majority secret-ballot vote amongst the workers; this "representation election" is overseen by the National Labor Relations Board (NLRB). We argue that it is plausible that there is at least some degree of unpredictability regarding the eventual vote tally, so that the firms and unions involved in elections where the union *barely won* (say, by one vote) are likely to be *ex ante* comparable to those firms and unions involved in elections where the union *barely lost* (by one vote). If this is true – that they are comparable "in all other ways" – then the difference in the survival rates subsequent to the election can be attributed to a causal impact of the union certification.

Figure Ia graphically summarizes our main empirical finding. Using data on NLRB representation elections conducted between 1983 and 1999, it plots the proportion of employers that are still in business by the year 2001, by the actual share of the votes in favor of the union. Each dot represents an average

among elections within a 0.05 interval of the vote share. All points to the left of the 0.50 line represent establishments where the union lost the certification election, and those to the right represent union victories. If unionization substantially impacted ability of the employer to remain economically viable – a claim frequently touted by employers during organizing drives [Bronfenbrenner 1994, Kleiner 2001] – we would expect to see a sharp drop in survival rates at the 0.50 threshold. No drop is evident in Figure Ia.

We interpret this smooth empirical relation through the 0.50 threshold as evidence that there is little or no causal effect of union status on employer survival. Two alternative explanations to the pattern in Figure Ia are 1) employers in which the union *barely* won and lost are *not ex ante* comparable, perhaps because there is *no unpredictability* in the outcome of the election, and that there is "sorting" of unions and employers on either side of the 0.50 threshold and 2) the *intensity* of the "treatment" is small among the employers and unions involved in close elections – that is, an employer that prevents union certification by 1 vote must make wage concessions as large as they would have had the union won by 1 vote.

As we will discuss in greater detail in later sections, there are several reasons why the two interpretations are difficult to reconcile with the implications of a simple economic model of the election process, as well as with the empirical evidence we present. First, if the exact vote tally could be predicted with complete certainty, it is difficult to explain why a union would expend resources to ultimately lose an organizing drive. At the very least, if vote tallies could be perfectly predicted for a substantial *fraction* of the election cases (and if there were systematic "sorting" around the 0.50 threshold) we would expect to see a sharp drop in the relative frequency of observed elections in which the union barely lost an election. In fact, as Appendix Table II and Appendix Figure I show, union losses are at least as common as union victories, and the distribution of vote shares looks approximately normal, centered around 0.40, with no sharp drop in the relative frequency of bare union losses.

More importantly, we present evidence below that employers and elections, in fact, look quite similar along many pre-determined characteristics on either side of the 0.50 threshold, as predicted by our implicit assumption of "as good as random" assignment. As one example, Figure Ic plots averages of our "union presence before the election" proxy – an indicator of whether a contract expiration notice

was filed prior to the election – against the election vote share for the union.[8] The figure reveals no sharp change in pre-election "union presence" around the 0.50 percent threshold, suggesting that at least along this dimension, employers involved in close wins and losses appear comparable.

Furthermore, the economic model we outline below illustrates that while the expected union wage could be expected to be higher given a higher probability that the union will win, we might also expect employers to offer a higher *non-union* wage in order to persuade some workers to vote against the union. Therefore, the *gap* between the expected union and non-union wage may not necessarily rise with the probability of a union victory. Actually, the *minimum* union-non-union wage gap needed in order to justify the unions' costs of conducting an organizing drive must be *larger* for elections in which there is a *lower* probability of a union victory. Put simply, it would be unlikely that an election would be conducted if the union had nothing to gain from winning (i.e. if the expected "treatment" is zero).

More importantly, we present evidence that is inconsistent with the hypothesis that union certification among close elections is ineffectual in altering union power. Figure Ib is analogous to Figure Ic, except we plot averages of our proxy for "union presence" *subsequent* to the NLRB representation election. It exhibits a striking discontinuity at the 0.50 threshold, suggesting that the certification has a significant causal influence in altering union power. Thus, it is evident in the data that something *is* "at stake" among these election cases.

The remainder of the paper explains in greater detail the above reasons why we interpret our findings as evidence of little or no *causal* impact of unionization on employer survivorship.

3 Econometric Framework

3.1 Reduced-Form Regression Discontinuity Framework

In the context of union representation elections, the internal validity of our regression discontinuity analysis primarily depends on two assumptions: 1) that the "treatment" (union recognition) is a known, discontinu-

[8] The sample for the figure includes only those employers that have survived as of the year 2001. Below we discuss how to interpret these graphs in light of sample selection bias.

ous function of an observed variable (the votes for the union), and 2) that there is at least *some* unpredictable component of the exact vote tally that has a smooth continuous distribution. U.S. labor law ensures 1); the importance of 2) is discussed below within a reduced-form econometric framework. We outline sufficient stochastic assumptions for identifying union effects in our context.

Suppose an employer outcome, such as the propensity of the establishment to survive, is determined by the equation

$$y_j^* = X_j\gamma + WIN_j\beta + \varepsilon_j \tag{1}$$

where $y_j^*$is the survival propensity, and WIN_j is an indicator variable determining whether the union won the representation election for employer j. X_j denotes all other pre-determined characteristics (observable and unobservable) that influence establishment survival and ε_j an independent error term.

It is clear that a "regression" of y_j^* on WIN_j will in general yield an inconsistent estimate of β if any components of X_j also determine WIN_j. As one example, X_j could represent the magnitude of the firm's economic rents, and it is plausible that unions are more likely to prevail in organizing drives in firms that enjoy high rents, because workers are less concerned that a union-induced wage gain will harm the economic viability of the employer. In particular, the NLRB election process implies that WIN_j is determined by

$$\begin{aligned} WIN_j &= \begin{cases} 1 \text{ if } V_j > \frac{1}{2} \\ 0 \text{ if } V_j \leq \frac{1}{2} \end{cases} \\ V_j &= v\left(X_j\right) + U_j \end{aligned} \tag{2}$$

where V_j is the vote share for the union, and $v\left(\cdot\right)$ is a function of X_j.[9]

The endogeneity of X_j is clear here. Another way of viewing the problem is that the distribution of X_j, conditional on a union win, will in general be different from the distribution conditional on a union loss. More formally, (assuming that X_j has finite and discrete support) $\Pr\left[X_j = x | V_j > \frac{1}{2}\right]$ will generally not equal $\Pr\left[X_j = x | V_j \leq \frac{1}{2}\right]$ for any x.

[9] To be more precise, one could let $V_j = \Lambda\left(v\left(X_j\right) + U_j\right)$ where Λ is a transformation from the real line to the $[0, 1]$ interval.

On the other hand, if U_j is continuously distributed, the distribution of X_j conditional on a *bare* union victory will be arbitrarily close to the distribution conditional on a *bare* union loss. That is,

$$\Pr\left[X_j = x | V_j = \frac{1}{2} + \Delta\right] \approx \Pr\left[X_j = x | V_j = \frac{1}{2} - \Delta\right] \tag{3}$$

for all x in the support of X_j, as Δ approaches zero.[10] This is the sense in which examining closer and closer elections can result in employers involved in union victories and losses becoming more similar along all other observable and unobservable characteristics. Thus, a test of the continuity of the distribution of U_j is to examine if elections appear different along observable pre-determined characteristics of employers involved in elections just below and above the 0.50 threshold.

In practice, rather than specifying functional forms for the distributions of $X_j\gamma$ and ε_j to estimate a normalized β, we will directly estimate $\Pr\left[Survival | V_j = \frac{1}{2} + \Delta\right] - \Pr\left[Survival | V_j = \frac{1}{2} + \Delta\right]$ (the discontinuity "gap" at 0.50 illustrated in Figures Ia-Ic). It is clear that a negative (positive) difference implies a negative (positive) impact β of unionization on employer survival propensities.

3.2 Conceptual Framework

While our data are not sufficiently rich to allow estimation of a dynamic structural model of union and firm behavior, we present a simple economic model provides a framework for interpreting our estimates and for describing the election context. Drawing upon ideas in Rosen (1969), we present a simple economic framework that describes the first-order objectives and constraints of the various participants in the NLRB election process.[11] Below, we show that the key identifying assumption (continuity of the distribution of U_j at $V_j = \frac{1}{2}$) is a natural consequence of this simple economic model of the election process.

Consider the structural relation between employer survival propensities and the wage W_j

$$y_j^* = \alpha W_j + \varepsilon_j \tag{4}$$

[10] To see this, note that the density of $v(X_j) + U_j$ conditional on X_j – $f(v|X_j = x)$ – is continuous in v. Therefore, by Bayes' Law, $\frac{f(v|X_j=x)\cdot\Pr[X_j=x]}{\sum f(v|X_j=x)\cdot\Pr[X_j=x]} = \Pr[X_j = x | v(x) + U_j = v]$ is continuous in v. Actually, all that is needed is continuity in v at $v = \frac{1}{2}$

[11] The model presented below has a similarity to those used to model final offer arbitration [see Farber, 1980; Ashenfelter and Bloom 1984]. Here, the union and management put forth wage "offers" optimally, given expectations of the preferences of the voters/employees, which are unknown to the two bargaining parties. The outcome of the election is akin to the decision process of an "arbitrator".

α is assumed to be negative, so that a higher wage leads to a higher probability that the employer is forced to shut down. Note however, that even if α is negative, given the necessarily non-linear relation between a probability and W_j, it could very well be that the marginal effect of W_j on the *probability* of survival could be small.

As in Ashenfelter and Johnson (1969), we assume that there are three separate agents, 1) the employer, 2) the union leadership, and 3) the workers – the voters – in the potential bargaining unit. Management and the union each offer different levels of wages to the workers, and the workers vote for or against the union, based on those choices, so that we have

$$\begin{aligned} W_j &= W_j^U WIN_j + W_j^N \left(1 - WIN_j\right) \\ WIN_j &= 1\left(V_j > \frac{1}{2}\right) \end{aligned} \tag{5}$$

where W_j^U and W_j^N are the wages offered by the union and management, respectively. This implies the relation

$$y_j^* = \alpha W_j^N + \alpha\left(W_j^U - W_j^N\right) WIN_j + \varepsilon_j \tag{6}$$

so that the causal effect of the union is represented by $\alpha\left(W_j^U - W_j^N\right)$.

Workers When considering whether or not to vote in favor of the union, the worker weighs the benefit of gaining a higher wage against the costs of a potentially higher probability that she will not retain employment at the firm. A lower probability of retaining the job may arise either because the union will induce the employer to shut down or move, or induce the employer to scale back employment. Indeed, a worker may find the wage (and its consequences) offered by the management to be more reasonable and individually desirable. We describe the aggregate voting behavior of the workers as

$$V_j = v\left(W_j^U, W_j^N\right) + U_j \tag{7}$$

where $v\left(\cdot\right)$ translates the offered wages into a predictable component of the ultimate vote tally, and U_j is the unpredictable (by all agents in the model) component of the union vote share.[12]

[12] Again, we could be more precise instead specifying $G^{-1}\left(V_j\right) = v\left(W_j^U, W_j^N\right) + U_j$, where G is a one-to-one transformation from the real line to the $[0, 1]$ interval.

The shape of $v(\cdot)$ characterizes the workers' preferences. We assume that $\frac{\partial v}{\partial W_j^U}$ and $\frac{\partial v}{\partial W_j^N}$ are both negative, capturing the notion that if the union raises the offer, it will lose the voters who are indifferent between the union's and management's offers. Similarly, the management can gain more "no" votes by promising a higher wage W_j^N.

Employer The management seeks to maximize profits, weighing the benefits of offering a lower wage against the cost that lowering the wage induces a higher probability that the union will win, resulting in a higher wage W_j^U. The firm's optimal choice of W_j^N can be expressed as

$$W_j^{N*} = \arg\max_{W_j^N} H\left(W_j^N, W_j^U, \Pr\left[WIN_j = 1\right]\right) \tag{8}$$

where $H(\cdot)$ is the employer's objective function. An example of a specific form for the objective function is the expected profits, given the employer's and union's wage offers:

$$H\left(W_j^N, W_j^U, \Pr\left[WIN_j = 1\right]\right) = \pi\left(W_j^N\right)\Pr\left[WIN_j = 0\right] + \pi\left(W_j^U\right)\Pr\left[WIN_j = 1\right] \tag{9}$$

where $\pi(\cdot)$ is the profit function.

Union The union leadership seeks to raise wages above that offered by the employer, but by offering higher wages, it reduces the probability of winning the election. The union's optimal choice of W_j^U facing the firm's offer W_j^N can be written as

$$W_j^{U*} = \arg\max_{W_j^U} J\left(W_j^U, W_j^N, \Pr\left[WIN_j = 1\right]\right) \tag{10}$$

where $J(\cdot)$ is the union's objective function. An example of a possible form for this objective function is the expected net benefit (expressed in dollars) for the union:

$$J\left(W_j^U, W_j^N, \Pr\left[WIN_j = 1\right]\right) = -c + \Pr\left[WIN_j = 1\right] U\left(W_j^U - W_j^N\right) \tag{11}$$

where c is a fixed cost to conducting an organizing drive, and $U(\cdot)$ is a benefit function with $U(0) = 0$.[13]

In a Nash equilibrium, in anticipation of how the workers will vote (on average), and given the correct expectation of the other party's wage offer, union and management optimally choose their wage

[13] In principle, $U(\cdot)$ could be decreasing in the wage gap at some point, if the union also gives weight to the employer's survival and/or the level of employment. However, it is easy to imagine that in many election cases $U(\cdot)$ is increasing in the wage gap in equilbrium.

offers to maximize their objective functions.

Implications It is clear from Equation 11 that if the outcomes of elections were known *ex ante* with certainty – if there were no U_j component – we should expect to observe no elections in which unions lose, if conducting an organizing drive is costly. In fact, as shown in Appendix Table II, over the sample period, the average vote share for the union and win rates are around 0.48 and 0.427, respectively. Furthermore, if in a large fraction of election cases, the outcome of a potential election were perfectly foreseen, we would expect to see a sharp drop in the relative frequency of a "close" union election loss. Appendix Figure I shows that empirically there is no such sharp drop; the distribution of vote shares is approximately normal, centered around 0.35 to 0.40. Our framework provides an intuitive explanation for these patterns: for every election, there is *some* ex ante probability (however small) that the union will prevail. In other words, there is some unpredictability in the final vote count. This would explain why unions would participate in elections that they so happen to eventually lose.

Furthermore, presuming the existence of an unpredictable component U_j to the ultimate vote share, the framework above implies that the distribution of U_j would be continuous at $V_j = v\left(W_j^{U*}, W_j^{N*}\right) + U_j = \frac{1}{2}$. This is because a *discontinuity* in the distribution of U_j at $V_j = \frac{1}{2}$ is *inconsistent* with the optimality of W_j^{U*} and W_j^{N*} for the union and management. This is because such a discontinuity would imply that $\Pr\left[WIN_j = 1\right]$ would be discontinuous in W_j^U and W_j^N at W_j^{U*}, W_j^{N*}.[14] As evident from Equations 9 and 11, if this were the case, W_j^{U*} (W_j^{N*}) would not be optimal, since the union (management) could lower (raise) wages by an arbitrarily small amount to affect a sharp rise (fall) in the probability of a union victory.[15] Intuitively, no firm or union would settle with making a wage offer that could be altered a tiny amount in order to cause a discontinuous increase in the probability that the election would result in their favor. Thus, the existence of Nash Equilibria gives a theoretical justification of the validity of the regression discontinuity approach described above.

[14] To see this, note that $\Pr\left[WIN_j = 1\right] = F\left(v\left(W_j^{U*}, W_j^{N*}\right) - \frac{1}{2}\right)$, where $F\left(\cdot\right)$ is the cdf of $-U_j$. A discontinuity in the distribution of $-U_j$ at $V_j = \frac{1}{2}$, implies that $F\left(\cdot\right)$ is discontinuous at $v\left(W_j^{U*}, W_j^{N*}\right) - \frac{1}{2}$. As long as $v\left(W_j^{U*}, W_j^{N*}\right)$ is a continuous function of its arguments at W_j^{U*}, W_j^{N*}, then $\Pr\left[WIN_j = 1\right]$ is discontinuous in W_j^U, W_j^N at W_j^{U*}, W_j^{N*}.

[15] This is true as long as the profit function $\pi\left(\cdot\right)$ and benefit function $U\left(\cdot\right)$ are continuous.

Nevertheless, we reiterate that the internal validity of the design can be empirically evaluated. It is a testable proposition whether or not the examination of close elections yields "treated" and "control" employers that look comparable along the observable dimensions of X_j.[16]

4 Background

4.1 Institutional Background: the industrial relations climate and the NLRB Election Process

Our sample of establishments is limited to the employers that are at risk for becoming "unionized." Thus, before proceeding any further, it will be instructive to place our analysis in the context of labor relations and the conduct of representation elections in the U.S.

The administration of fair, secret ballot elections to determine union recognition is one of the chief responsibilities of the NLRB, the most significant administrative agency to be a consequence of the National Labor Relations Act (NLRA) – the Wagner Act – of the 1930s. The law has been changing continuously since its enactment, most notably with the passage of Taft–Hartley Acts in 1947 (which among other things, provided for temporary government seizure of struck facilities in the event of a strike that creates an "emergency") and the Landrum–Griffin Act of 1959 (which among other things, outlawed a number of successful union tactics including "secondary boycotts"). In principle, the NLRA provides a neutral setting in which the right for workers to bargain collectively is enforced.

It is important to note that where U.S. law gives workers the right to unionize, an NLRB representation election is not required. In general, nothing prevents an employer from recognizing a union without the formalities of an election. Voluntary recognition of a union, however, is thought to be quite rare, and employers generally will attempt to resist an organizing drive. With data on firms who faced NLRB elections in the early 1990s, Brofenbrenner (1994) documents that most employers used multiple tactics to delay or deny a collective bargaining agreement. Among the most common are

[16] As in any empirical investigation, it is impossible to rule out violation of the identifying assumption, but we *can* test the restriction of the research design that *observable* characteristics are roughly balanced between the union-win and union-loss groups of employers.

1. “Captive meetings”. While employers are prohibited from directly firing workers because of lawful union activity, at captive meetings employers are allowed to inform workers of the possible (dire) consequences of unionization, including making the business more susceptible to closure.
2. Firing union activists. While “prohibited," the penalty imposed on employers, if found guilty, is generally quite minor – reinstatement with back pay. Indeed, the costs have been perceived as so minor that Freeman (1985) observes that the notices that firms are required to post when they engage in illegal firing are referred to as “hunting licenses."
3. Hire a “management consultant" who advises employers on a variety of tactics to discourage unionization.[17]
4. Alleging unfair labor practices, disputing the choice of bargaining unit, etc.[18]

Against this backdrop of employer opposition to unionization, it is perhaps not surprising that there is no single path to an NLRB election and eventual recognition of the union by the employer. Nonetheless, it is useful to describe a prototypical scenario that results in a establishment agreeing to bargain with its workers through a labor union:

1. A group of workers decide to try to form a union. These workers contact a labor union and ask for assistance in beginning an organizing drive.
2. In collaboration with the union, the employees begin a “card drive." The purpose of the card drive is to be able to petition the NLRB to hold an election. Unions generally seek to get cards from at least 50 percent of the workers in the 6 month period of time usually allowed (although in principle, only 30% is required to be granted an election by the NLRB.)
3. After the cards have been submitted, the NLRB makes a ruling on whether the people the union seeks to represent have a “community of interest” – basically form a coherent group for the purposes of bargaining. The NLRB makes a determination of which categories of employees fall within the union’s “bargaining unit.” Often the parties will differ on the appropriate bargaining unit – employers generally prefer larger and more heterogenous groupings than do unions.
4. Next, the NLRB holds an election at the work site (with exceptions to account for such things as the vagaries of employment seasonality). A simple majority (50 percent plus 1 vote) for one union is all that is required to win.[19]
5. Within 7 days after the final tally of the ballots, parties can file objections to how the election was conducted. In principle, with sufficient evidence that the election was not carried out properly, the NLRB can rule to invalidate the outcome of an election, and conduct another one thereafter. Specific ballots cannot be challenged after the voting is completed.
6. If after this, a union still has a simple majority, then the employer is, in principle, obligated to negotiate “in good faith.”

Two aspects of the industrial relations climate deem our sample of establishments particularly ap-

[17] For a colorful, albeit idiosyncratic discussion see Levitt (1993).

[18] In the case of graduate students at universities, for example, employers have often attempted to argue – sometimes successfully – that graduate student employees are not “employees" but “students receiving financial aid." Another example is employers arguing that its employees are not workers but “independent contractors" who are not covered by the provisions of NLRA.

[19] If two unions split the vote 50-50, they both lose, and neither become certified.

propriate for an analysis of the impact of unionization on employer outcomes.

First, that employers are thought to generally oppose organization drives [Kleiner 2001] suggests that both parties have "something at stake" in the outcome of the election. For example, we expect that both the union and management are expecting that a union win will generally lead to higher wages, more benefits, or better working conditions, at the cost of the employer. If very little were at stake, and if the elections themselves were *pro forma* events, then we would not expect to see a significant employer response to a union election victory. Such a finding would say more about the small size of the "treatment" ("unionization") than the potential magnitude of distortions caused by an aggressive union. This seems unlikely, however, since we analyze establishments which faced NLRB elections. Such a focus would seem likely to select establishments where union-management relations are contentious since in the overwhelming majority of cases the management of such establishments always has the option of *voluntarily* recognizing the union *without* a (costly) NLRB election. Thus, it would seem more reasonable to assume that the outcome of the election is far from inconsequential to both parties.

Second, combined with a contentious atmosphere, the secret-ballot nature of the vote undoubtedly generates a certain amount of uncertainty in the outcome of the election, particularly when the vote is expected to be close. As shown in Section 3 a certain degree of uncertainty is a crucial element to our theoretical and econometric framework. The assumption of some randomness to the vote would likely not be justified if union certification could be secured through a public petition. For example, if all that was required were 50 percent or more signatures, one could imagine that the sample of establishments/unions where the unions submitted a petition with 51 percent of the signatures would be very different from a (peculiar) group of establishments/unions where the workers submitted signatures that totalled 49 percent. By contrast, it is very easy to imagine in a secret-ballot context that those unions that won 26 out of 50 votes in a secret-ballot election possessed virtually the same *ex ante* chance of winning as unions that obtained 25 out of 50 votes (and lost).

4.2 Data Set Construction: the NLRB, FMCS, and InfoUSA, Inc.

Deferring the details to the Appendix, we summarize here the most important features of the dataset used in the analysis. First, electronic records on all representation election cases handled by the NLRB in the fiscal years from 1984 to 1999 were obtained. These records have information such as the dates of the filing of the petition, the election, and the closing of the case, as well as the eventual vote tallies, as well as other characteristics such as the size of the voting unit, and the primary industry of the establishment in question.

Importantly, these files contain the establishment name and exact address. The names and addresses alone were submitted to a commercial marketing database company called InfoUSA, Inc. InfoUSA maintains an annually updated list of all active business establishments (with a telephone listing) in the United States. The basis for their database is the consolidation of virtually all telephone books in the country. InfoUSA makes a brief call to each establishment at least once a year, to verify their existence, and to update their information on various items such as 1) the total number of employees at the establishment, 2) the estimated sales volume of the establishment, 3) the primary product of the business, and various other characteristics. If InfoUSA found a record in their current database (as of May, 2001) with the same name and address, they appended their information to the record. They were not given any information beyond the name of the business and the street address.

This merged data was then additionally merged to a database of all contract expiration notices between 1984 and February, 2001 – more than 500,000 case records – obtained from the Federal Mediation and Conciliation Service (FMCS) through a Freedom of Information Act (FOIA) request. According to the U.S. Code of Federal Regulations (29 CFR 1425.2)

> In order that the Service may provide assistance to the parties, the party initiating negotiations shall file a notice with the FMCS Notice Processing Unit ... at least 30 days prior to the expiration or modification date of an existing agreement, or 30 days prior to the reopener date of an existing agreement...

Thus, in principle, parties to collective bargaining agreements are required to file so-called "30-day notices" with the FMCS. This was used to obtain our proxy for the "presence" of a union at the establishment – both before and after the election – under the presumption that contracts eventually expire,

typically after two or three years.

There are a few important limitations to our data. First, our data do not constitute a true panel dataset. We only observe "survival" or "death" as of one point in time - in the year 2001. We know little about what happens between the time of the election and 2001, except the observation of contract expirations at that particular location. While we do observe a few "baseline" characteristics from the NLRB election file, InfoUSA does not retain historical records, so we do not have detailed employment and sales data for period between the election and the year we observe survival status (2001).

Second, since we are measuring employer "survival" as a match (by name and address) in the InfoUSA database, there will undoubtedly be some measurement error. Consequently, we will inevitably treat some firms as having "died", when instead we have simply been unable to match them. However, while this may mean that estimates of the *level* of survival rates may be downward biased, it is highly unlikely that establishments with close union winners are systematically less or more likely to match to the InfoUSA database than counterpart close union losers, except if there is a true impact of union certification on survival probabilities.

Likewise, our measure of "union presence" will also likely be biased in *levels*, although this is unlikely to have important consequences for our comparison of close winners to close losers. For example, we understate the extent of unionization to the extent that our matching algorithm fails to locate a match in the FMCS data when such a match exists or to the extent that noncompliance with the law (regarding notifying the FMCS when a contract expires) is widespread. Alternatively, we overstate the extent of unionization to the extent that our matching algorithm produces "false positive" matches. Although the levels may be mis-measured, it seems reasonable to assume that these sources of measurement error are unlikely to be systematically different between close winners and close losers. On balance, we believe the benefits of being able to compare the bare winners and losers on the basis of some other measure of "union presence" other than the legal certification that *necessarily* results from winning the election outweighs the inability to obtain an accurate measure of the overall *level* of union presence.

4.3 Descriptive Statistics

Since the primary outcome of interest in this analysis is the survival probability of the employer, we first provide a broad picture of what our data implies about exit rates of establishments over time. Three important patterns emerge from our sample of establishments that experience NLRB representation elections: 1) as might be expected, establishments' survival probabilities decline as one examines longer and longer intervals, 2) employers where the organizing campaign succeeded have, on average, a lower probability of surviving than those where the union was defeated, and 3) establishments' death/exit rates appear to be the dominant component to the overall decline in the total employment they provide over time. Table I illustrates these basic patterns.

Table I and the subsequent analysis in this paper is essentially based on the universe of establishments that experienced NLRB representation elections between 1983 and 1999.[20] The first column of Table I shows that in this sample, as would be expected, the probability of survival declines significantly as one examines longer and longer intervals. For example, the table shows that among the employers that experienced NLRB representation elections in 1984, roughly 28 percent of them were still in existence as of the year 2001. By contrast, about 58 percent of establishments that experienced an election in 1999 had survived as of 2001. The survival probability grows monotonically as we examine more recent elections; this would be expected if the establishments that experienced elections were, on average, comparable over time. The implied exit rates are comparable to other estimates from existing research that utilizes establishment-level longitudinal data.[21]

The next three columns of Table I show that establishments where unions were recognized are, on average, less likely to survive both in the short- and long-run. For example, among elections that occurred in 1999, 54 percent of those employers where the union won were still "alive" by the year 2001, compared

[20] The NLRB election data are representation election cases that are disposed within the fiscal years from 1984 to 1999; thus, most of the elections were held between the years of 1983 and 1999, with a few elections occuring before 1983.

[21] For example, Dunne, Roberts, and Samuelson [1989] report a 5-year exit rate of about 40 percent, as calculated from Census of Manufacturing data (1967-1977). And an analysis of food-manufacturing plants by McGuckin, Nguyen, and Reznek [1998] imply a 10-year exit rate of about 60 percent in the LRD from 1977 to 1987. As seen in Table I, the corresponding implied exit rates in our data are 48 and 59 percent respectively.

to 61 percent for the non-unionized employers. There is also a difference in survival rates 13 years after the election (elections in 1988). Averaging across all years yields a statistically significant difference of 3 percentage points. Presumably, this difference reflects a combination of both the *causal* impact of union recognition on survival, and the likelihood that there are systematic differences between employers that won or lost the election.

Taken together, the fifth and ninth columns in Table I suggest that in this sample, employer death or exit is a significant component in the decline of total employment provided by employers over time.[22] Among employers that faced elections in 1984, the average employment level - where "dead" employers are counted as having zero employment - is about 61, while the corresponding numbers for elections conducted in the late 90s are over 100.[23] By contrast, the average log employment (ninth column) *conditional on survival by 2001* appears to be relatively stable over time. This implies that much of the decline over time in the average employment provided by establishments operates through the "deaths" of employers.[24]

Finally, the differences between the 10th and 11th columns show that, conditional on survival, employment levels are much smaller among employers where the union was victorious. Again, this difference (an average of 0.22 in logs over the entire sample period) presumably reflects a combination of both the causal impact of unionization on employment levels, and a selection bias resulting from systematic differences between employers that do and do not successfully resist an organizing campaign.

A more detailed examination of the differences between employers where the union won or lost the election reveals three additional patterns: 1) establishments where unions won are significantly smaller, in terms of sales volume as measured in 2001, than those where unions lost, 2) across establishments, the election outcome is significantly associated with our own proxy of union presence constructed from the FMCS data, and 3) the election outcome is also associated with several other pre-determined characteristics of the establishment (e.g. industry, size of the voting unit).

---

[22] The employment variable is employment level, as of the year 2001. The variable comes from the InfoUSA, Inc. database.

[23] All "dead" establishments were assigned zero employment. There are 17622-16355=1267 missing values for employment among the surviving employers as of 2001.

[24] Longitudinal evidence indicates that establishment "deaths" alone can account for a significant share of job destruction in the manufacturing sector. On average, 25 percent of job destruction in the manufacturing sector is due solely to establishment "deaths" [Davis and Haltiwanger 1992]. The rate appears to be higher in other sectors of the economy [Pivetz, Searson, and Spletzer 2001]

Table II provides the details of these findings. The fifth row reports that employers where the union wins produce roughly 35 percent less in sales compared to cases where the union lost. Row (6) in Table II also shows that the outcome of the representation election is highly correlated with our proxy for union presence. This computation is made among the restricted sample of surviving (as of 2001) establishments. Among "union-loss" establishments we observe a contract expiring a approximately 10 percent of the time. When the union wins the election, on the other hand, there is a 36 percent chance that we will observe a union contract ending after the election.

The rest of Table II provides good reason for the analyst to resist interpreting the union-won/loss differences in rows (1) - (5) as causal effects of union certification. For example, the establishments where the union won are about 15 to 20 percent smaller than the "union-loss" establishments, as measured by the number of eligible voters or the ultimate number of votes cast in the NLRB election. In light of these differences, it is thus not surprising that we observe differences in employment *after* the election, in the same direction, and of roughly the same magnitude.

Similarly, row (7) of Table II reveals that we are more likely to detect the presence of a union *before the election* among establishments where the union won recognition compared to employers where the union lost: the respective proportions of pre-election "union presence" are 0.179 and 0.095.

In addition, employers differ by election outcomes on a number of other dimensions; these differences give more reason to maintain some doubt in any causal interpretation of the comparisons in rows (1) - (5) of Table II. For example, as row (12) of Table II indicates, establishments where the union won the election are much less likely (33 versus 42 percent) to be classified in the manufacturing sector. Moreover, as rows (13) and (14) of Table II indicate, establishments where the union won are more likely to be in the service sector (35 percent in "union-win" establishments versus 22 percent for "union-loss" establishments) and the voting unit less likely to be classified by the NLRB as "truck drivers". On the other hand, measures of state economic conditions are not strongly related to the outcome of the election. The union won/loss differences in the levels and changes in the unemployment rate and the log(employment) level are statistically but not economically significant.

In sum, Table II provides evidence that *caution the analyst against* making inferences about the impacts of union certification on employer outcomes from simple differences in outcomes by election outcome.[25] The evidence is suggestive that union recognition by election may be *negatively selected* – that unions are more likely to prevail in a representation election in smaller, and potentially *less* robust establishments. This would be consistent with the notion that larger establishments with greater resources may be more able to resist organizing drives. However, this interpretation of Table II is at best speculative without an independent estimate of the causal effect of union certification.

5 Estimates of the Impact of Unionization

5.1 Evidence on Validity of the Regression Discontinuity Design

As mentioned above, if the regression discontinuity design is valid, employers involved in close union wins should be similar, on average, to those involved in close union losses, in terms of their pre-determined characteristics – whether or not they are observed by the econometrician. As in any empirical analysis, assessing whether "unobservables" are balanced is impossible. However, we can at least assess whether or not the regression discontinuity design is succeeding in balancing *observable* determinants of establishment survival. Our empirical analysis reveals that the examination of close elections *does* result in "treatment" and "control" establishments that appear to be otherwise similar on observable dimensions.

Table III reports differences in characteristics of the employer, by union victory/loss, in the overall sample, and by sub-samples that isolate closer and closer elections. For example, in elections where the union lost, the average number of eligible voters is about 113, compared to about 92 where the union eventually won. That difference remains large when we examine elections where the union won between 25 and 75 percent of that vote. But it drops in half when we focus on the comparison among elections where the union won between 35 and 65 percent of the vote. The same holds true in percentage terms. The difference in terms of the log of the vote cast falls from -0.19 to about -0.10 when we move from the first

[25] The researcher might be tempted to conduct the analysis conditional on the pre-determined characteristics such as industry, and size of voting unit, under the presumption that the election outcome is random conditional on those covariates. Besides being somehwat ad hoc, by "using up" the covariates, this approach has the drawback of eliminating any possibility of gauging the internal validity of the comparison.

to third set of columns.

The differences in these average characteristics become even smaller when we focus our attention on all elections where the share of the vote for the union is between 0.45 and 0.50. For twenty-person votes, this means the outcome was decided by one vote. Table III shows that, for example, the differences in the pre-election size of the employer (as measured by the number of eligible voters and votes cast) fall to 2 or 3 (on bases of more than 100). Employers involved in union losses are more likely to be classified as manufacturing establishments in the overall sample (first set of columns), but that difference falls to a statistically insignificant -.025 when examining elections decided by the narrowest margin (the fourth set of columns). The monotonically decreasing differences, as one compares closer and closer elections, is also true for the proportion of employers categorized as service sector establishments, and for the proportion of voting units classified by the NLRB as "trucking".

Table III also shows that as one examines closer elections, the estimated standard errors rise, which would be expected, since the number of observations used for the analysis necessarily declines. At some point, restricting the sample to even closer elections will result in *no* observations for analysis. This illustrates the well-known trade-off between bias and variance in non-parametric estimation of an unknown conditional expectation function. Indeed, the averages in the last set of columns can be interpreted as kernel regression estimates using a uniform kernel of bandwidth 0.05. Insofar as the slope of the true conditional expectation function (of the variables with respect to the vote share) is nonzero, *any* kernel regression estimate will necessarily be biased in finite samples.

A simple alternative way of using data points away from the 0.50 threshold to estimate population means at the threshold, is to specify a flexible-form parametrization of the underlying function. Figures IIa, b, and c illustrate the results from regressing the corresponding dependent variables on a fourth-order polynomial in the vote share, including a dummy variable $V_j > 0.50$, and the dummy variable interacted with a linear term in V_j. The predicted values of those regressions are super-imposed upon local averages by 0.05 intervals.

Figure IIa, IIb, and IIc reveal 1) that the predicted values from the polynomial come reasonably

close to the local averages, 2) there is a generally smooth empirical relation between, for example log(total votes cast), the probability that the employer is a manufacturing or service sector establishment, and the observed vote share, and 3), there is no striking discontinuity in any of these relations at the 0.50 threshold.

Overall, Table III and Figures IIa-c lend credence to the interpretation of any discontinuity in *post-election* outcomes as the causal effect of union recognition.

5.2 Effects on Survival Rates

The survival rate differences between union victories and losses, by the margin of victory/loss, are reported in the first row of Table III. It shows that the modest difference in survival probabilities in the overall sample falls to a point estimate of -0.023 in the second set of columns. It falls further to -0.014 in the third set of columns, and when the sample is restricted to elections where the union vote share is between 0.45 and 0.55, the difference becomes a statistically insignificant, -0.007 with a estimated standard error of 0.015. Given the magnitude of the standard error, the estimate is consistent with both a negative effect of up to -.037, as well as a positive impact of up to 0.023 at conventional levels of significance.

Similar to Figures IIa-c, Figure Ia reveals a relatively smooth relation between the fraction of surviving employers and the vote share for the union, with no apparent discontinuity at the 0.50 threshold. Again, the polynomial specification (the same specification used in Figures IIa-c) yields predicted values that closely track the local averages by vote share. The polynomial specification also yields a causal estimate of around -0.007 with a standard error of 0.014.

Robustness to Alternative Specifications Our causal estimates of the impact of unionization of employer survival are robust to a variety of different specifications. The robustness of the estimates to varying specifications is in fact an implication of a valid regression discontinuity design. Intuitively, *if examining close elections generates "as good as randomized" variation in union status, then not only should union status be independent of pre-determined "baseline" characteristics (Table III), but the inclusion of those characteristics as covariates in a regression analysis should not significantly alter the point estimates of the effect of certification.*

Table IV provides evidence that the estimates are indeed robust to various specifications. The estimate that results from the basic polynomial specification (depicted in Figure Ia) is reported in Column (1) (top panel) of Table IV. The first row of Table IV demonstrates that the estimate of the impact of union recognition on survival probabilities is robust to the inclusion of any combination of pre-determined characteristics, with the estimates ranging from -0.003 to -0.007. In Column (2), a set of election-year dummy variables is included. In Column(3) state dummies are additionally included, and in Column (4) industry dummies and unit dummies (indicating how the NLRB classified the primary type of worker in the bargaining unit) are included. In Columns (5) and (6) our proxy for the presence of a union *before* the election is included (since it is pre-determined as of the election date), as is the log of the number of eligible voters in the bargaining unit. It is important to note that the significant coefficient on the pre-election union presence dummy should not be interpreted as a *causal effect*, but simply indicative that this proxy appears to absorb some of the "residual" variance in the dependent variable.

We consider one final robustness check. If the regression discontinuity design is valid, we can replace the survival indicator with a "residualized" version of the indicator (the residuals from a regression of the survival indicator on all the covariates) and find a similar estimate. Indeed, when we use the resulting residuals as the dependent variable in a polynomial specification in the vote share (as in Column (1)), Column (7) shows that the estimate is -0.007 – nearly identical to the other estimates in the first row.

Estimates of Heterogeneous Effects We next examine the extent to which the "treatment" effect of unionization, as discussed above, varies along three potentially important ways. By analogy to Ordinary Least Squares with a binary treament variable and other covariates, we examine whether there any interesting "interactions" between the treatment and other exogenous covariates. As the results from Table V make clear, however, the data cannot reject the hypothesis that the estimated "treatment" effect of unionization, as presented above, are constant along the three dimensions we explore.

First, since we observe survival at one point in time (the year 2001), the "overall" estimate we obtained is an average of 2- through 18-year survival rates. Since a *positive* effect on survival in the short-

run could be canceling out a long-run *negative* effect (or vice versa), it is instructive to stratify the analysis by groups of years. The 2nd row of the first column presents the estimate from Column (6) of Table IV. The 3rd row reports that among elections that were held before 1988, the corresponding effect of union recognition on the probability of survival is about -0.022 with a standard error of 0.020. The following three rows report the interaction effects for the periods 1988-1991, 1992-1995, and after 1995, respectively. The interactions effects are small and statistically insignificant.[26]

Second, the effect could potentially vary significantly by industry. The next three rows in the first column of Table V show that the effects are slightly larger for service sector establishments, but again the interactions are not jointly statistically significant. Third, the effects could vary by the size of the voting unit (a rough proxy for initial size of the establishment). The final three rows of Table V show that the estimates are positive (0.005) for voting unit sizes between 20 and 40 workers, and are slightly negative (0.005-0.032=-0.027) for units between 40 and 100. But all interactions are not statistically meaningful at conventional levels of significance.

The second column reports that the estimates of the overall effect and the various interactions do not change significantly, when we use an alternative measure of establishment survival. As mentioned in Section 4, we consider that an establishment has survived as of 2001 if the company name and address matches an entry in the InfoUSA database. However, in principle, if bare losers are much more likely than bare winners to undergo an ownership change – and hence change their name – then our primary measure of establishment survival may mask a true effect on establishment closure. A comparatively robust way to address this issue is to consider that an establishment has survived if *any* establishment is present at that exact address as of the year 2001 – irrespective of whether the company name changes. The second column of Table V reports the estimates from using this measure (Survival (2)), and shows that the estimates mirror that of the first column.[27]

On balance, while we cannot rule out small heterogeneous effects by these three observable di-

[26] Specifically, the specification was the same as Column (6), except year dummies were replaced with time-period dummies, their interactions with the WIN_j indicator and their interactions with V_t.

[27] Apparent from the first row, the obvious exception, as expected, is that the proportion of establishments that have *any* business (regardless of name) as of the year 2001, is significantly higher, at about 0.643.

mensions due to the magnitudes of the sampling errors, we interpret the estimates as indicating that our main estimate is not being wholly driven by a particular sub-sample, as defined along these observable dimensions.

5.3 Further Evidence on the Consequences of Union Recognition

It is tempting to conjecture that a union that barely wins a representation election possesses the same degree of "bargaining power" as a union that barely lost. After all, even if the NLRA mandates that the employer bargain "in good faith" with the union as the exclusive representative of the workers in the unit, there is no guarantee that a first contract will be secured. Also, since nothing prevents a losing union from attempting another organizing drive (as long as one year has passed since the first election), one might conjecture that the outcome of a *close election* may in the long-run have no effect on the extent of union presence or power at the employer.

As we discuss in greater detail in Section 6, this conjecture is difficult to reconcile with the simple economic framework we have outlined above. Among other reasons, it is difficult to explain why a union would undergo a costly organizing campaign if the outcome of the election was inconsequential for the union.

More importantly, this conjecture is strongly inconsistent with our analysis of the data we have collected on post-election union presence. Specifically, while we do not directly observe the securing of a first contract, we observe the expiration of a first contract (and expirations of subsequent contracts). Thus, our post-election "union presence" variable is whether or not we observe at the employer's location an FMCS contract expiration notice subsequent to the date of the election. The second to last row of Table III shows that there is a large difference in the probability of observing an expiration notice between union victories and losses. That difference becomes smaller, when examining closer elections, but remains a highly statistically significant 0.159 when examining elections with a union vote share between 0.45 and 0.55. In fact, our post-election "union presence" variable is the only variable in Table III where the differences remain large when examining the closest of elections.

The behavior of our post-election "union presence" proxy also stands out in our graphical analysis of the data. Figure Ib shows a smooth empirical relation between the vote share and the probability of observing a contract expiration notice – everywhere except at the 0.50 threshold, where there is a sharp jump in that probability from about 0.12 to 0.28. By contrast, the last row of Table III and Figure Ic, suggest no corresponding striking change for our pre-election "union presence" variable (an indicator of whether we observe a contract expiration notice at the address of the employer *before* the election). These figures suggest that the outcome of the representation election is far from inconsequential – that there is a permanent *causal* effect of a union victory on this particular proxy of union power. Also, the effect on our post-election union presence proxy is robust to alternative specifications, as shown in Table IV. This would be expected if the assumptions of the regression discontinuity design were valid. The estimates of the effect of union recognition on the probability that we observe a contract expiration notice at the establishment are precisely estimated and range from 0.132 to 0.152. Note from the comparison of Columns (3) and (5) or (4) and (6) that the inclusion of the *pre-election* union proxy does not meaningfully affect the union recognition effect, despite its own independent predictive power (t-statistic over 20).[28]

Some care needs to be taken in interpreting these findings in Table III and Figures Ib and Ic, because the averages are computed using the sample of establishments that have survived as of the year 2001. In principle, this induces a censored sample selection problem. In the same way that wages are not observed for the non-employed, our post-election union presence variable – and any other measure of union presence – is defined only for those surviving establishments[29], there is therefore the potential that the discontinuity in Figure Ib is an artifact of sample selection bias [Heckman 1976].

However, in this particular context, the sample selection bias problem may not be important after all. Lee [2002] shows that if a treatment is "as good as randomized", and if treatment affects sample selection in a monotonic way, then equal probabilities of selection in the treatment and control group imply that there is *no* sample selection bias. These two conditions are applicable here: 1) the maintained hypothesis

[28] Again, the coefficient on the pre-election union presence variable is not to be interpreted as a causal effect; rather it is more properly thought of as a partial correlation; its inclusion "absorbs" residual variation.

[29] Actually, we do have some information for those that are not in business as of the year 2001, but we do not know when, between the date of the election and 2001, the establishment shut down.

is that the regression discontinuity design generates "as good as randomized" variation in the union status treatment, and the data fail to reject the restrictions implied by that hypothesis, and 2) Equations 1 and 5 both satisfy the monotonicity condition in Lee [2002]. Given that we estimate little or no effect of union recognition on survival (here, sample selection), this suggests that there is little or no sample selection bias in our causal estimate of the effect of union recognition on post-election union presence.

Furthermore, Lee [2002] shows that if the selection probabilities are the same, the independence and monotonicity conditions imply that the *selected sample* of treated and control populations should possess similar distributions of baseline (or pre-determined) characteristics. Such a pattern is apparent in these data, as shown in Appendix Table III, which is analogous to Table III, except that it restricts the sample to establishments that have survived as of the year 2001.[30]

Finally, since the evidence suggests that sample selection bias may not be important, we proceed by examining union impacts on four other measures of employer outcomes: the levels of employment and estimated sales volume, as well as the logs of both variables. Table V reports regression discontinuity estimates for these outcomes. Overall, the results are mixed; the employment and sales responses are small relative to the overall variability in outcomes across establishments. However, the estimated standard errors are too large to rule out economically meaningful negative or positive effects on employment.

The third column reports regression discontinuity estimates for the level of employment, where we have assigned "0" to those establishments that have closed by the year 2001. The point estimate is essentially 0 with a standard error of 8. While the null hypothesis of a zero effect cannot be rejected at conventional levels of significance, neither can a negative response of about 13 employees – about 15 percent of the mean (83.4).

The fifth column reports the estimates for estimated sales volume, where again we have assigned "0" to establishments no longer in existence. The estimates imply a positive impact on sales volume on the order of $250,000 dollars, but it is not statistically different from zero. Furthermore, a substantial

[30] Technically, it also conditions on having non-missing employment information. There are some suriving establishments that did not report employment levels.

negative effect (of about $2.6 million, about 20 percent of the mean) could not be ruled out at conventional levels of significance. As with employment, the cross-sectional variability in sales is quite significant, and suggests that even large, economically meaningful effects on sales are small, relative to the cross-sectional heterogeneity in output across establishments, even while including industry dummies.

The fourth and sixth columns report the discontinuity estimates for the log of employment and sales volume, respectively; hence, "dead" or "0 employment" establishments are necessarily dropped from the sample. The null hypothesis that the effects are zero cannot be rejected at conventional levels of significance, but the estimated standard errors are themselves of economically significant magnitudes. Nonetheless, we are able to statistically rule out large effects: for example, a 25 percent negative effect on employment and a 20 percent positive effect on sales volume.

6 Economic Implications

We believe that our estimates constitute an important step in empirically assessing the magnitude of economic distortions caused by unions. Considering it as a first step to providing a broader picture of the causal effects of unions (while adequately considering the potential biases induced by self-selection and omitted variables), we are hesitant to draw strong inferences regarding the magnitude of potential welfare losses. However, it is instructive to consider our findings' implications in light of five issues of economic interpretation.

6.1 Is the "treatment" small?

An alternative explanation of the lack of effects on survival rates is that the wage demands by unions, on average, are themselves small – too small to have a measurable impact on employer survival rates. It is tempting to conjecture that even though a union election win causes greater union presence (as measured by the existence of a contract), a union that barely wins an election cannot negotiate wages any larger than what would have been offered by the management had the union barely lost.

However, the notion that the gap between the union and management offered wage is small among close elections, and large among votes where the union happens to overwhelming win, is not a robust

prediction of our framework of optimizing employers and unions. Within our framework, it is possible to generate specific examples where such a prediction would hold, given specific assumptions about the shapes of the objective functions for the employer and union, the shape of $v(\cdot)$, and the distribution of $-U_j$. On the other hand, it is just as easy to generate the opposite prediction – that the gap in the wage offers $W_j^U - W_j^N$ *declines* with an exogenous increase in the probability of a union victory.

To see this, suppose that δ_j is a parameter that characterizes how much the workers care about wages so that we have $v\left(W_j^U, W_j^N, \delta_j\right)$ where $\frac{\partial v}{\partial \delta_j} > 0$. Now suppose that the union leadership has a limited range of credible wage offers; to make the example stark, suppose that it is (correctly) expected by all agents that if the union wins, the wage W_j^U will be fixed at $\overline{W_j^U}$. In this case, the equilibrium is determined solely by the management's counter-offer wage. One can show that there are some reasonable assumptions under which $\frac{\partial W_j^{N*}}{\partial \delta_j} > 0$ and $\frac{\partial \Pr[WIN_j=1]}{\partial \delta_j}$, which would imply that the wage gap $W_j^{U*} - W_j^{N*}$ *diminishes* with an exogenous increase in the probability that the union will win.[31] Intuitively, faced with an exogenous increase in wage demands on the part of the workers (increase in δ_j), fearing the prospect of paying the high union wage, management offers a larger non-union wage in order to reduce the chance of losing the election to the union. In equilibrium, the probability of a union victory does increase, but it is moderated by the management's optimal response. Therefore, in this case, we would expect to see a *larger* wage difference among close elections (where the probability of a union victory is more moderate) compared to elections in which the union overwhelmingly won (in which the probability was higher).

There is another reason to expect that $W_j^{U*} - W_j^{N*}$ may even be larger with a lower probability of the union winning: a union requires a larger minimum gain $W_j^{U*} - W_j^{N*}$ in order to justify a costly

[31] Let $v\left(W_j^U, W_j^N, \delta_j\right) = -W_j^U - W_j^N + \delta_j$. Then the first-order conditions for the employer amounts to the equation $\frac{f(v)}{1-F(v)} - \frac{\frac{\partial \pi\left(W_j^N\right)}{\partial W_j^N}}{\pi\left(W_j^U\right) - \pi\left(W_j^N\right)} = MB(v) - MC\left(W_j^N\right) = 0$, where $f(\cdot)$ and $F(\cdot)$ are the density and cdf for $-U_j$. The first term can be interpreted as the marginal benefit from raising the offered wage, which reduces the probability that the union will win, and the second term can be though of as the marginal costs (due to lower profits). An interior solution is guaranteed if $\frac{f(v)}{1-F(v)}$ and $\frac{\frac{\partial \pi\left(W_j^N\right)}{\partial W_j^N}}{\pi\left(W_j^U\right) - \pi\left(W_j^N\right)}$ are decreasing and increasing, respectively, in W_j^N. This will be true if $-U_j$ is normally distributed and $\frac{\partial^2 \pi\left(W_j^N\right)}{\left(\partial W_j^N\right)^2} < \frac{\left(\frac{\partial \pi\left(W_j^N\right)}{\partial W_j^N}\right)^2}{\pi\left(W_j^N\right) - \pi\left(W_j^U\right)}$. By the implicit function theorem $\frac{\partial W_j^N}{\partial \delta_j} = \frac{\frac{\partial MB}{\partial v}}{\frac{\partial MB}{\partial v} + \frac{\partial MC}{\partial W_j^N}}$ which will be positive but less than 1. Therefore, an increase in δ_j leads to an increase in the offered wage W_j^N and in the equilibrium probability that the union will win.

organizing drive. This is immediately apparent from Equation 11, which shows that the expected benefit – itself a product of the probability and the benefit function $U(\cdot)$ – needs to exceed c to justify having an election in the first place. Put simply, the lower probability that the union will prevail, the larger wage gain is needed to justify the costs of organizing.

For these reasons, it seems more plausible that the outcome of the election is far from inconsequential to both the employer and the union, perhaps *especially* among close elections (where the *ex ante* probabilities of a union win are more moderate). However, whether or not the outcome of a representation election has any measurable impact on compensation and working conditions is ultimately an empirical question. Future research could show that the outcomes of elections *are* inconsequential in terms of altering compensation and working conditions, which would suggest that the conventional wisdom regarding how unions affect wages would need to be re-evaluated.

6.2 Is the effect "economically" small?

Our analysis obtains estimates around -0.01, and the null hypothesis of "no effect" cannot be rejected at conventional levels of statistical significance. However, it is also instructive to consider whether or not the estimates are consistent with an alternative null hypothesis – *that the decline in the union sector in the U.S. in recent years is entirely attributable to the union impact on employer survival*.

Such "back-of-the-envelope" calculations require a great deal of abstraction. However, suppose we consider an economy initially made up of N_0 establishments with identical, constant hazard rate of closure of d per year, and a constant inflow of bN_0 establishments per year. Normalizing $N_0 = 1$, it is straightforward to show that the number of establishments at time t is represented by

$$n(t) = \lambda + (1 - \lambda) e^{-dt} \tag{12}$$

where $\lambda = \frac{b}{d}$, so that if $b = d$, the number of establishments remains constant over time.[32]

Over the period from 1983 to 1998, union density among private sector workers fell by approximately 40 percent. The implied baseline hazard rate from our data of establishments implies a constant

[32] This follows from a the differential equation $n'(t) = dn(t) + b$.

hazard of $d = 0.10$.[33] This implies $\lambda = \left(0.6 - e^{-0.10(15)}\right) \frac{1}{1-e^{-0.10(15)}} = 0.485$. Thus, if the decline of the union sector was entirely due to the union effect on the ability of establishments to survive (i.e. if the establishments were not unionized, λ would be 1), then the causal effect of union recognition would have to be a doubling of the hazard rate d. With a base hazard rate of 0.10, this implies that we should expect causal estimates of the 1-15 year survival rates to be on the order of -0.20.[34] To the contrary, however, our causal estimates are around -0.01 and we are able to reject magnitudes larger than -0.04.

Thus, our estimates cast considerable doubt on the proposition that the primary mechanism of recent union decline is through union effects on establishment closure. Of course, these rough calculations should be viewed with caution, as they are based on a number of compositional, aggregation, and behavioral assumptions – the empirical relevance of which can only be assessed with large-scale micro-data on establishments in the U.S.

6.3 The Impacts of Union Threat

Our estimates of the impacts of unionization are *conditional* on having an NLRB election, and our model makes it clear that we are identifying the impacts of $W_j^U - W_j^N$ on survival rates. As our model makes explicit, however, there is another potential impact of unions, which is the distortion due to "union threat" [Rosen 1969]. In other words, employers may face a higher closure rate because their own offered wage W_j^N is forced to be significantly higher than the competitive market wage W_j^M. There are two components to the "overall" impacts of unionization: one component is the effect that arises when wages are pushed from W_j^M to W_j^N, and the other component – which we have estimated in this paper – results when wages are increased from W_j^N to W_j^U. Since we find little evidence of effects on survival of the second kind, we conclude that evidence of large union effects on closure would more likely be found in analyses of union threat effects.

However, our theoretical framework cautions against making the conjecture that threat effects

[33] Actually, our data seem to fit a Weibull baseline better; however, as usual, it is difficult to know whether the empirical duration dependence is "real" or an artifact of unobserved heterogeneity. The 10 percent hazard rate is also roughly consistent with exit rate estimates from Dunne, Roberts, and Samuelson [1989] and McGuckin, Nguyen, and Reznek [1998].

[34] This can be seen by comparing the survivor function $e^{-.1t}$ and $e^{-.2t}$ over a 15-period interval.

should necessarily be larger than the union effects that we have estimated in this analysis. To see this, suppose that the firm will survive only if y_j^* in Equation 4 exceeds some scalar a. Then the probability of closure is $\Pr[Closure] = F(a - \alpha W_j)$, where $F(\cdot)$ is the cdf of ε_j. $\frac{d\Pr[Closure]}{dW_j} = -f(a - \alpha W_j)\alpha$ and $\frac{d^2\Pr[Closure]}{dW_j^2} = f'(a - \pi(W_j))\alpha^2$; the sign of the second derivative depends on the shape of the distribution of the error term, and can easily be positive, which would mean that a marginal impact on closure rises with the wage. Thus, a wage increase that results from a union victory, which is *incremental* on top of an already existing above-market wage due to union threat – could easily lead to a larger effect on closure, compared to the effect induced by an equally sized wage gain due to union threat.

Ultimately, the magnitude of the union threat effect requires empirical investigation.

6.4 Is "no effect" in survival rates consistent with monopoly unionism?

Put simply, yes. There are many margins on which unions could cause allocative distortions. First, even if employers' probabilities of closure are entirely unaffected, they could cut their level of employment. This could be occurring *within* every establishment in the union sector. Second, even if employment is not affected, if the employer's production techniques are constrained by the terms of a contract or union threat, productivity and hence output could fall.

It is instructive to consdier a benchmark for what one might expect to observe in the analogous case where adjustments occur primarily through the "intensive" margin of employment. Interpret $\lambda = \frac{(1-\Delta)b}{d} = 1 - \Delta$ in terms of the proportion of total employees at an establishment, so that Δ is now the "within-employer" response. If we assume that the inflow of new establishments equals the hazard rate, under the null hypothesis that the sole reason for the union decline was due to an intensive margin effect, we would expect the measured causal impact of union certification on employment to be about a 50 percent decline in the level of employment at the establishment. [35] Even given the imprecision of our intensive margin estimates, however, we can easily reject an effect of such magnitude. On the other hand, we cannot rule out a smaller negative intensive margin employment effect of unionization of, say, 15 percent. Given the

[35] Alternatively, if the effects were on the margin of affecting the appearance of establishments in the union sector, it is easy to show that if it entirely explained recent union decline in the U.S., the effect would be a quite large effect of 0.50 in probability.

often cited estimate of the union wage effect of 15 percent [Lewis, 1963] this would imply a labor demand elasticity of -1.

The magnitude of intensive margin effects is a topic for future research. But examining the extensive margin is a pre-requisite to examining the intensive margin. Even in the ideal scenario (from a purely scientific standpoint) where union recognition were randomly assigned, it would not be straightforward to estimate intensive margin effects on employment if the "treated" employers were more likely to "die" and hence "drop out of the sample". Our findings that there are negligible survival effects and that among the survivors both the bare winners and losers look similar along observable characteristics; this suggests that the sample selection issue may well be a second order issue.

6.5 Is "no effect" unsurprising?

Finally, it may be tempting to argue on purely theoretical grounds that the question of whether or not union recognition impacts employer survival is a non-issue in the first place, if we assume that workers and unions are rational. After all, unionized workers also lose if an employer is forced to close its operations.[36] This is certainly true in the unrealistic case that unionization led to closure with complete certainty. But if the union effect works through a negative impact on the *probability* of survival, a large effect (say a doubling of a hazard rate of 0.10) could easily be consistent with rationally behaving workers and unions.[37] Thus, arguments purely based on the presumed rationality of workers are not informative in bounding the union effects on employer survival.

Nonetheless, the notion that the organizing workers and union leadership may be behaving rationally – and have a direct stake in maximizing the viability of the employer – has important implications. Indeed, not only could the union be interested in reducing the risk of closure, but they could be interested

[36] This is pointed out in Kuhn [1986] and Freeman and Kleiner [1999].

[37] If the worker's outside option is equivalent to the firm's non-union wage offer, then it is trivial that any worker will prefer to vote for the union, even if there are substantial effects of the wage on closure rates, as long as there is some probability that the establishment will still exist so that they can obtain the union wage.

If the worker's outside option is below the firm's offered wage, then for the indifferent worker (under risk neutrality) we would have $\frac{W_N - W_M}{1-\delta(1-d)} = \frac{W_u - W_M}{1-\delta(1-2d)}$, where W_U, W_N, and W_M denote the union, firm's non-union wage offer, and outside options, respectively, and δ is the discount factor, and d is the constant hazard rate for the establishment. If $W_U - W_N$ were 0.10 in logs and δ was 0.95, and d were 0.10, then $W_N - W_M$ would have to be about 0.06 (in logs) – a plausible number – in order for the worker to be indifferent.

in maximizing the profitability of the business – insofar as it would lead, for example, to a larger wage bill for the workers. Indeed, this possibility has been the focus of the "efficient contracts" literature (McDonald and Solow (1981), Brown and Ashenfelter (1986), MacCurdy and Pencavel (1986), Card (1986), Abowd (1989), Abowd and Lemieux (1993)). The efficient contracts model departs conceptually from the monopoly union/"right–to–manage" model by observing that union members could value both the level of employment and the wage. And if the firm enjoys some economic rents – through monopoly power in the product market, for example – the monopoly union outcome is "inefficient" in the sense that at least one of the two parties can be made better off without making the other party worse off. In some situations – when there is a "strongly efficient" contract – there is a possibility that unions do not lower employment, but instead act to redistribute rents from firms to workers.

7 Conclusion

This study meets two important challenges of credibly estimating the magnitude of the causal effects of unions. First, we have constructed a large data set that represents a virtual universe of establishments facing potential unionization, linked to comprehensive database on survivorship on businesses. Using over 27,000 observations, we have also exploited a feature of the NLRB election process to produce quasi-experimental estimates that are likely to be free of selection and omitted variable biases. Our results suggest that establishment closure is not the main mechanism of the employment reallocation response to unionization. Rather, it seems more likely that employers respond by reducing employment.

In the existing literature, there is a fair amount of variation in estimates of "within-firm" employment responses to unionization.[38] It would seem fruitful to utilize this study's research design to learn more about this margin of employment adjustment. There is also some uncertainty regarding the labor costs imposed by unions. The existing literature suggests that union wage premiums are large, and that unions have

[38] Estimates range from no effect to signficant effects. For example, Lalonde, Marschke and Troske [1996] suggest there is significant negative employment response. Card [1990] examines indexed and non-index union contracts and finds a significant negative employment response to higher real wages. On the other hand, Bronars and Deere [1993] examine a panel of publically-traded firms and finds no systematic relation between union growth and firm growth. Freeman and Kleiner [1990] find only modest employment effects (and modest wage effects) associated with new unionization.

significant effects on profitability [Ruback and Zimmerman 1984; Abowd 1989]. At the same time there is some evidence indicating only modest wage gains associated with new unionization [Freeman and Kleiner 1990; Lalonde, Marschke, and Troske 1996]. A useful avenue for future research is to use NLRB election data, as we have here, to explore the impact of unionization on: the level and distribution of wages, capital investment, and total factor productivity.

Appendix A.

There are three sources of information that were merged for the analysis. We first describe how our data from the National Labor Relations Board (NLRB) was matched to firm data from InfoUSA. Next we describe how the result of this matching process, henceforth the "NLRB/InfoUSA data" was matched to data from the Federal Mediation and Conciliation Service (FMCS).

A.1 The NLRB to InfoUSA match

First, electronic records on all representation election cases handled by the NLRB in the fiscal years 1984 to 1999 were obtained. These records contain information such as the dates of the filing of the petition, the election, and the closing of the case, as well as the eventual vote tallies, as well as other characteristics such as the size of the voting unit, and the primary industry of the establishment in question. Most importantly the file contains information on the name and street address at which the representation election was held.

These 139,881 records were then matched by name and address to a commercial marketing database company called InfoUSA, Inc. Before being sent to InfoUSA, however, the address fields were first "standardized" using a program called "Mailers $+4$ Postal Automation Software." For example, "1 Broad Street" was changed to "1 BROAD ST". This was done to facilitate matching the NLRB data to the data from InfoUSA.

As discussed in the text, InfoUSA maintains an annually updated list of all business establishments (with a telephone listing) in the United States. The basis for their database is the consolidation of virtually all telephone books in the country. InfoUSA makes a brief call to each establishment at least once a year, to verify their existence, and to update their information on various items such as 1) the total number of employees at the establishment, 2) the estimated sales volume of the establishment, 3) the primary product of the business, and various other characteristics.

We submitted the name and address information from our "address standardized" NLRB data to InfoUSA who matched as many of the submitted records to their current database (as of May, 2001) and then appended their information to the record. Apart from the name and address information, no other

information was given to InfoUSA.

Before merging this data to our data from the Federal Mediation and Conciliation Service (described below) the data were cleaned for duplicates. There were three types of duplicates: 1) genuine duplicates – more than one NLRB case with a specific employer, 2) duplicates which where an artifact of the fact that our NLRB data came in two files: one contained data from 1977 to 1991 and the other contained the records for 1984-1999. Most of the duplicate pairs therefore occurred for the years 1984–1991, although their were some duplicate pairs in other years because of the fiscal/calendar year distinction; 3) a very small number of duplicates where two records containing exactly the same information.

A.2 The NLRB/InfoUSA to FMCS match

The most difficult task was to take this NLRB and InfoUSA matched data and merge it to a database of 563,565 expiration notices between 1984 and February, 2001 obtained from the Federal Mediation and Conciliation Service (FMCS) through a Freedom of Information Act (FOIA) request. Like the NLRB data the addresses were standardized using "Mailers $+4$ Postal Automation Software."

Many of the FMCS address could not be standardized. Reasons included:

- The ZIP Code was invalid or does not match the city name.
- Canadian ZIP Code
- Unknown Street. No street could be found within the city that matches the street name given in the address field.
- Non-delivery Address. The location given in the address field physically exists in the city but the post office has indicated that there are no houses there. This may occur when one side of the street has railroad tracks or a river along side it.
- Address Out of Range. The address was not within the delivery range.
- Multiple Addresses. The national database found two or more possible ranges for the address.
- Multiple Components. More than one component of your address was in error. Address components are the pre-direction, post-direction, and suffix.
- No Data Available for City. Address data for this city is not in the database.

We chose to keep all FMCS records that had successfully standardized addresses, and ran an automatic matching algorithm to link NLRB/InfoUSA records to the resulting database. The matching involved matching by address and employer name. Our algorithm first involved removing spaces, punctuation, and

frequently used words in company names (i.e., INCORPORATED, BROTHER, COMPANY, etc.). From this we created two separate strings of a length which we could vary: the first sub-string started from the beginning and the second sub-string begins from the end and went in reverse order. The longer the string, the more "stringent" the test for two records to be declared a "match." Matches could occur when the first sub-strings matched or when the second sub-strings matched.

Depending on whether the address was standardized, we varied the length of the comparison string – when addresses were standardized then we enforced a less stringent standard than those which were unable to be standardized. Our final algorithm (using only the standardized data) used strings of length 5.

A.3 Sample Selection and Variable Construction

First, in order to minimize measurement error in our survival indicator, we keep only those NLRB records that have a non-missing street address, and those addresses that were successfully standardized using our address standardization software. In addition, we keep all elections in which 20 or more votes were cast. Appendix Table I reports the means and standard deviations of the variables for the entire merged database and the restricted sample used for the estimation. The table shows that the means are reasonably similar between the two samples, except in the variables that reflect the scale of the employer (number of eligible voters, votes cast, employment, sales volume).

Finally, great care was taken to construct the vote share for the union. There is a problem with simply computing the ratio of the number of votes for the union to the total number of votes. This is because there is substantial variability in the number of votes cast, and a union victory is secured by obtaining strictly more than 50 percent of the vote (plus 1 vote). Consider all elections where an even number of votes are cast. Elections with any number of votes cast could result in exactly 50 percent of the vote. However, it is *impossible* that an election with less than 100 votes cast could have a vote share between 50 and 51 percent of the vote. This *mechanically* induces a discontinuity in the size distribution at the 50 percent threshold of the vote share, and this is entirely an artifact of the fact that the vote share is not *literally* continuous, and instead has finite and discrete support, with the support changing with the number of votes cast.

Thus, we made a minor adjustment to the vote share variable in order eliminate this problem. For every case where there was an *even* number of votes cast, an amount equal to $0.5/(\#$ votes cast$)$ was subtracted from the vote share. For example, if 25 out of 50 votes were for the union, the vote share became 0.50 - 0.01 = .49; 26 out of 50 votes meant a vote share of 0.52 - .01 = 0.51. Cases where an odd number of votes cast were unadjusted. This minor adjustment restores symmetry in the support for vote share, and the new "vote share" variable still possesses the property that strictly more than 0.50 implies a union victory. Finally, the vote share was "binned" so that all vote shares between 0.50 and 0.55 were assigned the vote share of 0.525, shares between 0.45 and 0.50 were assigned the share of 0.475, and so forth. In this way, vote shares were standardized to the support for the elections with the smallest number of votes cast (20).

A completely different approach is to abandon the use of the vote share completely, by focusing on the *absolute* vote count, and comparing elections in which the union either won or lost by literally 1 vote. This eliminates this "integer problem", but at the same time tends to push larger establishments away from the threshold that determines victory (generating a pronounced U-shape in the average size of the establishment, with respect to the absolute vote margin of victory/loss). This was the approach used in DiNardo and Lee [2001]; it should be noted that the results reported there are qualitatively and quantitatively similar to the results in this paper, suggesting that our findings are not sensitive to the method used to address the integer problem.

References

[1] Abowd, John M. "The effect of wage bargains on the stock market value of the firm" *American Economic Review* 79:774–800, September 1989.

[2] Abowd, John M. and Thomas Lemieux. "The Effects of Product Market Competition on Collective Bargaining Agreements: The Case of Foreign Competition in Canada." *Quarterly Journal of Economics* 108, (1993): 983-1014.

[3] Angrist, Joshua D., and Victor Lavy. "Using Maimondies' Rule to Estimate the Effect of Class Size on Scholastic Achievement." *Quarterly Journal of Economics* 114 (1998): 533-75.

[4] Ashenfelter, Orley and George E. Johnson. "Bargaining Theory, Trade Unions, and Industrial Strike Activity." *American Economic Review*, 59 (1969) 35-49.

[5] Boal, William M., and John Pencavel, "The Effects of Labor Unions on Employment, Wages, and Days of Operation: Coal Mining in West Virginia," *Quarterly Journal of Economics* 109 (1994) 267-298.

[6] Bronars, Stephen G., and Donald R. Deere, "Union Organizing Activity, Firm Growth, and the Business Cycle," *American Economic Review*, 83 (1993) 203-220.

[7] Bronfenbrenner, Kate. "Employer behavior in certification elections and first contracts: Implications for labor law reform" In Sheldon Friedman, Richard Hurd, Rudy Oswald, and Ronald Seeber, editors, *Restoring the Promise of American Labor Law*, pages 75–89. ILR Press, Ithaca, New York, 1994.

[8] Bronfenbrenner, Kate, *Uneasy Terrain: The Impact of Capital Mobility on Workers, Wages and Union Organizing*, research paper provided by the U.S. Trade Deficit Review Commision, 2000.

[9] Brown, James N. and Orley Ashenfelter. "Testing the efficiency of employment contracts" *Journal of Political Economy* 94:S40–S87, 1986.

[10] Campbell, D. T. "Reforms as Experiments." *American Psychologist* 24 (1969): 409-29.

[11] Card, David. "Efficient contracts with costly adjustment: Short run employment determination for airline mechanics" *American Economic Review* 76:1045–1071, December 1986.

[12] Card, David, *American Economic Review*, 80 (Sep., 1990), pp. 669-688.

[13] Commission for Labor Cooperation, *Plant Closings and Labor Rights: A Report to the Council of Ministers on The Effects of Sudden Plant Closings on Freedom of Association and the Right to Organize in Canada, Mexico, and the United States*, 1997.

[14] Davis, Steven J. and John Haltiwanger, "Gross Job Creation, Gross Job Destruction, and Employment Reallocation," *Quarterly Journal of Economics* 107 (1992) 819-863.

[15] DiNardo, John and David S. Lee. "The Impact of Unionization on Establishment Closure: A Regression Discontinuity Analysis of Representation Elections," *Center for Labor Economics Working Paper #38*, September, 2001.

[16] Dunne, Timothy, Mark J. Roberts, and Larry Samuelson. "The Growth and Failure of U.S. Manufacturing Plants." *Quarterly Journal of Economics* 104 (1989): 671-698.

[17] Freeman, Richard B. and James L. Medoff. *What Do Unions Do?* Basic Books, New York, 1984.

[18] Freeman, Richard, and Morris Kleiner, "The Impact of New Unionization on Wages and Working Conditions," *Journal of Labor Economics*, 8 (1990) S8-S25.

[19] Freeman, Richard B. and Morris M. Kleiner "Do Unions Make Enterprises Insolvent?", *Industrial and Labor Relations Review*, Vol. 52, No. 4, July 1999, pp. 507- 524.

[20] Freeman, Richard B. "Why are unions faring poorly in NLRB representation elections?" In Thomas Kochan, editor, *Challenges And Choices Facing American Labor*. MIT Press, Cambridge, 1985.

[21] Hahn, Jinyong, Petra Todd, and Wilbert van der Klaauw. "Identification and Estimation of Treatment Effects with a Regression-Discontinuity Design." *Econometrica* 69 (2001): 201-209.

[22] Heckman, James. "The Common Structure of Statistical Models of Truncation, Sample Selection, and

Limited Dependent Variables and A Simple Estimator for Such Models." *Annals of Economic and Social Measurement* 5 (1976): 475-492.

[23] Heckman, James J. "Sample selection bias as a specification error." *Econometrica* 47 (1979): 153-62.

[24] Kleiner, Morris. "Intensity of Management Resistance: Understanding the Decline of Unionization in the Private Sector" *Journal of Labor Research*, Volume XXII, Number 3, Summer 2001.

[25] Kuhn, Peter, "Wages, Effort, and Incentive Compatibility in Life-Cycle Employment Contracts." *Journal of Labor Economics*, 4 (1986) 28-49.

[26] Lalonde, Robert J., G. Marschke, and K. Troske, "Using Longitudinal Data on Establishments to Analyze the Effects of Union Organizing Campaigns in the United States," *Annales D'Economie et de Statistique* 41/42 (1996) 155-185.

[27] Lee, David S. "The Electoral Advantage to Incumbency and Voters' Valuation of Politicians' Experience: A Regression Discontinuity Analysis of Close Elections" *Center for Labor Economics Working Paper #31*. UC Berkeley, April, 2001.

[28] Lee, David S. "Trimming for Bounds on Treatment Effects with Missing Outcomes" *Center for Labor Economics Working Paper #51*, UC Berkeley, March, 2002.

[29] Lewis, H. Gregg. *Unionism and relative wages in the United States*. University of Chicago Press, Chicago, 1963.

[30] Lewis, H. Gregg. *Union Relative Wage Effects: A Survey*. University of Chicago Press, Chicago, 1986.

[31] Macdonald, Ian and Robert M. Solow. "Wage bargaining and employment". *American Economic Review* 71:886–908, 1981.

[32] MaCurdy, Thomas and John Pencavel. "Testing the efficiency of employment contracts" *Journal of Political Economy* 94:S3–S39, 1986.

[33] McGuckin, Robert H., Sang V. Nguyen, and Arnold P. Reznek. "On Measuring the Impact of Ownership Change on Labor: Evidence from U.S. Food-Manufacturing Plant-Level Data." in *Labor Statistics Measurement Issues*, J. Haltiwanger, M. Manser, and R. Topel, eds. Chicago, Illinois: University of Chicago Press, 1998.

[34] Nickell, Steven, and Richard Layard, "Labor Market Institutions and Economic Performance," *Handbook of Labor Economics*, Vol. 3C, Orley Ashenfelter and David Card, ed. Elsevier Science, New York, 1999.

[35] Pivetz, Timothy R., Searson, Michael, and James R. Spletzer, "Measuring job and establishment flows with BLS Longitudinal Microdata," *Monthly Labor Review*, April 2001.

[36] Rosen, Sherwin. "Trade Union Power, Threat Effects and the Extent of Organization." *Review of Economic Studies* 36 (1969): 185-196.

[37] Ruback, Richard and Martin Zimmerman, "Unionization and Profitability: Evidence from the Capital Market," *Journal of Political Economy*, 92 (1984) 1134-57.

[38] Thistlethwaite, D., and D. Campbell. "Regression -Discontinuity Analysis: An alternative to the ex post facto experiment." *Journal of Educational Psychology* 51 (1960): 309-17.

[39] Van der Klaauw, Wilbert. "Estimating the Effect of Financial Aid Offers on College Enrollment: A Regression-Discontinuity Approach." *Unpublished manuscript* (1996).

Figure Ia: Probability of Establishment Survival by 2001, by Vote Share

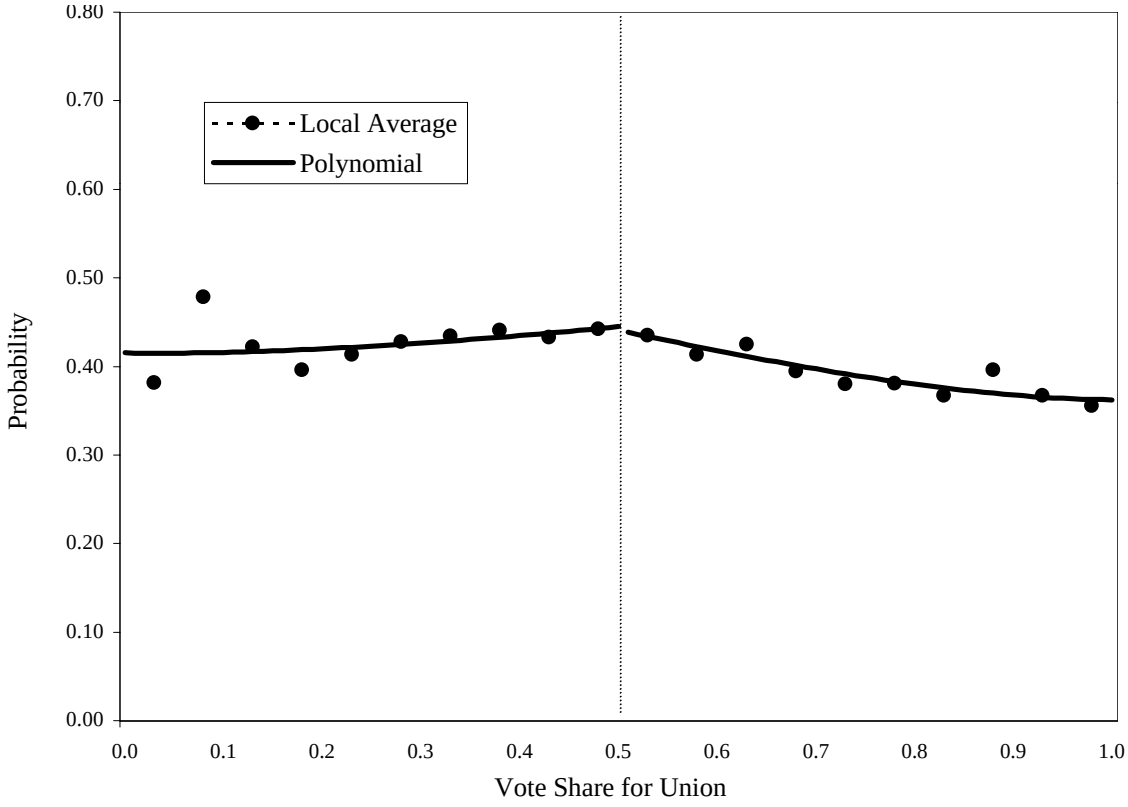


Figure Ib: Probability of Post-Election Union Presence, by Vote Share

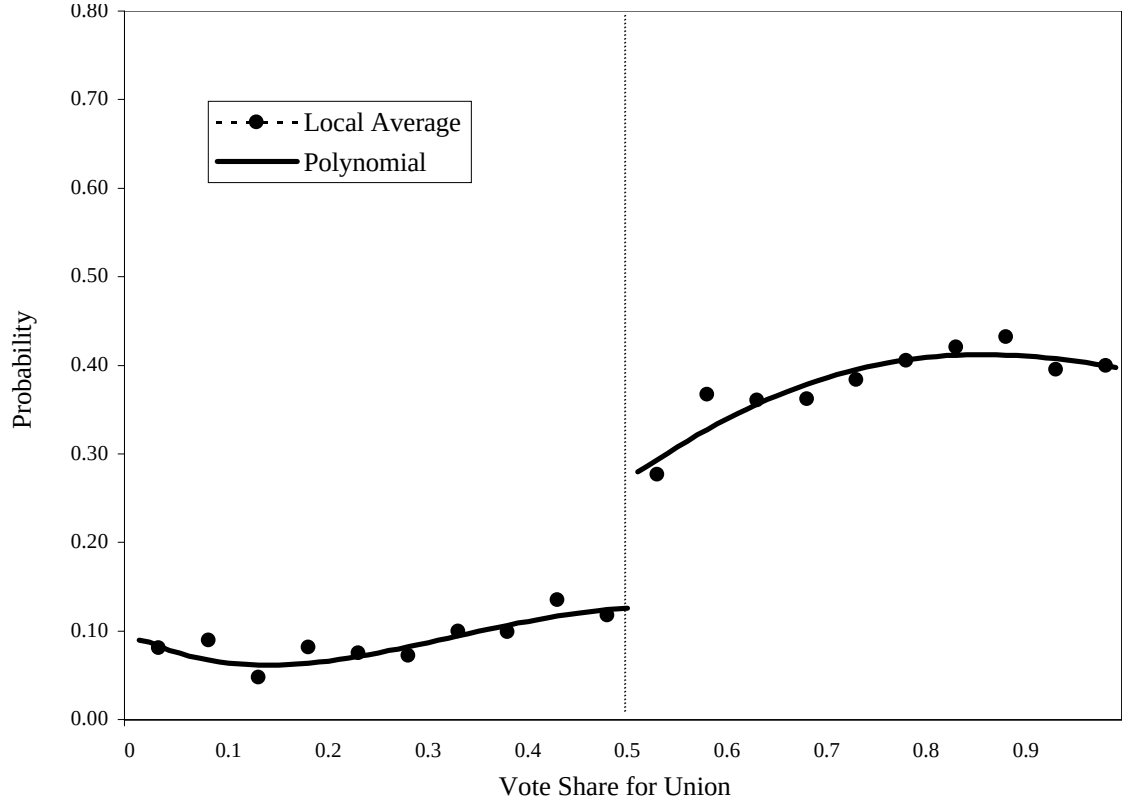


Figure Ic: Probability of Pre-Election Union Presence, by Vote Share

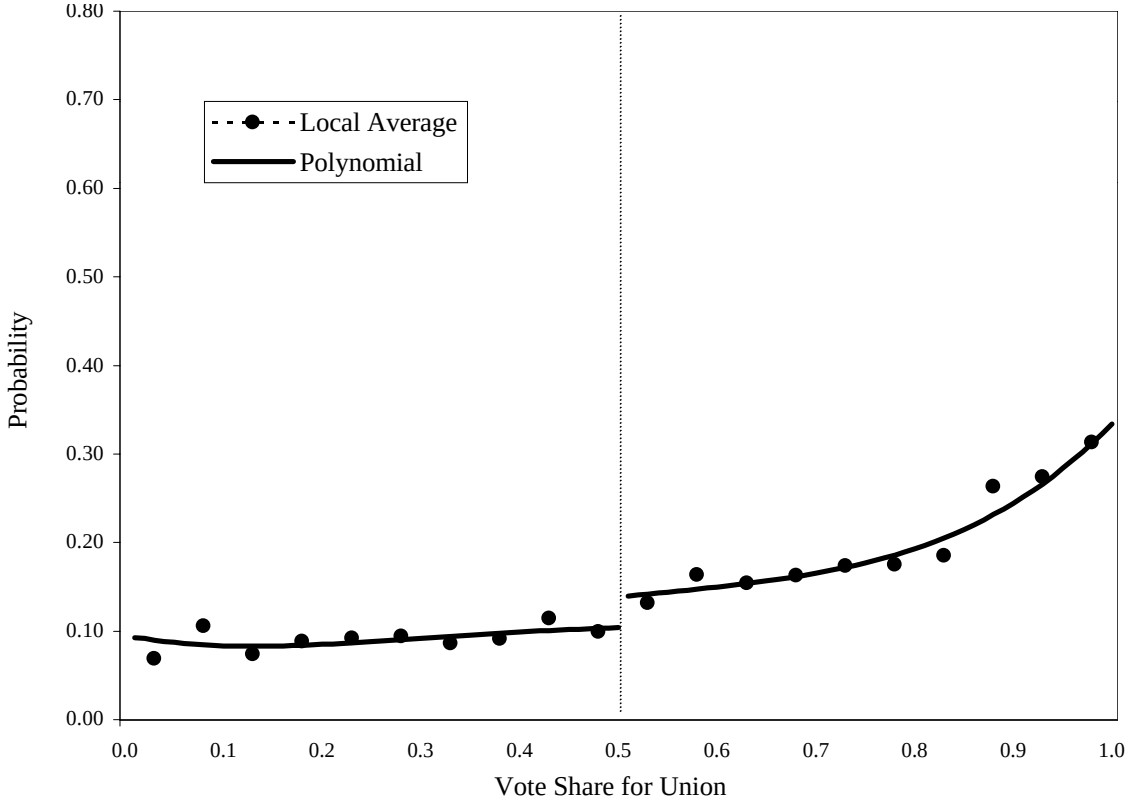


Figure IIa: Log of Total Votes Cast in NLRB Election, by Vote Share

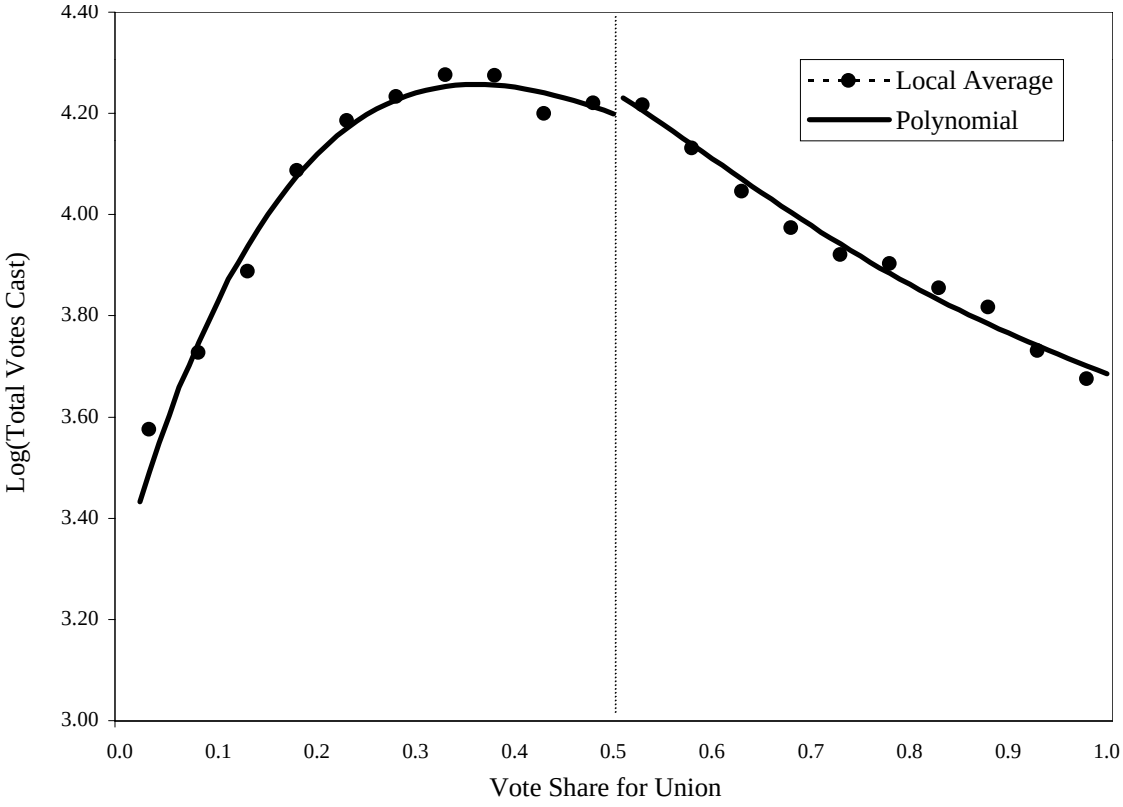


Figure IIb: Probability in Manufacturing (before Election), by Vote Share

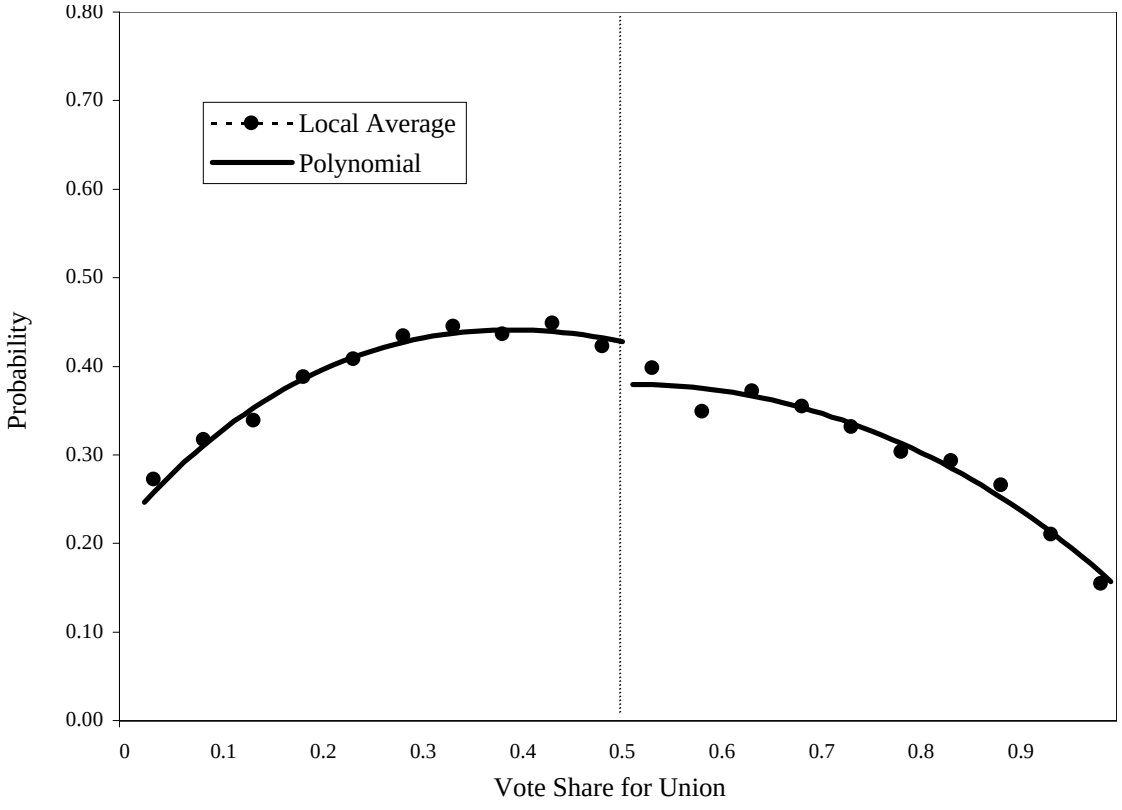
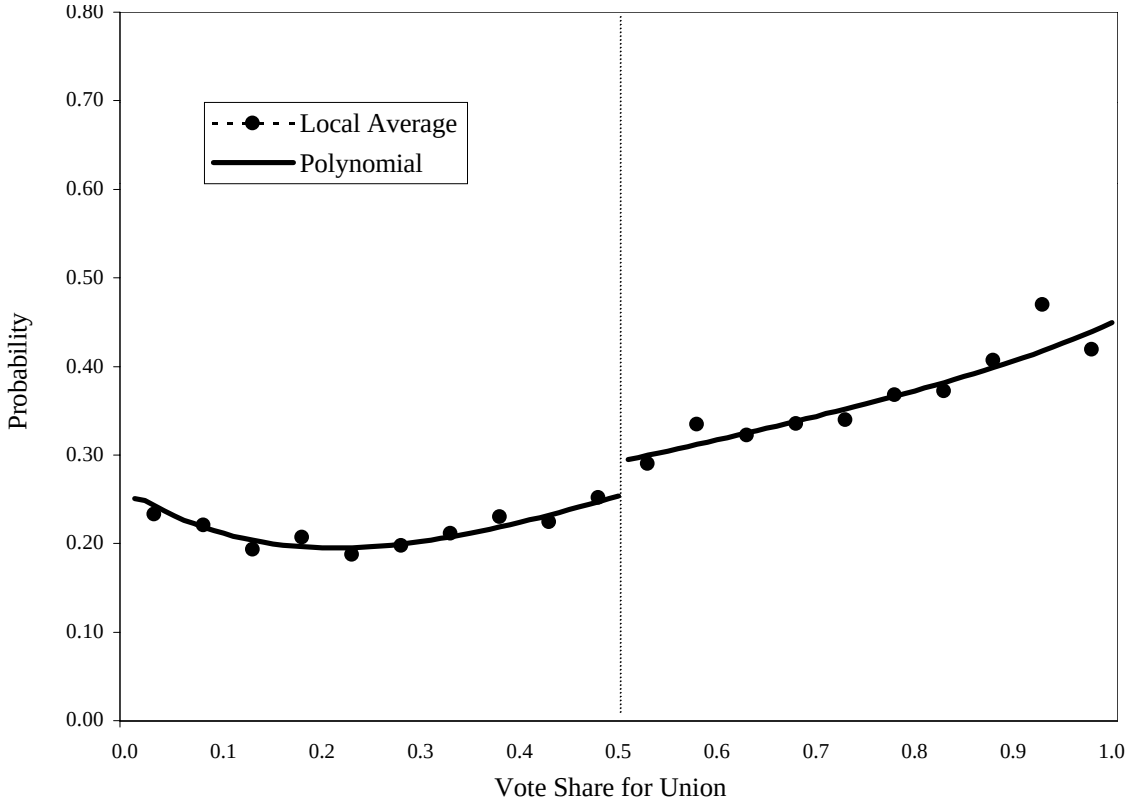


Figure IIc: Probability in Service Sector (before Election), by Vote Share



Appendix Figure I: Estimated Density of Union Vote Share

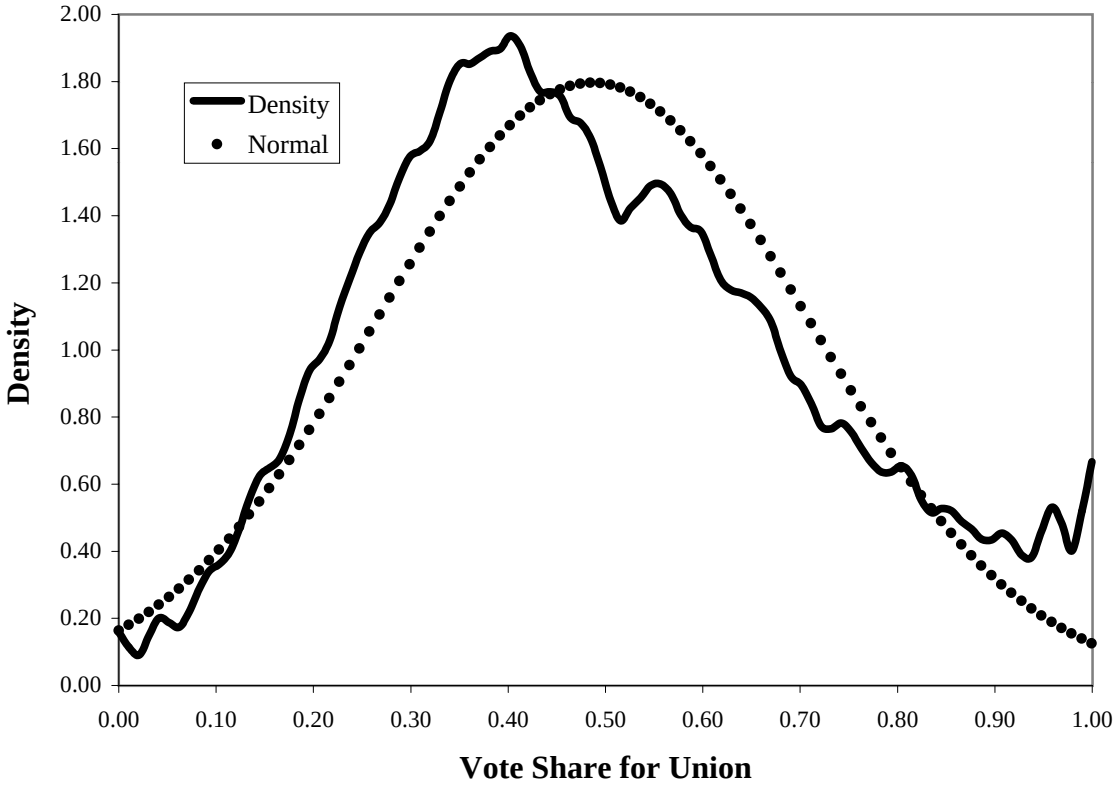


Table I: Establishment Outcomes (as of 2001) by Election Outcome: NLRB Elections 1983-1999

Year of	Proportion Survived as of 2001				Mean Employment as of 2001				Mean Log of Employment as of 2001			
Election	All	Loss	Win	Diff.	All	Loss	Win	Diff.	All	Loss	Win	Diff.
<=1983	0.304	0.318	0.280	-0.037	65.4	80.4	40.8	-39.5	4.35	4.55	3.99	-0.55
1984	0.277	0.294	0.255	-0.039	61.4	68.8	51.0	-17.8	4.38	4.48	4.22	-0.26
1985	0.312	0.336	0.276	-0.060	57.6	67.3	43.2	-24.1	4.35	4.39	4.27	-0.12
1986	0.309	0.333	0.275	-0.058	53.2	61.6	41.2	-20.4	4.33	4.39	4.21	-0.19
1987	0.327	0.348	0.302	-0.045	57.4	67.1	45.3	-21.9	4.39	4.51	4.22	-0.29
1988	0.360	0.372	0.343	-0.029	68.6	73.6	61.9	-11.7	4.43	4.56	4.25	-0.31
1989	0.372	0.380	0.361	-0.019	75.8	76.7	74.7	-1.9	4.40	4.52	4.24	-0.28
1990	0.393	0.395	0.390	-0.005	66.2	70.3	60.4	-9.9	4.25	4.39	4.06	-0.33
1991	0.411	0.429	0.385	-0.044	84.9	93.7	71.5	-22.3	4.37	4.46	4.23	-0.23
1992	0.432	0.450	0.409	-0.040	80.0	84.7	73.7	-11.0	4.40	4.45	4.32	-0.13
1993	0.416	0.429	0.401	-0.027	75.1	78.0	71.4	-6.5	4.37	4.50	4.18	-0.32
1994	0.465	0.458	0.474	0.016	105.4	102.5	109.3	6.7	4.53	4.61	4.43	-0.18
1995	0.509	0.521	0.491	-0.030	107.1	103.6	112.0	8.4	4.59	4.60	4.57	-0.02
1996	0.522	0.525	0.519	-0.007	107.5	105.5	110.0	4.5	4.47	4.48	4.45	-0.03
1997	0.572	0.613	0.521	-0.092	133.7	153.8	108.9	-44.8	4.57	4.67	4.41	-0.26
1998	0.572	0.578	0.565	-0.013	119.8	111.6	129.9	18.2	4.43	4.52	4.31	-0.21
1999	0.578	0.610	0.542	-0.068	115.5	134.0	94.7	-39.3	4.42	4.56	4.24	-0.32
All	0.417	0.430	0.400	-0.030	83.4	88.3	76.8	-11.5	4.42	4.51	4.30	-0.22
	(0.003)	(0.004)	(0.005)	(0.006)	(1.7)	(2.2)	(2.7)	(3.5)	(0.01)	(0.02)	(0.02)	(0.03)
Obs.	27622	15818	11804		26355	15104	11251		10265	6092	4173	

Note: Standard errors in parentheses. Entries are outcomes, as of 2001, of establishments that experienced an NLRB certification election in a given year. In the middle four columns, zero is assigned to the employment of "dead" establishments; 27622-26355=1267 establishments survived but did not report employment levels. "Loss" and "Win" indicates the outcome of the NLRB rerpresentation election. Details of the sample selection criteria are in the Data Appendix.

Table II: Means of Establishment and Election Outcomes and Characteristics, by Representation Election Outcome, 1983-1999

		N	Full Sample	Union Loss	Union Win	Difference
1	Survival (Indicator Variable), 2001	27622	0.417	0.430	0.400	-0.030
			(0.003)	(0.004)	(0.005)	(0.006)
2	Employment, 2001	26355	83.4	88.3	76.8	-11.5
			(1.7)	(2.2)	(2.7)	(3.5)
3	Log of Employment, 2001	10265	4.42	4.51	4.30	-0.22
			(0.01)	(0.02)	(0.02)	(0.03)
4	Sales Volume, 2001	25719	14225	16250	11501	-4750
			(321)	(454)	(441)	(633)
5	Log of Sales Volume, 2001	9629	9.34	9.48	9.14	-0.35
			(0.02)	(0.02)	(0.03)	(0.04)
6	Presence of Union Post-Election (Indicator Variable)	11532	0.206	0.097	0.363	0.266
			(0.004)	(0.004)	(0.007)	(0.005)
7	Presence of Union Pre-Election (Indicator Variable)	11532	0.129	0.095	0.179	0.084
			(0.003)	(0.004)	(0.006)	(0.005)
8	Number of Eligible Voters	27622	104.1	113.4	91.6	-21.8
			(0.8)	(1.2)	(1.1)	(1.6)
9	Log of Eligible Voters	27622	4.22	4.29	4.14	-0.15
			(0.01)	(0.01)	(0.01)	(0.01)
10	Number of Votes Cast	27622	91.7	101.9	78.0	-23.9
			(0.7)	(1.0)	(0.9)	(1.4)
11	Log of Votes Cast	27622	4.10	4.18	3.99	-0.19
			(0.01)	(0.01)	(0.01)	(0.01)
12	Manufacturing Sector (Indicator Variable)	27622	0.380	0.421	0.326	-0.094
			(0.003)	(0.004)	(0.004)	(0.006)
13	Service Sector (Indicator Variable)	27622	0.273	0.218	0.348	0.130
			(0.003)	(0.003)	(0.004)	(0.005)
14	Trucking Voting Unit (Indicator Variable)	27622	0.150	0.174	0.119	-0.055
			(0.002)	(0.003)	(0.003)	(0.004)
15	Log of State Employment, Election Year	27622	15.08	15.06	15.10	0.04
			(0.01)	(0.01)	(0.00)	(0.01)
16	Log of State Employment, 2000	27622	15.19	15.18	15.21	0.04
			(0.01)	(0.01)	(0.02)	(0.02)
17	Change In Log Emp. (2000 - Election Year)	27622	0.115	0.117	0.113	-0.005
			(0.001)	(0.001)	(0.008)	(0.008)
18	State Unemployment Rate, Election Year	27622	6.23	6.24	6.22	-0.02
			(0.01)	(0.02)	(0.02)	(0.02)
19	State Unemployment Rate, 2000	27622	4.14	4.11	4.17	0.06
			(0.01)	(0.01)	(0.01)	(0.01)
20	Change in UR (2000 - Election Year)	27622	-2.09	-2.13	-2.04	0.08
			(0.01)	(0.01)	(0.02)	(0.02)

Note: Standard errors in parentheses. Details of the merged data from the NLRB, FMCS, and InfoUSA are in the Data Appendix. Rows 2 and 4 impute 0 for non-surviving establishments (some data are missing for surviving esetablishments). Rows 6 and 7 contain only the establishments that survive to the year 2001. Presence of Union post-election (pre-election) indicates whether or not a union at the location of the establishment filed a contract expiration between the election date and 2001 (between the beginning of the FMCS data and the date of the election).

Table III: Establishment Survival, Union Presence, and Pre-determined Characteristics, by Vote Share for the Union

	Full Sample			0.25<= Vote Share <= 0.75			0.35<= Vote Share <= 0.65			0.45<= Vote Share <= 0.55		
	Loss	Won	Diff.	Loss	Won	Diff.	Loss	Won	Diff.	Loss	Won	Diff.
Survival, 2001	0.430	0.400	-0.030	0.436	0.413	-0.023	0.438	0.424	-0.014	0.442	0.435	-0.007
	(0.004)	(0.005)	(0.006)	(0.005)	(0.005)	(0.007)	(0.006)	(0.007)	(0.009)	(0.011)	(0.011)	(0.015)
Eligible Voters	113	92	-22	120	99	-21	118	106	-12	116	114	-2
	(1)	(1)	(2)	(1)	(1)	(2)	(2)	(2)	(3)	(3)	(3)	(5)
Log(Elig. Voters)	4.29	4.14	-0.15	4.34	4.20	-0.14	4.33	4.25	-0.08	4.31	4.32	0.00
	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)	(0.02)	(0.02)	(0.02)	(0.03)
Votes Cast	102	78	-24	108	87	-21	107	93	-13	105	102	-3
	(1)	(1)	(1)	(1)	(1)	(2)	(2)	(2)	(2)	(3)	(3)	(4)
Log(Votes Cast)	4.18	3.99	-0.19	4.24	4.08	-0.16	4.23	4.13	-0.10	4.22	4.22	0.00
	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)	(0.02)	(0.02)	(0.03)
Manufacturing	0.421	0.326	-0.094	0.437	0.363	-0.074	0.436	0.372	-0.064	0.422	0.397	-0.025
	(0.004)	(0.004)	(0.006)	(0.005)	(0.005)	(0.007)	(0.006)	(0.006)	(0.009)	(0.010)	(0.011)	(0.015)
Service Sector	0.218	0.348	0.130	0.223	0.322	0.099	0.234	0.315	0.081	0.251	0.290	0.038
	(0.003)	(0.004)	(0.005)	(0.004)	(0.005)	(0.006)	(0.005)	(0.006)	(0.008)	(0.009)	(0.010)	(0.014)
Trucking	0.174	0.119	-0.055	0.162	0.128	-0.034	0.148	0.125	-0.023	0.135	0.124	-0.011
	(0.003)	(0.003)	(0.004)	(0.003)	(0.004)	(0.005)	(0.004)	(0.004)	(0.006)	(0.007)	(0.008)	(0.010)
Number of Obs.	15818	11804		11851	8112		7351	5557		2217	1923	
Union Present Post-Election	0.097	0.363	0.266	0.105	0.344	0.239	0.117	0.332	0.216	0.117	0.276	0.159
	(0.004)	(0.007)	(0.007)	(0.004)	(0.008)	(0.008)	(0.006)	(0.010)	(0.011)	(0.010)	(0.015)	(0.018)
Union Present Pre-Election	0.095	0.179	0.084	0.097	0.155	0.058	0.101	0.149	0.048	0.099	0.132	0.033
	(0.004)	(0.006)	(0.006)	(0.004)	(0.006)	(0.007)	(0.005)	(0.007)	(0.009)	(0.010)	(0.012)	(0.015)
Number of Obs.	6806	4726		5163	3350		3222	2358		980	836	

Note: Standard errors in parentheses. Entries are means and differences by election outcome, in the full and, three separate sub-samples, by election vote share. Upper panel includes establishments, whether or not they survive as of the year 2001, and the lower panel includes only those establishments that survive as of the year 2001."Union Present post-election" (pre-election) indicates whether or not a union at the location of the establishment filed a contract expiration between the election date and 2001 (between the beginning of the FMCS data and the date of the election). Details of data set construction in the Data Appendix.

Table IV: Reduced Form Specification: Effect of Union Victory on Probability of Survival (2001), and Post-Election Presence of Union

	(1)	(2)	(3)	(4)	(5)	(6)	(7)
Probability of Survival							
Union Victory	-0.007	-0.006	-0.003	-0.004	-0.008	-0.008	-0.007
	(0.014)	(0.014)	(0.014)	(0.013)	(0.014)	(0.013)	(0.013)
Presence of Union	---	---	---	---	0.094	0.093	---
(Pre-Election)	---	---	---	---	(0.010)	(0.010)	---
Log(Eligible Vote)	---	---	---	---	0.022	0.012	---
	---	---	---	---	(0.004)	(0.004)	---
Year Dummies	No	Yes	Yes	Yes	Yes	Yes	---
State Dummies	No	No	Yes	Yes	Yes	Yes	---
Industry Dummies	No	No	No	Yes	No	Yes	---
Unit Dummies	No	No	No	Yes	No	Yes	---
Probability of Post-Election Union Present							
Union Victory	0.152	0.150	0.143	0.145	0.131	0.135	0.132
	(0.017)	(0.017)	(0.017)	(0.017)	(0.016)	(0.016)	(0.016)
Presence of Union	---	---	---	---	0.401	0.394	---
(Pre-Election)	---	---	---	---	(0.013)	(0.013)	---
Log(Eligible Vote)	---	---	---	---	0.015	0.006	---
	---	---	---	---	(0.004)	(0.004)	---
Year Dummies	No	Yes	Yes	Yes	Yes	Yes	---
State Dummies	No	No	Yes	Yes	Yes	Yes	---
Industry Dummies	No	No	No	Yes	No	Yes	---
Unit Dummies	No	No	No	Yes	No	Yes	---

Note: N=27622 for upper panel, N=11532 (includes only those establishments that survive by 2001) for lower panel. Robust standard errors in parentheses. Upper panel refers to survival, as of 2001, as the dependent variable; lower panel refers to the observation of a contract expiration after the election. All specifications are least squares regressions, for the upper (lower) panel include a 4th order polynomial in the vote share, a dummy variable for win/loss and the dummy variable interacted with the linear term in the vote share. Column (7) regresses the residuals - from an initial regresssion of survival (presence of union) on all the covariates - on a 4th order polynomial in the vote share, a dummy variable for win/loss and the dummy variable interacted with the linear term in the vote share. Details of the data set in the Data Appendix.

Table V: Reduced-Form Results: Impact of Certification on Establishment Outcomes, Overall, and by Year of Election, Industry, and Voting Unit Size

Dependent Variable	Survival	Survival (2)	Empl.	Log(Empl.)	Sales	Log(Sales)
Mean	0.417	0.643	83	4.42	14225	9.34
(Std. Dev)	(0.493)	(0.479)	-276	-1.46	-51542	-1.67
Overall Effect	-0.008	0.012	0	-0.07	250	-0.03
	(0.013)	(0.013)	(8)	(0.06)	(1470)	(0.07)
Year: before 1988	-0.022	0.009	-17	-0.18	-326	-0.10
(Main)	(0.020)	(0.021)	(10)	(0.11)	(1889)	(0.12)
Year: 1988-1991	0.001	0.003	13	0.17	-777	0.10
(Interaction)	(0.028)	(0.028)	(14)	(0.15)	(2708)	(0.16)
Year: 1992-1995	0.034	0.013	26	-0.02	2065	-0.02
(Interaction)	(0.029)	(0.029)	(16)	(0.14)	(3013)	(0.16)
Year: after 1995	0.022	0.003	34	0.25	1536	0.17
(Interaction)	(0.029)	(0.028)	(17)	(0.14)	(3349)	(0.15)
Other Industry	-0.009	0.018	-2	0.06	1641	0.06
(Main)	(0.021)	(0.020)	(9)	(0.09)	(2087)	(0.12)
Manufacturing	0.002	-0.013	2	-0.24	-3887	-0.24
(Interaction)	(0.025)	(0.024)	(12)	(0.10)	(2857)	(0.13)
Service	-0.016	-0.004	3	-0.07	917	0.04
(Interaction)	(0.027)	(0.026)	(17)	(0.14)	(2551)	(0.16)
El. Vote: < 40	0.005	0.023	-5	-0.11	2308	0.00
	(0.022)	(0.021)	(10)	(0.09)	(1861)	(0.12)
El. Vote: 40-100	-0.032	-0.005	-4	0.02	-1223	-0.03
	(0.026)	(0.025)	(11)	(0.11)	(2040)	(0.13)
El. Vote: > 100	-0.008	-0.028	30	0.06	-4318	-0.09
	(0.028)	(0.027)	(18)	(0.13)	(3476)	(0.16)
Number of Obs.	27622	27622	26355	10265	25719	9629

Note: Standard Deviations in first row, robust standard errors otherwise. Survival(2) denotes whether any establishment was present at the exact street address as of 2001, third and fifth columns assign "0" to the "dead" establishments. Estimated Annual Sales Volume is in thousands of dollars. Specifications: Base specification is Column (6) of Table IV. See text for details on interaction specifications. See Data Appendix for details on data set construction

Appendix Table I: Summary Statistics for Merged NLRB-FMCS-InfoUSA data, full sample and sample for estimation

	All Certification Elections			Sample for Estimation		
Variable	Obs.	Mean	Std. Dev.	Obs.	Mean	Std. Dev.
Survival (Indicator Variable), 2001	51132	0.394	0.489	27622	0.417	0.493
Survival (2) (Indicator Variable), 2001	51132	0.623	0.485	27622	0.643	0.479
Employment, 2001	48836	66	290	26355	83	276
Log of Employemt, 2001	17863	4.02	1.54	10265	4.42	1.46
Sales Volume, 2001	29367	28603	103667	16349	32865	74884
Log of Sales Volume, 2001	29367	8.68	1.83	16349	8.99	1.84
Union Present, Post-Election	51132	0.184	0.388	27622	0.175	0.380
Union Present, Pre-Election	51132	0.117	0.321	27622	0.102	0.303
Eligible Voters	51132	63	111	27622	104	135
Log(Elig. Voters)	51132	3.33	1.25	27622	4.22	0.83
Votes Cast	51132	55	98	27622	92	119
Log(Votes Cast)	51083	3.20	1.25	27622	4.10	0.82
Manufacturing	51132	0.306	0.461	27622	0.380	0.485
Service Sector	51132	0.260	0.439	27622	0.273	0.446
Trucking	51132	0.177	0.382	27622	0.150	0.357
Log(State Emp.), Year of Election	50284	15.08	0.87	27622	15.08	0.85
Log(State Emp.), Year 2000	50284	15.19	0.87	27622	15.19	0.85
Change in Log(Emp.)	50284	0.115	0.097	27622	0.115	0.096
State UR, Year of Election	50284	6.2	1.8	27622	6.2	1.8
State UR, Year 2000	50284	4.2	0.9	27622	4.1	0.8
Change in UR	50284	-2.1	1.7	27622	-2.1	1.7

Note: Sample restriction is that the number of votes cast be greater than or equal to 20, and the establishment is within the 50 U.S. states and District of Columbia. Details of data set construction in Data Appendix

Appendix Table II: NLRB Elections: Win rates and Average Union Vote Share, 1983 - 1999

Year of Election	Obs.	Winning Percentage	Vote Share for Union	
			Mean	Std Dev.
<=1983	721	0.376	0.463	0.199
1984	1802	0.416	0.474	0.220
1985	1810	0.403	0.471	0.217
1986	1793	0.408	0.476	0.222
1987	1768	0.445	0.494	0.229
1988	1809	0.425	0.493	0.227
1989	1890	0.442	0.496	0.229
1990	1846	0.413	0.488	0.224
1991	1648	0.397	0.474	0.221
1992	1446	0.431	0.488	0.223
1993	1710	0.447	0.499	0.222
1994	1625	0.431	0.485	0.226
1995	1508	0.417	0.477	0.215
1996	1629	0.427	0.487	0.218
1997	1760	0.445	0.492	0.222
1998	1741	0.455	0.505	0.218
1999	1116	0.470	0.511	0.226
All	27622	0.427	0.487	0.222

Note: Restricted sample of elections with 20 or more valid votes cast. See Appendix Table I.

Appendix Table III: Union Presence, Pre-determined Characteristics for Surviving Establishments, by Vote Share for the Union

	Full Sample			0.25<= Vote Share <= 0.75			0.35<= Vote Share <= 0.65			0.45<= Vote Share <= 0.55		
	Loss	Won	Diff.	Loss	Won	Diff.	Loss	Won	Diff.	Loss	Won	Diff.
Union Present Post-Election	0.097	0.371	0.274	0.103	0.350	0.247	0.116	0.338	0.222	0.120	0.275	0.155
	(0.004)	(0.007)	(0.008)	(0.004)	(0.009)	(0.009)	(0.006)	(0.010)	(0.011)	(0.011)	(0.016)	(0.019)
Union Present Pre-Election	0.092	0.180	0.087	0.095	0.152	0.058	0.101	0.145	0.044	0.102	0.126	0.024
	(0.004)	(0.006)	(0.007)	(0.004)	(0.007)	(0.008)	(0.006)	(0.008)	(0.009)	(0.010)	(0.012)	(0.016)
Eligible Voters	120	99	-21	125	107	-18	124	114	-10	123	126	3
	(2)	(2)	(3)	(2)	(3)	(4)	(3)	(3)	(5)	(6)	(6)	(8)
Log(Elig. Voters)	4.33	4.18	-0.15	4.37	4.24	-0.13	4.35	4.29	-0.07	4.35	4.38	0.03
	(0.011)	(0.013)	(0.017)	(0.013)	(0.015)	(0.020)	(0.017)	(0.019)	(0.025)	(0.029)	(0.032)	(0.044)
Votes Cast	108	85	-23	113	94	-19	112	101	-11	110	113	3
	(2)	(2)	(3)	(2)	(2)	(3)	(3)	(3)	(4)	(5)	(5)	(7)
Log(Votes Cast)	4.22	4.04	-0.19	4.27	4.13	-0.15	4.26	4.18	-0.08	4.25	4.28	0.03
	(0.011)	(0.012)	(0.017)	(0.013)	(0.015)	(0.020)	(0.016)	(0.018)	(0.025)	(0.029)	(0.032)	(0.043)
Manufacturing	0.450	0.335	-0.115	0.464	0.373	-0.091	0.456	0.380	-0.075	0.420	0.403	-0.017
	(0.006)	(0.007)	(0.010)	(0.007)	(0.009)	(0.012)	(0.009)	(0.011)	(0.014)	(0.017)	(0.018)	(0.025)
Service Sector	0.234	0.380	0.147	0.243	0.352	0.109	0.259	0.339	0.079	0.277	0.310	0.033
	(0.005)	(0.008)	(0.009)	(0.006)	(0.009)	(0.011)	(0.008)	(0.010)	(0.013)	(0.015)	(0.017)	(0.023)
Trucking	0.168	0.112	-0.055	0.157	0.123	-0.034	0.146	0.120	-0.025	0.131	0.118	-0.013
	(0.005)	(0.005)	(0.007)	(0.005)	(0.006)	(0.008)	(0.007)	(0.007)	(0.010)	(0.011)	(0.012)	(0.016)
Number of Obs.	6092	4173		4630	2949		2876	2079		886	739	

Note: Standard errors in parentheses. Entries are means and differences by election outcome, in the full and, three separate sub-samples, by election vote share. Observations include only those establishments that survive as of the year 2001, and have nonmissing employment."Union Present post-election" (pre-election) indicates whether or not a union at the location of the establishment filed a contract expiration between the election date and 2001 (between the beginning of the FMCS data and the date of the election). Details of data set construction in the Data Appendix.

Tab 73

MEMBER LOGIN



News

MANITOBA'S OUTDATED LABOUR LAWS

Posted on August 2, 2016 (September 27, 2018) by admin

winnipegfreepresslogo2

Manitoba's outdated labour laws

By: Darrel Reid

August 2, 2016

Rewind to 1960s Manitoba when the rotary phone was gaining in popularity, the minimum wage was about 75 cents an hour and the first cable TV was hooked up.

This was the era in which the practice of project labour agreements (PLAs) gained a foothold. Manitoba was building hydro dams and wanted to make sure it had a steady, stable source of skilled workers to draw from, especially in remote regions.

Back then, this monopoly was granted in exchange for labour peace. While a lot has happened in the half-century since then, Manitoba's antiquated labour laws have stayed pretty much the same.

Finally, that is about to change.

"We want more Manitoba companies to participate in our bidding process," PC Leader Brian Pallister declared during his election campaign. "The better the participation, the better value for money."

Premier Pallister believes levelling the playing field could save taxpayers as much as $12 million by increasing competition that makes tax dollars go further on infrastructure projects and encourages investment and job growth.

It's refreshing to hear fairness and value for hardworking taxpayers are the principles that should be guiding public policy in

Manitoba. For too long, that's not how it's been.

For example, under the PLA in 2004, all workers were advised they had to pay union dues if they wanted to work on the Red River Floodway expansion project.

The same currently applies to Manitoba Hydro.

MEMBER LOGIN

In order to work on any one of a number of large-scale hydroelectric projects, workers have to pay union dues, like it or not. This policy has even forced unionized employees to switch unions. The PLA for the Bipole lll Transmission Line and Keeyask Generating Station required all workers to belong to a select union. It's a monopoly that all too often leads to cost overruns and delays on many large-scale public infrastructure projects.

As the new Manitoba government begins to revamp lopsided labour laws, the Lake Manitoba flood control channel seems a practical place to start. Described as a top priority during his campaign, Pallister vowed if elected his party would do what it takes to build the $495-million project in five years. This is an opportunity for the new government to save millions in flood claims and reduce construction costs by openly tendering the project to all who qualify to work on it, not just those who carry the right union card.

Although traditionalist union members beg to differ, it's hard to argue that ending forced unionization is anything but the right thing to do.

Opening government tendering to all experienced companies and workers whether they have a craft union or alternative union affiliation, or otherwise, is fair and democratic.

When there's fair competition, workers, employers and taxpayers all benefit. Besides, there are far more skilled workers employed by alternative union and non-union contractors than there were in the 1960s, which is why the rationale for PLAs simply no longer applies.

Restoring workers' rights and allowing a tendering process that's fair, open and competitive in Manitoba, would be a welcome change that's long overdue.

———

Darrel Reid is the vice-president of policy and advocacy at the Progressive Contractors Association of Canada.

See also PCA's letter to the editor on this topic in the Winnipeg Sun here.

Recent Posts

PCA and CLAC Campaign Shows Where Parties Stand on Workers' Rights

PCA Announces New Director of Public Affairs in Ontario

[Manitoba] Guidance Procedures Following COVID-19 Diagnosis

PCA Launches "Opportunity Knocks" Campaign

B.C.'s Transportation and Infrastructure Minister Crossed the Line in Imposing CBA

Search ... Search

Tab 74

Project Briefing

No 42 • July 2010

The economic impact of competition

Karen Ellis and Rohit Singh

Key points

- Competitive markets deliver better market outcomes, but competition can be constrained by government policy and anti-competitive business practices, with economic costs
- Governments should assess and factor in the likely impact of their policy decisions on competition
- Competition authorities can play an important role in advocating for pro-competition reforms, investigating anti-competitive practices, and building a stronger competition culture and evidence base

Overseas Development Institute

ODI is the UK's leading independent think tank on international development and humanitarian issues.

ODI Project Briefings provide a focused and specialised summary of a project, a country study or regional analysis.

This and other ODI Project Briefings are available from www.odi.org.uk

How do government policies and business practices affect the degree of competition in a given market? How does competition, in turn, affect market outcomes, such as prices, innovation and access to services?

With funding from the UK Department for International Development, ODI has compared economic performance in four product markets – sugar, cement, beer and mobile phone services – across Bangladesh, Ghana, Kenya, Viet Nam and Zambia. These countries have very different policy frameworks and competition climates, and the study shows this has a significant impact on competition, market outcomes, and economic performance in the different countries. Here we look at the findings for each product market in turn, then discuss broader conclusions on the role of competition.

The sugar market

Sugar is an important agricultural product in many countries, and part of the staple diet in most, as well as being a source of rural livelihoods. As a result, the state is heavily involved in the sugar industry in some countries, including Bangladesh, Kenya and Viet Nam. In all three countries, however, the state-led sugar industries exhibit low productivity and poor performance, and the use of obsolete technology and inefficient farming methods mean poor cane yields and sugar outputs. All three are struggling to compete and survive in the face of competition from sugar that is either privately produced or imported. They need substantial levels of costly government subsidisation, which is unlikely to be sustainable in the long run, thus jeopardising many livelihoods.

In stark contrast, Zambia, which has a private sector-led sugar industry, produces the highest amounts of sugar per hectare of the five countries, (three times higher than Viet Nam which is the next most efficient country). This very profitable, internationally competitive industry is expanding to take advantage of new export opportunities, and has the potential to create new jobs and growth. This suggests that private sector incentives and management expertise are important for creating a successful, efficient and internationally competitive sugar industry.

Significant reform is needed to achieve a healthier sugar sector in Bangladesh, Kenya and Viet Nam but this could put some of the existing sugar mills out of business. Localised interests would make this deeply unpopular politically, and therefore hard to achieve, despite being in the best interests of the country as a whole. This demonstrates the importance of mobilising interest groups that stand to gain from reform, such as consumer groups and the business community, to offset vested interests opposed to change.

Despite Zambia's success in creating a growing, private sector-led industry, it still has very high domestic sugar prices when compared to other countries – well above the price that Zambian sugar sells for on international markets. This is the result, at least in part, of the monopolistic market structure of the industry within Zambia, where one firm wields significant market power and is protected from external competition by barriers to imports. The Zambian Competition Commission has investigated this, but has been unable to tackle the problem effectively so far, perhaps because the government may have vested interests in the industry's profitability.

Ghana also used to have a state-led sugar industry, but it collapsed in the early 1980s as a result of low productivity and poor performance. The country now imports all its sugar, and there are allegations of a cartel amongst sugar importers. These allegations are unsubstantiated, however, and cannot be properly investigated as there is no competition authority in Ghana.

The Ghanaian Government faces a dilemma as there are two potential new entrants into the sugar industry, which could generate jobs and revenue. However, these new entrants are requesting protection from sugar imports, which could increase domestic prices and undermine the competitiveness of Ghanaian-produced sugar in future. This demonstrates the possible trade-off between attracting new investment by promising protection, and promoting a market environment that will create the right incentives to ensure a good economic performance.

The cement market

The price and availability of cement matters. Cement is vital for construction and infrastructure development, which in turn underpin growth, industrialisation and private sector development, and also represent a significant proportion of government spending.

The cement sector is often highly concentrated because of its cost structure and the need for large scale production if the industry is to be efficient. As a result, the market often suffers from limited competition and has been a source of concern for competition authorities across the world. In addition, the cement sector is often dominated by multinational firms, which operate on a regional basis, often ensuring monopoly profits by agreeing not to compete with each other in the same countries. This challenge to cross border competition could be tackled through regional competition authorities, or through wider policy coordination.

The study identified a range of potential competition problems in Ghana, Kenya and Zambia:

- issues of joint ownership amongst the three Kenyan cement firms, which the Kenyan competition authority has been monitoring – the authority has been active in preventing further consolidation
- allegations about supply constraints by the monopolist cement firm in Zambia during a cement shortage which were investigated by the Zambian Competition Commission
- price hikes in Ghana, with allegations that this was due to the market dominance and price leadership of one of the two players in the market, though the absence of a competition authority in Ghana means this has not been investigated.

In comparison, there seems to be a much greater degree of both price and non-price competition in Bangladesh and Viet Nam, which have cement industries that are less highly concentrated with many different market players. The two Asian nations enjoy the lowest prices of the five countries, and significant non-price competition, with cement firms trying to attract customers by offering credit, technical support and various promotions. It seems that even though there is a high minimum efficient scale of production in cement which suggests having fewer firms is more efficient, the competitive stimulus of having many players in the market generates stronger incentives for reduced prices and efficient production.

The price of cement in Zambia has fallen by almost 10% since 2008, coinciding with the entry of a new market player in 2009 to compete with the incumbent monopoly. This happened at a time when cement prices rose in the other four countries, showing that the introduction of competition can have a significant and immediate impact on prices.

The beer market

Beer is consumed throughout much of the developing world, including by the poor. The market is usually highly concentrated, as a result of its cost structure and the importance of marketing and brand loyalty, which represent barriers to entry. It is, therefore, another industry that is plagued by anti-competitive practices in many countries, and, ideally, it needs monitoring by a competition authority.

Like the cement industry, beer prices are highest in Zambia, with its concentrated market and monopoly beer producer, and lowest in the least concentrated market (Viet Nam, with seven beer producers), and non-price competition also seems strongest in the least concentrated markets: nevertheless, competition problems abound:

- Many anti-competitive practices were identified in Kenya, including territorial allocation, exclusive dealership and price fixing. A price war had been followed by a regional carve-up, with two producers agreeing to avoid competing in Kenya and Tanzania, and to instead share in each other's monopoly profits in the other country, by buying shares in each other.
- In Zambia the competition authority has imposed conditions on the monopoly beer producer, to prevent abuse of its dominant position. They have also identified various barriers to entry, and have investigated issues relating to resale price maintenance and exclusive dealership.
- There have been allegations of price leadership in Ghana, although its two beer firms seem to compete quite fiercely and its beer prices are considerably lower than in Kenya and Zambia, which have monopolies.
- There have also been allegations of exclusive dealing and the abuse of dominance by beer players in Viet Nam, including a case where a new entrant was driven out allegedly as the result of exclusive dealing arrangements that prevented the effective distribution of their product.

The mobile telephony market

Substantial evidence now exists of the development benefits of mobile telephony. These include: improved connectivity that has enabled countries to leapfrog the need to develop fixed line infrastructure, providing connectivity to many people for

the first time; its role in reducing transaction costs for both households and enterprises; facilitating job creation and private sector development; and enhancing access to financial services.

The mobile phone market is relatively young, and evolving fast. Regulation is important for competition in this area, and regulators are grappling with how best to handle this fast changing market.

The analysis of the introduction of competition in the mobiles market in each case study country finds that competition drives rollout of services, increased market penetration, and falling prices. A competitive environment strengthens incentives to design services to meet the needs of customers, including price and product promotions for poor customers, and value added services with additional development benefits, such as money transfer services.

Until recently, Kenya has had a relatively concentrated market compared to the other four countries, and prices were relatively high. However, competition in the market increased through the entry of two new players in 2008/09, and since then tariffs have fallen by as much 50%.

Zambia has the lowest mobile penetration rate and highest tariffs of the five countries. The market is performing relatively poorly, at least in part because of a lack of competitive neutrality in relation to the government monopoly that controls the international gateway. The government charges high tariffs to private operators to access the gateway, which means that private operators have to subsidise their international calls to be price competitive with the state firm.

In Ghana there appears to be intense competition between the operators. The country has good mobile penetration and relatively low prices, and an effective regulator that has facilitated a competitive market. There has been good regulation of interconnection and the liberalisation of the international gateway, as well as an effective form of a universal access fund. The lack of these elements has slowed down market development in other countries.

The Vietnamese mobiles market is heavily dominated by state owned enterprises, but the operators do appear to compete fiercely with each other, and the sector is performing fairly well.

Bangladesh has a relatively competitive mobiles market and the lowest tariffs across the five countries. There are some regulatory concerns, however, such as a regulated price floor, which is not in line with international best practice, and has been set at less than the regulated termination charge. This puts smaller mobile operators and new entrants at a disadvantage and highlights the importance of considering potential competition impacts when taking regulatory decisions.

Overall conclusions

The study has shown that markets characterised by more competition, with more players, more dynamic entry and exit, and more intense rivalry for customers (e.g. through price promotions, special offers, and marketing campaigns etc.) tend to deliver better market outcomes. These outcomes include lower prices and better access to services for consumers, including other businesses that rely on these products as inputs for their own enterprises. It is also important to ensure that domestic production is internationally competitive, and can, therefore, generate increased exports, foreign exchange, jobs and industrial growth. The introduction of competition – or indeed even the prospect of increased competition – can have a significant and immediate impact on prices.

However, the research has also shown that competition is often constrained, for various reasons. Problems such as market dominance and anti-competitive practices are very common in some markets, and competition authorities have an important role to play in monitoring, publicising and tackling such behaviour.

It is also clear, however, that the role of the state is very important in determining competition and market outcomes – perhaps more important than the behaviour of business itself. The influence of the state can take various forms: regulation; state ownership and privatisation; price controls or subsidisation; other policy mechanisms such as import protection or industrial policy; or corrupt business deals and ownership by individual politicians or their families.

Sometimes the involvement of government is self-serving, while at other times it is essentially benevolent in nature. In some countries and markets, there is a close relationship between business and government, as government actors seek to share in some way in the profits of businesses, (e.g. through ownership or taxation etc.). This gives government an incentive to protect those businesses from competition. In these situations the relationship between business and government seems in practice to determine commercial success more than market competition, and competition authorities may face political barriers to addressing competition problems.

This kind of relationship between government and big business creates a powerful economic elite, with vested interests in opposing pro-competition, pro-growth reforms. One way to tackle vested interests who oppose reform, is to establish and facilitate coordination amongst other interest groups who stand to gain from reform. This includes household and industrial consumers and potential new entrants to the market. Competition authorities can build the evidence base, which can be used to help mobilise such interest groups to lobby for reform. Thus, where political difficulties and resourcing and capacity constraints make legal enforcement problematic for competition authorities in developing countries, they can still play a valuable role in promoting competition through advocacy and evidence building, and engagement with other government

agencies to ensure that policy is pro-competitive.

In sum, competition improves the performance of markets, generating better outcomes including lower prices, greater productivity and competitiveness leading to industrial growth and jobs, and better access to services. It can undermine the dominance of a few powerful players, allowing new enterprises to gain a foothold in the market, and underpinning private sector development and employment creation.

Appropriate policies are crucial to create the conditions within which competition can thrive, and competition authorities can help to build a culture of competition, and increase awareness of competition issues amongst policy-makers and the public.

Policy recommendations

- Government policies should create competitive market conditions. This means assessing and factoring in the competition impacts of a wide set of policies, including trade policy, industrial policy, privatisation, regulation, state ownership, subsidisation and investment promotion. Competition authorities can help by raising concerns when government policy may have negative competition impacts.
- Regulatory bodies should take into account the competition impacts of regulation to avoid undermining the market and weakening economic performance. One way to achieve this is to implement a process for regulatory impact assessment to examine the competition implications of such issues as regulation of tariffs and interconnection, infrastructure sharing, and the implementation of a universal access fund.
- Governments should consider establishing competition laws and competition authorities, which can investigate anticompetitive practices, build a stronger competition culture, and advocate for pro-competition reforms.
- Competition authorities can help to build the evidence base on competition problems and associated costs, and publicise the findings that will inform and mobilise interest groups to lobby in favour of reform, in order to offset vested interests opposed to change. These interest groups may include household and industrial consumers and potential new entrants to the market.
- Tools such as DFID's Competition Assessment Framework can be used to guide competition analysis and help build capacity and understanding of competition issues in developing countries.
- The poor performance of the state-led sugar industries in Bangladesh, Kenya and Viet Nam, as compared with the successful, internationally competitive, private sector-led sugar industry in Zambia, demonstrates the superior performance that can be achieved through private management incentives. Steps to a healthier sugar sector in these countries would include the establishment of efficient new entrants, a reduction of state intervention in the sector, an end to bail-outs, a reduction in trade protection, and an acceptance that some of the existing sugar mills will go out of business. Social safety nets and retraining programmes might help to make such reform more politically acceptable.
- Competitive neutrality between state and private sector players can help to ensure a competitive market outcome. This is likely to become an increasingly important issue in Viet Nam, which is still heavily dominated by state players, as reform continues, but is also an issue elsewhere e.g. in relation to the Zambian mobile telephony market.
- A reduction of import tariffs can help to stimulate competition where there is limited domestic competition.
- Regional competition authorities and regional cooperation are needed to tackle competition problems caused by multinational companies, who sometimes seek to minimise competition by taking a strategic approach to cross-border production decisions.

Written by Karen Ellis, Head of ODI's Business and Development programme (k.ellis@odi.org.uk) and Rohit Singh, ODI Research Officer (r.singh@odi.org.uk).

References and project information

References

Ellis, K. and Singh, R. (2010) 'Assessing the economic impact of competition'. ODI research report commissioned by DFID. London: ODI.

DFID (2008) 'Competition Assessment Framework: An operational guide for identifying barriers to competition in developing countries'. London: DFID (www.m4pnetwork.org/node/51).

Project information

This Project Briefing draws on research carried out in Bangladesh, Ghana, Kenya, Viet Nam and Zambia in 2008 and 2009. The methodology used for assessing competition in each market was in line with the approach set out in the Competition Assessment Framework published by the UK Department for International Development (DFID) in 2008. In addition to the general conclusions on the impact of competition on economic performance, the research has generated a set of findings and policy recommendations for each country, published in five separate country summary notes.

Overseas Development Institute

111 Westminster Bridge Road, London SE1 7JD

Tel +44 (0)20 7922 0300

Fax +44 (0)20 7922 0399

Email publications@odi.org.uk

Readers are encouraged to quote or reproduce material from ODI Project Briefings for their own publications, as long as they are not being sold commercially. As copyright holder, ODI requests due acknowledgement and a copy of the publication.

The views presented in this paper are those of the author(s) and do not necessarily represent the views of ODI or DFID.

© Overseas Development Institute 2010

ISSN 1756-7602

Tab 75

The Benefits of P3s

Why do P3s work?

P3s are a long-term performance-based approach for procuring public infrastructure where the private sector assumes a major share of the responsibility in terms of risk and financing for the delivery and the performance of the infrastructure, from design and structural planning, to long-term maintenance.

P3 projects involve greater consideration of whole life cycle:

P3s put into an integrated contract the entire life-cycle -- design, build and operate and maintain; this ensures that overall cost and risk is considered; for example, design takes into account of cost to build, maintain and operate and avoid white elephants.

P3 projects engage the expertise of the private sector:

The private sector has the experience and expertise to deliver large projects. They bring innovation and learnings from other projects. Many Canadian and international firms have developed significant expertise developing and executing P3s, which can be employed for the benefit of taxpayers.

P3 projects ensure private sector capital is at risk, bringing capital market discipline and incentives:

Most importantly, P3 projects require private sector capital to be at risk. The public sector pays only when the infrastructure is available and performs. This generally means that no payments are made until the infrastructure is built and a substantial portion is paid over the life of the asset, if it is properly maintained and performs. This “skin in the game” means that taxpayers are not on the financial hook for cost overruns, delays or any performance issues over the assets life. It also means that the profit motive is harnessed to ensure effective results. Finally, this requires the private sector to raise both equity and debt capital, meaning that there is substantial oversight by lenders and investors in both the upfront due diligence and project execution. This is a discipline that the public sector cannot match.

P3 projects allow the public sector to focus on its core business:

The public sector’s core focus should be on the defining the output it wants (i.e., *x* litres of clean water, *y* traffic capacity). Leave it to the private sector to provide the most effective solution to deliver on those outputs.

On-Time & On-Budget Delivery	• Payment triggered by completion • P3s have a proven track record
Accountability	• Performance standards • One contractor to deal with
Risk transfer	• Transfer of key risks to the private sector • Design, construction, lifecycle maintenance risks
Fiscal planning certainty	• Foreseeable payments over life of asset • Cost certainty for up to 30 years
Focus on Outcomes & Core Business	• Enables governments to focus on outcomes, instead of inputs. • Core competencies of public and private sectors
Investment in upfront planning	• Forces disciplined planning process
Integration	• Encourages private sector to take a long-term approach
Innovation	• Greater scope for creativity and innovation – design, construction, operations, and maintenance

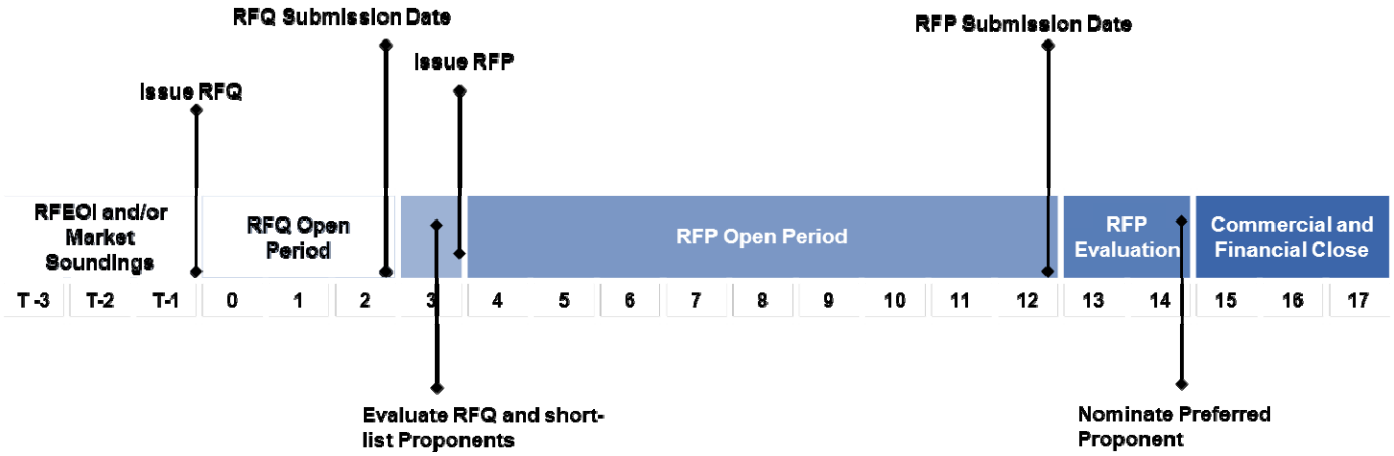
Canada – A Global Leader in P3s

Factors contributing to Canada's Emergence as a P3 Infrastructure Leader

Dedicated P3/Infrastructure Procurement Agencies	The creation of dedicated P3 agencies in a variety of Canadian jurisdictions has hastened the maturity of the Canadian P3 market. These agencies have aggregated project pipelines to stage and deliver consistent and sustainable deal flow and have imposed the application of accepted project methodologies, deal structures and documentation which reduce bidding costs and reinforce success, which in turn strengthen deal flow.
Sustained Pipeline of Projects	The Canadian market has learnt that in order to position itself above its global competitors for infrastructure providers, it needs to capture the private sector's attention through a sustained and consistent pipeline of projects. The existance of the provincial organizations has aggregated project pipelines to stage and deliver consistent and sustainable deal flow. As we have identified in our analysis below, 57 P3 projects have been in procurement since 2009 covering almost every sector.
Application to Greater Number of Asset Classes	The overwhelming acceptance of the P3 delivery model in Canada has led to its application beyond simple vertical infrastructure and into transport, information technology and communications, water, recreation and culture and other sectors.
Government Support & Potential Application of P3s by Other Public Sector Sponsors (Municipalities, First Nations)	Provincial governments and the federal government in Canada remain supportive of P3s as a means of replacing critical outdated infrastructure on-time and on-budget. The federal government's support for municipal and First Nation P3s also demonstrates the active support and efforts to expand the use of P3s into relatively new infrastructure spaces.
Highly Competitive Market	The Canadian private sector has been actively participating in P3 projects across the country. Competitive tension between bidders has remained high, with very few P3 projects failing due to lack of private sector interest. Competition in the Canadian P3 infrastructure space has also increased over the last 5 – 6 years due to the arrival of a significant number of large foreign multinational corporations bidding P3 opportunities. The procurement processes (RFQ, RFP) adopted by the dedicated agencies continue to ensure sufficient levels of high quality competition.
P3 Friendly Legislative and Policy Frameworks	Legislative and policy frameworks are an international best practice adopted by many of Canada's leading P3 jurisdictions (e.g. BC, Ontario, Quebec) and are the foundation for a robust P3 program and market because they ensure that all infrastructure investments are at least considered for a P3 delivery approach. In addition, these frameworks: • Ensure policy alignment across government departments; • Send positive signals to the market; • Provide transparency and clarity for stakeholders and the public; • Provide solid procurement principles; and • Create market confidence in tender and contracting law practices that are supportive of P3 projects.
Development and Application of Market Accepted Methodologies and Contracts	In Canada, P3 agencies have been responsible for crafting deal methodologies and structures accepted by the market, including: • Fair and rigorous procurement processes; • Well defined deal structures with market tested risk allocation; • Comprehensive value for money methodologies; • Tested and financeable payment mechanisms; and • Standard contractual documentation. Well established methodologies and deal structures have been important for two reasons: a) they have imposed discipline on public sector project sponsors, ensuring careful consideration of project suitability to a P3 delivery approach and a high degree of planning and development; and b) P3s can be expensive for both the public and private sectors. Standardized methodologies and accepted deal structures have helped to "template" transactions and reduce costs for both the public and private sectors. This has been accomplished through workshops, standardized contracts, and using financial, legal and technical advisors conversant with the P3 methodology.

Average Procurement Timelines

Procurement Stage	Typical Length of Time
RFQ	1.5 to 3 months open period
RFQ Evaluation	1 month
RFP	7 to 11 months open period
RFP Evaluation	1-2 months
Time between Nomination of Preferred Proponent and Financial Close	2 to 4 months



Distribution of P3 Projects in Procurement by Sector (2009-2011)

Sector	Number of Projects	Percentage of Total Projects
Hospitals & Healthcare	23	40%
Transportation	12	21%
Justice & Corrections	11	19%
Recreation & Culture	4	7%
Education	2	4%
Communication	1	2%
Defence	1	2%
Energy	1	2%
Real Estate	1	2%
Government Services	1	2%

Distribution of P3 Projects in Procurement by Jurisdiction and Procurement Method (2009-2011)

Procurement Method	AB	BC	MB	NB	NS	ON	PEI	QC
Alternative Service Delivery						1		
Build Finance						4		
Design Build Finance		1				5		
Design Build Finance Operate	2	1						
Design Build Finance Maintain	2	6	2	1		22		4
Design Build Finance Operate Maintain		1		1		2		
To be decided		1		1*	1*		1*	

Distribution of P3 Projects in Procurement by Procurement Method (2009-2011)

Procurement Method	Number of transactions	Type of Transaction
Alternative Service Delivery (ASD)*	**1**	**1 Government Services**
Build Finance (BF)*	**4**	**4 Hospitals & Healthcare**
Design Build Finance (DBF)	6	4 Recreation & Culture 2 Transportation
Design Build Finance Operate (DBFO)	3	3 Transportation
Design Build Finance Maintain (DBFM)	37	1 Defense 2 Education 18 Hospitals & Healthcare 11 Justice & Corrections 1 Real Estate 4 Transportation
Design Build Finance Operate Maintain (DBFOM)	4	3 Transportation 1 Hospitals & Healthcare
To be decided (TBD)/Other	2	1 Communication* 1 Energy

*Note: These models are not considered P3s by all Canadian jurisdictions, including PPP Canada.

PPP Canada

Achieving better value, timeliness and accountability to taxpayers through public-private partnerships.

Who We Are

PPP Canada was created as a Crown Corporation by the Government of Canada to improve the delivery of public infrastructure by achieving better value, timeliness and accountability to taxpayers, through public-private partnerships (P3s).

PPP Canada's operations focus on building P3 procurement knowledge and capacity amongst federal departments, and leveraging greater value for money from federal investments in provincial, territorial, municipal and First Nations infrastructure with the P3 Canada Fund.

Advancing Provincial, Territorial, Municipal and First Nation P3s: The P3 Canada Fund

The P3 Canada Fund is the first infrastructure program, anywhere in Canada, which directly targets P3 projects. The $1.2 billion Fund is a merit-based program with the objective of supporting P3 infrastructure projects that achieve value for Canadians, develop the Canadian P3 market and generate significant public benefits.

PPP Canada has to date announced over $109 million in funding commitments to seven P3 projects; examples include:

Chief Peguis Trail Extension

- Winnipeg, MB
- Federal funding: $25.00 Million
- Procurement Model: Design - Build - Finance - Maintain (30 - year concession term)
- P3 Canada Fund Infrastructure Category: Local Road Infrastructure

- This project will extend the Chief Peguis Trail an additional 3.7 kilometres to relieve the traffic pressure on residential streets. The Project also included the construction of noise walls and berms to reduce traffic noise; landscaping; and multi-use pathways to encourage walking and cycling. Construction of the project has been completed approximately one year in advanced of the scheduled completion date.

On July 12, 2010, a joint announcement was held with the Province of Manitoba and the City of Winnipeg, where Public Safety Minister Vic Toews announced that the Government of Canada would contribute up to $25 million to support the extension of the Chief Peguis Trail in Winnipeg to relieve traffic pressure on residential streets. The total capital value of the project is $108.5 million. The remainder of the project's construction costs will be financed by the Province of Manitoba, City of Winnipeg and DBF2 Limited Partnership (DBF2), the private consortium selected to design-build-finance and maintain the roadway and structures.

This P3 model is expected to have estimated value for money savings of approximately $31 million (17. 6%) over a traditional procurement.

Evan Thomas Water and Wastewater Treatment Plant

- Kananaskis County, AB
- Federal funding: $9.95 Million
- Procurement Model: Design-Build-Finance-Operate-Maintain
- P3 Canada Fund Infrastructure Category: Wastewater Infrastructure

- The proposed project will include upgrades that will address the treatment plant's current capacity constraints; bring the treatment plant back to environmental compliance; replace the aging infrastructure; and deliver public health benefits through the introduction of leadership standards for the area's potable water.

Once selected, the private sector partner will design, construct and provide partial financing for the Evan-Thomas Water and Wastewater Treatment Facility project. The partner will also be responsible for operations and maintenance of the new water treatment plant, the new wastewater treatment plant, and the water storage and distribution systems for 10 years after construction is completed.

Downtown Eastside Housing Renewal Project

- Vancouver, BC
- Federal funding: $29.10 Million
- Procurement Model: Design - Build - Finance - Maintain (30 - year concession)
- P3 Canada Fund Infrastructure Category: Brownfield Redevelopment Infrastructure

- The project will include the renovation and restoration of 13 provincially-owned Single Room Occupancy hotels into safe, clean social housing units, in Vancouver's Downtown Eastside.

This project will respond to the current housing restraints of the Downtown Eastside; reduce the number of people at risk of homelessness; improve living conditions for residents; restore the heritage features of these century old buildings; and deliver invaluable social benefits to its residents.

Once selected, the successful proponent will be required to design, build, finance, and maintain the project. The P3 contract transfers considerable risk which is anchored by the requirement for construction and long-term financing.

Advancing Federal P3s

In addition to our work under the Fund, PPP Canada has been given the mandate to support federal P3 procurements by providing expertise and advice through the mandatory P3 screen. The Federal Screen will assess the potential for large federal capital projects as P3s. On a go forward basis, infrastructure projects with a life span of 20 years or more and having capital costs of $100 million or more will be subject to the screen. If it is determined that there is P3 potential for the project, the procuring department will then be required to develop a procurement proposal that includes a P3 among the possibilities.

There is high potential for a reasonable flow of P3 projects at the federal level, as shown by the departments exploring P3s. Ultimately, the P3 procurement of services, and other non-traditional P3 arrangements, may present the largest opportunity in the federal market.

Prospective clients for PPP Canada services among the federal market segments will largely come from Departments and agencies that are only periodic or intermittent procurers of major capital assets – with the latter group requiring greater efforts and support from PPP Canada.

In addition to supporting procuring departments, PPP Canada's federal business line strategy focuses on creating strategic partnerships with key federal policy leaders to create clarity and consistency in decision-making and P3 procurement practices.

Tab 76

SUBSCRIPTION Manage your print subscription. Manage your print subscription.

Sections Search SASKATOON STARPHOENIX Subscribe Sign In

News Sask Election Business Opinion Sports Arts Life Driving Healthing The GrowthOp Podcasts ePaper

Saskatchewan / Politics / Local News

Two months after opening, Saskatchewan Hospital North Battleford needs entire roof replacement

Access Prairies Partnership, the consortium that constructed the hospital under a P3 model, "recommends full replacement of the entire roof as the best way to address the problem."

Alex MacPherson • Saskatoon StarPhoenix
May 22, 2019 • Last Updated 1 year ago • 3 minute read



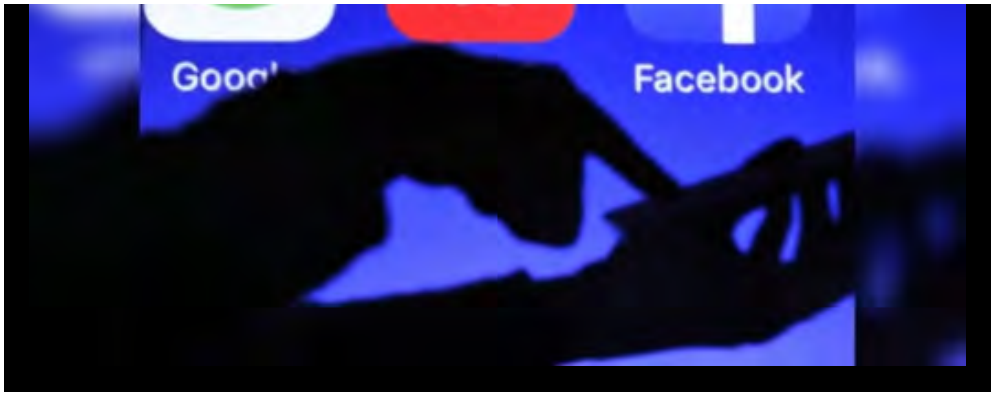
The brand-new Saskatchewan Hospital North Battleford needs its entire roof replaced. PHOTO BY LIAM RICARDS /Saskatoon

TRENDING

The Saskatchewan government is defending its decision to build the $407-million Saskatchewan Hospital North Battleford using a public-private partnership after the new facility's roof failed two months after it opened, necessitating a complete replacement.

It is not clear how long the fix will take, how much it will cost, or how much it will disrupt the facility's 140-odd patients, but government officials say the failure — which allowed water to leak into the building — was "unforeseeable" and taxpayers won't be on the hook to repair it.

Unlock The Saskatoon StarPhoenix. Subscribe now to get unlimited online access.
You have 9 free articles left.



“If this was a traditional build, from the government standpoint, this would be a huge problem, because you’d likely be into some kind of legal argument over who’s responsible for what cost,” Health Minister Jim Reiter told reporters Wednesday afternoon in Saskatoon.

“Right now, it’s very clear: The taxpayers aren’t going to be on the hook for any of this,” Reiter said, referring to the P3 model wrapping every cost associated with a major capital project such as the hospital into a single build-and-maintain contract.

STORY CONTINUES BELOW

The head of the Crown corporation responsible for major infrastructure projects said he believes the “best team” won the government’s P3 procurement process, and that experts hired to oversee and assess plans could not have identified the potential failure.

“It was a new product and they’re realizing now that they took on some significant risk in using that product,” SaskBuilds CEO Kyle Toffan said of the “innovative” modular roofing panels selected by the consortium that built the facility, Access Prairies Partnership.

SaskBuilds project director Jill Zimmer said staff noticed leaks in the building during spring melt, which were subsequently traced to shrinkage in the insulation beneath the roof itself. Zimmer didn’t say how much water entered the building but said it was “not significant.”

According to the province, the first leak was detected on March 13 and the contractor, after conducting inspections, recommended the roof be replaced on May 14.

A spokeswoman for Access Prairies Partnership did not respond to a request for comment.

Construction on the hospital began in late 2015 and was originally expected to be done in June 2018. Last spring, however, the government said the project would be delayed by two to three months due to “a subcontractor unable to deliver according to the overall schedule.”

The province said at the time that taxpayers will not be liable for any cost overruns associated with construction delays, and that the contractor would be fined about $1.25 million for each month the project was delayed. Toffan said Wednesday more fines could be coming.

STORY CONTINUES BELOW

Unlock The Saskatoon StarPhoenix. Subscribe now to get unlimited online access.
You have 9 free articles left.



Government officials have also said repeatedly that P3 projects are delivered on time and on budget. Reiter said he believes the project remains on budget because "the contract calls for keeping the government whole," including costs associated with moving patients within the facility.

"With these latest delays it's concerning (Reiter) can not provide certainty around timelines for repairs or what the impact on patient care will be," Saskatchewan NDP Health Critic Vicki Mowat said in a statement.

"I think using the model we did clearly paid off," Reiter said.

The SHNB was designed to replace North Battleford's century-old psychiatric hospital and two correctional facilities. It opened March 8. As of this week, around 130 of its psychiatric care beds were occupied, along with 10 of the 96 beds in the secure correctional wing.

amacpherson@postmedia.com
twitter.com/macphersona

The StarPhoenix Headline News

Sign up to receive daily headline news from the Saskatoon StarPhoenix, a division of Postmedia Network Inc.

Email Address

youremail@email.com

Unlock The Saskatoon StarPhoenix. Subscribe now to get unlimited online access.
You have 9 free articles left.